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# Financing Non-Residential Photovoltaic Projects:
## Options and Implications

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# Executive Summary

## 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%. 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 properties[i] – 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. This relative growth trend is expected to have continued through 2008.

The non-residential sector's commanding lead in terms of installed capacity in recent years primarily reflects two important differences between the non-residential and residential markets: (1) the greater federal "Tax Benefits" – including the 30% investment tax credit (ITC) and accelerated tax depreciation – provided to commercial (relative to residential) PV systems, at least historically (this relative tax advantage has largely disappeared starting in 2009) and (2) larger non-residential project size. These two attributes have attracted to the market a number of institutional investors (referred to in this report as "Tax Investors") seeking to invest in PV projects primarily to capture their Tax Benefits. The presence of these Tax Investors, in turn, has fostered a variety of innovative approaches to financing non-residential PV systems.

This financial innovation – which is the topic of this report – has helped to overcome some of the largest barriers to the adoption of non-residential PV, and is therefore partly responsible (along with the policy changes that have driven this innovation) for the rapid growth in the market seen in recent years.[ii] Specifically, due to financial innovation, non-residential entities interested in PV no longer face prohibitively high up-front costs, no longer need to be able to absorb Tax Benefits in order to make the economics pencil out, no longer need to be able to operate and maintain the system, and no longer need to accept the risk that the system does not perform as expected.

## Policy Drives Financing Evolution

The financing structures currently being used to support non-residential PV deployment have, in part, emerged and evolved as a way to extract the most value from a patchwork of federal and state policy initiatives. In combination, these state and federal incentives provide a significant

[i] 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. Though not the focus of this report, some of these central-station systems are included in Appendix D of the full report, which describes how very large PV systems have been financed in the United States.

[ii] Indeed, on average, the installed costs of PV projects have not fallen over the last several years; nor has their efficiency improved markedly. Moreover, the level of state financial incentives (per system) has largely declined over this period. On the other hand, electricity prices have generally risen (improving the comparative economics of PV), federal tax incentives have increased, and state-level solar incentives and mandates have become more widespread.

amount of value, yet this value is delivered through a variety of sources and mechanisms. For example, a substantial fraction of a commercial system's installed costs can be recovered through federal Tax Benefits, state tax incentives sometimes increase this percentage considerably (by 30%-50% in a few states), and state- or utility-level cash incentives (either capacity- or performance-based incentives – CBIs or PBIs) and/or renewable energy certificates (RECs or SRECs) may provide additional value. Finally, net metering and/or attractive rate design can help to maximize the value of the solar power generated. Non-taxable entities may not be able to directly benefit from tax incentives, but may instead reap differentially higher cash incentives at the state level, and also may have access to attractive tax-exempt municipal debt or even "zero-interest" Clean Renewable Energy Bond (CREB) financing at the federal level.

In recent years, a number of different financing structures have arisen in response to this patchwork of incentives and the varying ability of project sponsors to make efficient use of them. Though each structure is, at its core, intended to maximize incentive capture while minimizing risk, certain structures are more appropriate than others in certain situations. Furthermore, certain structures are only applicable to taxable site hosts (e.g., commercial and industrial entities), while others are only applicable to tax-exempt site hosts (e.g., governmental entities and non-profits).

*Taxable Site Hosts*

Among taxable site hosts, viable financing options that are examined in this report include the following:

- **Balance Sheet:** The site host finances the project on its balance sheet (as described in Section 3.1 of the full report).
- **Operating Lease:** The site host finances the project through an operating lease (as described in Section 3.2.2 of the full report). A capital lease is also possible, but is less widely used.
- **PPA (Partnership):** The site host enters into a PPA, which in turn is financed by a special allocation partnership structure (as described in Section 3.3 and Appendix C).

The description of these three financing options traces the evolution of non-residential PV finance in the United States over the past few years. Site hosts using balance sheet finance – once the only viable option for non-residential PV – may struggle with many of the adoption barriers that analysts have described for years: high up-front costs, a steep learning curve for a non-core business function, technology and performance risk, and a potential inability to make efficient use of the project's Tax Benefits. Operating leases – a financial tool commonly used by the commercial sector for many years, but that has only made inroads with the solar market since EPAct 2005 increased the ITC from 10% to 30% – address high up-front costs and efficient use of Tax Benefits, but leave O&M responsibilities and performance risk with the site host. The PPA model theoretically addresses all of these issues simultaneously and, as a result, the market is purported to be moving away from balance sheet and lease finance and towards PPAs.[iii]

[iii] Somewhat paradoxically, while PV site hosts may be gravitating towards PPAs and away from lease financing, there are some indications that PV developers seeking to finance the projects that back their PPAs are moving *towards* lease financing (and away from partnership structures) as a means of doing so. Appendix C of the full report provides a discussion of how developers, rather than site hosts, finance their projects.

Nevertheless, given the wide diversity of potential site hosts interested in PV, a "one-size-fits-all" approach to PV finance does not make sense. Different site hosts will face a variety of different financial, operational, and strategic considerations that may favor one approach over another. For example, even though a PPA may ultimately be less risky (and perhaps similarly priced), certain site hosts may value – and also have the wherewithal to execute – balance sheet finance and ownership for strategic or other non-financial reasons.

Acknowledging that few decisions can be boiled down to this level of simplicity, Figure ES-1 provides a basic decision tree that might help guide taxable non-residential site hosts to a suitable financing structure. 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 insufficient 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. If the site host is not sufficiently creditworthy to support a lease or a PPA, and also has limited tax appetite (or perhaps has adequate tax appetite but is not willing to accept performance risk), then it may be difficult to structure an economically viable project.

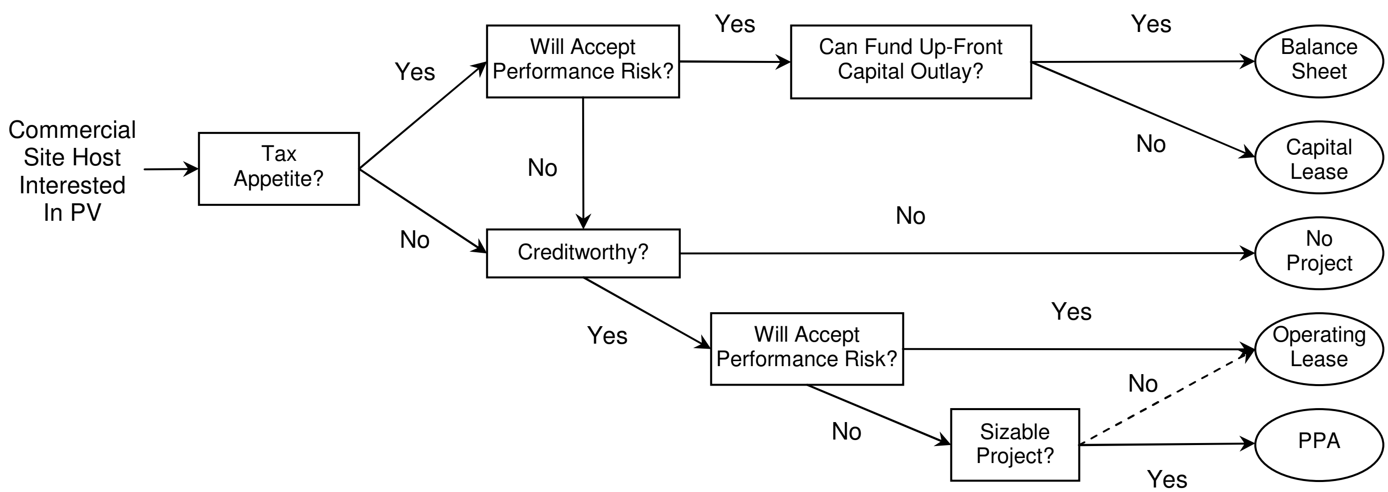



**Figure ES-1. Choosing a Finance Structure: Taxable Site Hosts**

*Tax-Exempt Site Hosts*

Thanks in part to efforts by the federal government to level the playing field for different types of entities, and in part to the rise of third-party ownership, tax-exempt non-residential site hosts have several more financing choices than their taxable counterparts. Specifically, among tax-exempt site hosts, financing options include the following:

- **Balance Sheet:** A tax-exempt site host without bonding authority (e.g., a non-governmental, non-profit entity) finances the project on its balance sheet (as described in Section 4.1 of the full report).
- **Muni Bonds:** The site host finances the project using low-cost, tax-exempt municipal debt (as described in Section 4.2.1 of the full report).
- **CREBs:** The site host finances the project using Clean Renewable Energy Bonds (as described in Section 4.2.2 of the full report).
- **Tax-Exempt Lease:** The site host finances the project using a tax-exempt lease, in which the lease payments are exempt from taxation (as described in Section 4.3 of the full report).
- **Service Contract (Partnership):** The site host enters into a service contract (i.e., a PPA), which in turn is financed by a special allocation partnership structure (as described in Section 4.4 and Appendix C of the full report).
- **Pre-Paid Service Contract:** The site host enters into a pre-paid service contract, through which it pre-pays a lump sum covering a portion of the PV power cost, and then makes ongoing payments to cover the remainder of the cost throughout the PPA term. This structure makes use of both tax-exempt debt and the project's Tax Benefits (as described in Section 4.5 of the full report).

The careful reader will note the use of the term "service contract" rather than "PPA" in the preceding bullets, with respect to tax-exempt site hosts. Since tax-exempt entities cannot enter into a normal operating lease transaction without jeopardizing the use (by either lessor or lessee) of the project's Tax Benefits, it is vital that a solar PPA with a tax-exempt site host be properly structured as a "service contract" under Section 7701(e) of the Internal Revenue Code, which distinguishes a service contract from a lease. Most PPA's with taxable site hosts already meet the four requirements of a service contract, however, so the use of the term "service contract" (rather than "PPA") in the context of a tax-exempt site host is mostly a terminology issue.

**Generic Base-Case Modeling Results**

To analyze the impact of financing structure on the price of power from a non-residential PV system, Berkeley Lab has developed a number of simple pro forma financial models. The general approach common to these models is to start with a series of user-defined assumptions about the PV system, as well as the financial constraints imposed by the various investors in that system (e.g., return targets, debt coverage ratios, etc.), and then to back into a required amount of revenue that will satisfy all constraints. This approach is essentially the same as a PV project developer might take when conducting a first-cut analysis to determine whether a project is (economically) worth pursuing. The models used for this report, however, are by no means sophisticated enough to be used in actual project financings. Nevertheless, they do provide a first-order approximation of the amount of revenue required by a non-residential PV system under a variety of financing or ownership structures, and are therefore sufficient for our intended purpose of comparative analysis.

In all cases, the financial analysis ignores the impact of power bill savings on site host economics, under the assumption that power bill savings will not differ under the various financing structures examined. 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 rebates 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 the modeled revenue requirement, then the project will likely be economical (presuming the model's assumptions reflect reality over time). These simplifying assumptions greatly reduce the complexity of the modeling, since power bill savings in particular 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 report.

Table ES-1 presents base-case assumptions and modeling results for taxable site hosts, while Table ES-2 presents the corresponding information for tax-exempt site hosts. Tables ES-1 and ES-2 assume that no state-level incentives are present, as a way to better isolate the impact of financing structure on project economics, independent of the vagaries of state policy. Although PV systems are widely expected to operate for longer than 20 years (and some PV panels are sold with a 25-year warranty), each financing structure is uniformly evaluated over a 20-year term in order to maintain comparable results.

The first two rows in the "RESULTS" section of Tables ES-1 and ES-2 show the first-year and levelized 20-year (nominal) $/kWh revenue that is required to satisfy all modeling constraints. As explained above, 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). Since these $/kWh numbers potentially include REC revenue, and assume no state-level incentives, they should *not* be equated with representative solar PPA prices, which will be lower to the extent that state incentives are available and/or the PPA provider strips off the RECs and sells them separately.

For taxable site hosts, Table ES-1 shows that even though balance sheet finance and a site host operating lease generate the same 10% project-level return, the operating lease requires slightly less revenue over the full 20-year analysis period due to its assumed 20% residual value. Meanwhile, a solar PPA (in this case financed by a special allocation partnership "flip" structure between the PPA provider and a tax investor, though a lease structure would yield similar results) appears to be more economical than either balance sheet finance or a site host operating lease. This result is due almost exclusively to the lower assumed IRR hurdle rate for the PPA – i.e., 7.7% at the project level, versus 10% for either balance sheet finance or an operating lease. Commercial site hosts with a sufficient tax base and a return requirement of 7.7% or less will find balance sheet finance to be more attractive (in terms of amount of revenue required); conversely, third-party ownership will look increasingly attractive as a taxable site host's return requirement increases above 7.7%.

**Table ES-1. Base-Case Results for Taxable Site Hosts (No State Incentive)**

| | Balance Sheet | Operating Lease | PPA (Partnership) |
|---|---|---|---|
| **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) | $30 | | |
| Annual O&M Escalation (%/year) | 3% | | |
| Period of Analysis (years) | 20 | | |
| State Incentive Type | NONE | | |
| State Incentive Level | NONE | | |
| PV Price Escalator | 4% | | 4% |
| Flip Point Target (year) | | | 18 |
| Lease Term (years) | | 20 | |
| Residual Value (% of installed cost) | | 20% | |
| Debt Leverage (% of installed cost) | 0% | | |
| **RESULTS** | | | |
| First-Year Revenue ($/kWh) | 0.336 | 0.397 | 0.270 |
| Levelized 20-Year Revenue ($/kWh) | 0.441 | 0.413 | 0.354 |
| Tax Investor 20-Year After-Tax IRR | | 10.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | 20.0% |
| Project 20-Year After-Tax IRR | 10.0% | 10.0% | 7.7% |

Turning to the generic results for tax-exempt site hosts, the first thing to note in Table ES-2 is that the results for the PPA/service contract model do not differ from those presented above in Table ES-1. That is, other than some minor changes to the documentation in order to ensure that a PPA with a tax-exempt site host is clearly viewed as being a "service contract" rather than a lease, the underlying economics of the financing model are the same as they are for taxable site hosts.

Whereas the PPA was the most economical finance option for taxable site hosts, there are – at least in theory, based on the assumptions used in this analysis – two other potentially more-economical options for tax-exempt site hosts.

Specifically, the Pre-Paid Service Contract, which combines the advantages of both tax-exempt debt financing and full use of the project's Tax Benefits, appears to be the lowest-cost financing option available to tax-exempt site hosts. Despite its potential appeal, this structure is not in common use, in part due to its relative complexity and associated legal and other transaction costs (perhaps not adequately captured here), which may be prohibitive for non-residential PV projects, most of which cost less than $10 million to build. Indeed, the only working examples of this structure in use for renewable energy projects involve large wind power projects with installed costs in excess of $350 million.

**Table ES-2. Base-Case Results for Tax-Exempt Site Hosts (No State Incentive)**

| | Balance Sheet | Muni Bonds | CREBs | Tax-Exempt Lease | Service Contract (Partnership) | Pre-Paid Service Contract |
|---|---|---|---|---|---|---|
| **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) | $30 | | | | | |
| O&M Escalation (%/year) | 3% | | | | | |
| Period of Analysis (years) | 20 | | | | | |
| State Incentive Type | NONE | | | | | |
| State Incentive Level ($/kWh) | NONE | | | | | |
| PV Price Escalator | 4% | | | | 4% | |
| Flip Point Target (year) | | | | | 18 | |
| Lease Term (years) | | | | 20 | | |
| Residual Value (% of installed cost) | | | | 0% | | |
| Debt Term (years) | | 20 | 15 | | | 20 |
| Debt Interest Rate | | 5% | 1% | | | 5% |
| Debt Service Coverage Ratio | | 1.0 | 1.0 | | | 1.0 |
| Debt Leverage (% of installed cost) | | 100% | | | | 30% |
| **RESULTS** | | | | | | |
| First-Year Revenue ($/kWh) | 0.432 | | | 0.442 | 0.270 | 0.240 |
| Levelized 20-Year Revenue ($/kWh) | 0.568 | 0.397 | 0.328 | 0.462 | 0.354 | 0.284 |
| Tax Investor 20-Year After-Tax IRR | | | | 7.0% | 7.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | | | 20.0% | 18.3% |
| Project 20-Year After-Tax IRR | 10% | | | 7.0% | 7.7% | 7.5% |

Financing the entire project using CREBs (with an assumed effective 1% interest rate) appears to be the next-most-attractive option. Like the Pre-Paid Service Contract, however, CREB financing requires considerable up-front legwork, in this case to secure an allocation and then issue the bonds. These early transaction costs, which are approximated here by a 1% (i.e., rather than 0%) interest rate, may not be adequately accounted for in this analysis.

The loss of Tax Benefits in the Balance Sheet model adds more than $0.12/kWh (i.e., $0.568/kWh vs. $0.441/kWh) to the levelized revenue requirement of a tax-exempt site host, making this the most-expensive option (though perhaps the only direct ownership option available to non-governmental, non-profit site hosts). The advantage of low-cost municipal debt (with an assumed 5% interest rate) more than makes up for this deficit in the Muni Bonds model (i.e., $0.397/kWh vs. $0.441/kWh), suggesting that states that provide differentially higher incentives to tax-exempt project owners may be doing so unnecessarily. Without differentially higher state-level incentives, however, the Muni Bonds option is still not quite competitive with the Service Contract (PPA) at $0.354/kWh.

Finally, a Tax-Exempt Lease avoids some of the up-front transaction costs associated with Muni Bonds and CREBs (by being a non-budgetary item, by not requiring voter pre-approval, etc.), yet is less-economical than Muni Bonds due to the higher assumed return requirement of the Tax Investor/lessor. This higher return is necessary to account for the fact that a tax-exempt lease is less-secure than a municipal bond.

## State-Specific Base-Case Modeling Results

Although comparing financing structures independent of the influence of state-level incentives is informative, it is also unrealistic. Very few non-residential PV systems have been installed without the aid of state-level incentives. Section 5.3 and 5.4 of the main report, therefore, incorporate state-specific incentives and assumptions into the analysis in order to provide a more-realistic assessment of actual (though subsidized) PV costs in some of the largest solar markets in the U.S. Specifically, Section 5.3 models California-based projects, while Section 5.4 briefly looks at projects financed and built in Colorado and New Jersey – both markets relying heavily on long-term REC contracts as a financing tool.

In California, the inclusion of a 5-year PBI of $0.22/kWh (i.e., under Step 5 of the California Solar Initiative incentive schedule) reduces the amount of other revenue required by almost $0.09/kWh (on a 20-year levelized basis) for all three models shown earlier in Table ES-1 (i.e., for taxable site hosts). The relative ranking of the different models, however, does not change.

California's differentially higher PBI of $0.32/kWh (vs. $0.22/kWh) provided to tax-exempt system owners, however, does have an impact on the relative attractiveness of the financing structures available to tax-exempt site hosts. Specifically, the higher PBI payments make CREBs more economical than the Pre-Paid Service Contract, and Muni Bonds more economical than a normal Service Contract (i.e., PPA). The Tax-Exempt Lease is among the least-economical options, for two main reasons. First, as a capital lease, where the lessee is considered to be the owner for tax purposes, this structure does not take advantage of the project's Tax Benefits (i.e., neither the lessor nor lessee claims them). Second, presuming that the lessor is a taxable entity, a project financed by a tax-exempt lease will not qualify for the higher tax-exempt PBI ($0.32/kWh) in California, and instead will receive the lower taxable PBI ($0.22/kWh).

Finally, New Jersey and Colorado are two growing markets that rely significantly on solar REC revenue rather than (or in addition to) CBIs. In Colorado, non-residential systems sized between 10 kW and 100 kW receive not only a $2/W CBI, but also a 20-year SREC contract priced at $0.115/kWh. Non-residential PV projects in New Jersey, meanwhile, are eligible to compete for 15-year solar REC contracts with the obligated utilities, at prices upwards of $0.30/kWh. Using the PPA (Partnership) model in each state yields levelized revenue requirements of just $0.084/kWh in Colorado and $0.09/kWh in New Jersey. Note that these are "post-REC" revenue requirements that must be met solely with power bill savings, and are therefore not directly comparable to the other results presented earlier.

## Scenario and Sensitivity Analysis

Several alternative scenarios to the California-specific base-case results, involving project-level debt as well as cash incentives structured as CBIs rather than PBIs, reveal that it is difficult to highly leverage PV projects, and in particular those receiving CBIs rather than PBIs. Specifically, CBIs reduce up-front costs (which mitigates the need for leverage), but provide no ongoing support for debt service coverage. As a result, CBI projects are generally only able to achieve leverage of 30%-33% of total installed costs, depending on the model. PBI projects did slightly better, at 43%-46% leverage, as the additional 5-year income stream helps to support additional debt. In general, though, the sizable Tax Benefits provided to PV projects mean that relatively little cash income is required to generate target returns, which in turn limits the amount of debt that these projects can support.

California sensitivity analysis reveals that, all else equal, for each $/W change in installed costs, required revenue changes by between 4 and 9 cents/kWh, depending on the model. Meanwhile, as PBI payments decline to the next step in the California Solar Initiative (i.e., from Step 5 to Step 6), required revenue increases by about 3 cents/kWh on a 20-year levelized basis. Hence, all else equal, as PBIs decline to the next step, installed costs will have to decline by at least $0.5/kW_{DC}$ in order to maintain the base-case status quo.

All else is not equal, however. As of late 2008, the credit crisis had reportedly pushed Tax Investor return requirements roughly 200 basis points higher than where they had been just a few months earlier. Moving from a Tax Investor target return of 7% to 9% pushes levelized revenue requirements for the third-party ownership models up by roughly 7 cents/kWh, with the exception of the Pre-Paid Service Contract, which in general is not as sensitive as other structures to changes in individual variables (because it represents a blend of structures). Direct ownership models not involving third-party Tax Investors (e.g., Balance Sheet finance) are presumably not as impacted by the credit crisis, and therefore may look more-attractive in the near term.

Another way to think about the recent increase in tax equity yields is to translate them into installed cost terms. In other words, by how much would installed costs need to fall in order to exactly offset the recent increase in tax equity yields? According to the PPA (Partnership) model with base-case California assumptions, installed costs would need to drop to nearly $5.00/W_{DC}$ (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%. Taking this analysis one step further, if the 20-year after-tax IRR hurdle rate remains at 9% over time, then installed costs must drop further to $4.56/W, $4.16/W, and $3.89/W as PBI levels decline in the future to $0.15/kWh, $0.09/kWh, and $0.05/kWh (Steps 6-8), respectively, in order to maintain the base-case revenue requirements (first-year and levelized) shown earlier in Table ES-3.

**Conclusions**

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 performance-based incentives at the state-level, third-party ownership has transformed the market for non-residential PV. With installed costs largely stagnant for the last several years and with state-level incentives declining over much of this period, third-party ownership – in concert with the more-attractive federal ITC starting in 2006 – has been a primary driver of the strong growth of PV in the non-residential sector. This is particularly true among tax-exempt non-residential entities, which potentially stand to gain the most from third-party ownership.

