

Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments

Karlynn Cory, Jason Coughlin, and
Charles Coggeshall

Technical Report
NREL/TP-670-43115
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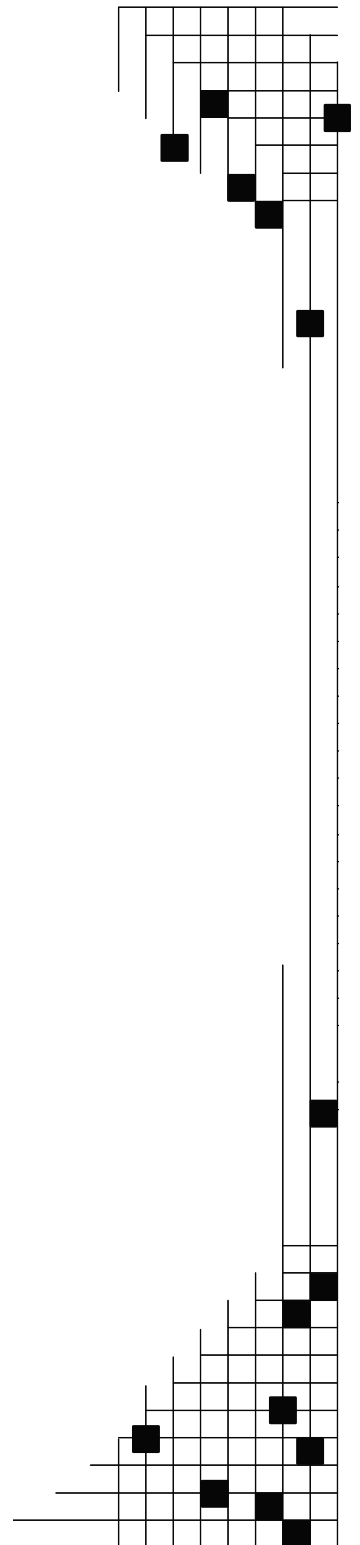
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List of Acronyms

ACUA	Atlantic County Utilities Authority	ITC	Investment tax credit (federal)
AEI	Advanced Energy Initiative	kW	Kilowatt
BETC	Business Energy Tax Credit	LED	Light emitting diode
CCEF	Connecticut Clean Energy Fund	LEED	Leadership in Energy and Environmental Design
CCSE	California Center for Sustainable Energy	LSE(s)	Load-serving entity(ies)
CEC	California Energy Commission	MACRS	Modified Accelerated Cost Recovery System (federal)
CESA	Clean Energy States Alliance	MassDev	MassDevelopment
CL&P	Connecticut Light & Power	MECA	Mayor's Energy Conservation Account (San Francisco)
CORE	Community Office for Resource Efficiency	MTC	Massachusetts Technology Collaborative
COSRE	Customer On-Site Renewable Energy	MW	Megawatt
CPUC	California Public Utilities Commission	MWh	Megawatt-hour
CREB	Clean renewable energy bonds	NJBPU	New Jersey Board of Public Utilities
CSI	California Solar Initiative	NJCEP	New Jersey's Clean Energy Program
DG	Distributed generation	NMFA	New Mexico Finance Authority
DIA	Denver International Airport	NREL	National Renewable Energy Laboratory
DOE	U.S. Department of Energy	NYSERDA	New York State Energy Research and Development Authority
DOER	Division of Energy Resources (Massachusetts)	O&M	Operating and maintenance
DPUC	Department of Public Utilities Control (Connecticut)	OEE	Office of Energy Efficiency (Ohio Department of Development)
DSIRE	Database of State Incentives for Renewables and Efficiency	PBI	Performance-based incentive
EIA	Energy Information Administration	PG&E	Pacific Gas & Electric
EPA	Environmental Protection Agency	PPA	Power purchase agreement
EPBB	Expected performance-based buy-down	PTC	Production tax credit
GHG	Greenhouse gas emissions	PV	Photovoltaics
H.R. 5351	Renewable Energy and Energy Conservation Tax Act of 2008	R&D	Research and development
HB. 32	Energy Efficiency and Renewable Energy Bonding Act 2005	REC	Renewable energy certificates
HVCE	Hudson Valley Clean Energy	REPI	Renewable energy production incentives (federal)
IREC	Interstate Renewable Energy Choices	RFP	Request for proposals
IRS	Internal Revenue Service	RFQ	Request for qualifications
		RPS	Renewable portfolio standard
		SAC	Solar America Cities
		SAI	Solar American Initiative
		SAS	Solar America Showcase
		SB1	Million Solar Roofs Bill
		SBC	Systems benefit charge

SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SFPUC	San Francisco Public Utilities Commission
SMUD	Sacramento Municipal Utility District
SPE	Special purpose entity
SREC	Solar renewable energy certificates
UI	United Illuminating
USBP	Universal Systems Benefit Program
VEPCO	Virginia Electric Power Company

Executive Summary

State and local governments have grown increasingly aware of the economic, environmental, and societal benefits of taking a lead role in U.S. implementation of renewable energy, particularly distributed photovoltaic (PV) installations. Recently, solar energy's cost premium has declined as a result of technology improvements and an increase in the cost of traditional energy generation. At the same time, a nationwide public policy focus on carbon-free, renewable energy has created a wide range of financial incentives to lower the costs of deploying PV even further. These changes have led to exponential increases in the availability of capital for solar projects, and tremendous creativity in the development of third-party ownership structures.

As significant users of electricity, state and local governments can be an excellent example for solar PV system deployment on a national scale. Many public entities are not only considering deployment on public building rooftops, but also large-scale applications on available public lands. The changing marketplace requires that state and local governments be financially sophisticated to capture as much of the economic potential of a PV system as possible. Therefore, a key issue facing policy makers at the state and local level is how to most efficiently allocate public dollars and leverage incentives to develop a significant amount of energy generation from public-sector PV. This report examines ways that state and local governments can optimize the financial structure of deploying solar PV for public uses.