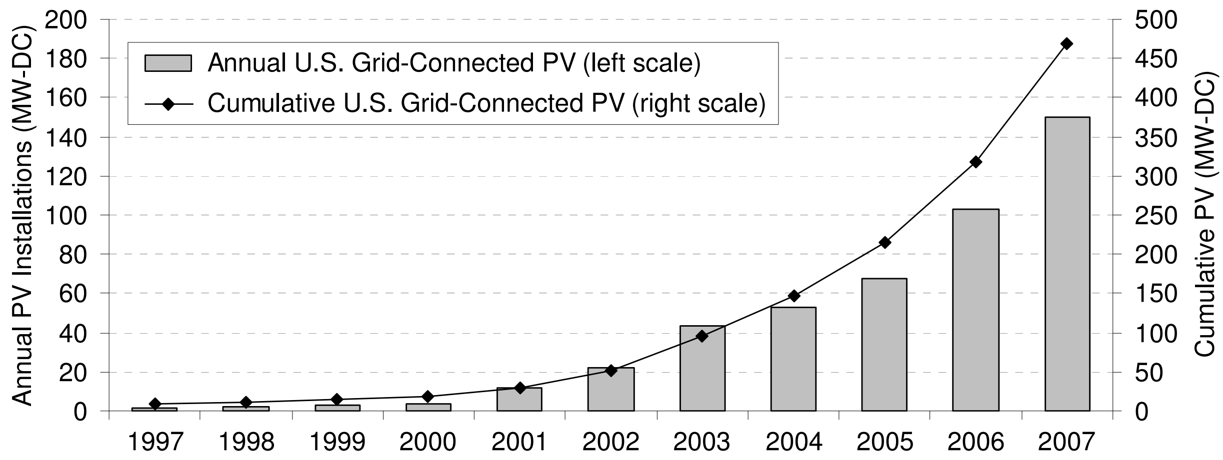
Looking ahead, ongoing financial innovation is likely to be more evolutionary than revolutionary in nature. The recent eight-year extension of the 30% federal ITC provides a stable foundation upon which to structure projects and invest in supply chain capacity. Declining state-level incentives, however, may make third-party ownership (and solar in general) a harder sell, absent reductions in installed project costs. Moreover, the fallout from the current financial crisis will exacerbate the affordability challenge, as Tax Investors require higher returns in exchange for use of their tax base.

Against this backdrop, evolutionary tweaks to financial structures and product offerings are occurring. For example, in the face of a harder sell for PV alone, some PPA providers are now bundling short-payback energy efficiency improvements along with PV, resulting in a more-attractive overall package. Other PPA providers are asking the site host to share in O&M costs. Though still not common for PV, debt financing at the project or portfolio level is looking more attractive (notwithstanding its limited availability during the current financial crisis) as a way to boost investor returns in this challenging environment. And a few developers are now trying to adapt third-party ownership models to the residential sector (although a portion of their competitive advantage recently dissolved when the $2000 cap on the residential ITC was removed).

More substantial twists on existing models may also emerge. For example, the pre-paid service contract capitalizes on the advantages of both tax-exempt and taxable ownership, and though limited in use for PV to date, may gain traction in the future among tax-exempt site hosts working on larger projects. Models that can better accommodate Cash Investors (such as private equity funds) may also become more prevalent as the financial crisis takes its toll on the traditional Tax Investor market (comprised mainly of banks and insurance companies, many of which are currently in a state of distress). Utilities are also likely to become more directly involved in PV ownership going forward, now that they are able to claim the ITC; utility ownership should also help to cement the trend towards larger, "utility-scale" PV projects.

# 1. Introduction

Installations of grid-connected photovoltaic (PV) systems in the United States have increased dramatically in recent years, growing by one measure from less than 20 MW in 2000 to nearly 500 MW at the end of 2007, a compound average annual growth rate of 59% (Figure 1). This strong growth has been driven by a variety of factors, including increasing environmental and energy security concerns, heightened energy prices and price volatility, the proliferation of state and federal regulations and incentives in support of solar power, and – the topic of this report – financing innovations that have made solar power more affordable.




*Source: Interstate Renewable Energy Council (IREC)*

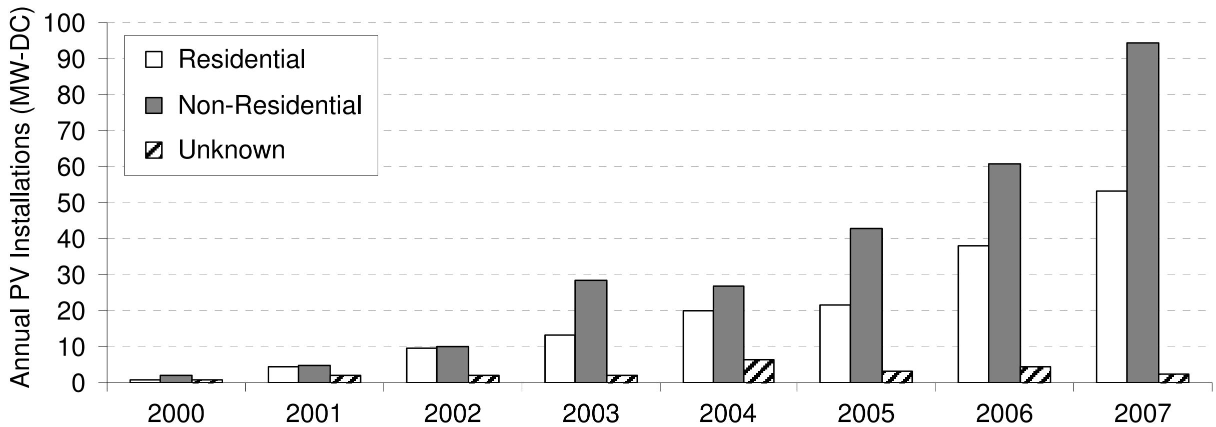
**Figure 1. Annual and Cumulative Grid-Connected PV Capacity in the U.S.**

Of particular note is the increasing contribution of "non-residential" 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 properties[1] – to the overall growth trend. Although there is some uncertainty in the numbers, non-residential PV capacity has grown from approximately half of aggregate annual capacity installations in 2000-2002 to nearly two-thirds in 2007 (Figure 2). This growth trend is expected to have continued into 2008.

The non-residential sector's commanding lead in terms of installed capacity primarily reflects two important differences between the non-residential and residential markets: (1) the disparate federal tax treatment (at least historically) of commercial and residential systems, and (2) project size.

Although commercial solar (along with geothermal) projects have long been eligible for a federal investment tax credit (ITC) equal to 10% of qualifying costs, the Energy Policy Act of 2005 (EPAct 2005) increased this credit from 10% to 30% (for solar only – geothermal remains at

[1] 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. Though not the focus of this report, one of the largest central-station PV systems – the 8.22 MW Alamosa project in Colorado – is included in Appendix D, which describes how very large PV systems have been financed in the United States.




*Source: Interstate Renewable Energy Council (IREC)*

**Figure 2. Annual Grid-Connected PV Capacity in the U.S. By Host Type**[2]

10%) through 2007. Subsequent legislation extended the 30% ITC through 2008, and in October 2008, the 30% credit was extended for an additional eight years, through the end of 2016. In addition to the 30% ITC, commercial solar property can, with some limitation, be depreciated for tax purposes using a 5-year schedule of deductions under the Modified Accelerated Cost Recovery System ("MACRS"). This 5-year accelerated depreciation schedule recovers another 26% of system costs on a present value basis (only 12% of which is attributable to the *acceleration* of the depreciation schedule; the remaining 14% would be realized even if commercial PV were instead depreciated using a less-advantageous 20-year straight-line schedule). Taken together, then, the ITC and accelerated depreciation (which, in aggregate, are referred to in this report as a project's "Tax Benefits") provide an incentive equal to about 56% of the installed cost of a commercial PV system.[3]

Historically, the numbers have been much lower for residential systems. Prior to 2006, there was no federal tax credit at all for residential solar. EPAct 2005 implemented a new residential solar investment tax credit of 30% of qualifying costs, but unlike the commercial (Section 48) ITC, the residential (Section 25D) credit has been capped at $2,000 per system (this cap will be removed for systems installed from 2009 through 2016). Given the high costs of residential PV (e.g., a 2 kW system might cost as much as or more than $18,000), this dollar cap has been binding for all but the smallest household systems (Bolinger and Wiser, 2007). As such, even though both are nominally 30% credits, the residential solar ITC has typically been worth less on a percentage basis than the commercial ITC (e.g., for the 2 kW system mentioned above, the capped $2,000 residential credit is worth only 11% of the $18,000 system cost). In addition, residential PV systems cannot be depreciated for tax purposes, which has further limited their tax appeal.[4]

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[2] Figure 2 does not limit non-residential systems to behind-the-meter applications, as defined earlier.

[3] This combined 56% Tax Benefit, however, is *reduced* by the income tax that a self-financed commercial PV system must pay on utility bill savings (because those savings offset an operating expense that would otherwise have reduced taxable income) or that a third-party-owned system must pay on net income from power sales. On a present value basis, these income tax payments come to somewhere around 30% of installed costs (depending on the price of power offset or sold), leaving the *net* tax benefits available to commercial PV systems at slightly less than 30% of installed costs.

[4] On the other hand, unlike commercial PV systems, residential systems are not taxed on utility bill savings, which means that starting in 2009 (once the $2,000 cap on the residential ITC is removed), residential PV systems will

In addition to having enjoyed greater Tax Benefits historically, commercial PV projects are also typically larger – often by an order of magnitude – than residential systems, which has several implications. First, larger systems can capture economies of scale, which lead to lower installed costs and therefore more-competitive systems (independent of the incremental Tax Benefits discussed above). Commercial systems may also be large enough – either on their own or as part of a portfolio of similar projects – to attract institutional investors (referred to in this report as "Tax Investors") seeking to invest in PV projects primarily to capture their Tax Benefits. Larger projects will be better able to absorb the transaction costs associated with such third-party financings and spread them over a greater number of kWh, and may also be in a better position to participate in regulatory programs such as solar set-asides within state renewables portfolio standards (RPS).

These two differences – greater Tax Benefits (historically) and larger project size – have, in turn, fostered a variety of innovative approaches to financing non-residential PV systems. For example, whereas just a few years ago a non-residential entity interested in PV had little choice but to follow a standard "finance, build, own, and operate" development model, enhanced Tax Benefits have recently made it profitable for leasing companies to enter the market, allowing non-residential entities to lease rather than own PV systems. Similarly, PV project developers backed by Tax Investors have developed the innovative "solar services" (also known as a power purchase agreement or "PPA") model, whereby a non-residential entity does not own or operate the system, but rather simply hosts it and purchases its power output through a long-term PPA.[5] These new third-party finance models are proving to be particularly useful to the tax-exempt side of the non-residential sector, such as governmental entities that otherwise would not be able to take direct advantage of a project's Tax Benefits.

This financial innovation – the topic of this report – has single-handedly overcome some of the largest barriers to the adoption of PV, and as such is largely responsible (along with the enhanced Tax Benefits that have driven this innovation) for the rapid growth in the market seen in recent years (Figure 1).[6] Specifically, due to financial innovation, non-residential entities interested in PV no longer face prohibitively high up-front costs, no longer need to be able to absorb Tax Benefits in order to make the economics pencil out, no longer need to be able to operate and maintain the system, and no longer need to accept the risk that the system does not perform as expected.

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receive net tax benefits equal to 30% of the project's tax credit basis, which is roughly the same amount that commercial systems currently receive, considering the combination of ITC, 5-year accelerated depreciation, and effective taxation of utility bill savings.

[5] Both of these models – leasing and PPAs – have more-recently made inroads into the residential solar market as well, in an attempt to capitalize on the tax disparity between the commercial and residential sectors. Whether the recent lifting of the $2000 cap on the residential ITC hurts residential PPAs and leases remains to be seen.

[6] Indeed, on average, the installed costs of PV projects have not fallen over the last several years; nor has their efficiency improved markedly. Moreover, the level of state financial incentives (per system) has largely declined over this period. On the other hand, electricity prices have generally risen (improving the comparative economics of PV), federal tax incentives have increased, and state-level solar incentives and mandates have become more widespread.

With a goal of informing state and federal policymakers, as well as the broader market, about the PV system financing options available to the non-residential sector and how those options impact the cost of solar power, this report proceeds as follows. Section 2 provides an overview of policy support for non-residential PV at both the federal and state levels. Section 3 traces the recent evolution of non-residential PV finance by describing the three primary ways in which a taxable non-residential entity might finance a PV system. Section 4 does the same for tax-exempt non-residential site hosts. Section 5 describes and uses a pro forma financial model to assess (from the non-residential site host's perspective) the impact of these different financing structures on the economics of PV. Section 6 discusses the primary policy implications associated with this financial innovation. Section 7 concludes. In addition, there are four appendices: Appendix A provides a glossary of terms and acronyms used in this report; Appendix B provides modeling results from scenario analysis in California; Appendix C discusses how developers (rather than site hosts) finance PV projects that generate the power behind site-host PPAs; and Appendix D describes how very large, utility-scale solar projects have been financed in the United States.

# 2. Policy Support for Non-Residential PV Deployment

The financing structures currently being used to support non-residential PV deployment have, in part, emerged and evolved as a way to extract the most value from federal and state policy initiatives. As such, a basic understanding of federal and state policy drivers supporting PV deployment is a critical prerequisite to understanding the financing structures described in later sections of this report. To this end, this chapter provides a brief overview of both federal and state policy initiatives supporting PV deployment, and in particular non-residential PV deployment.[7]

## 2.1 Federal Policy Support for Non-Residential PV Deployment

Federal policy support for non-residential PV deployment has been concentrated within the US tax code, in the form of an investment tax credit, accelerated tax depreciation, and more recently, tax credit bonds (for certain tax-exempt entities). This section briefly describes each of these, in turn.

### 2.1.1 Federal Investment Tax Credit

Section 48 of the Internal Revenue Code provides an investment tax credit (ITC) for certain types of energy projects, including "equipment which uses solar energy to generate electricity." Historically, through 2005, the size of the solar credit was equal to 10% of the project's "tax credit basis" – i.e., the portion of system costs to which the ITC applies.[8] The *Energy Policy Act of 2005* temporarily increased the solar credit to 30% of a project's tax credit basis, for projects placed in service between January 1, 2006 and January 1, 2008. In late-December 2006, the *Tax Relief and Healthcare Act of 2006* extended the in-service deadline to December 31, 2008, and in October 2008, the *Energy Improvement and Extension Act of 2008* extended it once again for a full eight years, through December 31, 2016. Unless extended again or otherwise altered over the next eight years, the Section 48 solar credit will revert back to 10% on January 1, 2017.

The credit is realized in the year in which the PV project begins commercial operations, but vests linearly over a 5-year period (i.e., 20% of the 30% credit vests each year 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. This period is sometimes referred to as the 5-year "clawback" period.

Certain limitations exist on use of the ITC in combination with other incentives. Specifically, if a non-residential entity receives a rebate, buy-down, grant, or other incentive related to the project that is *not* considered to be taxable income (i.e., the entity is not required to pay income tax on the incentive), then the tax credit basis must be reduced by the amount of the incentive

[7] Since R&D policy does not directly impact deployment, it is not discussed here.

[8] In most cases, 100% of the installed project costs will be considered part of a non-residential PV project's tax credit basis. Potential exceptions might include costs related to mounting structures that serve a dual purpose (i.e., other than supporting the PV panels) – e.g., roof replacement, shade structures. Moreover, as discussed later in this section, in some cases the tax credit basis may need to be reduced by the amount of certain other incentives received.

received.[9] Similarly, if the system is financed in part or in whole using "subsidized energy financing,"[10] then the portion of the project cost financed in this way is not eligible for the ITC.

### 2.1.2 Accelerated Tax Depreciation

Section 168 of the Internal Revenue Code provides a Modified Accelerated Cost Recovery System through which certain investments in solar power (and other types of) projects can be recovered through accelerated income tax deductions for depreciation. Under this provision, which has no expiration date, "equipment which uses solar energy to generate electricity" qualifies for 5-year, 200 percent (i.e., double) declining-balance depreciation. In most cases, 100% of a PV project's cost will qualify for this accelerated schedule.[11] However, the project's "depreciable basis" (i.e., the dollar amount to be depreciated) must be reduced by the amount of any non-taxable cash incentives received (again, 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 value of the Section 48 investment tax credit. 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.

Assuming a 40% combined effective state and federal tax bracket and a 10% nominal discount rate, on a present value basis this 5-year MACRS depreciation schedule provides a tax benefit equal to about 26% of system costs (only 12% of which is attributable to the *acceleration* of the depreciation schedule; the remaining 14% would be realized even if commercial PV were instead depreciated using a less-advantageous 20-year straight-line schedule). Taken together, then, the 30% ITC and accelerated depreciation provide a combined Tax Benefit equal to about 56% of the installed cost of a commercial PV system.[12] Moreover, these Tax Benefits are fully realized within a 6-year period, which is significantly shorter than, for example, the 10 years that it takes commercial wind power projects to fully realize their Tax Benefits (which, in the case of wind, include the 10-year production tax credit, or PTC, rather than the ITC).

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[9] In most cases, state cash incentives provided to *non-residential* PV systems *will* be considered taxable income, which makes a tax credit basis reduction (due to a non-taxable incentive) unlikely. For residential systems, this issue is not as clear-cut (for more information, see Bolinger and Wiser, 2007).

[10] Section 48(a)(4)(C) of the U.S. tax code defines the term "subsidized energy financing" to mean "…financing provided under a Federal, State, or local program a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." The instructions to IRS Form 6497 ("Information Return of Nontaxable Energy Grants or Subsidized Energy Financing") expand upon the Section 48 definition, noting that "Financing is subsidized if the terms of the financing provided to the recipient in connection with the program or used to raise funds for the program are more favorable than terms generally available commercially." Moreover, "The source of the funds for a program is not a factor in determining whether the financing is subsidized."

[11] Again, potential exceptions might include costs related to mounting structures that serve a dual purpose (i.e., other than supporting the PV panels) – e.g., roof replacement, shade structures.

[12] As mentioned earlier, however, this combined 56% Tax Benefit is *reduced* by the income tax that a self-financed commercial PV system must pay on utility bill savings (because those savings offset an operating expense that would otherwise have reduced taxable income) or that a third-party-owned system must pay on net income from power sales. On a present value basis, these income tax payments come to somewhere around 30% of installed costs (depending on the price of power offset or sold), leaving the *net* tax benefits available to commercial PV systems at slightly less than 30% of installed costs.

Depreciation deductions (as well as the ITC) in excess of net income generated by a project can be carried forward to future years under certain circumstances. However, due to the time value of money and the fact that a significant share of overall project returns come from Tax Benefits, it is important for an investor to be able to utilize such Tax Benefits in the years in which they are generated.

### 2.1.3 Clean Renewable Energy Bonds (CREBs)

Section 1303 of EPAct 2005 created Clean Renewable Energy Bonds (CREBs), a financing tool intended to "level the playing field" for non-taxable entities (specifically, governmental entities and electric cooperatives, and recently extended to public power providers) that cannot directly use the Section 45 (PTC) and Section 48 (ITC) federal tax credits (or accelerated tax depreciation benefits) targeting wind, solar, and other types of renewables. CREBs are "tax credit bonds," which means that the bond purchaser receives a federal income tax credit in lieu of interest payments. From the borrower's perspective, CREBs are therefore essentially the equivalent of a zero-interest loan (ignoring the various transaction costs of bond issuance described below, which reportedly can be considerable – see, e.g., Cory et al., 2008).

EPAct 2005 authorized $800 million of CREB funding, which was allocated through a solicitation/auction process in early 2006. In anticipation of a strong response, the IRS stated that it would allocate bonds starting with the smallest qualifying request and working its way up to larger and larger requests until the $800 million cap was reached. Results announced in November 2006 showed a 3-to-1 over-subscription, leaving a good deal of unsatisfied demand. Perhaps as a result, the *Tax Relief and Health Care Act of 2006* (the same bill that extended the 30% ITC through 2008), authorized an additional $400 million in funding for CREBs, to be allocated through a second-round solicitation with applications due in July 2007. Results announced in February 2008 showed that this second round was also over-subscribed. An additional $800 million for new CREBs was passed in October 2008 as part of the *Energy Improvement and Extension Act of 2008* (which itself was part of H.R. 1424, known colloquially as the $700 billion "bailout bill").

Due to their small size (e.g., relative to wind projects), PV projects have fared relatively well under the IRS's "smallest-to-largest" allocation method: 434 of the 610 projects funded in the first round were solar projects, receiving nearly half of the full $800 million allocation. In the second round, solar accounted for 139 of the 310 funded projects, receiving over $84 million of the $405 million allocated.

Success in winning a CREB allocation does not, however, ensure success in bringing the project online. A number of the first-round allocation winners have since found that the transaction costs associated with issuing the bonds can be prohibitively high, particularly relative to the rather modest capital needs of most of the PV projects that received allocations. As a result, some allocation-winners have reportedly forfeited their allocations (Cory et al., 2008), thereby enabling the allocation to be re-distributed to other projects in future funding rounds. Demand for the bonds has also not been as strong as hoped, and some issuers are not able to offer the AA credit rating used as a benchmark to set the credit amount. As a result, CREBs may need to be sold at a discount, or else with a supplemental interest payment (above and beyond the tax credit), in order to entice buyers (Cory et al., 2008) – either of these transactional difficulties will erode the promise of 0% financing. The *Energy Improvement and Extension Act of 2008* has taken steps to try and alleviate some of these problems, but only for the additional $800 million in CREBs that it authorized.

## 2.2 State and Local Policy Support for PV Deployment

In addition to the federal support described above, many states, municipalities, and utilities offer incentives for the deployment of PV. Since the scope and breadth of these incentives vary considerably from state to state, this section describes state-level incentives for PV deployment in general terms only. Readers interested in learning about specific incentives available in a specific state can find more information at www.dsireusa.org.

### 2.2.1 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.[13]

If, on net 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. Depending on the state or utility in question, this rolling forward of net excess generation might occur indefinitely, or might eventually terminate after some pre-defined period, such as a calendar year. At that time, the utility either compensates the customer/generator for any remaining balance of net excess generation, or else simply claims the net excess generation as its own, with no compensation. Rules (and rates of compensation) vary by state and/or utility.

As of September 2008, forty-four states plus the District of Columbia offered some form of net metering (DSIRE, 2008). All but seven allow for the rollover of *monthly* net excess generation; these seven states compensate monthly net excess generation in different ways – e.g., at wholesale rates or avoided costs (Fox et al., 2008). *Annual* net excess generation is handled in a variety of ways: nineteen states provide no compensation at all; eight pay avoided costs; two pay retail rates; and eight others allow indefinite rollover, with no annual true-up (Fox et al., 2008).