A number of revenue streams, incentives, and financial structures can be utilized by state and municipal governments who want to support solar projects. PV systems produce two main products that can be sold in the marketplace: electricity and the green attributes of this electricity. For any particular solar PV project, the revenue will depend on its geographic location, the quality of the resource, and access to purchasers that place a high value on solar renewable energy certificates (SRECs). For state and local governments, several methods of financing the production of these goods are available, including systems benefit charge (SBC) funds, issuance of energy bonds, clean renewable energy bonds (CREBs) approved by the Internal Revenue Service (IRS), and federal renewable energy production incentives (REPI). Additionally, private sector financiers are able to take advantage of another set of incentives, which include the federal investment tax credit (ITC) and accelerated depreciation under the federal Modified Accelerated Cost Recovery System (MACRS). Finally, there may be additional state, local, or utility incentives available to further reduce the installed costs of PV. The primary vehicle that has emerged to finance public-sector PV is the third-party ownership model because it allows the public-sector systems to take advantage of federal tax incentives without a large up-front outlay of capital. Under this structure the government entity hosts, but does not own, a solar PV system and is able to secure, on average, 15- to 25-year fixed-price power at or below current retail rates. The combination of these options has led to the installation of many PV systems with the transactions increasing both in terms of size and complexity. In this paper, the mechanisms underlying these transactions are analyzed in detail, and their specific relevance to state and local governments is explored.

Based on the research and analysis conducted, several themes emerged that highlight the opportunities and challenges with deploying PV on public-sector buildings and lands:

- **Reduce electricity bills.** State and local governments can reduce electricity bills by producing electricity on-site with a solar PV system. However, the savings are not

currently enough to justify deployment solely based on these savings, even over a 20-year payback period.

- **Value of green attributes.** Where available, SRECs offer an additional revenue stream that can be combined with incentives to offset the high cost of PV deployment. The value of an SREC is highest in states with solar tiers in their renewable portfolio standard (RPS) requirements; voluntary SRECs command a smaller, but sizable premium as well.
- **Use state incentives.** SBC funds provide a significant source of capital to lower the up-front costs of installing PV, including public-sector applications. There is significant flexibility in how SBC-funded programs can be designed and administered.
- **Take advantage of third-party ownership.**
 - **Capture federal incentives.** As many state and local governments pursue aggressive PV expansion programs, the third-party ownership model will be a key financing structure to take advantage of federal tax incentives like the ITC and MACRS. However, unless significant rebates are available or if the system is being installed in or near a state with a solar tier in its RPS, the economics of on-site solar in many states may still be marginal when compared to average retail electric rates, even with the federal incentives.
 - **Consider an option for ownership.** Two relatively new structures, the sale-leaseback and partnership flip, create the financing mechanism for third-party ownership model. Both of these structures allow an option for the public entity to ultimately own the project in six years, before the power purchase agreement (PPA) or lease expires. However, each structure has complicated tax issues that must be addressed.
 - **Defray up-front costs.** In certain states, the transition to performance-based incentive programs and away from up-front incentives may change the nature of how PV projects are financed. This may encourage a greater reliance on third-party structures, especially for the public sector and residential markets.
- **Own and finance public-sector solar PV.** For those state and local governments that desire to own the PV system on their site, there are several options for structuring the financing:
 - **Issue bonds.** Securing up-front capital through general obligation bonds is how public renewable energy projects have traditionally been financed, though they do require voter approval.
 - **Issue energy bonds.** Issuing state or municipal energy revenue bonds that are repaid with energy savings is an attractive concept; however bringing these bonds to market can be challenging.
 - **Apply to the IRS for a CREBs allocation.** For approved applicants, the federal incentive CREBs can be a valuable source of low-cost financing, if steps are taken to reduce the high transaction costs associated with their issuance.
 - **Use REPI.** While the REPI is designed to provide a production incentive to public projects like the production tax credit (PTC), the incentive is consistently underfunded by annual congressional appropriations; therefore, it is difficult to depend on it for supporting significant public deployment of solar PV.
- **Understand insurance requirements.** Utility insurance requirements for PV systems, including general liability and property, can be onerous. Their cost can significantly negatively impact the economics of solar PV projects and can be large enough to derail public-sector PV projects.

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1.0 Introduction

The opportunity to deploy PV on public buildings is tremendous. According to the Energy Information Administration's (EIA) Commercial Buildings Energy Consumption Survey, there were approximately 574,000 state and local government-owned buildings in the United States in 2003.¹ This represents 12% of the total number of all nonresidential buildings in the country. In 2003, these buildings consumed approximately 178 billion kW hours of electricity.² If only 1% of their total demand were provided by solar PV (assuming a capacity factor of 14%), approximately 1,450 MW of solar PV capacity would be needed. This is 10 times the annual U.S. grid-tied PV capacity installed in 2007 of 150 MW-dc.³ Clearly, state and local government electricity consumption is significant and represents an opportunity to increase small- and large-scale distributed solar PV power generation.

Many state and local governments are already pursuing PV installations on public property. To do this successfully, sound public policy, financial incentives, and committed program administrators are required. While each state and local government will have its own reasons for pursuing PV, the most common benefits associated with public-sector solar programs include the following:

- PV can reduce current utility expenses;
- PV offers predictability of future utility expenses;
- PV reduces public-sector greenhouse gas (GHG) emissions;
- Public-sector PV motivates other sectors to deploy solar;
- PV promotes the creation of local jobs; and
- PV can provide emergency power benefits for critical municipal services during and directly after a disruption to the electrical grid.

Under a basic revenue analysis, PV systems produce two saleable commodities: 1) electricity and 2) the green attribute of that electricity. The production of these commodities can be financed by state and local incentive programs, utility incentives, federal incentives, or by third parties who can monetize federal and state tax incentives available for solar energy generation. The details of the main financing options for solar PV on state and local buildings and lands are identified and discussed in this report. Research was conducted, including interviews with state and local officials and other industry professionals actively engaged in the deployment of PV on public buildings. The goal was to identify creative structures of public-sector PV financing, industry trends, and continued barriers to implementation. Individual examples from state and local government deployment of solar PV are captured in Appendix 1. The critical steps for structuring a few of the more complicated financing structures (CREBs, third-party ownership, and tax-exempt bond issuance) are described in Appendices 2-4.