One recent trend has been towards larger size limits for eligible net-metered systems: while limits within the range of 10-100 kW were once common, sixteen of the forty-four states with net metering now allow systems as large as, or even larger than, 1 MW to net meter. Although the ability to net meter is not strictly necessary if a system is sized such that its peak output will never exceed baseload consumption, the spread and improvement (in terms of system size,

[13] Wiser et al. (2007) also demonstrate that non-residential retail electricity rates can vary widely by utility, and that certain rate designs are more favorable than others for on-site PV generation. Specifically, those rates comprised primarily of volumetric energy charges rather than fixed demand charges (or other fixed charges) will typically provide more favorable economics for non-residential PV hosts. Some states have developed retail rates with a specific purpose of supporting, or at least not unduly impeding, PV deployment.

treatment of net excess generation, etc.) of net metering policies has nevertheless been a policy driver of the growth of non-residential PV systems in the United States.

### 2.2.2 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. The incentive level is often expressed on a $/W basis, and is sometimes accompanied by a percentage cap that limits the size of the incentive to no more than 50% (for example) of total installed costs. California's *Emerging Renewables Program*, which began funding PV systems in 1998, was among the first of these programs in the United States. Since then, many other states and individual utilities have followed suit.

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 providing 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). Although the PBI structure encourages better system performance, it does so by imposing performance risk on the recipient. A PBI also leaves the system owner shouldering more of PV's high up-front cost than it would under a CBI. As discussed later, these characteristics have important implications for the types of PV financing structures that have emerged (e.g., solar PPAs have emerged, in part, in response to a greater need for up-front capital, and in part as a way of shielding the site host from the increased performance risk associated with a PBI).

The most notable example of this shift towards PBIs is the *California Solar Initiative* (CSI), which, starting in 2007, provides PBIs to systems larger than 50 kW (CEC-AC rating). Systems less than 50 kW (with the threshold dropping to 30 kW starting in 2010) can elect to receive either a PBI, or alternatively what's known as an "expected performance-based buy-down," or EPBB. By paying the incentive up-front on a $/W basis (like a CBI), but adjusting the capacity-based payment level based on a variety of factors (such as azimuth, tilt, and shading) that will impact expected performance, and EPBB represents an intermediate approach between CBIs and PBIs (Barbose et al., 2006). In recognition of their inability to benefit from tax incentives, systems owned by non-taxable entities receive higher PBI and EPBB incentive levels than those owned by taxable entities (some other states also provide differentially higher incentive levels to non-taxable entities for this reason).

As planned, both PBI and EPBB incentive levels under the California Solar Initiative have declined over time as certain capacity targets are achieved. This design feature was intended as a way to drive down installed system costs as more and more PV is installed. In reality, installed costs have not dropped as quickly as have incentive levels (Wiser et al., 2008), making PV a harder sell in California (and in other states with similarly declining incentive levels). This, in turn, has had an impact on the types of financing structures being used in the market.

### 2.2.3 State Tax Incentives

Though not as common as cash incentives, a number of states have enacted tax incentives to support customer-sited PV. For example, Oregon and Hawaii offer owners of PV systems investment tax credits of 50% (taken over 5 years) and 35% of qualifying installed costs, respectively. In both cases, these state tax credits can be taken *in addition to* the 30% federal investment tax credit. Many other states exempt PV systems from paying sales tax, and/or from property tax assessments (DSIRE, 2008).

One issue arising with state income tax credits is that the project owner typically needs to have sufficient in-state tax liability in order to efficiently use the credits. In addition to tax-exempt entities (which have trouble directly benefitting from any sort of tax incentive), third-party owners of PV systems may find this necessity to be troublesome, to the extent that they are based out-of-state and/or carry out the bulk of their income-generating activities in other states. Oregon has addressed this issue by allowing the state's Business Energy Tax Credit to be "sold" to a "pass-through partner" in exchange for an up-front, lump-sum, discounted cash payment.[14]

### 2.2.4 Set-Asides or Multipliers within State RPS Policies

In addition to or instead of providing cash and tax incentives for PV installations (or PV power), a number of states encourage the deployment of solar power (including PV) as part of a renewables 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 November 2008, 28 states plus the District of Columbia have 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).[15] Berkeley Lab estimates that 35% of all grid-connected PV capacity installed in the U.S. in 2007 occurred in states with solar or distributed generation set-asides. Excluding California from the denominator (California does not have a solar set-aside, but is nevertheless the nation's largest solar market), this percentage increases to 85% (Wiser and Barbose, 2008).

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

[14] For more information on Oregon's Business Energy Tax Credit, see http://www.oregon.gov/ENERGY/CONS/BUS/BETC.shtml.

[15] 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.

currency;[16] as such, RECs are very much an instrument of policy. In fact, in some cases, a REC's market value is closely tied to policy design (e.g., in an under-supply situation, the market price of RECs may hover just below a policy-induced price cap).

Solar RECs (SRECs) are typically used to demonstrate compliance with the solar set-aside portion of an RPS policy, and can represent an important source of revenue for non-residential PV systems. For example, New Jersey's ambitious solar set-aside has led to average SREC prices in excess of $300/MWh, and the state has recently begun to transition away from providing any cash incentives to PV systems (over 10 kW), relying instead on the attractiveness of the SREC market to encourage the installation of PV. Colorado is another growing solar market that is relying heavily on SRECs to provide financial value to PV systems. As with the trend towards PBIs, this growing reliance on SRECs rather than up-front incentives has also supported the development of the PPA finance model.

## 2.3 Policy Summary

Though not exhaustive, the wide array of financial incentives and policy mandates for PV deployment presented in this chapter is indicative of the need to package together a variety of incentives in order to make a PV system economical. For example, non-residential systems owned by taxable entities can recover 30% of installed costs through the federal ITC, and another 26% (only 12% of which represents incremental value over normal "book" depreciation) through 5-year accelerated tax depreciation. State tax incentives may cover an additional 30%-50% of costs in a few states, and cash incentives and/or SRECs often provide additional value in a greater number of states. Finally, net metering and/or attractive rate design can help to maximize the value of the solar power generated. Non-taxable entities may not be able to directly benefit from tax incentives, but may instead reap higher cash incentives at the state level, and also may have access to attractive tax-exempt or even "zero-interest" CREB financing at the federal level.

In combination, these state and federal incentives provide a significant amount of value, yet this value is delivered through a variety of mechanisms – e.g., federal taxes, state taxes, cash incentives (either capacity- or performance-based), SREC revenue, and avoided electricity purchases. As will be demonstrated in this report, PV project financing structures have evolved in response to this patchwork of incentives, in an attempt to efficiently capture as much of this value as is possible.

[16] 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."

# 3. Financing Options for Taxable Non-Residential Site Hosts

As discussed in the previous chapter, an ability to capitalize on the wide array of state and federal incentives for solar is critical to the financial viability of most PV systems. Not all non-residential entities interested in adopting solar, however, are able to make efficient use of these incentives, with tax incentives being the most obvious example – e.g., tax-exempt project sponsors cannot directly benefit from tax incentives.

In recent years, a number of different financing structures have arisen in response to this patchwork of incentives and the varying ability of project sponsors to make efficient use of them. Though each structure is, at its core, intended to maximize incentive capture while minimizing risk, certain structures are more appropriate than others in certain situations.

The purpose of this chapter and the next is to describe these structures in some detail. To simplify their presentation, this chapter describes only those financing structures in use among *taxable* non-residential site hosts. Chapter 4 then describes those structures suitable for tax-exempt site hosts.

Specifically, this chapter covers the three basic financing options available to taxable non-residential entities wishing to have a PV project operating on their side of the electric meter. These options include the "site host" (Text Box 1 defines the major players that may be involved in a solar project) financing the system on its balance sheet, leasing the system, or entering into a power purchase agreement (PPA) for the output of the system. A description of these three structures literally traces the recent evolution of non-residential PV finance.

**Text Box 1: Cast of Characters**

To facilitate the description of the various financing structures in this chapter and the next, this text box briefly defines and characterizes the types of entities that might participate in a non-residential PV project.

For the sake of simplicity, this report uses the term **PV project developer** (or just "developer") to generically refer to the entity or entities that develop, engineer, and/or install the PV project. This broad use of the term "developer" is intended to encompass many of the more-specialized roles within the industry, such as system integrator and system installer.

The **site host** is the entity that owns or controls the space (e.g., a commercial rooftop or parking lot) that the PV system will occupy. Depending on the financing structure, the site host might serve as the system owner, the system lessee, or the purchaser of power from the system. In order to limit complexity, this report only considers owner-occupied buildings – i.e., landlord-tenant issues are ignored.

**Cash Investors** are those investors in a PV project who cannot always make efficient use of the project's Tax Benefits, due to insufficient income tax liability. **Tax Investors**, on the other hand, are able to efficiently use a PV project's Tax Benefits. Cash Investors might include the project developer and the site host, while Tax Investors are typically third-party investors, including banks and other institutions with a sizable U.S. tax liability.

In the case where the PV system is leased, the **lessor** is the entity that owns the PV system, while the **lessee** is the entity that operates, maintains, and uses the power from it. Particularly in the case of an operating lease, the lessor will typically be a Tax Investor, while the lessee will be a Cash Investor – i.e., either the site host or the project developer (serving as a PPA provider).

Finally, in structures involving a power purchase agreement (PPA), the **PPA provider** is typically the project developer (or more accurately, some special purpose entity involving the project developer and a Tax Investor). The **power purchaser** is the site host.

## 3.1 Balance Sheet Finance

Only a few years ago, a non-residential 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. Third-party project-level debt may be available 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 SREC revenue (should it choose to sell its SRECs), 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 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.

In other words, the non-residential PV market has, for some time, been ripe for financial innovation that can address these barriers. Though signs of such innovation began to unfold even prior to the increase in the ITC from 10% to 30% under EPAct 2005, the 30% credit has proven to be a strong impetus. With the federal government now providing incremental Tax Benefits equivalent to 42% of the cost of a PV system through the combination of the ITC and accelerated tax depreciation, Tax Investors – already active in the commercial wind sector – have begun to take a closer look at PV, enabling the development of the third-party ownership structures described in the next two sections.

## 3.2 Leasing

In this case – the first of the third-party finance options described – 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 (but not RECs, unless contractually arranged, since by default RECs reside with the system owner) 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). In this way, a lease overcomes the barrier of PV's high up-front cost, but otherwise leaves O&M responsibilities and performance risk with the site host.

The size of the lease payments is a function of two main variables (besides the implicit interest rate and any cash or tax incentives provided to the project): the length of the lease term and the estimated "residual value" of the system at the end of the lease term (i.e., how much economic value is projected to remain at the end of the lease). In general, the greater the projected residual value, the lower the lease payments – i.e., the lessee only pays for the amount of economic value that it is expected to "consume." Furthermore, if the lessee is able to spread the repayment of that consumed economic value over a longer term, the lease payments should be lower as well.[17] As a long-lived asset (e.g., some leases reportedly assume a 40-year life for PV modules) that can be easily redeployed if needed, PV systems are good candidates for both lengthy lease terms and high residual values, which in turn can make leasing an attractive finance option.

Beyond this basic description, the mechanics of leasing quickly become considerably more complicated, and depend upon the type of lease being used. For taxable non-residential site hosts, there are two possibilities: a "capital" lease or an "operating" lease (Text Box 2 provides formal definitions of each). This section describes both types of leases, with more emphasis on operating leases, which are more common than capital leases for commercial PV systems.

**Text Box 2. Operating Leases versus Capital Leases**

In general, taxable entities can choose from two basic types of leases, as defined (though somewhat differently) by the Internal Revenue Service (IRS) and the Financial Accounting Standards Board (FASB). The IRS distinguishes between "true" leases (sometimes referred to as "tax" leases) and "non-tax-oriented" leases. The corresponding terms from the FASB are "operating" leases and "capital" leases (sometimes referred to as "finance" leases). To qualify as a "true" lease (under IRS Revenue Procedure 2001-28) or "operating" lease (under Financial Accounting Standard 13), the following conditions must be met (otherwise, the lease will be considered a capital lease):

- The lessor must make (and maintain throughout the lease term) a minimum unconditional "at risk" (equity) investment equal to at least 20% (10% under FAS 13) of the cost of the leased property.
- At the end of the lease term, the leased property must have a remaining life of at least 1 year or 20% (25% under FAS 13) of the originally estimated useful life, whichever is greater.
- If the lessee has an option to purchase the leased property, the option must be priced at no less than the fair market value (FMV) of the leased property at the time the option is exercised.
- In addition, the IRS requires that true leases be "pre-tax positive," meaning that they generate a positive return for the lessor prior to accounting for any Tax Benefits. However, based on the more recent Revenue Procedure 2007-65, which found (among other things) that the Section 45 production tax credit can be considered a cash-equivalent for such purposes with respect to wind projects, many Tax Investors in solar projects are now similarly assuming that the ITC can be factored into the "pre-tax positive" test on a cash-equivalent basis (Martin, 2008). The IRS, however, has not taken a position on this matter (Revenue Procedure 2007-65 pertains only to wind projects).

For the purposes of this report we will adopt the FASB terminology of "operating lease" to describe any lease that meets the above requirements, and "capital lease" to describe all other types of leases. Moreover, although there are subtle differences involved, we will make the simplifying assumption that the term "operating lease" is interchangeable with "tax lease" and "true lease," while that the term "capital lease" is interchangeable with "finance lease" and "non-tax-oriented lease."

[17] Note that these two variables are somewhat conflicting – a longer lease term might lead to a lower residual value (in both nominal and discounted dollars), so the two are not necessarily reinforcing.

### 3.2.1 Capital Lease

Under a capital lease, the site host typically leases the project with the explicit intent to eventually own it (in addition to the various names presented in Text Box 2, capital leases are also sometimes referred to as "sales-type" leases, "installment leases," or "lease-to-own" leases). In fact, at least for tax and accounting purposes, the site host (lessee) is effectively considered the owner of the project: the lessee is entitled to all of the project's Tax Benefits, and must also list both the project (as an asset) and the lease payments (as a liability) on its balance sheet.

In this way, a capital lease closely resembles ownership financed through a bank loan, with perhaps two primary differences: (1) one can often finance the full cost of a system with a capital lease (whereas a bank typically requires a down-payment), and (2) capital leases often include a buyout option at the end of the lease term, usually at a "bargain purchase price" (as opposed to "fair market value" or FMV) that is fixed in advance (e.g., one dollar, or some other nominal amount set at the time the lease is established). In other words, the lease payments are calculated assuming little or no (i.e., 0%-20%) residual value, such that the lessee pays for essentially the full cost of the system over the lease period, based on the intent to own the system after making the "bargain purchase" payment at the end of the lease term.

Apart from these differences, capital leases offer PV projects little incremental advantage over a conventional bank loan. Although a capital lease addresses the up-front cost barrier as well as (or even better than) a traditional bank loan, it still leaves the project's Tax Benefits with the site host (lessee), which is sub-optimal if the lessee cannot efficiently use them (many can not). Consequently, capital leasing of commercial PV systems is not very prevalent in the market. Instead, most lease financing of commercial PV installations has been done through operating leases, described next.

### 3.2.2 Operating Lease

Unlike a capital lease, an operating lease is *not* structured on the assumption that the lessee will eventually own the project (although most operating leases do provide the lessee with a "fair market value" purchase option at the end of the lease term). For tax and accounting purposes, the lessor is considered the owner of the leased asset, and as such retains the rights to the project's Tax Benefits. This allocation can provide an important advantage to both parties, since the lessor – typically a Tax Investor, or else backed by one – is more likely than the lessee to be in a position to make efficient use of these Tax Benefits, and in turn can "monetize" and pass along some portion of them to the lessee through lower lease payments. The lessee does not book either the leased asset or payment liability on its balance sheet, but instead merely treats the lease payments as an operating expense (thus, operating-lease financing is sometime referred to as "off-balance-sheet" finance).

From the site host's (lessee's) perspective in particular, the underlying objective is often to structure an operating lease so that its net operating expenses are unchanged or even reduced: i.e., the lease payments are equal to or less than the electricity bill savings from use of the PV power. As noted above, the parties have two principal (and somewhat interdependent) levers that can be adjusted to achieve this goal: the term of the lease and the assumed residual value.

One leasing company active in the commercial PV market reports that operating lease terms have typically been 10 years, though some have been as short as seven years, and more recently they have been asked (particularly by site hosts with strong credit) to go out as long as 15 years (Kuhn, 2007). This recent trend towards longer lease terms reflects the challenge of making PV projects economical in the face of stagnant system costs and declining state incentive levels.

The residual value is a second lever that can be adjusted in structuring a deal: the higher the residual value, the lower the lease payment (since the lessee is using up less of the asset's economic value). In order to qualify as an operating lease, the Financial Accounting Standards Board (FASB) requires that the residual value of the system be at least 10% (the IRS requires 20% residual value – see Text Box 2), and early PV operating leases were often conservatively structured around this minimum residual. Things are changing, however, as lessors become increasingly comfortable with PV as a reliable and long-lived technology (20- to 25-year module warranties are now common, and some lessors are now reportedly assuming a 40-year economic life) and as lessees seek increasingly lower lease payments in response to state-level PV incentives declining at a faster rate than system costs. As a result, residual values are now reportedly being pushed up to 30% or higher in some cases (McLawhorn, 2007).

Although lease payments must generally be fixed in advance for the term of the lease (indeed, this is one of the defining characteristics of a lease), payments can be customized to step up or down during the lease term to better match the lessee's anticipated cash flow from the leased property. For example, as discussed in Chapter 2, some states provide PV systems with performance-based cash incentives (PBIs) for a fixed number of years (e.g., 3-5 years) after the start of commercial operations; such incentives can be used to support a lower lease payment in the early years of the lease term, which steps up to a higher fixed payment once the PBIs expire.

In sum, operating leases provide a number of potential advantages over the financing structures presented so far: they address PV's up-front cost barrier, they efficiently allocate the project's Tax Benefits to those parties best able to use them, and they do not directly impact a site host's balance sheet. Performance risk, however, along with the responsibility to operate and maintain the system, continues to reside with the lessee/site host.

Moreover, the FASB, along with the International Accounting Standards Board (IASB), is currently in the midst of proposing changes to the way in which operating leases are accounted for. Though not yet finalized, the new standards are likely to blur the distinction between capital and operating leases by requiring that operating leases, like capital leases, be reported on the lessee's balance sheet. Though seemingly a superficial change presumably intended to enhance transparency, this proposal could have negative ramifications on the use of operating leases to finance PV systems. Specifically, once the operating lease is "booked" on the site host's balance sheet, then it is, in essence, being financed at the site host's weighted-average cost of capital, which may be higher than the rate of return generated by the PV system, making it a losing proposition (Shah, 2007).

## 3.3 Power Purchase Agreements (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). 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 (Appendix C provides more details on how, in the case of a PPA, the *developer* finances the PV system using either a partnership or sale/leaseback structure). Related, 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 annually by anywhere from 1% to 5% (nominal), and therefore may end up being either higher or lower than utility rates in the future.[18] The PPA term can range anywhere from 10 to 25 years, with 20 years being common.[19] As with leasing, longer terms can lead to more attractive pricing. 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 (FMV) 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; MMA Renewable Venture's PPA with AC Transit (a public transit company in the San Francisco Bay area) is reportedly structured this way (Scanlon, 2007).

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

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[18] Instead of (or in addition to) offering a fixed PPA price with annual escalation, some solar PPA providers offer to price the PPA at a fixed discount to utility rates over time (e.g., 5% below utility rates, whatever they may be in the future). This floating-price structure imposes more risk on the PPA provider than does a fixed-price agreement, and also does not provide the site host with a price hedge should utility rates increase significantly in the future. On the other hand, it protects the site host in the event that utility rates decrease, rather than increase, going forward (although PPAs priced in this manner also typically must designate a fixed floor price in order to appease the Tax Investors). PPA providers that offer both options have reported that most site hosts select the fixed-price schedule to protect themselves against expected utility rate increases (Chadbourne & Parke LLP, 2008).

[19] The term of early solar PPAs tended toward the shorter end of this range, with some of SunEdison's early PPAs (e.g., with Staples and Macy's) featuring 10-year terms. Since then, however, State-level incentives have generally declined faster than installed project costs, necessitating longer PPA terms in order to make the economics pencil out. In addition, Tax Investors have grown increasingly comfortable with the added credit risk from longer PPAs as the number of deals has increased.

in the future. The primary difference – which reportedly is a major selling point for the PPA (Chadbourne & Parke LLP, 2008) – is that, under a PPA, the site host is not required to operate and maintain the system, and likewise faces no performance risk.[20] 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 (though see footnote 20).

Although it is purchasing the power produced by the PV system, the site host does not automatically own the renewable energy certificates, or RECs, associated with that power.[21] Rather, RECs typically reside with the system owner, which in the case of a PPA is the project developer and/or its Tax Investors. Most PPA providers, however, give the site host the right of first refusal to purchase some or all of the project's RECs, and will roll the REC purchase into the PPA price if so desired.[22]

The PPA structure was first introduced by SunEdison back in 2003/2004, and since then has spread rapidly. By one estimate (Guice, 2008), 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). Other estimates are more-conservative (Detering and Lugar, 2007), but still exhibit and predict strong growth for the PPA model.

The number of PPA providers has also multiplied considerably. Besides SunEdison, other developers pursuing the PPA model include MMA Renewable Ventures, SunPower, Regenesis, Solar Power Partners, Tioga Energy, Recurrent Energy, Soltage, MP2, Chevron Energy Solutions, EI Solutions, Helio Micro Utility, and others. Some of these providers are targeting niche segments of the non-residential market; for example, Recurrent Energy specializes in structuring solar PPAs with owners and/or tenants of buildings occupied under complicated "triple net lease" agreements. Others are trying to carve out market share in other ways, such as offering a fixed discount to utility rates, rather than a fixed (but escalating) PPA price. As with all maturing industries, a certain degree of consolidation among PPA providers is expected to occur over time – such consolidation may occur sooner rather than later as a result of the financial crisis that unfolded in late 2008.

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[20] Although conventional wisdom holds that operations and maintenance (O&M) are the responsibility of the PPA provider, at least one recent PPA (between Chevron Energy Services and the Milpitas Unified School District) involves the site host paying a "not-to-exceed" annual amount to Chevron for preventive O&M services, with unscheduled maintenance charged to the site host on a time and materials basis. To the extent that this arrangement is not typical (our sample of actual solar PPAs is limited), it may be indicative of one way in which PPA providers are meeting their return targets in the face of declining State-level incentives – i.e., by asking the power purchaser (site host) to share in the O&M costs.

[21] Not owning the RECs limits the types of statements or claims that a site host can make about the power it buys from the PV system; for example, without the RECs, the site host cannot legally make the claim that it is purchasing "solar" power.

[22] The value of solar RECs varies widely from state-to-state, and is driven in large part by the design of state renewables portfolio standards. For example, New Jersey's RPS contains an aggressive solar set-aside that has pushed the value of solar RECs up to above $300/MWh at times, whereas in California, which does not have a solar set-aside within its RPS, solar RECs are reportedly selling on the order of just 1-2 cents/kWh in the voluntary green power market (Cheney, 2007).

**Text Box 3. Challenges to Third-Party Ownership**

Despite its growing popularity, third-party ownership of non-residential PV systems remains somewhat vulnerable to at least four issues that deserve brief mention.

**1) *Declining Incentive Levels:*** In the largest markets in the U.S., such as California, state-level incentives have been declining at a faster rate than system costs (Wiser et al., 2008). If this trend continues, it will become increasingly difficult to beat, or even match, utility rates, making it harder to sell solar PPAs or leases.

**2) *Credit Quality:*** Credit quality is an important issue for third-party ownership, in that the lessee or power purchaser must be sufficiently creditworthy to support a 15- to 25-year contract. In most cases, this means that the lessee or power purchaser must have an investment-grade rating from one of the large credit rating agencies, such as S&P or Moody's. Some PPA providers, however, have expressed a willingness (at least prior to the recent credit crisis) to work with unrated entities that have strong balance sheets and are otherwise willing to provide letters of credit and/or co-signatures (Detering, 2008). In general, the goal of the industry is to achieve sufficient scale such that credit risk can be aggregated and securitized. As the number of projects increases, the overall portfolio-level impact of any single project defaulting decreases. Moreover, with sufficient scale, predicting the likely default rate becomes a statistical exercise that is familiar to investors (although this exercise may become more difficult as a result of the unfolding credit crisis, discussed next).

**3) *The Credit Crisis:*** The severe financial turmoil of late 2008 has impacted the non-residential PV market in at least two ways. First, the pool of site hosts with sufficient credit to support third-party finance has deteriorated. Second, and more importantly, many of the tax equity investors who have financed PPA providers and their projects have reportedly pulled back from the market, as their own taxable income (in need of sheltering) becomes less-predictable. As a result, projects are reportedly having a difficult time securing tax equity, and are having to pay higher returns to those tax equity investors who are still investing. This results in projects that are less-competitive with utility rates.

**4) *Legality of Third-Party Ownership:*** A number of states have begun to investigate the legality of third-party ownership of net-metered PV systems. There are at least two related issues at stake: whether third-party owned PV systems should be eligible for net metering; and whether, by selling power to one or more ratepayers, the PPA provider should be considered a "utility" and be subject to utility regulation. Arizona appears to have endorsed third-party ownership in general (though without *explicitly* doing so) by eliminating from its proposed net metering rules a requirement that net-metered systems be "owned and operated" by the site host (Ayers and Hurlocker, 2008). Utah and Florida, meanwhile, appear to allow only leased (or, of course, customer-owned) systems to net meter (Fox et al. 2008). More certainty is available in Oregon, which, on July 31, 2008, became the first state to rule definitively on these issues. Specifically, the Oregon Public Utilities Commission ruled in favor of third-party ownership, finding that PPA providers should *not* be regulated like utilities, and confirming that third-party owned systems *are* eligible for net metering (i.e., in Oregon's net metering law, the term "customer generator" refers to the *user* of the generation facility, and is silent on facility ownership). The Public Utilities Commission of Nevada followed suit in November 2008, ruling that third-party-owned PV systems are allowed to net meter, and that third-party system owners may not legally be considered utilities (IREC 2008). Though these rulings in Oregon and Nevada may influence other states considering these issues, net metering legislation and regulations obviously vary from state to state. As such, it remains to be seen to what extent the PPA and lease models will survive this legal challenge in other states.

## 3.4 Choosing a Structure

The description of these three financing options literally traces the evolution of non-residential PV finance in the United States over the past few years. Balance sheet finance – once the only viable option for non-residential PV – struggles with many of the adoption barriers that analysts have described for years: high up-front costs, a steep learning curve for a non-core business function, technology and performance risk, and a potential inability to make efficient use of the project's Tax Benefits. Operating leases – a financial tool commonly used by the commercial sector for many years, but that has only made inroads with the solar market since EPAct 2005 increased the ITC from 10% to 30% – address high up-front costs and efficient use of Tax Benefits, but leaves O&M responsibilities and performance risk with the site host. The PPA model theoretically addresses all of these issues simultaneously and, as a result, the market is purported to be moving away from balance sheet and lease finance and towards PPAs.[23]

Nevertheless, given the wide diversity of potential site hosts interested in PV, a "one-size-fits-all" approach to PV finance does not make sense. Different site hosts will face a variety of different financial, operational, and strategic considerations that may favor one approach over another. For example, even though a PPA may ultimately be less risky (and perhaps similarly priced), certain site hosts may value – and also have the wherewithal to execute – system ownership for strategic or other non-financial reasons.

Acknowledging that few decisions can be boiled down to this level of simplicity, Figure 3 provides a basic decision tree that might help guide taxable non-residential site hosts to a suitable financing structure. Although this tree could potentially be branched in a number of different ways, the question of tax appetite seems to be the most logical starting point. 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. If the site host is not sufficiently creditworthy to support a lease or a PPA, and also has limited tax appetite (or perhaps has adequate tax appetite but is not willing to accept performance risk), then it will be difficult to structure an economically viable project, although some PPA providers are reportedly beginning to offer terms to less-creditworthy site hosts (Detering, 2008).

[23] While PV site hosts may be gravitating towards PPAs and away from lease financing, there are some indications that PV developers seeking to finance the projects that back their PPAs are moving *towards* lease financing (and away from partnership structures) as a means of doing so. Appendix C provides a discussion of how developers, rather than site hosts, finance their projects.

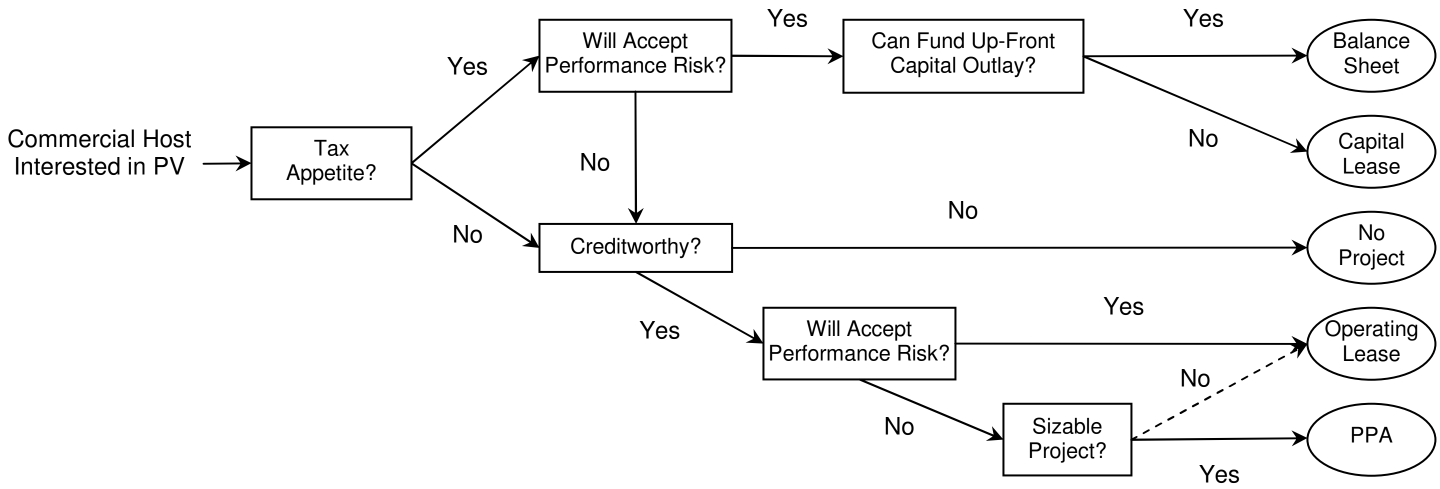


**Figure 3. Choosing a Finance Structure: Taxable Site Hosts**

# 4. Financing Options for Tax-Exempt Non-Residential Site Hosts

The previous chapter discussed non-residential PV financing options in common use among *taxable* site hosts, which, at least in theory, are in a position to benefit from the substantial Tax Benefits provided to non-residential solar power projects. Many non-residential site hosts, however, are *tax-exempt* entities that cannot directly benefit from these Tax Benefits. In an attempt to create a level playing field for all types of site hosts, federal (and in some cases, state) policymakers provide different (or in some cases just differentially greater) incentives to site hosts unable to benefit from tax incentives. These targeted incentives, in combination with specialized laws and regulations governing tax-exempt entities, have encouraged the development of PV financing structures that differ in some cases from those in use among taxable entities. The purpose of this chapter is to describe these structures in some detail.

Before proceeding, it is worth noting that tax-exempt non-residential entities fall into two primary categories: governmental entities and non-profit entities. As will be seen in this chapter, governmental entities generally have a wider array of financing options available to them, in part due to their bonding authority.

## 4.1 Balance Sheet Finance

Like a taxable site host, a tax-exempt site host may have an ability to finance a PV project on its balance sheet, using reserves or working capital. Indeed, this may be the only direct ownership option available to tax-exempt site hosts that lack bonding authority – e.g., non-governmental, non-profit entities. The site host benefits not only from avoided electricity costs and SREC revenue (should it choose to sell its SRECs), but also from any state CBIs or PBIs, which in some states are provided to tax-exempt system owners at differentially higher levels to account for their inability to take advantage of the project's tax benefits.

Balance sheet finance raises the same issues for tax-exempt site hosts as it does for taxable site hosts – and then some. Specifically, this financing model faces a high up-front expenditure and a steep learning curve for a non-core business item, and leaves the site host with technology and performance risk. In addition, a tax-exempt site host is unable to benefit from the federal tax benefits generated by the project. As a result, other financing options are, if available, likely to be more advantageous.

## 4.2 Tax-Advantaged Debt

Certain tax-exempt governmental entities are able to tap into the capital markets by issuing low-cost, tax-advantaged debt. Of most relevance to this report are traditional municipal bonds and Clean Renewable Energy Bonds (CREBs). In this case, the host owns the PV system and finances all or part of the system's cost with attractive debt.

### 4.2.1 Municipal Bonds

State and local governments have the authority, with voter approval, to issue bonds featuring tax-exempt (and therefore relatively low) interest payments. These bonds typically fall into one of two categories: (1) general obligation bonds, which are backed by the full taxing authority of the municipality, or (2) revenue bonds, which are backed solely by the revenue generated (or, in the case of PV, the utility expense avoided) by the project being financed. Most municipalities also maintain cash reserve funds that could be used to finance a PV system; in general, the opportunity cost of reserve funds is assumed to be the cost of issuing debt to replenish those funds.

#### 4.2.2 Clean Renewable Energy Bonds (CREBs)

With the passage of the Energy Policy Act of 2005, certain tax-exempt entities now also have access to Clean Renewable Energy Bonds (CREBs), which provide the bondholder with a tax credit in lieu of an interest payment. As such, CREBs offer the promise of a 0% interest rate to the borrower over a 10- to 15-year term; in practice, however, transaction costs have reportedly eroded much of this promise (Cory et al., 2008). As with municipal bonds, CREBs are not available to (non-governmental) non-profit entities; only projects sponsored by governmental entities, electric cooperatives, and public power providers are eligible for CREB financing. Furthermore, the typical maturity of a CREB – 10 to 15 years – is shorter than the 20- to 30-year maturity often seen for municipal bonds. For more information on CREBs, see Section 2.1.3 (earlier).

### 4.3 Tax-Exempt Lease

Since tax-exempt entities are not entitled to a PV project's Tax Benefits, the capital and operating lease transactions described earlier in Section 3.2, which provide for either the lessee or lessor, respectively, using the Tax Benefits, are not permissible. Instead, tax-exempt site hosts may be able to enter into what's known as a "tax-exempt lease," sometimes referred to as a "municipal lease." A tax-exempt lease is essentially a capital (aka, finance) lease featuring a relatively long term (although it is typically structured as a series of successive one-year terms, subject to annual budgetary appropriations – see the description of the "non-appropriations clause" below) and a relatively low interest rate, reflecting the fact that the lease payments are tax-exempt income to the lessor.

In a structural sense, then, a tax-exempt lease is not much different from the use of municipal debt described in the previous section, with several important distinctions. First, a tax-exempt lease is a "non-budgetary item," which means that it can be entered into at any time, does not require voter pre-approval, and does not officially impact the lessee's debt limit.[24] Second, tax-exempt leases typically include a "non-appropriations clause," which gives the lessee the right to skip one or more lease payments or even terminate the lease if, despite its best efforts, it is unable to secure sufficient appropriations to cover the lease payments (Association for Governmental Leasing & Finance, 2000). In return for granting this flexibility, the lessor will typically require a "non-substitution" clause, which prohibits the lessee, if it has terminated the lease, from replacing the leased equipment with the same or substantially similar equipment for a stated period of time.

[24] Although tax-exempt leases are not officially considered to be debt, the existence of such a lease must still be noted in annual reports, and the lease obligation is sometimes effectively counted as debt regardless.

In short, compared to general obligation or revenue bonds, a tax-exempt lease is easier to both originate and terminate. Ease of origination makes a tax-exempt lease useful for relatively small projects, in the range of $1 to $5 million. Ease of termination, however, means that the effective interest rate on the lease is likely to be higher than the corresponding yield on municipal bonds, which are more secure. Moreover, in states that offer differentially higher incentives to tax-exempt project owners (e.g., California), a project financed through a tax-exempt lease is unlikely to qualify for these higher incentives, assuming that the lessor is a taxable entity. As such, tax-exempt leases may be at a disadvantage to both tax-advantaged debt (which has a lower cost of capital and may qualify for differentially higher incentive levels in some states) and other forms of third-party finance (which can make use of the project's ITC and depreciation tax benefits).

Although tax-exempt leases are used primarily by governmental entities, non-profits can also reportedly use this vehicle provided they are able to secure a governmental sponsor (McLawhorn, 2006; Glass, 2007).

## 4.4 Service Contract (PPA)

Just as a taxable site host might choose to enter into a PPA with a project developer and its Tax Investor for the output of a PV project installed behind its meter, so might a non-taxable site host. The mechanics of the arrangement are not appreciably different from those described earlier for taxable site hosts in Section 3.3, and so will not be re-stated here.

In the case of a tax-exempt site host, however, greater care must be taken to structure the PPA as a "service contract" under Section 7701(e) of the Internal Revenue Code, which distinguishes a service contract from a lease. Since tax-exempt entities cannot enter into a "normal" lease transaction (i.e., a taxable operating or capital lease, as described earlier in Section 3.2) without jeopardizing the use (by either lessor or lessee) of the project's Tax Benefits, it is vital that a solar PPA with a tax-exempt site host be properly structured as a service contract, so that it cannot be misconstrued as a lease.

Section 7701(e)(4) of the Code lists four requirements that must be met for a service contract not to be considered a lease. First, the service recipient (in this case, the tax-exempt site host) cannot operate the facility that will be providing the services (i.e., the PV system). Second, the site host cannot shoulder performance risk (i.e., it cannot be asked to pay for electricity that it did not receive). Third, the site host cannot share in any significant financial upside that might occur if operating costs are lower than expected. Finally, if the site host has a purchase option, it must be priced at no less than the facility's fair market value at the time of exercise. Since most PPA's with taxable site hosts already meet these four requirements of a service contract, the use of the term "service contract" (rather than "PPA") in the context of a tax-exempt site host is mostly a terminology issue.

In contrast to the previously discussed financing options for tax-exempt site hosts, which operate within the confines of those instruments available to tax-exempt entities (i.e., tax-advantaged debt or tax-exempt leases), a service contract trades away the advantages of being tax-exempt for the potentially greater Tax Benefits thrown off by a PV project and available to the private sector (the economics of this tradeoff are examined in the next chapter). A service contract also arguably incurs significantly fewer transaction costs than issuing tax-advantaged debt or entering into a tax-exempt lease. Finally, non-governmental non-profit entities may not have particularly good access to any of the previously discussed financing options, and therefore may find a solar service contract to be among the few viable options available.

## 4.5 Pre-Paid Service Contract (PPA)

While a standard solar service contract eschews the low-cost, tax-exempt financing available to many tax-exempt entities in favor of the monetization of private sector Tax Benefits, a "pre-paid" service contract seeks to capitalize on *both* tax-exempt debt *and* the project's Tax Benefits. It accomplishes this by having the tax-exempt site host issue tax-advantaged debt, the proceeds from which are used to pre-pay a portion (e.g., 50%) of the power to be generated by the PV system over the contract term. The project developer and its Tax Investor use the prepayment to help finance project construction, but book the prepayment as income over time as it is earned when power is generated and delivered to the site host. Apart from the prepayment, the site host must also make ongoing payments during the contract term to cover the cost of any power generated above and beyond the pre-paid quantity (these ongoing payments also help maintain positive after-tax cash flow for the project owner). 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 to the site host can be significantly lower than under other financing options. In addition, as with a normal PPA/service contract, the pre-paid contract may include a site host purchase option (at the greater of fair market value or a contractually agreed upon amount) exercisable at some point after the project's sixth year, once the Tax Benefits have been exhausted.

Pre-paid service contracts are a relatively new financing structure. In 2003, the Treasury issued revised regulations enabling publicly owned utilities to use tax-exempt financing to prepay both natural gas and electricity supplies (among other things).[25] Subsequently, Section 1327 of the Energy Policy Act of 2005 codified natural gas prepayments into the US tax code, leaving some uncertainty over the validity of pre-paid electricity contracts (though such contracts were at least mentioned in Section 1327).

Although pre-paid contracts for conventional power had been executed earlier, the first pre-paid service contract involving renewables closed in late 2006 for the White Creek wind project located in Washington State. This 204.7 MW project featured four publicly owned utilities (two cooperatives and two public utility districts) pre-paying a portion of the project's output, in what amounted to a payment equal to roughly half of the installed project costs. Tax Investors own the project and monetize the Tax Benefits (which in this case include the 10-year PTC and five-year accelerated depreciation), and the utilities have an option to purchase the project at its fair market value at the end of 10 years, once all the Tax Benefits have run. The project began commercial operations in late November 2007.

[25] See http://www.ustreas.gov/press/releases/js629.htm or http://www.ustreas.gov/press/releases/reports/td9085.pdf.

Though other wind projects are reportedly pursuing similar structures,[26] the pre-paid service contract has been slower to catch on with solar projects. One early effort to institutionalize this structure in California was sponsored by the California Statewide Communities Development Authority (a joint powers authority) and known as the "Go-Solar" program. Despite some initial marketing efforts,[27] the program ultimately never launched due to a general lack of interest. It may be difficult to justify the use of this rather involved and complex structure for relatively small PV projects (as opposed to larger wind projects), though a structured program such as the "Go-Solar" program could help to minimize associated transaction costs.

It appears unlikely that non-governmental non-profits would benefit from this particular structure, given their inability to tap into the tax-exempt debt market. As such, governmental partners are the only realistic market for these transactions.

## 4.6 Choosing a Structure

For non-governmental, non-profit site hosts that are sufficiently creditworthy, a service contract (PPA) seems to be an obvious choice, given the inability of non-profit organizations to directly benefit from a project's Tax Benefits, and the lack of some of the other financing mechanisms that are available to governmental entities. The choice of financing structure among governmental tax-exempt site hosts, however, is less clear-cut than it is for taxable site hosts. That is, the subjective considerations facing governmental entities make it difficult to construct a "decision tree" along the lines of Figure 3 in Section 3.4.

For those governmental site hosts desiring direct and immediate ownership, tax-advantaged debt is the obvious choice, and as shown in the next chapter, may even be the most economical choice, depending on interest rate and transaction costs (and, in the case of CREBs, whether or not the site host can secure a CREB allocation in the first place). If immediate ownership is not critical, then a service contract (PPA) merits strong consideration, given its low risk profile and likely competitiveness.

Of all the financing options discussed in this chapter, a *pre-paid* service contract is, in theory, likely to be the most-economical for governmental entities, but only *if* legal and other transaction costs can be minimized. Conversely, despite the flexibility that it offers, a tax-exempt lease is likely to be among the least-economical options, since it will have a higher effective interest rate than municipal debt, yet bears the same burdens of tax-exempt ownership (i.e., no Tax Benefits, must assume O&M and performance risk), and furthermore may forfeit any differentially higher state-level incentives for tax-exempt entities (to the extent that the lessor is a taxable entity).

Though qualitative considerations may ultimately trump quantitative ones in many cases, the next chapter will nevertheless take a closer look at the comparative economics of these financing structures.

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[26] For example, First Wind's Milford wind project in Utah has entered into a 20-year prepaid PPA with the Southern California Public Power Authority (acting on behalf of several municipal utilities in California) for the first 200 MW of the project. The project is expected to be built in 2009.

[27] For example, see http://www.scag.ca.gov/rcp/ewg/documents/GoSolarPresentation3-14-2007.pdf

# 5. The Impact of Financing Structure on the Cost of Solar Energy

A variety of both qualitative and quantitative considerations will impact how a non-residential site host ultimately decides to finance a PV system. While the two previous chapters described many of the qualitative considerations facing a site host, this chapter relies upon some basic financial modeling to focus on the primary quantitative consideration – the effective price of power from, or more accurately the revenue required by, the system. The chapter begins with a brief overview of the models and modeling assumptions used in the analysis, before presenting and discussing base-case results, along with scenario and sensitivity analysis.

## 5.1 Overview of Pro Forma Financial Models and Assumptions

To analyze the impact of financing structure on the price of power from a non-residential PV system, Berkeley Lab has developed a number of simple pro forma financial models. The general approach common to these models is to start with a series of user-defined assumptions about the PV system, as well as the financial constraints imposed by the various investors in that system (e.g., return targets, debt coverage ratios, etc.), and then to back into a required amount of revenue that will satisfy all constraints. This approach is essentially the same as a PV project developer might take when conducting a first-cut analysis to determine whether a project is (economically) worth pursuing. The models used for this report, however, are by no means sophisticated enough to be used in actual project financings.[28] Nevertheless, they do provide a first-order approximation of the amount of revenue required by a non-residential PV system under a variety of financing or ownership structures, and are therefore sufficient for our intended purpose of comparative analysis.

The models themselves correspond to most (but not all) of the various financing options described in the two previous chapters. Specifically, for *taxable* site hosts, the models include the following:

- **Balance Sheet:** The site host finances the project on its balance sheet (as described in Section 3.1)
- **Operating Lease:** The site host finances the project through an operating lease (as described in Section 3.2.2)
- **PPA (Partnership):** The site host enters into a PPA, which in turn is financed by a partnership (as described in Section 3.3 and Appendix C)

Meanwhile, for *tax-exempt* site hosts, the models include the following:

- **Balance Sheet:** The site host finances the project on its balance sheet (as described in Section 4.1)
- **Muni Bonds:** The site host finances the project using municipal debt, or with reserve funds that have an opportunity cost of capital approximated by municipal debt interest rates (as described in Section 4.2.1)
- **CREBs:** The site host finances the project using CREBs (as described in Section 4.2.2)

[28] For example, the partnership models do not track each partner's capital account or outside basis, as described in Martin (2008).

- **Tax-Exempt Lease:** The site host finances the project using a tax-exempt lease (as described in Section 4.3).
- **Service Contract (Partnership):** The site host enters into a service contract/PPA, which in turn is financed by a partnership (as described in Section 4.4 and Appendix C).
- **Pre-Paid Service Contract:** The site host enters into a pre-paid service contract (as described in Section 4.5).