¹ "2003 CBECS Detailed Tables- Table C-13- Total Electricity Consumption and Expenditures, 2003," accessed January 2008, at http://www.eia.doe.gov/emeu/cbecs/cbecs2003/detailed_tables_2003/2003set10/2003pdf/c13.pdf

² Ibid.

³ "U.S. Solar Industry Year in Review: 2007," Solar Energy Industry Association and Prometheus Institute for Sustainable Development, released April 21, 2008, at http://www.seia.org/Year_in_Review_2007.pdf

2.0 PV System Revenues

There are two main revenue streams that are derived from the operation of solar PV systems: electricity and the SRECs that represent the environmental attributes of the electricity generated. This section details how the value of these revenue streams can be analyzed.

2.1 Electricity Revenues⁴

A PV system located on a customer's site is typically located "behind-the-meter" and therefore produces electricity that offsets retail electricity purchased from the local utility, or load-serving entity (LSE).⁵ As shown in Figure 1, the on-site generation is fed directly to the customer for its use. The advantage is that generation produced behind-the-meter ultimately reduces the demand from the customer's local utility, and thus the utility electricity bill.

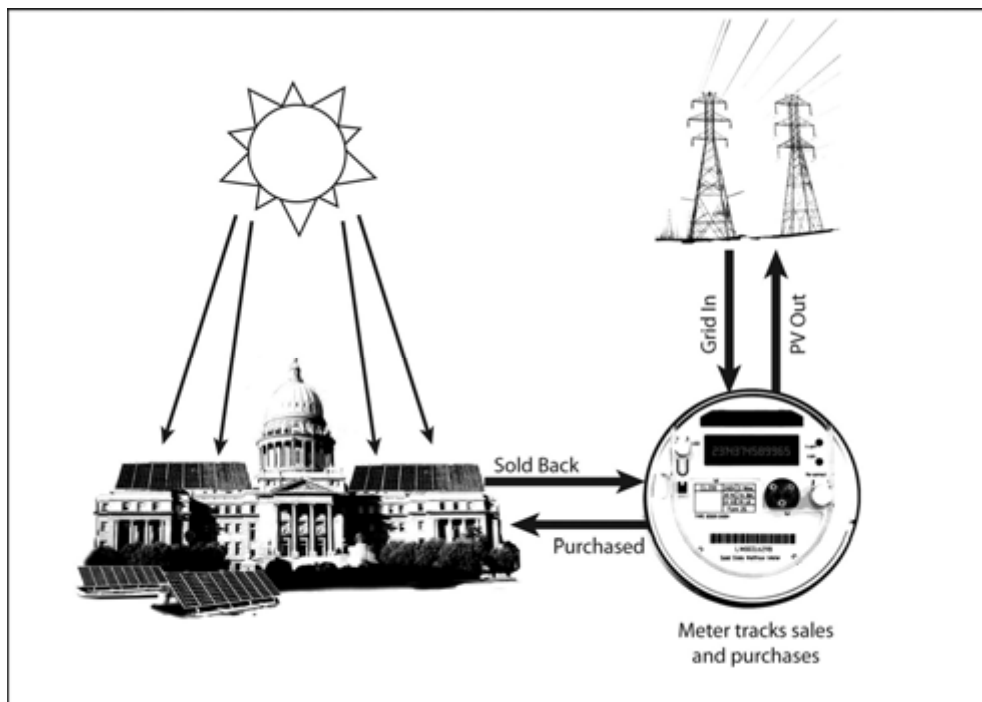


Figure 1. On-site generation and net metering

In addition to avoiding the utility's retail rate, the majority of U.S. states allow customers to have on-site generation and to sell the excess renewable power to their utility, also known as net metering.⁶ The amount the utility purchases will allow depends on how much excess generation is created, above what is used by the customer. Depending on the state, the utility may pay for this excess generation at their retail rate (the highest rate, as it includes transmission and distribution), at the utility's avoided generation cost, or at the utility's wholesale generation rate. Net metering can also allow excess generation in any given month to be carried over to the next

⁴ Municipalities that own and operate their own electric utilities are not considered.

⁵ A load-serving entity includes (1) investor-owned utilities in regulated electricity markets, (2) default/standard offer utilities in restructured electricity markets (or deregulated generation markets), and (3) competitive retail electricity suppliers in restructured electricity markets.

⁶ For more information, see "State Energy Alternatives: Net Metering," U.S. Department of Energy Web site, EERE State Activities and Partnerships, at http://www.eere.energy.gov/states/alternatives/net_metering.cfm

billing month, typically for up to one year. In states that do not have net metering, rather than having the meter spin backwards, the customer is usually required to install a second meter and the utility may pay for excess generation at the avoided or wholesale generation rate. Government entities that wish to learn more about net metering in their state should access the Database of State Incentives for Renewables and Efficiency (www.dsireusa.org).

The actual retail rate avoided will depend on the geographic location and season, and could depend on the time of day (for customers with time-of-use rates). Over an average month, retail electricity will sell in the continental United States for \$0.05 – \$0.16 per kWh, with the lower price representing Idaho and the higher price representing New York State.⁷ Figure 2 shows the average electricity price by state for July 2007. However, there are many congested areas in the country that have higher peak prices during particular hours, especially during the summer. Some examples include the cities of New York, Los Angeles, Chicago, and Boston. For example, in 2007 the Long Island day-ahead electricity market reached more than \$0.24 per kWh on August 3 at 3 p.m. and the real-time dispatched spot market (hour-ahead for 5- to 10-minute intervals) reached more than \$2.14 per kWh on August 8 at 3:20 p.m., nearly 10 times the day-ahead peak.⁸ Note that these peak prices occur during certain hours and days during the summer peak period and may be significantly higher than average rates.

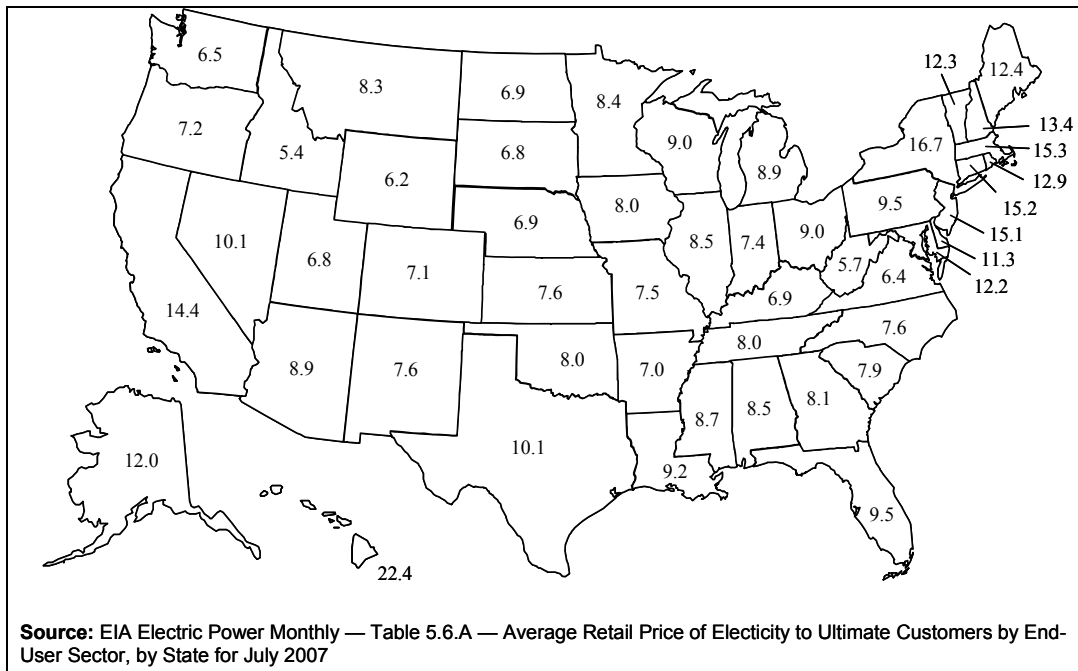


Figure 2. Retail price of electricity for commercial customers averaged for July 2007 (in cents per kW hour)

⁷ “Electric Power Monthly – Table 5.6.A – Average Retail Price of Electricity to Ultimate Customers by End-User Sector, by State” for July and December 2007, from October 2007 and February 2008 monthly reports, respectively. http://www.eia.doe.gov/cneaf/electricity/epm/epmxmlfile5_6_a.xls

⁸ “Day-Ahead Market LBMP” and “Real-Time Market LBMP” zonal information from the New York Independent System Operator’s Web site, for the “LONGIL” zone, representing Long Island. Data for the month of August 2007 was examined. http://www.nyiso.com/public/market_data/pricing_data.jsp

Reducing annual expenditures on electricity may free up cash for other purposes, and the pursuit of lower electricity bills can be a factor in the decision to pursue a public-sector PV system. However, in the absence of other incentives, it is unlikely that simply offsetting a percentage of a facility's retail electricity purchases with PV-generated electricity will be sufficient to make the economic case for solar energy, given the high up-front capital costs. As a result, additional revenue streams, like the sale of renewable energy attributes and other incentives, are critical to making a project economically attractive.

2.2 REC and Solar REC Revenue

SRECs are increasingly critical for structuring the financing of new solar PV projects. This section explains why renewable energy certificates (RECs) were developed, how they can be used in the marketplace, and the importance of SRECs in financing solar installations.

2.2.1 RECs Overview and Background

RECs⁹ have become the dominant mechanism for compliance with renewable portfolio standard (RPS) policies and voluntary green power purchases. The RPS is a state-level mechanism, which requires LSEs in a given state to meet a certain percentage of its customer electricity demand with renewable energy sources. While RECs are not used for RPS compliance everywhere, the manner in which RECs are defined and treated in RPS policies varies by state and region, and can vary between the different utilities and green power marketers operating in the voluntary market.

RECs are tradable commodities, separate from the electricity produced, that bundle the “attributes” of renewable electricity generation. Because they are unbundled from the electricity, RECs are not subject to transmission constraints. One REC typically represents the attributes of 1 megawatt-hour (MWh) of renewable electricity generation. The definition of "attributes" can vary across contracts, but will likely include any future carbon trading credits, emission reduction credits, and emission allowances. Once the REC is separated from the underlying electricity and sold to another party, claims to the attributes can only be made by the REC owner, and not by the electricity owner or the owner of the project. For example, the host of a solar system may not be able to claim they are using “green power” if they are selling the RECs generated by the project to another entity. This concept will be revisited when the third-party ownership model is discussed in Section 6.

RECs are currently used by 1) LSEs to demonstrate compliance with regulatory requirements, such as renewable energy mandates ("the compliance market"), and 2) green power marketers and utilities to supply renewable energy products to end-use customers who voluntarily purchase RECs ("the voluntary market"). When an LSE is required to meet a certain level of electricity demand with renewable energy as part of a RPS, RECs are typically, but not always, used to demonstrate compliance with such a mandate. California provides an exception, where the attributes must be bundled with the power in the same contract with the utility. However, the state utility regulators are considering the use of tradable RECs for compliance with their RPS.¹⁰

⁹ Also called renewable energy credits, tradable renewable certificates, or green tags.

¹⁰ For more information, please see the California Public Utility Commission Web site: <http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/ongoing.htm>

In addition, RECs are becoming the dominant mechanism for marketing renewable power into the voluntary market.¹¹ When companies like Intel¹² or Pepsico¹³ announce that they are offsetting a percentage of electricity use with renewable energy, more often than not, the companies have purchased RECs in the voluntary market rather than installing wind turbines or PV systems on-site. To put these two large purchases into context, the Intel purchase of 1.3 billion kWh equates to the generation from 450 MW of wind (33% capacity factor), and the Pepsico purchase of 1.1 billion kWh equates to the generation from approximately 150 MW of baseload landfill gas or biomass (85% capacity factor).¹⁴ The advantage of RECs is that corporations and government agencies can support renewable energy without having to develop or support their own project, allowing them to focus on their core business. And because RECs are not subject to transmission constraints, voluntary green power customers can purchase RECs from a variety of projects from across the country to match some or all of their electricity demand. Voluntary RECs are created by entities that are producing renewable power beyond what is needed to demonstrate legal compliance with RPS requirements or by renewable energy generators that are not located in or near markets with RPS policies.