In all cases, the financial analysis ignores the impact of power bill savings on site host economics, under the assumption that power bill savings will not differ under the various financing structures examined. 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 rebates 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 the modeled revenue requirement, then the project will likely be economical (presuming the model's assumptions reflect reality over time). These simplifying assumptions greatly reduce the complexity of the modeling, since power bill savings in particular 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 report (Wiser et al., 2007).

Although PV systems are widely expected to operate for longer than 20 years (and some PV panels are sold with a 25-year warranty), each financing structure is uniformly evaluated over a 20-year term in order to maintain comparable results. Twenty years seems to be a typical term for a PPA/energy service contract, and therefore sets the standard. Furthermore, the modeling ignores any end-of-term or early buyout options (i.e., it assumes that, if present, these options are *not* exercised), once again for the sake of simplicity. As discussed in Chapters 3 and 4, these purchase options must be priced at a minimum of "fair market value." To the extent that a project's "fair market value" can be equated with the present value of future cash flows under a full-term (i.e., 20 years in this case) continuation of the existing contractual arrangement, then the modeling results should be largely indifferent as to whether or not a purchase option is exercised (particularly if the discount rate used is the same as the implied project-level IRR).

Base-case modeling assumptions, common across all financing structures except where noted, include the following (and are also listed in Tables 1 and 2 in the next section):

- A 500 $kW_{DC}$ system (rated output under standard test conditions) with an installed cost of $\$6/W_{DC}$. Though system size does not materially impact the modeling (given that assumptions are specified on a per-kW basis), a 500 kW system falls within a size range where most of the financing structures discussed in this report are feasible. For example, 500 kW is not necessarily too large for a typical lease, nor too small for a typical PPA (particularly if part of a portfolio of projects). Based on extensive installed cost data collected by Berkeley Lab (Wiser et al., 2008), the average pre-incentive cost for systems of this size installed in the United States in 2007 is roughly $\$7/W_{DC}$, with some systems installed for $\$6/W_{DC}$ or less. Given anecdotal reports of a significant decline in module prices in 2008 (and expected to continue into 2009 and beyond), and an increasing likelihood that only the lowest-cost projects will be built in this challenging financial environment, \$6/$W_{DC}$ seems to be a reasonable installed cost assumption.

- Except for those financing structures specifically using municipal debt or CREBs, no leverage is used at the project level. This assumption is largely consistent with reality – i.e., non-residential PV projects are often too small, and in most cases do not throw off enough cash, to warrant the use of project-level debt. In order to reach a critical mass on investment size, Tax Investors will typically want (or even need) to equity-finance essentially the full cost of the project, and will also prefer to avoid the inter-creditor issues that arise when debt is introduced at the project-level. That said, with PV economics becoming more-challenging as state-level incentives decline faster than installed costs, the use of project- or fund-level (i.e., portfolio-level) debt may be one way to boost equity returns back up to the levels necessary to attract investment. As such, debt financing is explored later through scenario analysis.
- Federal tax incentives include a 30% ITC and 5-year MACRS depreciation. For taxable owners, the ITC is applied to the full installed cost of the project (i.e., because the state-level cash incentives are assumed to be taxable, there is no reduction in the project's tax credit basis). Depreciation, meanwhile, is applied to 85% of the project's installed cost, i.e., after deducting 50% of the 30% ITC.
- The base-case generic analysis presented in Section 5.2 assumes *no* state-level incentives, to allow for an examination of the financing structures independent of the vagaries of state policy. In other words, some states (like California) provide differentially higher incentive levels to tax-exempt system owners as a way to make up for their inability to use the ITC; these different incentive levels mask the impact of financing structure on revenue requirements, and so are initially ignored. Section 5.3, however, re-runs the analysis assuming California state incentives, as laid out under the California Solar Initiative (CSI).
- Annual system performance is assumed to be 1,350 kWh/$kW_{DC}$ in the first year (i.e., roughly a 15.4% capacity factor in DC terms), degrading by 0.5% per year over the full 20-year analysis period (Itron, 2008). O&M costs are assumed to equal \$30/kW-year in year one, increasing at a 3% nominal escalation rate.
- Where applicable, a nominal PV price escalator of 4%/year is built into the model. This falls within the 1%-5% range that is often cited with respect to solar PPA escalation rates, and is at the high end of that range in acknowledgment of the increasing difficulty that PPA providers are having in matching first-year utility prices (i.e., a higher escalation rate can enable a lower first-year PPA price).[29]

[29] Incidentally, another tool that PPA providers might use to make the economics of a PPA pencil out vis-à-vis utility rates, particularly for those site hosts who want to eventually own the system anyway, is to start the PPA artificially low in years 1-6 (so that it beats utility pricing), and then have a significant step up in price starting in year 7 (accompanied by an early buyout option at the end of year six). This step up would encourage the site host to exercise the early buyout option, thereby making the Tax Investor and developer whole before the PPA price becomes uncompetitive. By the end of six years, the early buyout price could be relatively low, given that the project's Tax Benefits and cash incentives (i.e., CBIs or PBIs) will have been exhausted. For example, in a recent PPA between Chevron Energy Solutions and the Milpitas School District, the early termination value at the end of year six – which will also serve as the early buyout price *if* it is greater than the project's FMV – is just 52% of the estimated installed project costs. Once it owns the project, a taxable site host is also free to re-depreciate it (starting from the purchase price, not the original installed cost), thereby providing some limited tax benefit.

- For financing structures involving leases, the lease term is assumed to be 20 years, with a 20% residual value. The one exception is the tax-exempt lease, which is structured as a capital (rather than operating) lease with 0% residual value. A 20-year term may be too long for a typical operating lease with a taxable site host (10-15 years is probably more representative), but assuming a 20-year term simplifies the comparison to other structures. A minimum 20% residual value assumption is required by the IRS in order to qualify as a "true" or operating lease (see Text Box 2 in Section 3.2).
- The applicable federal and state income tax rates are assumed to be 35% and 7%, respectively, with state depreciation following the federal 5-year MACRS schedule.
- For PPA projects that are financed by the developer partnering with a Tax Investor in a special allocation partnership flip structure, the developer puts up 1% of the project equity and receives a proportional 1% of the project's cash and tax allocations prior to the flip. After the flip, the developer receives 95% of all cash and tax allocations. The Tax Investor, meanwhile, puts up 99% of the equity, and receives 99% of all cash and tax allocations prior to the flip, dropping to 5% after the flip. The flip is assumed to occur at the end of 18 years, which is relatively late in the project's life, particularly considering that the project's Tax Benefits will have largely been exhausted by the end of six years (and hence the flip could occur that early). A late flip is necessary, however, to generate a competitive solar PPA price that a site host might find attractive; the earlier the flip occurs, the higher that PPA price will be.[30] Though not ideally efficient, a late flip is not necessarily a deal-killer for Tax Investors, which in general prefer to see their capital invested for longer rather than shorter periods (Abel, 2007; Levin, 2008).
- For those projects financed with Tax Equity, the Tax Investor's target internal rate of return (IRR) is assumed to be 7% (after-tax, unleveraged, over the full 20-year term), which is consistent with figures quoted in Martin (2008). The one exception is the "Operating Lease" model, which assumes a 10% after-tax IRR hurdle rate to reflect the relatively greater involvement and risk taken by the Tax Investor in putting together the deal. The current financial crisis has reportedly pushed tax equity yields up by roughly 200 basis points; the impact of this higher required return is explored later through sensitivity analysis. In the case of the "Balance Sheet" model, which does not involve third-party Tax Equity, the 20-year after-tax IRR hurdle rate is assumed to be 10% (for both taxable and tax-exempt site hosts – the difference in revenue requirements will simply equal the value of the project's tax benefits).
- The "Muni Bonds" and "CREBs" models assume that 100% of project costs are financed either by municipal bonds or CREBs, respectively. Some governmental entities may instead choose to finance some portion of the project with "equity" (e.g., drawn from reserves), but in such cases the opportunity cost of that equity is presumed to be the cost

[30] Said another way, setting the solar PPA price equal to or less than the current utility power price will ensure that a Tax Investor cannot achieve its target rate of return in just 6-7 years (i.e., when the flip in allocations could first feasibly occur). Instead, the Tax Investor will need to maintain its preferred allocations for a significantly longer period of time – e.g., 18 years is our base-case assumption – in order to meets its after-tax IRR hurdle rate. A scheduled flip date that is this late in the life of a 20-year PPA does not allow much leeway for project underperformance, which would have the effect of postponing the flip date until the Tax Investor's return hurdle is met. As discussed in Appendix C, however, PV projects are likely to have less overall return variability than are wind projects, where the wind resource might vary significantly from year to year. Finally, note that such a late flip date helps to minimize the potential impact of specialized accounting issues relating to each partner's capital account (as described in detail in Martin, 2008).

of borrowing through municipal debt, thereby resulting in minimal impact on the model. Tax-exempt municipal bonds are assumed to have a 20-year term, a 5% interest rate, and a debt service coverage ratio of 1.0.[31] CREBs are assumed to have a 15-year term, a 1% interest rate (i.e., greater than 0%, in a crude attempt to reflect transaction costs), and a debt service coverage ratio of 1.0.

- In the "Pre-Paid Service Contract" model, the tax-exempt site host is assumed to pre-pay an amount equivalent to 30% of project costs using tax-exempt municipal debt, with terms as described in the previous bullet. A pre-paid contribution of more than 30% leaves the Tax Investor and project developer with insufficient ongoing cash flow to cover tax payments in later years (recall that the pre-payment is received up-front, but is booked as taxable income over time as it is earned).

## 5.2 Generic Modeling Results

Table 1 presents base-case assumptions and modeling results for taxable site hosts, while Table 2 presents the corresponding information for tax-exempt site hosts. As noted in the previous section, Tables 1 and 2 assume no state-level incentives, as a way to better isolate the impact of financing structure on project economics. Since the previous section discussed modeling assumptions in detail, this section focuses only on the base-case results.

The first two rows in the "RESULTS" section of Tables 1 and 2 show the first-year and levelized 20-year (nominal) \$/kWh revenue that is required to satisfy all modeling constraints. As explained above, 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). Since these \$/kWh numbers potentially include REC revenue, and assume no state-level incentives, they should *not* be equated with representative solar PPA prices, which will be lower to the extent that state incentives are available and/or the PPA provider strips off the RECs and sells them separately.

For taxable site hosts, Table 1 shows that even though balance sheet finance and a site host operating lease generate the same 10% project-level return, the operating lease requires slightly less revenue over the full 20-year analysis period due to its assumed 20% residual value. Meanwhile, a solar PPA (in this case financed by a special allocation partnership "flip" structure between the PPA provider and a tax investor, though a lease structure would yield similar results) appears to be more economical than either balance sheet finance or a site host operating lease. This result is due almost exclusively to the lower assumed IRR hurdle rate for the PPA – i.e., 7.7% at the project level, versus 10% for either balance sheet finance or an operating lease. Commercial site hosts with a sufficient tax base and a return requirement of 7.7% or less will find balance sheet finance to be more attractive (in terms of amount of revenue required); conversely, third-party ownership will look increasingly attractive as a taxable site host's return requirement increases above 7.7%.

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[31] As a result of the unfolding financial crisis, the spread between tax-exempt municipal bonds and taxable corporate bonds has narrowed considerably, thereby eroding some of the advantage of tax-exempt debt. The base-case assumptions used in this analysis, however, are intended to replicate a period of stability, rather than a period of crisis. As such, a 5% municipal bond yield seems broadly representative.

**Table 1. Base-Case Results for Taxable Site Hosts (No State Incentive)**

| | Balance Sheet | Operating Lease | PPA (Partnership) |
|---|---|---|---|
| **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) | $30 | | |
| Annual O&M Escalation (%/year) | 3% | | |
| Period of Analysis (years) | 20 | | |
| State Incentive Type | NONE | | |
| State Incentive Level | NONE | | |
| PV Price Escalator | 4% | | 4% |
| Flip Point Target (year) | | | 18 |
| Lease Term (years) | | 20 | |
| Residual Value (% of installed cost) | | 20% | |
| Debt Leverage (% of installed cost) | 0% | | |
| **RESULTS** | | | |
| First-Year Revenue ($/kWh) | 0.336 | 0.397 | 0.270 |
| Levelized 20-Year Revenue ($/kWh) | 0.441 | 0.413 | 0.354 |
| Tax Investor 20-Year After-Tax IRR | | 10.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | 20.0% |
| Project 20-Year After-Tax IRR | 10.0% | 10.0% | 7.7% |

Turning to the generic results for tax-exempt site hosts, the first thing to note in Table 2 is that the results for the PPA/service contract model do not differ from those presented above in Table 1. That is, other than some minor changes to the documentation in order to ensure that a PPA with a tax-exempt site host is clearly viewed as being a "service contract" rather than a lease, the underlying economics of the financing model are the same as they are for taxable site hosts.

Whereas the PPA was the most economical finance option for taxable site hosts, there are – at least in theory, based on the assumptions used in this analysis – two other potentially more-economical options for tax-exempt site hosts.

Specifically, the Pre-Paid Service Contract, which combines the advantages of both tax-exempt debt financing and full use of the project's Tax Benefits, appears to be the lowest-cost financing option available to tax-exempt site hosts. Despite its potential appeal, this structure is not in common use, in part due to its relative complexity and associated legal and other transaction costs (perhaps not adequately captured here), which may be prohibitive for non-residential PV projects, most of which cost less than $10 million to build. Indeed, the only working examples of this structure in use for renewable energy projects involve large wind power projects with installed costs in excess of $350 million.

Financing the entire project using CREBs (with an assumed effective 1% interest rate) appears to be the next-most-attractive option. Like the Pre-Paid Service Contract, however, CREB financing requires considerable up-front legwork, in this case to secure an allocation and then issue the bonds. These early transaction costs, which are approximated here by a 1% (i.e., rather than 0%) interest rate, may not be adequately accounted for in this analysis.

**Table 2. Base-Case Results for Tax-Exempt Site Hosts (No State Incentive)**

| | Balance Sheet | Muni Bonds | CREBs | Tax-Exempt Lease | Service Contract (Partnership) | Pre-Paid Service Contract |
|---|---|---|---|---|---|---|
| **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) | $30 | | | | | |
| O&M Escalation (%/year) | 3% | | | | | |
| Period of Analysis (years) | 20 | | | | | |
| State Incentive Type | NONE | | | | | |
| State Incentive Level ($/kWh) | NONE | | | | | |
| PV Price Escalator | 4% | | | | 4% | |
| Flip Point Target (year) | | | | | 18 | |
| Lease Term (years) | | | | 20 | | |
| Residual Value (% of installed cost) | | | | 0% | | |
| Debt Term (years) | | 20 | 15 | | | 20 |
| Debt Interest Rate | | 5% | 1% | | | 5% |
| Debt Service Coverage Ratio | | 1.0 | 1.0 | | | 1.0 |
| Debt Leverage (% of installed cost) | | 100% | | | | 30% |
| **RESULTS** | | | | | | |
| First-Year Revenue ($/kWh) | 0.432 | | | 0.442 | 0.270 | 0.240 |
| Levelized 20-Year Revenue ($/kWh) | 0.568 | 0.397 | 0.328 | 0.462 | 0.354 | 0.284 |
| Tax Investor 20-Year After-Tax IRR | | | | 7.0% | 7.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | | | 20.0% | 18.3% |
| Project 20-Year After-Tax IRR | 10% | | | 7.0% | 7.7% | 7.5% |

The loss of Tax Benefits in the Balance Sheet model adds more than $0.12/kWh (i.e., $0.568/kWh vs. $0.441/kWh) to the levelized revenue requirement of a tax-exempt site host, making this the most-expensive option (though perhaps the only direct ownership option available to non-governmental, non-profit site hosts). The advantage of low-cost municipal debt (with an assumed 5% interest rate) more than makes up for this deficit in the Muni Bonds model (i.e., $0.397/kWh vs. $0.441/kWh), suggesting that states that provide differentially higher incentives to tax-exempt project owners may be doing so unnecessarily. Without differentially higher state-level incentives, however, the Muni Bonds option is still not quite competitive with the Service Contract (PPA) at $0.354/kWh.

Finally, a Tax-Exempt Lease avoids some of the up-front transaction costs associated with Muni Bonds and CREBs (by being a non-budgetary item, by not requiring voter pre-approval, etc.), yet is less-economical than Muni Bonds due to the higher assumed return requirement of the Tax Investor/lessor. This higher return is necessary to account for the fact that a tax-exempt lease is less-secure than a municipal bond.

## 5.3 California-Specific Modeling Results

Although comparing financing structures independent of the influence of state-level incentives is informative, it is also unrealistic. Very few non-residential PV systems have been installed without the aid of state-level incentives. This section, therefore, incorporates state-level incentives into the analysis in order to provide a more-realistic assessment of actual (though subsidized) PV costs.

For two primary reasons, this section analyzes and compares each financing structure within the context of California's solar market. 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 report originated and has become most-firmly entrenched. Second, the California Solar Initiative – which offers not only two different types of incentives (PBIs and EPBBs), but also a transparent schedule of how incentive levels change over time as installed capacity goals are met – provides an ideal framework for scenario and sensitivity analysis that is, at least somewhat, grounded in reality (that is, the scenario and sensitivity analyses are based on the CSI's published schedule of incentive levels).

Although the remainder of this section focuses on California, Section 5.4 will provide some brief insights into other U.S. markets that are more-highly dependent on long-term SREC revenue (namely, New Jersey and Colorado).

### 5.3.1 Base-Case California Results

The base-case California state incentive is assumed to be a 5-year taxable PBI (CBIs are examined later, through scenario analysis), equivalent to the Step 5 CSI levels shown in Table 3 for either taxable ($0.22/kWh) or non-taxable ($0.32/kWh) owners, as the case may be. Step 5 is used because all three utilities participating in the CSI had reached Step 5 for non-residential system owners as of November 2008. Tax-exempt system owners receive higher CSI incentive levels to compensate for their inability to benefit from the project's Tax Benefits. Note that the differentially higher incentives provided to non-taxable entities only apply if the non-taxable site host is the project owner; taxable third-party owners selling power or leasing systems to a non-taxable site host will receive the lower (taxable) incentive levels.

**Table 3. Non-Residential Incentive Schedule for California Solar Initiative**

| | | 5-Year PBI ($/kWh) | |
|---|---|---|---|
| | | Non-Residential | |
| Step | MW | Taxable | Tax-Exempt |
| 1 | 50 | -- | -- |
| 2 | 70 | 0.39 | 0.50 |
| 3 | 100 | 0.34 | 0.46 |
| 4 | 130 | 0.26 | 0.37 |
| **5** | **160** | **0.22** | **0.32** |
| 6 | 190 | 0.15 | 0.26 |
| 7 | 215 | 0.09 | 0.19 |
| 8 | 250 | 0.05 | 0.15 |
| 9 | 285 | 0.03 | 0.12 |
| 10 | 350 | 0.03 | 0.10 |

Although the applicable federal income tax rate is still assumed to be 35%, state income tax rates follow California's rates in this case, which are either 10.84% (for banks and other financial institutions) or 8.84% (for all other commercial entities). All third-party Tax Investors are assumed to face the higher 10.84% state tax rate. California's depreciation schedule for state income tax purposes does *not* follow the federal 5-year MACRS schedule; instead, California uses a 12-year straight-line schedule for PV projects.

Table 4 shows modeling results for taxable site hosts in California. The first two rows in the "RESULTS" section show the first-year and levelized 20-year (nominal) $/kWh revenue that is required 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, Wiser 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 (i.e., below even the lowest first-year revenue requirement of $0.206/kWh shown in Table 4, for the PPA model).

Compared to Table 1, the amount of revenue required in Table 4 has decreased by almost $0.09/kWh (on a 20-year levelized basis) for all three models as a result of the 5-year PBI of $0.22/kWh. The relative ranking of the different models, however, is the same as that shown earlier in Table 1, with the PPA requiring the least amount of revenue (due to its lower return requirement of 7.6% at the project level, versus 10% for the other two models), followed by the operating lease (with its 20% residual value) and then balance sheet finance.

**Table 4. Base-Case Results for Taxable Site Hosts in California**

| | Balance Sheet | Operating Lease | PPA (Partnership) |
|---|---|---|---|
| **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) | $30 | | |
| Annual O&M Escalation (%/year) | 3% | | |
| Period of Analysis (years) | 20 | | |
| State Incentive Type | 5-Year PBI | | |
| State Incentive Level ($/kWh) | 0.22 | | |
| PV Price Escalator | 4% | | 4% |
| Flip Point Target (year) | | | 18 |
| Lease Term (years) | | 20 | |
| Residual Value (% of installed cost) | | 20% | |
| Debt Leverage (% of installed cost) | 0% | | |
| **RESULTS** | | | |
| First-Year Revenue ($/kWh) | 0.267 | 0.313 | 0.206 |
| Levelized 20-Year Revenue ($/kWh) | 0.351 | 0.326 | 0.270 |
| Tax Investor 20-Year After-Tax IRR | | 10.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | 18.8% |
| Project 20-Year After-Tax IRR | 10.0% | 10.0% | 7.6% |

Again, the revenue requirements under the PPA model may be met through some combination of power sales and REC revenue, and so therefore 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 first-year revenue requirement under the PPA model ($0.206/kWh) is in the ballpark of a recent 3+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.

Turning to tax-exempt site hosts, Table 5 illustrates the impact of the differentially higher PBI of $0.32/kWh (vs. $0.22/kWh) provided to the three direct ownership models (i.e., balance sheet, muni bonds, and CREBs). Specifically, the higher PBI payments have made CREBs more economical than the Pre-Paid Service Contract, and Muni Bonds more economical than a normal Service Contract (i.e., PPA).

The Tax-Exempt Lease is among the least-economical options, for two main reasons. First, as a capital lease, where the lessee is considered to be the owner for tax purposes, this structure does not take advantage of the project's Tax Benefits (i.e., neither the lessor nor lessee claims them). Second, presuming that the lessor is a taxable entity, a project financed by a tax-exempt lease will not qualify for the higher tax-exempt PBI ($0.32/kWh) in California, and instead will receive the lower taxable PBI ($0.22/kWh).