The value of a REC depends on a number of factors, including whether it is sold into a compliance or voluntary market, where in the U.S. the REC is sold, whether there is a shortage of RECs, and whether the REC was derived from a solar resource. Table 1 shows the different values of RECs, depending on these factors.

Table 1. REC and SREC Prices in Voluntary and Compliance Markets

	RECs	Solar RECs
Voluntary	\$1-7*/MWh	\$18-21/MWh
RPS	\$3-22/MWh	\$160-265/MWh**
RPS (shortage)	\$48-56/MWh	??? NJ SREC cap: \$711/MWh

* Not counting biomass

** New Jersey and Colorado only.

Sources: Evolution Markets, NREL, Xcel, NJ Clean Energy Program

As shown in the table, RECs used for RPS compliance have significantly more value than RECs in the voluntary market. However, in both cases, SRECs have higher value than generic RECs. Finally, REC values are highest in markets with a supply shortage.

¹¹ Bird, Lori, Leila Dagher, and Blair Swezey, “Green Power Marketing in the United States: A Status Report (Tenth Edition), National Renewable Energy Laboratory technical report NREL/TP-670-42502, December 2007, <http://www.nrel.gov/docs/fy08osti/42502.pdf>

¹² “Intel Becomes Largest Purchaser of Green Power in the U.S.,” Intel News Release, January 28, 2008, <http://www.intel.com/pressroom/archive/releases/20080128corp.htm>

¹³ “Pepsico Makes Largest Corporate Purchase of Renewable Energy Certificates,” Pepsico News Release, April 30, 2007, <http://phx.corporate-ir.net/phoenix.zhtml?c=78265&p=irol-newsArticle&ID=992341>

¹⁴ Note that, in reality, the two purchases by Intel and Pepsico are from a variety of renewable resources, such as geothermal, wind, solar, biomass, and potentially others. A simplifying assumption about technologies and capacity factors was made to put these large purchases into context.

2.2.2 SREC Revenue

SRECs are a separate commodity in most REC markets because their value is higher than other RECs. This is true for a variety of reasons. First, several states encourage solar or distributed generation (DG) through a specific solar/DG tier in their RPS. The goals of creating such a tier include increased deployment of solar and DG technologies, diversified electricity generation, and in-state economic development benefits. By separating solar and DG into their own tier, the RPS protects these higher-cost technologies from competing against more cost competitive, renewable technologies like wind and landfill gas. Second, for states with solar tiers in their RPS, the penalty price for non-compliance is often set higher than for standard RPS compliance. Higher penalty prices encourage LSEs to support new development, by accounting for the higher cost of solar and the lack of economies of scale with smaller projects. Third, SRECs tend to be quite desirable in the voluntary market and customers are willing to pay much more for SRECs than for wind or biomass RECs, as shown in Table 1.

SRECs have the most value in markets with a separate solar tier in their RPS (also called a “carve-out”) and a high penalty price for non-compliance above what the owner/developer needs to make project economics work. Examples of the significant project revenues from SREC set-asides can be found in Colorado and New Jersey, where SREC prices have ranged from \$160/MWh to \$265/MWh.¹⁵ Note that SREC values in New Jersey are expected to increase, because the state increased its SREC cap from \$300/MWh to \$711/MWh starting in 2009 (ramping down over time).¹⁶ This is the highest solar price cap in the nation. A higher SREC price cap, in conjunction with phasing out their up-front rebates, is expected to lead to significantly higher SREC prices going forward.

RPS programs that include solar/DG RPS set-asides include Arizona, Colorado, Delaware, Maryland, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Washington, and Washington D.C. As shown in Figure 3, of these:

- Ten states and the District of Columbia specify a certain quantity or percentage of the RPS must be met with *solar resources*;
- Three RPS programs have set-asides for *customer-sited or distributed systems*, which tend to favor solar; and
- Five policies offer *extra credit* to either solar or distributed generation.

Collectively, these provisions could result in the installation of several thousands of MW of solar electric capacity by 2025. For example, if it is met, Maryland’s solar set-aside is expected to result in 1,500 MW of new solar capacity.¹⁷ A recent report by the Lawrence Berkeley National Laboratory calculates that if compliance is achieved with the various state-level solar RPS set-

¹⁵ NREL estimate based on Xcel Energy’s “2008 Renewable Energy Standard Compliance Plan” Section 5 – Acquisition Plans at http://www.xcelenergy.com/docs/Section5-Acquisition_Plans_Final.pdf and New Jersey’s Clean Energy Program “SREC Pricing: SREC Trading Statistics,” Web site at

<http://www.njcleanenergy.com/renewable-energy/programs/solar-renewable-energy-certificates-srec/pricing/pricing>

¹⁶ “New Jersey Approves Solar REC-Based Financing Program: Frequently Asked Questions,” New Jersey Clean Energy Program, December 17, 2007,

[http://www.njcleanenergy.com/files/file/SOLARTransitionFAQs121707%20fnl2\(2\).pdf](http://www.njcleanenergy.com/files/file/SOLARTransitionFAQs121707%20fnl2(2).pdf)

¹⁷ Parker, S. “Maryland Expands RPS: 1,500 MW Solar by 2022,” Renewable Energy Access, April 12, 2007, at <http://www.renewableenergyaccess.com/rea/news/story?id=48102>

asides (in place as of early 2008), they could result in roughly 6,700 MW of additional solar capacity by 2025.¹⁸