**Table 5. Base-Case Results for Tax-Exempt Site Hosts in California**

| | Balance Sheet | Muni Bonds | CREBs | Tax-Exempt Lease | Service Contract (Partnership) | Pre-Paid Service Contract |
|---|---|---|---|---|---|---|
| **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) | $30 | | | | | |
| O&M Escalation (%/year) | 3% | | | | | |
| Period of Analysis (years) | 20 | | | | | |
| State Incentive Type | 5-Year PBI | | | | | |
| State Incentive Level ($/kWh) | 0.32 | | | 0.22 | | |
| PV Price Escalator | 4% | | | | 4% | |
| Flip Point Target (year) | | | | | 18 | |
| Lease Term (years) | | | | 20 | | |
| Residual Value (% of installed cost) | | | | 0% | | |
| Debt Term (years) | | 20 | 15 | | | 20 |
| Debt Interest Rate | | 5% | 1% | | | 5% |
| Debt Service Coverage Ratio | | 1.0 | 1.0 | | | 1.0 |
| Debt Leverage (% of installed cost) | | 100% | | | | 30% |
| **RESULTS** | | | | | | |
| First-Year Revenue ($/kWh) | 0.321 | | | 0.393 | 0.206 | 0.172 |
| Levelized 20-Year Revenue ($/kWh) | 0.422 | 0.251 | 0.182 | 0.411 | 0.270 | 0.195 |
| Tax Investor 20-Year After-Tax IRR | | | | 7.0% | 7.0% | 7.0% |
| Developer 20-Year After-Tax IRR | | | | | 18.8% | 13.0% |
| Project 20-Year After-Tax IRR | 10% | | | 7.0% | 7.6% | 7.2% |

### 5.3.2 California Scenario Analysis

The previous section presented California-based base-case modeling results that assume no project leverage (with the exception of the three models utilizing municipal bonds and CREBs) and a 5-year PBI. Along with these base-case results, Tables B.1 through B.8 in Appendix B present corresponding modeling results for each model from three alternative scenarios, including a leveraged PBI scenario and both a leveraged and unleveraged CBI (EPBB) scenario. The two leveraged scenarios assume 15-year debt at 7% interest, a minimum debt service coverage ratio of 1.4, and Tax Investor IRR targets that are 250 basis points higher than assumed in the base-case scenario (to account for the greater risk involved with debt). The two CBI scenarios assume an EPBB that is equivalent to the present value (using a 10% nominal discount rate) of the corresponding 5-year PBI from Step 5 of the CSI. As such, the assumed CBIs should yield roughly the same revenue requirements as the corresponding 5-year PBIs.[32] Aside from these changes, all other base-case assumptions described above are maintained.

Model-specific results are not particularly enlightening, and are therefore relegated to Appendix B. Two general observations, however, fall out of the numbers. First, in the two models financed entirely by tax-advantaged debt (municipal bonds and CREBs), the PBI-equivalent CBI yields significantly higher revenue requirements (on a 20-year levelized basis) than does the 5-year PBI itself. This is simply because a 5-year PBI leaves very little need for additional revenue (to cover debt service) during the project's first five years, which strongly impacts the 20-year levelization calculation.

Second, the leveraged scenarios illustrate that it is difficult to highly leverage most PV projects, and in particular those receiving CBIs rather than PBIs. Specifically, CBIs reduce up-front costs (which mitigates the need for leverage), but provide no ongoing support for debt service coverage. As a result, CBI projects were generally only able to achieve leverage of 30%-33% of total installed costs, depending on the model. PBI projects did slightly better, at 43%-46% leverage, as the additional 5-year income stream helps to support additional debt. In general, though, the sizable Tax Benefits provided to PV projects (30% ITC and 5-year MACRs) mean that relatively little cash income is required to generate target returns, which in turn limits the amount of debt that these projects can support. This is somewhat unfortunate, because, as a relatively long-term and stable investment, PV would otherwise be a natural candidate to benefit from the reduction in revenue requirements that comes with greater leverage.[33]

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[32] Although a published schedule of EPBB levels for the various CSI steps exists (similar to that provided for PBIs and shown in Table 3), these published EPBB levels represent the buy-down received by a system whose performance is expected to match that of a "reference system" for a given location. In other words, systems that are not expected to perform as well as the reference system will receive a de-rated buy-down payment that is lower than the published EPBB. Since the system performance assumed for the PBI-based analysis shown in Tables 4 and 5 is not intended to match the performance of any particular reference system, the most analytically sound method of constructing CBIs seemed to be to simply equate the CBI level to the present value of the 5-year PBI payments. This approach allows for an examination of the structural impact of CBIs vs. PBIs on required revenue, independent of any impacts caused by the incentive levels themselves (although differential tax effects – not accounted for here – will prevent the CBIs derived in this manner from *exactly* matching the PBIs, in terms of their impact on revenue requirements).

[33] Although a commercial PV project may not support much debt at the project-level, an equity investor in the project may still choose to borrow a portion of its equity stake, thereby adding leverage at the developer- or

The three exceptions to the previous paragraph are balance sheet finance for a tax-exempt site host, the tax-exempt lease, and the pre-paid service contract. The first two structures realize none of the project's Tax Benefits, and therefore can support incrementally more debt (as high as 67-68% with a PBI) through higher revenue and lease payments. The pre-paid service contract, on the other hand, cannot feasibly utilize any more leverage than what is already provided through the 30% pre-payment amount, because ongoing "normal" income is artificially reduced by the pre-payment, and is insufficient to support debt.

### 5.3.3 California Sensitivity Analysis

Using the California base-case assumptions described above as a starting point (i.e., unleveraged PBIs), this section takes a closer look at individual modeling assumptions to gauge their impact on the economics of non-residential PV systems in California. Specifically, this section analyzes variations in assumed installed costs, PBI incentive levels, municipal bond and CREB interest rates, residual values (for those models involving leasing structures), the year in which the "flip" occurs (for those models involving partnership structures), and Tax Investors' after-tax IRR targets.

Figure 4 shows the 20-year levelized revenue requirements over a range of installed costs from $4/W$_{DC}$ to $8/W$_{DC}$ ($6/W$_{DC}$ is the base-case assumption). In some cases, first-year revenue requirements might be considerably lower than the 20-year levelized revenue requirements shown (considering the 4% escalation rate). As installed costs drop from the $6/W$_{DC}$ base-case assumption to $5/W$_{DC}$, required revenue falls by $0.04/kWh to $0.09/kWh ($0.06/kWh on average), making the solar sale significantly easier. As cost falls to $4/W and below, the pre-payment percentage in the Pre-Paid Service Contract must drop from 30% to around 25% in order to maintain positive after-tax cash flow in the project's later years.

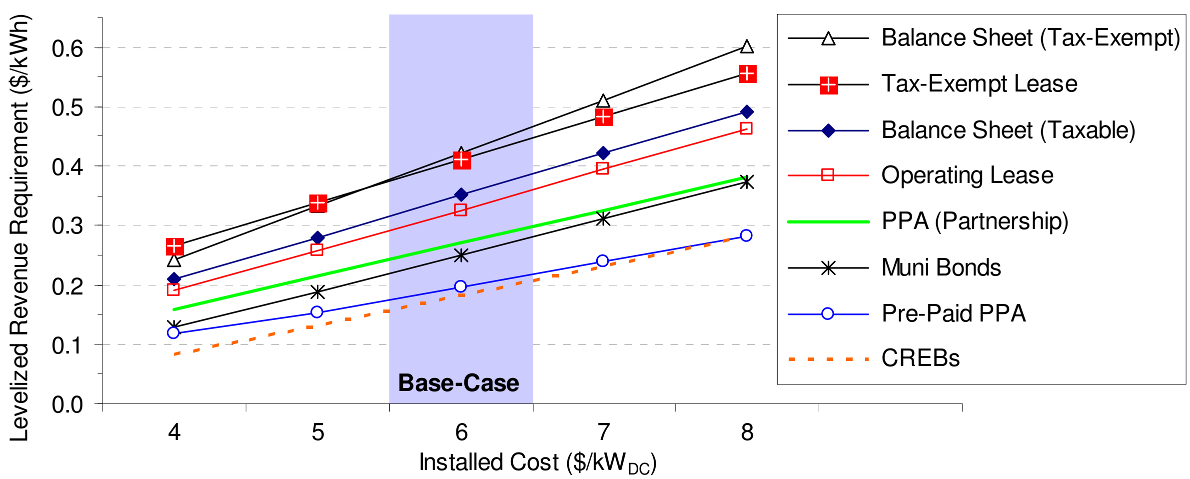


**Figure 4. Sensitivity to Changes in Installed Cost**

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investor-level. This "back-leverage" approach, which has gained popularity in the wind market in recent years, can boost investor returns while leaving the project itself unencumbered by debt.

Figure 5 shows the impact of changes in the PBI payment to both taxable and non-taxable owners, following the path from Step 2 to Step 7 (left to right) of the CSI, as laid out earlier in Table 3 from Section 5.3.1. The base-case assumption is Step 5, which all three participating utilities had reached as of late November 2008. Three of the eight models – Tax-Exempt Balance Sheet, Muni Bonds, and CREBs – involve the higher PBIs for tax-exempt owners, shown on the top x-axis. As PBI payments decline from Step 5 to Step 6, required revenue increases by about $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.[34]

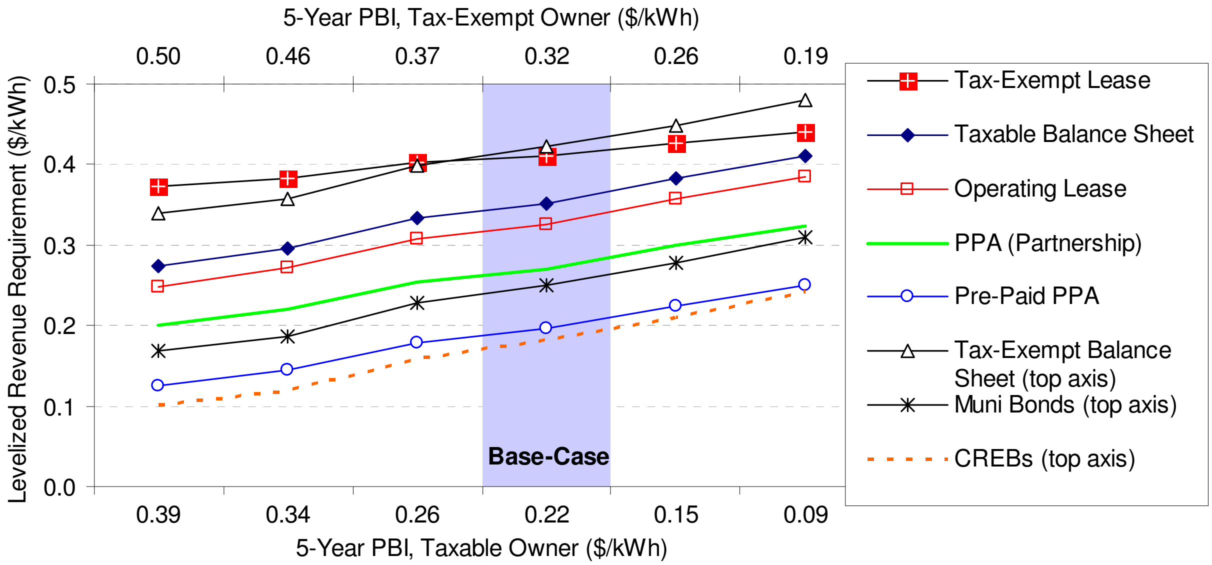


**Figure 5. Sensitivity to PBI Levels**

Figure 6 shows the impact of varying bond yields for both CREBs and municipal bonds. CREBs are nominally zero-interest bonds, though, as discussed earlier, this ideal has rarely been achieved in practice, as high transaction costs, sub-benchmark issuer credit, and in some cases weak demand have combined to make effective borrowing costs something greater than 0%. The base-case assumption is a 1% effective interest rate, which varies from 0% to 3% in Figure 6. Municipal bond rates, which impact the Municipal Bond and Pre-Paid Service Contract models, are shown in a range from 3% to 7% (the base-case assumption is 5%).

[34] For example, a February 2008 presentation on solar PPAs in California provides two examples of real contracts signed several years ago, one starting at $0.145/kWh and escalating at 1.85%/year, and the other starting at $0.165/kWh and escalating at 2.5%/year. These projects are old enough that they may have received incentives through California's Self-Generation Incentive Program, which preceded the California Solar Initiative. See http://www.solarschoolhouse.org/pdfs/forum/2008.2_SolarForum_LMerry_SolarPowerProviders.pdf for more information.

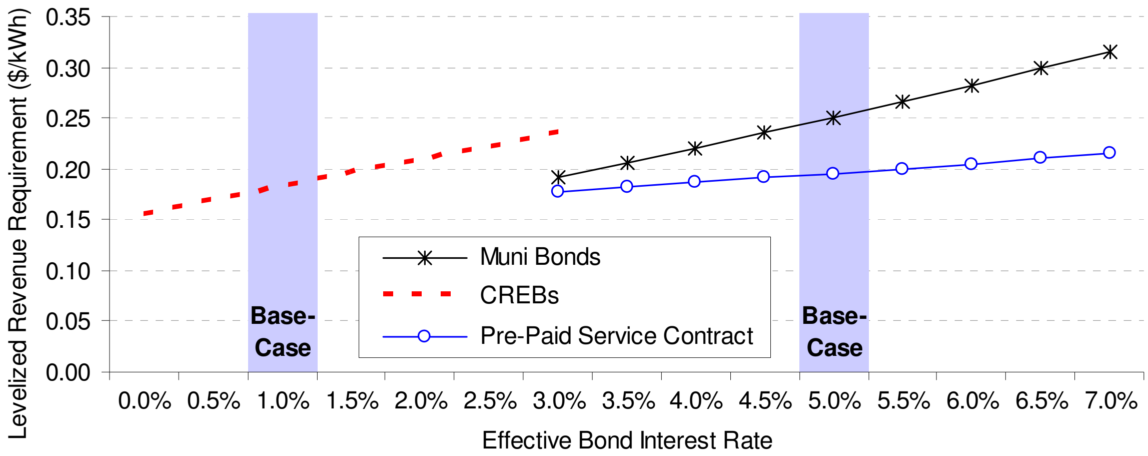


**Figure 6. Sensitivity to Bond Interest Rates**

Two items of interest arise. First, the Pre-Paid Service Contract is not as impacted by a change in municipal bond yields as is the Municipal Bond model, due to the difference in leverage between the two models (30% vs. 100%, respectively). Second, at an effective interest rate of 3%, CREBs are shown to be less economical than municipal bonds, for two reasons. First, the CREB term is 15 years, compared to the 20-year municipal bond. Second, CREB regulations have, at least under the first two rounds, required that principal be repaid in equal amounts, rather than using the back-loaded mortgage-style repayment schedule that is more commonly used for municipal debt. This leads to a higher debt-service burden in the early years, which in turn leads to higher levelized revenue requirements.

For those models taking a leasing approach, varying the assumed residual value of the project impacts levelized revenue requirements. The impact, however, is muted by the lengthy duration of the leases assumed here (20 years in all cases), which results in heavy discounting of the residual value. For example, varying the residual value from 15% to 30% changes levelized revenue requirements by only about $0.01/kWh in the Operating Lease model.

For the two models utilizing special allocation partnership flip structures, Figure 7 shows the impact of varying the year in which the flip is projected to occur (the base-case assumption is at the end of the 18$^{th}$ year). The PPA (Partnership) model is severely impacted by the flip date, particularly prior to year 10. Even though the flip could conceivably occur as early as the end of year 6 (by which time most of the project's Tax Benefits have run their course), in practice the need to have revenue requirements approach 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. Finally, as was the case with bond interest rates, the Pre-Paid Service Contract is not nearly as sensitive to changes in the flip date, because the pre-payment amount – which accounts for roughly half of revenue requirements – is not at all impacted by that flip date.

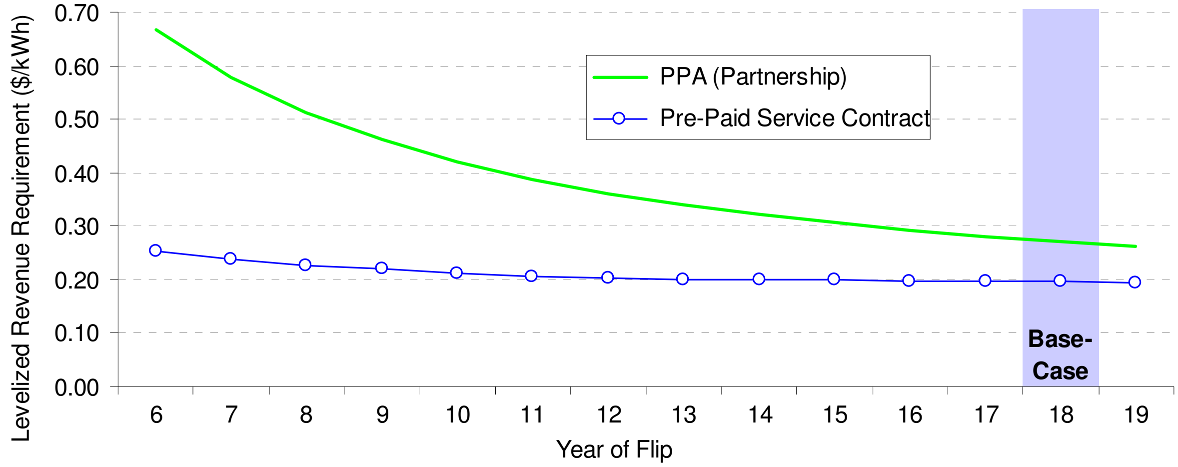


**Figure 7. Sensitivity to Flip Date**

With a nod towards the credit crisis currently roiling financial markets, Figure 8 shows the impact of changes in Tax Investor return hurdle rates. In the best of times, Tax Investor hurdle rates have fallen into the 6% range (our base-case assumption is 7%, except for the Operating Lease at 10%). Since the start of the financial crisis, however, yields are reportedly up by roughly 200 basis points (Raphael, 2008). Moving from 7% to 9% pushes levelized revenue requirements up by roughly 7 cents/kWh, with the exception of the Pre-Paid Service Contract, which – as has become the pattern – is not as sensitive to this variable since it does not impact the portion of the project that has been pre-paid and is financed by municipal debt. Although Figure 8 shows tax equity yields as high as 11%, it is perhaps unlikely that yields on unleveraged projects will reach or significantly surpass that level, as the ~9% yields that already exist are reportedly attracting new (non-financial) Tax Investors into the market.

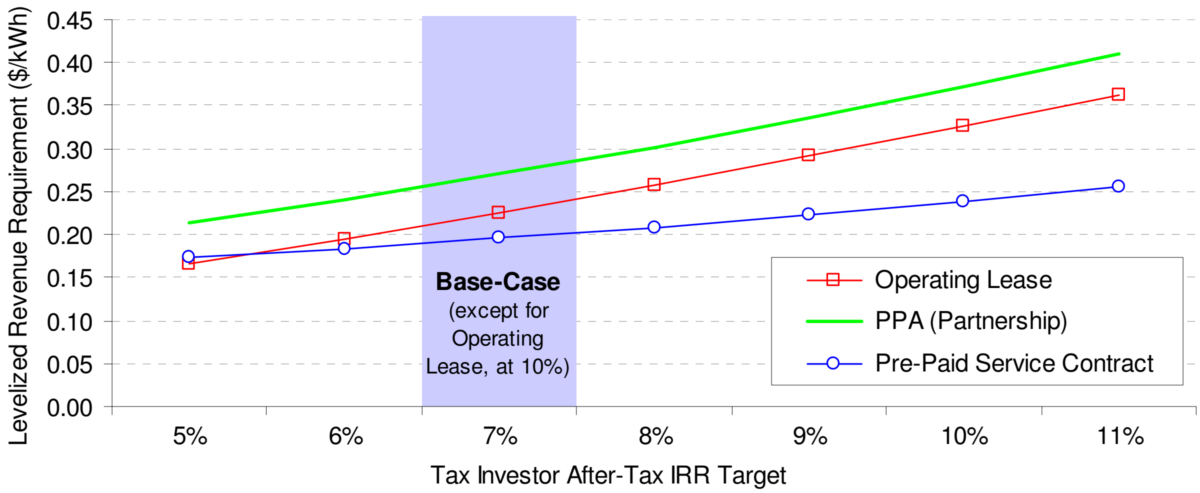


**Figure 8. Sensitivity to Tax Investor Return Targets**

Another way to think about the recent increase in tax equity yields is to translate them into installed cost terms. In other words, by how much would installed costs need to fall in order to exactly offset the recent increase in tax equity yields? According to the PPA (Partnership) model with base-case California assumptions, installed costs would need to drop to nearly \$5.00/$W_{DC}$ (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%. Taking this analysis one step further, if the 20-year after-tax IRR hurdle rate remains at 9% over time, then installed costs must drop further to \$4.56/W, \$4.16/W, and \$3.89/W as PBI levels decline in the future to \$0.15/kWh, \$0.09/kWh, and \$0.05/kWh (Steps 6-8), respectively, in order to maintain the base-case revenue requirements (first-year and levelized) shown earlier in Table 4.

## 5.4 A Very Brief Look at Other Markets

For reasons noted above, the analysis has so far been conducted first in a generic sense (i.e., with no state incentives), and then within the context of California's market. Several other states also feature growing PV markets, however, and some of these are employing significantly different policy structures to encourage PV. In particular, New Jersey and Colorado are two growing markets that are relying significantly on solar REC revenue rather than (or in addition to) CBIs. This section briefly examines the general economics of these two markets.

Both New Jersey and Colorado have enacted renewables portfolio standards (RPS) that include a specific requirement for solar. This "solar set-aside" creates demand for solar RECs among obligated electricity suppliers, leading to attractive SREC prices. In Colorado, non-residential systems sized between 10 kW and 100 kW receive not only a \$2/W CBI, but also a 20-year SREC contract priced at \$0.115/kWh. Plugging these revenue sources into the PPA (Partnership) model, while leaving all other base-case assumptions unchanged from those in Section 5.1 (except for the state income tax rate, which is changed to Colorado's 4.63% corporate rate), yields a levelized revenue requirement of just \$0.084/kWh (with a first-year requirement of just \$0.064/kWh, escalating at 4%/year thereafter). Note that this is a "post-REC" revenue requirement that must be met solely with power bill savings (and is therefore not directly comparable to the California-based results presented earlier, where REC prices are more modest and uncertain and have therefore not been broken out into a separate revenue stream).

New Jersey historically offered CBIs in combination with attractive solar REC pricing, but recently has transitioned to a market entirely dependent on solar RECs (for systems larger than 10 kW). PV projects in New Jersey are eligible to compete for 15-year solar REC contracts with the obligated utilities. Average spot prices have recently been in the range of \$0.25/kWh to \$0.35/kWh.[35] Plugging a 15-year REC contract priced at \$0.30/kWh into the PPA (Partnership) model, while leaving all other base-case assumptions unchanged from Section 5.1 (with the exception of (A) the state income tax rate, which is changed to New Jersey's 9% corporate business franchise tax rate; and (B) the flip date, which is shortened to the end of 15 years, which matches the duration of the REC contract), yields a 20-year levelized revenue requirement of \$0.09/kWh (with a first-year requirement of \$0.069/kWh, escalating at 4%/year thereafter). This is also a "post-REC" revenue requirement that must be met solely with power bill savings.

[35] Note that this is before full transition to solar RECs, so pricing might not be fully representative. For updated pricing information, see http://www.njcleanenergy.com/renewable-energy/programs/solar-renewable-energy-certificates-srec/pricing/pricing

From a modeling standpoint, these long-term SREC contracts have a similar impact as long-term PBIs, in the sense that they are performance-based and can also support greater leverage than a CBI (if leverage is used). The obvious difference is that with a PBI, the system owner retains the RECs, and their associated revenue potential (i.e., a PBI is an incentive or subsidy, not a payment in exchange for RECs). Furthermore, a long-term REC contract may have a significantly longer duration than most PBIs, thereby creating greater revenue certainty over time.