Solar/DG Provisions in RPS Policies

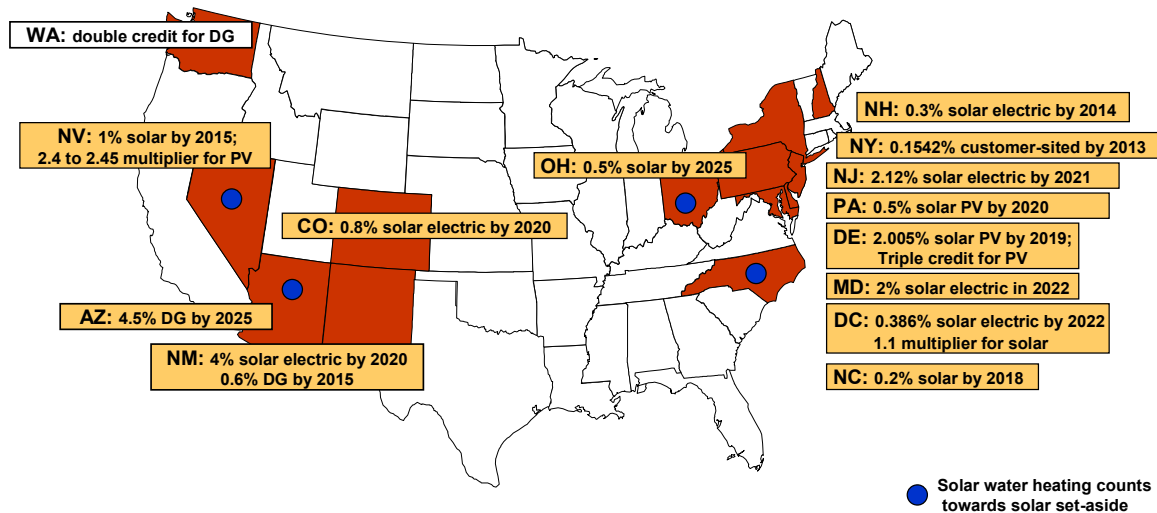


Figure 3. Solar/DG provisions in state RPS policies

Source: Database of State Incentives for Renewables and Efficiency (www.dsireusa.org)

SRECs can be a very important revenue stream for developing new projects. State and local governments may decide to sell the SRECs to nearby LSEs that must comply with solar set-asides in RPS programs. If the SRECs are sold (into either voluntary or mandatory markets), then the site host also sells the right to claim that it uses solar power. At the same time, the SREC cash-flow stream may very well determine whether or not a particular project is economically viable. According to 3 Phases Energy Services, SREC cash flows in Colorado account for roughly 40% of total project cash flows.¹⁹ Personal interviews with developers structuring deals have noted that SRECs can account for 40%-80% of the total revenue stream of a project, in particular states.²⁰ However, as explained earlier, not every state has SREC prices high enough to provide solar projects with this kind of support.

In states without solar rebates and/or a specific solar RPS carve-out, it can be very difficult to structure economically viable solar projects that provide payback periods acceptable to public entities, given the capital costs involved. This explains why most of the PV installations are taking place in states such as California, Colorado, and New Jersey. California has a state-wide

¹⁸ Wisser, Ryan, Galen Barbose, et al. "Renewables Portfolio Standards in the United States: A Status Report with Data Through 2007," Lawrence Berkeley National Laboratory technical report LBNL-154E, April 2008, at <http://eetd.lbl.gov/ea/EMS/reports/lbnl-154e.pdf>

¹⁹ 3 Phases, 2007. "Selling Solar with RECs," Presentation by 3 Phases Energy Services, January 31, California Solar Forum, http://www.californiasolarcenter.org/pdfs/forum/2007.1.31_SolarForum_TDerrick-3PhasesEnergy_SellingSolarRECs.pdf

²⁰ Cory, Karlynn, Jason Coughlin, et al., "Innovations in Wind and Solar PV Financing," National Renewable Energy Laboratory technical report NREL/TP-670-42919, February 2008, at <http://www.nrel.gov/docs/fy08osti/42919.pdf>

solar rebate program although it does not have an RPS with a specific solar tier. In Colorado, Xcel Energy, the state's largest utility, administers a program to purchase SRECs from end-users as part of its compliance activities with the solar tier of the state's RPS. Additionally, the Xcel program also includes an up-front solar rebate. New Jersey's SBC fund also provided a rebate to defray the up-front cost of PV installations, in conjunction with the sale of SRECs to the local utility. In December 2007, the state put a schedule in place to eliminate its up-front rebates in the hope that developers could rely on the SREC market (in addition to federal incentives). Note that while each program is structured differently, they have all been successful.

Specific examples of the role that SRECs play in structuring the financing of new solar PV projects can be found in several of the examples in Appendix 1.

3.0 State and Local Financing

In most cases, avoided electricity costs and the sale of SRECs will not be sufficient to structure a public-sector PV project with a payback period that is acceptable to the public entity. Therefore, state and local governments usually try to take advantage of the various incentives that exist in the marketplace to reduce the up-front cost of installing a PV system. This section explores the mechanisms that state and municipalities use to provide incentives and structure financing for new solar PV projects that they own. At the end of the paper, Appendix 1 provides additional detail and examples, including the SBC programs referenced below.

3.1 System Benefit Charge Programs

The primary source of incentives in many states derives from programs that are funded by a SBC, also called a public benefit fund. Since the mid 1990s, 17 states, including the District of Columbia, have implemented some variation of SBC funds²¹ to support renewable energy.²² The implementation of these SBC programs has generally been the result of electric utility restructuring legislation approved over the past 10 years.²³ The SBC is a required fee added to electricity bills, usually in the form of a usage charge (per kWh basis), or as a monthly flat fee. While the fee is usually modest to the consumer, in aggregate, significant funds are generated using this mechanism, as shown in Figure 4. According to the North Carolina Solar Center, between 1997 and 2017, \$6.8 billion dollars will be raised via the system benefit charge mechanism.²⁴ On its own, California will collect \$331 million just in 2008.²⁵

A standard stipulation for securing SBC incentives is that beneficiaries must be utility ratepayers. Therefore, if state and local governments are customers of utilities that collect an SBC, they are eligible to participate in SBC-funded programs.

SBC funds are used to support a variety of renewable energy-related activities through grants, loans, rebates, performance based incentives, and free technical assistance. A few examples of state SBC programs (further detailed in Appendix 1) include:

- **California.** The California Solar Initiative (CSI), funded by an SBC, aims to deploy 3,000 MW of new solar by 2017. Currently, public PV projects (<50 kW) will receive an up-front incentive of \$2.65/watt. This incentive will ramp down as target solar capacity levels are reached within each utility's territory. Public systems greater than 50 kW will receive periodic payments (performance-based incentives) based on actual production.

²¹ "Public Benefit Funds for Renewable Energy," Database of State Incentives for Renewables and Efficiency (DSIRE), latest review depends on the state, accessed April 6, 2008, at <http://www.dsireusa.org/library/includes/seeallincentivetype.cfm?type=PBF¤tpageid=7&back=regtab&EE=0&RE=1>

²² In addition to renewables, some states use SBC funds to target energy efficiency, energy R&D, weatherization, and low-income customer assistance.

²³ "State Energy Alternatives: System Benefit Charges," U.S. Department of Energy Web site, accessed April 6, 2008, at http://www.eere.energy.gov/states/alternatives/system_benefits.cfm

²⁴ "Public Benefit Funds for Renewables (Estimated Funding)." Report by Interstate Renewable Energy Council and North Carolina Solar Center. Accessed April 6, 2008, at http://www.dsireusa.org/documents/summarymaps/PBF_Map.ppt

²⁵ Ibid.

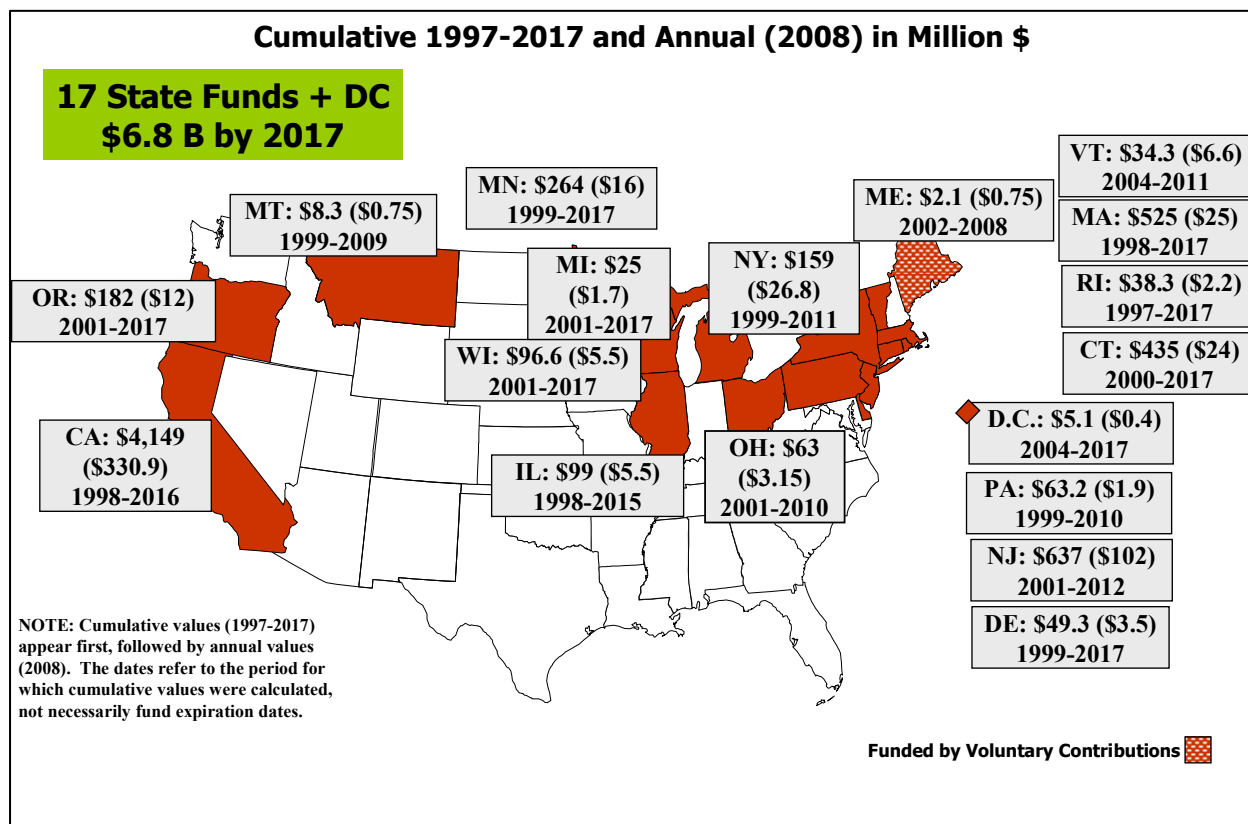


Figure 4. System benefit charge funding of renewables by 2017, by state

Source: Database of State Renewable and Efficiency Incentives (www.dsireusa.org)

- Ohio.** The Advanced Energy Fund in Ohio typically uses grants to offset a portion of the cost of systems purchased by local municipalities. For nonresidential customers, rebates start at \$3.50/watt and decrease to \$1.50/watt for systems up to 75 kW.
- New York.** New York's PV System Incentive Program provides \$5.00/watt for the first 25 kW of a public system and \$4.00/watt, up to 100 kW.
- Connecticut.** A portion of Connecticut's SBC funds are used to challenge cities and towns to a Clean Energy Campaign, whereby participation in green power programs leads to free PV systems for the community. New Haven has already earned 20 kW of new solar installations as a result of this program.
- Montana.** Montana's SBC funds have been used by one local utility to install PV systems and battery packs in to provide back-up power at fire stations, in case of a power outage.

Overall, SBC funds provide an important source of funding for public-sector PV. As illustrated above and in Appendix 1, a state can be creative in how it decides to manage its SBC funds. Certain programs provide across-the-board incentives whereas others focus on specific sectors. Some provide up-front grants and rebates while others create low-interest loan funds. In this sense, no two programs are exactly the same.