# 6. Policy Implications

Although the modeling results presented in Chapter 5 are interesting in and of themselves, they also raise a few broader policy implications at both the federal and state levels.

## 6.1 Federal

At the federal level, it is clear that the 30% ITC, combined with 5-year MACRS tax depreciation, provides a skewed investment climate that favors ownership by taxable over tax-exempt entities. On the other hand, a state and local government's ability to issue low-cost tax-exempt debt appears to more than make up for the shortfall, particularly when combined with differentially higher state-level cash incentives for non-taxable system owners. Furthermore, the recent introduction of CREBs provides qualifying tax-exempt site hosts with a financing vehicle that is difficult to beat, at least in theory (though in practice, transaction costs have reportedly eroded much of the incremental value promised by CREBs – recent changes to the program, made in connection with the third round of allocations, may mitigate some of these costs).

Perhaps more importantly than whether (or by how much) municipal bonds and CREBs can make up for lack of a tax base, however, is that a federal tax policy directed towards taxable entities need no longer be viewed as discriminating against tax-exempt site hosts that wish to pursue PV. In other words, the same Tax Benefits that favor private over public PV ownership have also led to the creation of a vibrant third-party finance model, through which taxable and tax-exempt site hosts alike can benefit. Though the use of tax-advantaged debt may prove to be slightly more (or less) economical than a solar services contract (i.e., a PPA) under different conditions, for those tax-exempt site hosts that are just as happy to host the system and purchase its power rather than owning it directly, a service contract can be an attractive way to "go solar" without incurring significant transaction costs or operational risk.

Finally, although the recent eight-year extension of the ITC likely renders these issues moot, the structure of the federal ITC has its own strengths and weaknesses from a policy standpoint. Starting with the negatives, the ITC rewards investment rather than production. Though an investment credit is arguably appropriate for small, decentralized technologies like PV, the recent up-scaling of PV project size in the non-residential sector calls into question the appropriateness of an ITC for what are essentially utility-scale projects. Indeed, many state and utility PV programs, particularly the leading market in California and New Jersey, are moving away from CBIs and towards PBIs or SREC markets for larger PV projects for this very reason.

The up-front, lump-sum nature of the credit also limits the number of developers and/or site hosts that are able to make efficient use of the credit in the year it is generated. Specifically, relative to the Section 45 PTC, which provides a more-gradual "payout" over a 10-year period, the ITC requires a significantly larger tax liability (at least proportionally) in the project's first year in order to fully absorb the credit.[36] This need has produced a growing dependence on Tax

[36] For example, a 500 $kW_{DC}$ PV system with a tax credit basis of $\$6/W_{DC}$ generates a 30% ITC of $900,000 in the project's first year. It would take 15 MW of wind power capacity – i.e., 30 times as much installed capacity, and generating roughly 65 times as much energy over the course of the year – to generate $900,000 of PTCs in a single

Investors to finance the surge in third-party ownership, which in turn has left the sector vulnerable to the current financial turmoil.

On the other hand, the fact that the ITC is fully absorbed in the first year of the project reduces the risk to Tax Investors, who can predict their tax capacity one year out much more accurately than they can ten years out (as is required for investments in wind projects). Furthermore, the up-front structure of the credit is theoretically appealing to Tax Investors because it potentially allows for an early exit from the project as soon as the credit has fully vested (by the end of year 5) and the project is fully depreciated (by the end of year 6). Many Tax Investors, however, prefer to invest their capital for longer periods, and otherwise are not able to exit the project that early anyway due to challenging economics which, as shown in Section 5.3.3, can require the Tax Investor to stay on into the project's late teens.

A final positive regarding the Section 48 ITC is its allowance of leasing, which is not available under Section 45 except where explicitly noted (e.g., for biomass projects). Although site host leases are increasingly rare, developers do often finance their PPA projects through operating leases (sale/leasebacks) with a Tax Investor. If federal tax support for PV were ever to migrate to Section 45 (where solar was once an eligible technology), a provision to allow leasing within Section 45 would presumably be welcomed by the industry.

## 6.2 State

State policy implications range from fundamental regulatory issues to PV incentive design considerations. Among the latter is the question of setting the proper incentive level, a task made more difficult by exogenous shocks to the market, such as the current financial crisis. Should incentive levels be increased (or decline more slowly, as the case may be) to account for the recent increase in Tax Investor return targets? Modeling analysis from the previous chapter suggests that a 200 basis point increase in tax equity yields may push PPA prices higher by 7 cents/kWh (levelized over 20 years), all else equal.

Unrelated to the financial crisis, now that third-party service contracts (PPAs) are a viable financing option, should tax-exempt PV system owners still receive differentially higher incentives, to make up for their inability to utilize federal Tax Benefits? Modeling analysis from the previous chapter (and independent from the third-party ownership option) suggests that differentially higher incentives for tax-exempt system owners may not be necessary if low-cost tax-advantaged debt is available.

In conjunction with the increase in the federal ITC from 10% to 30% starting in 2006, the growing trend away from state-level CBIs and towards PBIs (and SRECs) has hastened the shift towards third-party ownership. A site host will experience higher up-front ("post-rebate") costs and greater performance risk under a PBI than under a CBI. Third-party ownership effectively addresses these risks (up-front costs in the case of a lease, and both up-front costs and performance risk in the case of a PPA), and has as a result grown increasingly popular.

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year, assuming a 32.5% capacity factor and a PTC value of $21/MWh. Obviously, inclusion of tax depreciation benefits would alter this comparison considerably.

The rise of third-party ownership has, in turn, triggered a number of other issues for state policymakers to consider. As the economic tie between the PV system and the site host becomes less physical and more contractual under third-party ownership, PV program administrators will need to decide whether and under what conditions a PV system that has received a state- or utility-level incentive can be physically relocated. For example, if a site host defaults on its contractual commitments under a PPA, the system owner (the PPA provider or Tax Investor) might wish to relocate the system to a new site host. If that new site host is located outside of the state (or utility service territory, in the case of a utility incentive), then presumably the PV program administrator should have some mechanism by which to recapture some or all of the incentive that it had provided (this issue can become even more nuanced in the case of a CBI provided up front versus a PBI provided over time). A similar issue arises for "used" systems moving *into* the state or utility service territory – i.e., should they be eligible for incentives, even though they may have been previously subsidized elsewhere? Although this issue has always existed, even prior to the rise of third-party ownership (e.g., if a non-residential system owner goes bankrupt and sells the PV system to a different entity for use at a different location), the proliferation of third-party owners with no physical ties to a given location theoretically increases the probability of systems being relocated to maximize returns.

More generally, state regulators may need to decide the basic question of whether third-party owners of PV systems should be regulated as utilities, and whether third-party-owned systems should be eligible for net metering. As discussed earlier in Section 3.3 (Text Box 3), a number of states are currently looking into these issues, and at least two (Oregon and Nevada) have definitively ruled in favor of third-party ownership.

Another regulatory issue involves solar set-asides within state RPS policies, and whether to encourage or require obligated utilities to sign long-term contracts for SRECs. Attractive SREC pricing has emerged in a number of states with solar set-asides, but without long-term contracting provisions, REC prices will likely remain too uncertain to be factored into financing decisions. In other words, without a long-term contract, neither Tax Investors nor developers nor site hosts are likely to fully value this expected revenue stream, and instead will consider any upside potential from the sale of SRECs to be icing on the cake. As such, without long-term contracts, SRECs may not live up to their potential to drive greater PV deployment.

Finally, at both the state and federal levels, it is important to recognize that, because the PPA provider assumes the risk that the project does not perform as expected, and because the possibility of business failure resulting from widespread under-performance is without parallel (i.e., this risk is not as great in the case of direct ownership, where the site host's bottom line is presumably not particularly dependent on the performance of its PV system), the PPA model may favor more-established and more-financeable technologies such as crystalline PV at the expense of newer technologies such as thin-film (Chadbourne & Parke, 2008). This, in turn, could dampen innovation and/or delay the commercialization of promising new technologies. States wishing to promote certain PV technologies or applications could do so by providing differentially higher incentives as appropriate.

# 7. Conclusions

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 performance-based incentives at the state-level, third-party ownership has transformed the market for non-residential PV. With installed costs largely stagnant for the last several years and with state-level incentives declining over much of this period, third-party ownership – in concert with the more-attractive federal ITC starting in 2006 – has been a primary driver of the strong growth of PV in the non-residential sector. This is particularly true among tax-exempt non-residential entities, which potentially stand to gain the most from third-party ownership (since they cannot directly benefit from the federal tax benefits provided to solar).

Looking ahead, ongoing financial innovation is likely to be more evolutionary than revolutionary in nature. The recent eight-year extension of the 30% federal ITC provides a stable foundation upon which to structure projects and invest in supply chain capacity. Declining state-level incentives, however, may make third-party ownership (and solar in general) a harder sell, absent reductions in installed project costs. Moreover, the fallout from the current financial crisis will exacerbate the affordability challenge, as Tax Investors require higher returns in exchange for use of their tax base.

Against this backdrop, evolutionary tweaks to financial structures and product offerings are occurring. For example, in the face of a harder sell for PV alone, some PPA providers are now bundling short-payback energy efficiency improvements along with PV, resulting in a more-attractive overall package. Other PPA providers are asking the site host to share in O&M costs. Though still not common for PV, debt financing at the project or portfolio level is looking more attractive (notwithstanding its limited availability during the current financial crisis) as a way to boost investor returns while maintaining competitive PPA prices in this challenging environment. And a few developers are now trying to adapt third-party ownership models to the residential sector (although their competitive advantage recently dissolved when the $2000 cap on the residential ITC was removed).

More substantial twists on existing models may also emerge. For example, the pre-paid service contract capitalizes on the advantages of both tax-exempt and taxable ownership, and though limited in use for PV to date, may gain traction in the future among tax-exempt site hosts working on larger projects. Models that can better accommodate Cash Investors (such as private equity funds) may also become more prevalent as the financial crisis takes its toll on the traditional Tax Investor market (comprised mainly of banks and insurance companies, many of which are currently in a state of distress). Utilities are also likely to become more directly involved in PV ownership going forward, now that they are able to claim the ITC; utility ownership should also help to cement the trend towards larger, “utility-scale” PV projects.

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# Appendix A: Glossary of Acronyms and Terms

**Capital Lease:** A lease used primarily to finance the purchase of the leased asset, in which the lessee pays for substantially the entire asset over the course of the lease (i.e., the Residual Value of the leased property is quite low). In a Capital Lease, the lessee is considered the owner of the PV project for tax and accounting purposes, and is therefore entitled to the project's Tax Benefits.

**Cash Investor:** An investor in a PV project that prefers a cash-based return as opposed to one comprised primarily of Tax Benefits.

**CBI:** Capacity-Based Incentive – A rebate or buy-down, the size of which is based on the installed capacity of the system. CBIs are usually provided up-front, upon system completion, and are typically expressed on a $/W basis, sometimes accompanied by an overall percentage or dollar cap.

**Clawback Period:** The 5-year period during which the federal ITC vests, at a rate of 20% per year. If the project is sold prior to the end of the Clawback Period, the un-vested portion of the ITC must be recaptured.

**COD:** Commercial Operations Date – The date on which the project first achieves full commercial operations; often the same as the "placed-in-service" date. Except for sale/leaseback structures, Tax Investors must generally be fully invested in a PV project prior to its COD in order to claim the ITC.

**Depreciable Basis:** The dollar amount to which a tax depreciation schedule is applied. A PV project's Depreciable Basis is typically equal to the installed cost of the project, unless the project has received a non-taxable CBI, has otherwise utilized subsidized energy financing, or takes advantage of the federal ITC (in which case the Depreciable Basis must be reduced by one-half the value of the ITC).

**Developer:** Sometimes referred to as the project sponsor, installer, or integrator, this is the entity that initiates and develops the PV project, and may wish to participate in the ongoing ownership of the project through one of the financing structures described in this report.

**DOE:** United States Department of Energy

**DSCR:** Debt Service Coverage Ratio – The safety margin required by lenders to ensure that a project will generate sufficient cash flows to service its debt, i.e., to meet principal and interest payments. In this report, a DSCR of 1.4 was used for commercial debt (in scenario analysis only), which means that each project is expected to generate operating cash flows equal to 1.4 times the debt service in each period. In this way, the DSCR limits the amount of debt a project can support.

**EPBB:** Expected Performance-Based Buy-Down – A CBI that takes into account design factors that can impact the system's performance (e.g., orientation, tilt, shading). Systems that are expected to perform worse than a reference system will receive a de-rated EPBB.

**FASB:** Financial Accounting Standards Board – An organization that institutes accounting standards. Financial Account Standard Number 13 (FAS 13) governs the way in which businesses should account for lease transactions.

**Flip Point:** The point at which the Tax Investor has received a negotiated after-tax IRR on its investment. The Flip Point is typically structured to occur at some point *after* the federal ITC has fully vested and accelerated depreciation benefits have been exhausted. As such, the end of the sixth year is typically the earliest Flip Point that is possible in a solar project.

**FMV:** Fair Market Value – The price that a willing buyer would pay a willing seller for an asset that is sold through an arm's length transaction. FMV is often determined by a third-party appraisal, which may rely in part on a present value analysis of future cash flows. In most cases, the IRS requires that any purchase option embedded in a solar PPA or lease be priced no lower than the project's fair market value at the time the option is exercised.

**IRR:** Internal Rate of Return – In technical terms, the IRR is the discount rate that sets the net present value of an investment equal to zero. PV project financings are often structured to enable investors to reach a target after-tax IRR at a set point in time (i.e., at the Flip Point).

**ITC:** Investment Tax Credit – Section 48 of the U.S. Tax Code provides an investment tax credit equal to 30% of the installed cost (or Tax Credit Basis, if less) of a PV system.

**kW:** kiloWatt – One thousand Watts. In this context, a kW is a measure of electrical generation capacity. This report pertains primarily to

| | |
|---|---|
| | PV systems in the range of 10 kW to 2,000 kW, though a few larger systems are discussed in Appendix D. |
| **kWh:** | kiloWatt hour – The energy production of one kW for one hour. For example, 500 kW of PV capacity generating at peak output for two hours yields 1,000 kWh, or 1 MWh, of electricity. |
| **Lessee:** | The entity that receives financing from a Lessor, and remits regular lease payments in return. |
| **Lessor:** | The entity that provides financing to a Lessee, and receives regular lease payments in return. |
| **MACRS:** | Modified Accelerated Cost Recovery System – The method by which solar power assets are depreciated for tax purposes under the U.S. tax code. As a general rule of thumb, roughly 100% of a solar project's installed cost is eligible to be depreciated using a 5-year MACRS schedule (though in practice, the project's Depreciable Basis is reduced by half the amount of the federal ITC, which means that roughly 85% of the project's cost is depreciated). This accelerated tax depreciation (relative to the project's expected 30- to 40-year life) creates tax losses in the early years of a project, which Tax Investors use to offset taxable income from other business operations. |
| **MW:** | MegaWatt – One thousand kilowatts, or one million Watts. In this context, a MW is a measure of electrical generation capacity. |
| **MWh:** | MegaWatt Hour – The energy production of one MW for one hour. For example, 10 MW of capacity generating at peak output for two hours yields 20 MWh. |
| **Operating Lease:** | A type of lease that meets certain IRS and FASB requirements (described in Text Box 2 in the body of this report) and is used to finance the *use* of an asset, rather than the explicit *purchase* of the asset (e.g., at the end of the lease term, the Residual Value of the leased asset must be at least 20% of its original cost). In an Operating Lease, the lessor is considered the owner of the PV project for tax and accounting purposes, and is therefore entitled to the project's Tax Benefits. Refer to Text Box 2 and Section 3.2.2 in the body of the report for a more-formal definition of an Operating Lease. |
| **PBI:** | Performance- or Production-Based Incentive – A cash incentive paid over time, the amount of which depends on how well the |

system performs. PBIs are typically expressed on a $/kWh basis, and are often provided for just a few years (3-5 years).

**PTC:** Production Tax Credit – This federal incentive, contained in Section 45 of the U.S. tax code, currently provides an inflation-adjusted 10-year tax credit for each MWh of qualified renewable generation produced and sold. For 2008, the inflation-adjusted value of the PTC is $21/MWh.

**REC:** Renewable Energy Credit – A REC represents the attributes associated with one MWh of renewable power generation, and can either be bundled with or sold separately from the underlying generation from which it is derived. RECs are often used as a tool to evidence compliance with RPS policies.

**Residual Value:** The amount of economic value remaining in leased property at the end of a lease. For a lease to qualify as a "true" (Operating) lease, the IRS requires (among other things) that the residual value of the leased property must equal 20% of the original cost.

**RPS:** Renewables Portfolio Standard – A legislative or regulatory requirement that certain load-serving entities must source a minimum percentage of their generation portfolio from eligible renewable resources. More than half of all states have instituted RPS requirements, and more than half of all states with an RPS utilize a set-aside or REC multiplier to support solar within the RPS. Currently, there is no federal RPS, although Congress has considered one on several occasions.

**Sponsor:** The developer that initiates and develops the PV project, and may wish to participate in the ongoing ownership of the completed project through one of the financing structures described in this report.

**SREC:** Solar Renewable Energy Credit – A REC from a solar project.

**Tax Benefits:** Collective term including the federal Investment Tax Credit (ITC) and the income tax deductions provided to investors from accelerated tax depreciation (i.e., 5-year MACRS depreciation) of the assets of the PV project.

**Tax Credit Basis:** The dollar amount to which the ITC is applied. A project's Tax Credit Basis is typically equal to the installed cost of the project, unless the project has received a non-taxable CBI, or has otherwise utilized subsidized energy financing.

**Tax Equity:** The equity invested in a PV project by Tax Investors.

**Tax Investor:** An entity that invests in a PV project principally for the Tax Benefits. The entity seeks returns on excess capital relative to other passive investing opportunities and wants to offset its large tax obligations from its primary business activities. Examples have historically included large banks and insurance companies.

# Appendix B: California Scenario Analysis – Leverage and CBIs

**Table B.1 Scenario Analysis for "Balance Sheet" Model (Taxable Site Host)**

| State Incentive Type Scenario: | 5-Year PBI | | CBI | |
|---|---|---|---|---|
| **Term Debt Scenario:** | **Unlevered** | **Levered** | **Unlevered** | **Levered** |
| **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 | | | |
| O&M Escalation (%/year) | 3% | | | |
| Period of Analysis (years) | 20 | | | |
| State Incentive Level | $0.22/kWh | | $1.12/$W_{DC}$ | |
| PV Price Escalator | 4% | | | |
| Debt Term (years) | | 15 | | 15 |
| Debt Interest Rate | | 7% | | 7% |
| Debt Service Coverage Ratio | | 1.4 | | 1.4 |
| Debt Leverage (% of installed cost) | | 43% | | 30% |
| **RESULTS** | | | | |
| First-Year Revenue ($/kWh) | 0.267 | 0.182 | 0.263 | 0.189 |
| Levelized 20-Year Revenue ($/kWh) | 0.351 | 0.239 | 0.345 | 0.248 |
| Project 20-Year After-Tax IRR | 10.0% | 10.0% | 10.0% | 10.0% |

**Table B.2 Scenario Analysis for "Operating Lease" Model**

| State Incentive Type Scenario: | 5-Year PBI | | CBI | |
|---|---|---|---|---|
| **Term Debt Scenario:** | **Unlevered** | **Levered** | **Unlevered** | **Levered** |
| **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 | | | |
| O&M Escalation (%/year) | 3% | | | |
| Period of Analysis (years) | 20 | | | |
| State Incentive Level | $0.22/kWh | | $1.12/$W_{DC}$ | |
| Lease Term (years) | 20 | | | |
| Residual Value (% of installed cost) | 20% | | | |
| Debt Term (years) | | 15 | | 15 |
| Debt Interest Rate | | 7% | | 7% |
| Debt Service Coverage Ratio | | 1.4 | | 1.4 |
| Debt Leverage (% of installed cost) | | 46% | | 33% |
| **RESULTS** | | | | |
| First-Year Revenue ($/kWh) | 0.313 | 0.232 | 0.306 | 0.240 |
| Levelized 20-Year Revenue ($/kWh) | 0.326 | 0.242 | 0.319 | 0.251 |
| Tax Investor 20-Year After-Tax IRR | 10.0% | 12.5% | 10.0% | 12.5% |
| Project 20-Year After-Tax IRR | 10.0% | 12.5% | 10.0% | 12.5% |

**Table B.3 Scenario Analysis for "PPA (Partnership)" Model**

| State Incentive Type Scenario: | 5-Year PBI | | CBI | |
|---|---|---|---|---|
| **Term Debt Scenario:** | **Unlevered** | **Levered** | **Unlevered** | **Levered** |
| **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 | | | |
| O&M Escalation (%/year) | 3% | | | |
| Period of Analysis (years) | 20 | | | |
| State Incentive Level | $0.22/kWh | | $1.12/$W_{DC}$ | |
| PV Price Escalator | 4% | | | |
| Flip Point Target (year) | 18 | | | |
| Debt Term (years) | | 15 | | 15 |
| Debt Interest Rate | | 7% | | 7% |
| Debt Service Coverage Ratio | | 1.4 | | 1.4 |
| Debt Leverage (% of installed cost) | | 44% | | 31% |
| **RESULTS** | | | | |
| First-Year Revenue ($/kWh) | 0.206 | 0.185 | 0.208 | 0.192 |
| Levelized 20-Year Revenue ($/kWh) | 0.270 | 0.242 | 0.273 | 0.252 |
| Tax Investor 20-Year After-Tax IRR | 7.0% | 9.6% | 7.0% | 9.6% |
| Developer 20-Year After-Tax IRR | 18.8% | 23.6% | 19.4% | 23.9% |
| Project 20-Year After-Tax IRR | 7.6% | 10.4% | 7.6% | 10.5% |

**Table B.4 Scenario Analysis for "Balance Sheet" Model (Tax-Exempt Site Host)**

| State Incentive Type Scenario: | 5-Year PBI | | CBI | |
|---|---|---|---|---|
| **Term Debt Scenario:** | **Unlevered** | **Levered** | **Unlevered** | **Levered** |
| **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 | | | |
| O&M Escalation (%/year) | 3% | | | |
| Period of Analysis (years) | 20 | | | |
| State Incentive Level | $0.32/kWh | | $1.62/$W_{DC}$ | |
| PV Price Escalator | 4% | | | |
| Debt Term (years) | | 15 | | 15 |
| Debt Interest Rate | | 7% | | 7% |
| Debt Service Coverage Ratio | | 1.4 | | 1.4 |
| Debt Leverage (% of installed cost) | | 68% | | 48% |
| **RESULTS** | | | | |
| First-Year Revenue ($/kWh) | 0.321 | 0.280 | 0.321 | 0.286 |
| Levelized 20-Year Revenue ($/kWh) | 0.422 | 0.368 | 0.422 | 0.376 |
| Project 20-Year After-Tax IRR | 10.0% | 10.0% | 10.0% | 10.0% |

**Table B.5 Scenario Analysis for "Muni Bonds" Model**

| State Incentive Type Scenario: | 5-Year PBI | CBI |
|---|---|---|
| Term Debt Scenario: | Levered | |
| **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 | |
| O&M Escalation (%/year) | 3% | |
| Period of Analysis (years) | 20 | |
| State Incentive Level | $0.32/kWh | $1.62/$W_{DC}$ |
| Debt Term (years) | 20 | |
| Debt Interest Rate | 5% | |
| Debt Service Coverage Ratio | 1.0 | |
| Debt Leverage (% of installed cost) | 100% | |
| **RESULTS** | | |
| Levelized 20-Year Revenue ($/kWh) | 0.251 | 0.297 |

**Table B.6 Scenario Analysis for "CREBs" Model**

| State Incentive Type Scenario: | 5-Year PBI | CBI |
|---|---|---|
| Term Debt Scenario: | Levered | |
| **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 | |
| O&M Escalation (%/year) | 3% | |
| Period of Analysis (years) | 20 | |
| State Incentive Level | $0.32/kWh | $1.62/$W_{DC}$ |
| Debt Term (years) | 15 | |
| Debt Interest Rate | 1% | |
| Debt Service Coverage Ratio | 1.0 | |
| Debt Leverage (% of installed cost) | 100% | |
| **RESULTS** | | |
| Levelized 20-Year Revenue ($/kWh) | 0.182 | 0.247 |

**Table B.7 Scenario Analysis for "Tax-Exempt Lease" Model**

| State Incentive Type Scenario: | 5-Year PBI | | CBI | |
|---|---|---|---|---|
| **Term Debt Scenario:** | **Unlevered** | **Levered** | **Unlevered** | **Levered** |
| **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 | | | |
| O&M Escalation (%/year) | 3% | | | |
| Period of Analysis (years) | 20 | | | |
| State Incentive Level | $0.22/kWh | | $1.12/$W_{DC}$ | |
| Lease Term (years) | 20 | | | |
| Residual Value (% of installed cost) | 0% | | | |
| Debt Term (years) | | 15 | | 15 |
| Debt Interest Rate | | 7% | | 7% |
| Debt Service Coverage Ratio | | 1.4 | | 1.4 |
| Debt Leverage (% of installed cost) | | 67% | | 53% |
| **RESULTS** | | | | |
| First-Year Revenue ($/kWh) | 0.393 | 0.381 | 0.395 | 0.387 |
| Levelized 20-Year Revenue ($/kWh) | 0.411 | 0.398 | 0.413 | 0.404 |
| Tax Investor 20-Year After-Tax IRR | 7.0% | 9.5% | 7.0% | 9.5% |
| Project 20-Year After-Tax IRR | 7.0% | 9.5% | 7.0% | 9.5% |

**Table B.8 Scenario Analysis for "Pre-Paid Service Contract" Model**

| State Incentive Type Scenario: | 5-Year PBI | CBI |
|---|---|---|
| **Term Debt Scenario:** | **Levered (pre-pay only)** | |
| **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 | |
| O&M Escalation (%/year) | 3% | |
| Period of Analysis (years) | 20 | |
| State Incentive Level | $0.22/kWh | $1.12/$W_{DC}$ |
| PV Price Escalator | 4% | |
| Flip Point Target (year) | 18 | |
| Debt Term (years) | 20 | |
| Debt Interest Rate | 5% | |
| Debt Service Coverage Ratio | 1.0 | |
| Debt Leverage (% of installed cost) | 30% | |
| **RESULTS** | | |
| First-Year Revenue ($/kWh) | 0.172 | 0.174 |
| Levelized 20-Year Revenue ($/kWh) | 0.195 | 0.198 |
| Tax Investor 20-Year After-Tax IRR | 7.0% | 7.0% |
| Developer 20-Year After-Tax IRR | 13.0% | 14.2% |
| Project 20-Year After-Tax IRR | 7.2% | 7.2% |

# Appendix C: How Developers Finance PV Projects Used in PPAs

## C.1 Introduction

With respect to financing, one can consider a solar PPA from two different perspectives: that of the site host (e.g., how does the PPA compare to the site host's other financing options?), and that of the project developer (e.g., how does the project developer actually finance the project from which it delivers power to the site host?). For the sake of simplicity and consistency, the main body of this report is written from the site host's perspective only. For the sake of completeness, however, this appendix provides information on how *developers* finance PV projects that supply the power behind solar PPAs.

## C.2 Overview of Three Financing Approaches

The developer can finance a PPA project in one of at least three 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); or it can lease the project from a Tax Investor, using an operating lease. All three methods have been used in the market, in some cases by a single PPA provider (e.g., SunEdison has used each of these three structures at various times). Each approach has its strengths and weaknesses.

### C.2.1 Outright Sale and Buyback

Selling the project outright is perhaps the cleanest of the three approaches, incurring the lowest transaction costs. The developer, however, must fully relinquish control of the project, and may also have to pay the Tax Investor more to eventually buy back the project (presuming the developer desires long-term ownership) than it would to buy out that same Tax Investor under a lease or partnership structure. Furthermore, most Tax Investors are more interested in the project's Tax Benefits than they are in long-term project ownership; as such, they typically prefer to work with developers in partnership or lease arrangements, which often feature pre-defined exit strategies (e.g., early buyout options). As a result of these factors, the sale/buyback model is not very common.

### C.2.2 Special Allocation Partnership

Special allocation partnership "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 set up for the sole purpose of owning and operating the project (the "project company"). A substantial majority of the equity in the project company – 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 the operating project – distributable cash, taxable gains or losses, and tax credits – are allocated primarily in favor of the Tax Investor until it reaches an agreed upon internal rate of return, which is often expected to occur just after the project's Tax Benefits have been exhausted (though, as noted in Section

5.3.3, challenging project economics may lengthen the period of preferred allocations to the Tax Investor in solar deals). Once the Tax Investor's target return is reached, the allocations of distributable cash and taxable gain or loss (typically, any tax credits have been fully utilized by this point) shift or "flip" heavily in favor of the developer for the remainder of the partnership. 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. For a more-detailed description of special allocation partnership structures, including graphical representation, see Harper et al. (2007).

In late 2007, the IRS issued Revenue Procedure 2007-65, which provides safe harbor guidelines for wind projects financed through special allocation partnership structures. Among other things, the Procedure requires, with respect to taxable gains and losses, that the developer maintain at least a 1% interest at all times during the life of the partnership, and that the Tax Investor maintain at all times an interest that is not less than 5% of its *maximum* interest over the life of the partnership. In other words, a permissible allocation of taxable gains and losses to the Tax Investor and developer, respectively, could be as skewed as 99%/1% prior to the flip, switching to 4.95%/95.05% after the flip (i.e., 4.95% is 5% of the Tax Investor's maximum interest of 99%). The allocation of tax credits must follow the allocation of taxable gains and losses (so, in the example above, tax credits would be split 99%/1% between the Tax Investor and developer, respectively), while distributable cash can be allocated however the partners like, as long as they adhere to partnership accounting rules governing each partner's capital account balance. Although the safe harbor provided in Revenue Procedure 2007-65 is technically only applicable to wind projects, most Tax Investors (and their tax counsel) have taken the view that solar projects following the same guidelines will be unlikely to be challenged by the IRS.

C.2.3 Operating Lease

Section 3.2 of the main body of this report describes a financing approach whereby a taxable site host leases a PV system using either a capital lease (if the site host can use the Tax Benefits and/or otherwise desires ownership) or an operating lease (if the site host cannot use the Tax Benefits). Of interest to this appendix, however, is a different situation, in which a site host signs a solar PPA with a developer, and the developer in turn finances the PV system that stands behind that PPA using an operating lease (typically, under a sale/leaseback transaction, as described below). In other words, the developer, rather than the site host, serves as lessee and operates and maintains the project (selling the power to the site host), while a Tax Investor serves as lessor and uses the project's Tax Benefits. Other than this difference in who is the lessee, all of the material presented in Section 3.2 of the main report remains applicable.

Specifically, all of the requirements for an operating lease outlined in Text Box 2 in the main body of this report remain relevant in this situation. That is, at the end of the lease term, the remaining useful life of the project must be at least 1 year or 20% of the originally estimated useful life (whichever is greater), the residual value of the project must be at least 20% of the original cost, and any purchase option exercised by the lessee must be priced at the project's fair market value, as determined at that time. As explained in Text Box 2, operating leases are also required to be "pre-tax positive," though in the wake of Revenue Procedure 2007-65, Tax

Investors have generally been taking the position that the ITC can be treated as a cash-equivalent for this purpose (Martin, 2008).

Whereas projects financed *directly* through an operating lease with a site host (i.e., those described in Section 3.2) might be developed and constructed by the lessor (i.e., owned by the lessor from the start),[37] a more common approach for developers financing PPA projects is what is known as a "sale-leaseback," where the developer builds the project and then sells it to a leasing company (typically a Tax Investor, or else backed by a Tax Investor), who in turn leases it back to the developer through an operating lease. Besides potentially attracting a wider array of third-party Tax Investors to the market (since no project development experience is necessary), this sale-leaseback approach has another advantage over a normal operating lease. In a sale-leaseback transaction, the lessor has up to 90 days after the project has been placed in service to actually purchase the project and still receive the ITC. This stands in contrast to other financing structures, where the Tax Investor must officially own the project at the time it is placed in service in order to be eligible for the ITC. Thus, the 90-day grace period in a sale-leaseback not only reduces the lessor's risk (because it is purchasing an operating project with no remaining development or construction risk), it also slightly enhances its return – i.e., the lessor will earn its target rate of return over a marginally shorter period of investment.[38]

## C.3 Partnership versus Operating Lease

Each of the three financing approaches described above has its unique advantages and disadvantages. Setting aside the sale/buyback approach, which is not in common use today, this section briefly compares the relative pros and cons of special allocation partnership structures and operating leases.[39]

The relative advantages of a partnership flip structure over an operating lease include the following:

- **Lower buyout price:** Under a partnership structure, the Tax Investor's post-flip interest in project allocations could be as low as 5%. Hence, the fair market value buyout price could be as low as just 5% of the overall project's fair market value. In comparison, under an operating lease, the Tax Investor maintains an undivided 100% interest in the project over the entire lease term, and the residual value at the end of that term is required to be at least 20% of the original cost (although the fair market value buyout price could be more or less than the residual value).[40]
- **Less credit/default risk:** In a partnership, the developer and Tax Investor partner together and share (albeit disproportionally) not only the project's cash and tax

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[37] Or, put a different way, a few of the larger PV project developers – for example, Conergy – may offer lease financing for projects that they develop and construct.

[38] Somewhat counter-intuitively, though, some Tax Investors actually prefer to put their money to work over longer, rather than shorter, periods (Abel, 2007; Levin, 2008). This preference stems from the considerable time and effort that go into closing on tax equity investments, as well as the reinvestment risk that accompanies shorter-term investments.

[39] This section draws upon, and adds to, material from Feo (2008). Katz (2008) also discusses the differences between partnership structures and sale/leasebacks.

[40] Although a lower buyout price is certainly appealing, the flip side of this issue is that leases recognize residual value up-front rather than over time as it accrues; this potential advantage of a lease is discussed more below.

allocations, but also the risk that the project does not perform as expected. Under an operating lease, the Tax Investor extends 100% credit to the developer, who must make regular lease payments to the Tax Investor regardless of how the project performs. As such, an operating lease presents greater opportunities for default, and some developers may not have the credit necessary to support a lease.

The relative advantages of an operating lease over a partnership structure include the following:

- **100% financing:** In a partnership structure, the developer must typically invest some amount of equity (though as little as 1%) to become a partner. An operating lease can finance 100% of project costs, potentially even including soft costs, thereby enabling the developer to divert all of its cash towards developing new projects, rather than locking some of it up in existing projects.
- **More-efficient allocation of Tax Benefits:** Per guidance provided in Revenue Procedure 2007-65, a developer in a wind partnership must be allocated at least 1% of a project's Tax Benefits, irrespective of that developer's ability (or more likely, inability) to make efficient use of them. Although the IRS has not specifically provided similar guidance for solar deals, the market is generally assuming that the same standards would apply. In an operating lease, meanwhile, the Tax Investor owns 100% of the project, and therefore takes 100% of the project's Tax Benefits.
- **Up-front recognition of residual value:** Among other things (e.g., term and interest rate), lease payments are a function of the amount of the project's economic value that the lessee is expected to use up. If the project's residual value is expected to be 30% of original cost, then the lessee will only be charged for the use of 70% of the project's value. In effect, the lessee is able to "borrow" against the residual value to reduce its lease payments; the greater the residual value, the lower the lease payments. In contrast, partnership flip structures do not recognize residual value in advance; instead, the developer realizes any post-flip residual value in real time, as it accrues. Though this difference may be trivial from an economic standpoint (and also means that buyout prices are higher under a lease than a partnership, as noted above), the up-front recognition of residual value under a lease may enable the developer to put more of its cash to work doing what it does best – developing other new projects (and earning development fees).
- **Flexibility in closing date:** Under a partnership structure, the Tax Investor must be fully invested in a solar project prior to its in-service date in order to claim the ITC.[41] In a sale/leaseback structure, the Tax Investor has up to 90 days after the in-service date to buy the project (and lease it back to the developer). This 90-day grace period reduces the Tax Investor's exposure to construction risk, eases the pressure to close by a certain date, and reduces the risk of losing the ITC.
- **Greater upside potential for developer:** Under a partnership, the developer and Tax Investor will share in any upside resulting from lower-than-expected operating costs or higher-than-expected revenue. Under an operating lease, the developer agrees to make

[41] This issue is somewhat-specific to solar projects, which are able to claim the full ITC as soon as they are placed in service. Wind projects, on the other hand, receive a production tax credit (PTC) over a 10-year period. As a result, very little of the overall PTC value is at risk due to a failure to close prior to the in-service date. In fact, some wind projects are even financed using a Pay-As-You-Go structure, whereby the Tax Investor injects equity over time as PTCs are generated, thereby minimizing its performance risk. See Harper et al. (2007) for more information on this structure.

regular *fixed* lease payments to the Tax Investor, and therefore is free to retain 100% of any upside (of course, the opposite is true as well – the developer is on the hook to make lease payments even if the system does not perform as expected).

## C.4 Differences Between Wind and PV May Influence Choice of Financing Structure

When site hosts first became interested in solar PPAs, PV project developers and their Tax Investors looked to the wind power industry, and in particular the special allocation partnership "flip" structures commonly used for wind, for a replicable financing model. (Indeed, many of the early Tax Investors in PV projects had been investing in wind projects through such structures for a number of years.) Although flip structures are common and have worked well enough for PV, there is a growing recognition among solar PPA providers that several notable differences – both policy-related and physical – between wind and solar may render the partnership flip structure less-optimal for PV than it is for wind. This section highlights some of these differences between solar and wind, as well as their implications for choice of financing structure.

**Availability of Leasing:** Section 45 of the U.S. tax code, which implements the production tax credit (PTC) for wind and other resources, specifically requires that a qualifying wind project be both *owned* and *operated* by the taxpayer, which is not possible with a lease (i.e., in leasing, the lessor owns and the lessee operates the project). Section 48 of the code, which implements the investment tax credit (ITC) for solar, makes no such requirement, thereby allowing leasing for solar. The relative benefits of leasing, relative to the partnership flip structures that are more common for wind, are discussed in the previous section.

**Project Size:** Even the largest customer-sited PV projects are generally much smaller than typical wind projects, making it more difficult to attract the attention of Tax Investors, and to absorb the relatively high transaction costs associated with partnership flip structures. Developers and their Tax Investors have overcome this size challenge by aggregating individual projects at similar stages of development into larger portfolios that can be financed through dedicated funds, with each individual project tapping into the fund as it achieves commercial operations. This solution is not without risk, however – e.g., one Tax Investor has expressed frustration at going through the work to set up such a fund only to have several projects drop out of the portfolio for various reasons, leaving the total amount invested considerably less than expected (Ravis, 2007). Because leasing tends to be more standardized and easily replicable, it is arguably better-suited to financing smaller projects such as PV projects.

**Return Variability:** The Tax Investor return profile should be less-variable with PV than with wind, for several inter-related reasons. Unlike wind's 10-year PTC, the solar ITC is fully realized in the project's first year (though it vests over 5 years), and is not production-dependent like the PTC. Moreover, the wind resource arguably fluctuates more than the solar resource from year to year (barring major volcanic eruptions that could affect the amount of sunlight reaching the Earth's surface), impacting not only cash revenue from power sales, but also the quantity of PTCs generated. Partnership flip structures are designed to shelter the Tax Investor from such variability, by tying the flip in allocations to the Tax Investor reaching its target return, regardless of how long it takes. Tax Investors in PV projects arguably do not need this level of protection. Or, put another way, project developers should have greater comfort being liable for fixed lease payments for a PV project than they would for a wind project (were leasing possible for wind).

**Residual Value:** Wind turbines are typically expected to have a useful life of 20-30 years (though often come with just 2-year warranties), while PV panels are often expected to have a useful life of 40+ years (and come with 20- to 25-year warranties – not including inverters). Meanwhile, Tax Investors in wind projects earn the bulk of their return during the 10-year PTC period (i.e., one-third to one-half of the project's expected life), while Tax Investors in PV projects earn the bulk of their return over a 5- to 6-year period (i.e., one-eighth of the project's expected life). If need be, PV panels are also more easily relocated than wind turbines. In other words, PV panels should have a significantly greater expected residual life and value than do wind turbines. Unlike leases, which factor expected residual value into the calculation of lease payments, partnership flip structures do not recognize residual value in advance; instead, the developer simply realizes the project's residual value over time as it occurs (post-flip). A lease enables the solar PPA provider to, in effect, borrow against PV's greater residual value, and thereby put more cash to work developing new projects, rather than tying it up over the long-term in existing projects.

In summary, while it is reasonable to look to the wind industry for guidance, solar PPA providers should keep in mind that they have at their disposal a financing tool that is not available to the wind industry – leasing. The characteristics of solar projects – small in size, relatively stable Tax Investor return profile, and relatively high residual value – make leasing a potentially attractive means of bringing in Tax Investors. As discussed in the previous section, over the long term, project developers will likely pay more at any given time to buy out a Tax Investor from a lease than they would under a partnership flip structure (post flip). In the short-run, though, a lease should provide developers with more cash to do what they do best – develop a pipeline of quality projects to build market share in this early stage of the solar PPA market.

# Appendix D: Utility-Scale Solar – Larger Projects, Similar Financing Strategies

Although this report focuses primarily on non-residential "rooftop" PV projects in the range of 10-2,000 kW, PV projects that are significantly larger than this size range have been (and are being) built in the United States and elsewhere. Two such "utility-scale" projects were built in the U.S. in 2007, one interconnected on the customer side of the meter, the other on the utility side of the meter. These two projects, along with a larger solar thermal project also built in 2007, are described below. Though somewhat outside of the scope of this report (and therefore relegated to this appendix), the basic financing structures used by these three "utility-scale" solar projects does not differ significantly from what is described in the rest of this document.

In Colorado, the 8.22 MW (DC) **Alamosa** PV project reportedly cost around $60 million, or $7.3/W (DC). The project was developed by SunEdison, which financed the project through a 20-year **sale/leaseback** with Bankers Commercial Corporation, an affiliate of Union Bank of California (the Tax Investor). The project's power and RECs are sold to Xcel Energy under a 20-year bundled contract that is reportedly priced around 22 cents/kWh. The project combines a mix of fixed-mounted and both single- and double-axis tracking systems; one goal of the project is to gain real-world experience with, and compare the economics of, each of these three different system types operating side by side. In aggregate, the project expects a 24% capacity factor.

In Nevada, the **Nellis Air Force Base** is home to a 14.2 MW (DC) project that reportedly cost around $100 million, or $7/W (DC). The project was developed by SunPower (and its subsidiary, PowerLight) and MMA Renewable Ventures; the latter financed the project through a **special allocation partnership** featuring Citicorp and Allstate as majority Tax Investors, and MMA as a minority Cash Investor.[42] Construction financing was provided by Merrill Lynch, and John Hancock Financial Services provided term debt. All of the project's power is sold to the Air Force base, reportedly at a fixed price of just 2.2 cents/kWh. This low power price is made possible by Nevada Power's 20-year purchase of the project's RECs for RPS compliance. Although the REC pricing has not been publicly disclosed, under Nevada's RPS rules, the Nellis RECs qualify for a customer-sited PV "multiplier" of 2.45, which means that each Nellis REC is worth 2.45 "non-PV" RECs (e.g., RECs from solar thermal, rather than PV, power). As a result, a relatively high REC price might be expected – e.g., a Nellis REC priced as high as 20 cents/kWh equates to a cost of less than 8.2 cents for a non-PV solar REC. The project features SunPower's single-axis tracking technology, and is expecting a capacity factor of roughly 24%.

Finally, though outside the scope of this report because it utilizes solar thermal trough technology (rather than PV), the 64 MW **Nevada Solar One** project also began operations in mid-2007. The project reportedly cost $266 million ($4.2/W), and was financed using a

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[42] According to the project's "Notice of Self-Certification as a Qualifying Small Power Production Facility" filed with the FERC in June 2007, the two institutional Tax Investors own 99.9% of the project, while MMA owns the remaining 0.1%. Though one cannot necessarily assume pro rata sharing of the project's cash and tax allocations, it is nevertheless worth noting that IRS Revenue Procedure 2007-65, which was issued several months after this filing, prohibits (at least for wind projects) tax allocations to the developer (MMA, in this case) of less than 1%, suggesting that this seemingly more-aggressive structure may fall outside of the safe harbor.

**leveraged lease** structure, with JPMorgan, Northern Trust, and Wells Fargo providing tax equity, and two Spanish banks (Banco Santander and BBVA) and a Portuguese bank (CAIXA Geral de Depositos) providing term debt. The project's power and RECs are bundled and sold to Nevada Power and Sierra Pacific under 20-year contracts priced at roughly 18 cents/kWh. Based on the quantity of power deliveries described in those contracts, the project expects an annual capacity factor of at least 23%; in the 12-month period from October 2007 through September 2008, the project reported a capacity factor of 23.7%.

In 2008, this trend towards larger, utility-scale solar projects remains alive and well. In August 2008, Pacific Gas & Electric (PG&E) announced that it had signed two PPAs for PV projects totaling a massive 800 MW (one 250 MW PPA with SunPower, the other a 550 MW PPA with OptiSolar). More recently in October 2008, PPA provider MMA Renewable Ventures and panel manufacturer SunTech launched a joint venture called Gemini Solar Development Company, set up to develop and finance PV projects exceeding 10 MW of capacity. And in December 2008, Sempra Generation and First Solar announced the completion of a 10 MW thin-film project in Nevada, that will sell its entire output to PG&E for a 20-year period. In addition, thousands of MW of solar thermal capacity remain in various stages of development across the American southwest.

Given the recent financial turmoil that has greatly diminished the ranks of Tax Investors, some market observers are beginning to question whether there will be enough tax equity available to bring all of these projects to fruition. In this sense, the fact that utilities are now eligible for the ITC could bring some much-needed capital – with tax appetite – into the market.