Specific examples in Appendix 1 explore in greater detail some of the ways that SBC funds are used to promote PV for the benefit of public entities. Programs and financing structures for a variety of projects are included from California, Connecticut, Montana, New York, and Ohio. These states were selected because their SBC funds are administered by different agencies, including state government (California, Ohio), a third party (New York, Connecticut), and the utility imposing the surcharge (Montana).

3.2 State and Local Government Bonds^{26, 27, 28}

Public entities can also issue bonds to secure capital for PV projects. In conjunction with, or instead of SBC funds, municipal bonds (also called securities) can be issued by state and local governments to finance capital expenditures, including PV installations. In Appendix 5, a description of the critical steps necessary to issue a tax-exempt bond is provided for public entities that are unfamiliar with the process.

There are two types of municipal bonds:

1. **General obligation bonds.** The principal and interest are secured by the full faith and credit of the issuer, and are usually supported by the issuer's taxing power. These bonds are voter approved, the rules of which differ by state and can range from a simple majority to complex formulas for taxpayer approval. The municipality is generally limited in the amount of debt that can be incurred, either as a percentage of a jurisdiction's assessed valuation (sometimes as a multiplier of revenues, like in Connecticut) or based on the type of project. Sometimes the bond issue is indirectly restricted through limitations based on annual revenue growth, the overall tax rate, or on the rate of spending (e.g., cannot outpace inflation).²⁹
2. **Revenue bonds.** These bonds are often issued by special authorities created for specific purposes, usually infrastructure related such as a toll road, bridge, airport, water and sewage treatment plants, hospitals, or low income housing. Principal and interest are secured from revenues derived from fees and/or charges paid by the users of the facility. For example, toll roads collect fees from motorists for their usage; the initial capital was secured through revenue bonds in anticipation of repayment through fees.

3.2.1 Issuing Energy Bonds

As an alternative to traditional municipal bond issuances, local governments can also consider issuing energy bonds whose proceeds may be used to finance renewable energy installations.

²⁶ Note that some municipal bonds are taxable at the federal level, because the government has determined that certain activities (e.g., sports stadium) do not provide a public benefit. These types of federally taxed bonds are not considered in this document.

²⁷ Much of the information in this section is taken from the Web site of The Securities Industry and Financial Markets Association, from the menu "Learn More > Types of Bonds > Municipal Bonds," found at: <http://www.investinginbonds.com/learnmore.asp?catid=5&subcatid=24>, unless otherwise noted

²⁸ Also see "Municipal Bond Basics," on the Web site of the Corporate Research Project of Good Jobs First, at http://www.publicbonds.org/bond_basics/municipal_bonds.htm

²⁹ Wandschneider, Philip, Ronald Faas, and Douglas Young, "How a Community Decides to Issue Bonds," from the Municipal Bonds Series by the U.S. Department of Education, December 1982. http://www.eric.ed.gov/ERICDocs/data/ericdocs2sql/content_storage_01/0000019b/80/2e/c6/53.pdf.

However, obtaining the authorization to issue these bonds to finance renewable energy projects may be easier than actually getting the bonds to market.

Four examples of public bond programs that have been approved specifically for renewable energy (including PV) can be found in San Francisco in 2001,³⁰ Honolulu³¹ and New Mexico³² in 2004, and Delaware in 2007.³³ Of these four, however, only Honolulu has successfully issued its energy bond.

In the cases of Honolulu and New Mexico, general obligation bonds for renewable energy projects were authorized by the respective authorities. As mentioned earlier, with general obligation bonds, the taxing authority of the issuing entity supports the repayment of the debt. Conceptually, however, the energy savings from the renewable energy and energy efficiency investments would be expected to pay for the bonds over time, backed up by the taxing authority of the issuer, if necessary.

In the cases of San Francisco and Delaware, revenue bonds for renewable energy were approved. As noted, the repayment of revenue bonds comes from revenue generated (or saved) by the specific project financed with the bond proceeds. Because revenue bonds do not add to a government's general debt burden and are not supported by tax revenues, they do not require voter approval and do not technically add to the government's tax burden. However, these bonds may be more complicated to bring to market. Energy savings are used as the sole source of repayment and might be viewed as a less certain revenue stream when compared to more traditional revenue bonds with easily identified cash flows available for debt repayment (i.e., tolls from a toll road).

Here are some more specific details of each of these four bond authorizations:

- **Honolulu.** The city issued \$7.85 million in solar general obligation bonds in FY05 and used the proceeds for solar powered parking lots, energy retrofits, and LED streetlamps.³⁴
- **New Mexico.** The New Mexico Finance Authority (NMFA) has approval to issue up to \$20 million in general obligation bonds. The proceeds would go toward the Public Project Revolving Fund to make loans to state agencies, universities, and public schools to fund energy efficiency and renewable energy investments. It is expected that 90% of

³⁰ DeLonge, Danielle. "Solar Bond Will Help City Focus on Renewable Energy," *Pacific Business News*, June 18, 2004. Accessed April 6, 2008, at <http://www.bizjournals.com/pacific/stories/2004/06/21/focus3.html>

³¹ "Energy Efficiency and Renewable Bonding Act," New Mexico Finance Authority Web site, accessed April 6, 2008, at <http://www.nmfa.net/loan/?t=State%20Building%20Automation%20Project%20Financing>

³² Energy Efficiency and Renewable Energy Bonding Act 2005 (HB. 32), at <http://legis.state.nm.us/Sessions/05%20Regular/final/HB0032.pdf>

³³ McDowell, Harris B., and John Byrne, "A Sustainable Energy Future for Delaware," as chair and co-chair of the Sustainable Energy Utility Task Force, presented to the Delaware General Assembly on April 16, 2007. Accessed April 6, 2008, at http://www.seu-de.org/docs/fina_report_brief.pdf

³⁴ E-mail communication with Lori Goropse Winguard, chief of staff to Honolulu City Council Member Charles K. Djou on 10/16/2007.

the energy savings would be “captured” from the participating agencies to fund debt service.³⁵ As of January 2008, no bonds have been issued under this authorization.³⁶

- **San Francisco.** Proposition B was approved by San Francisco voters in 2001; it gave the city the authority to issue up to \$100 million of revenue bonds for renewable energy projects, including PV. In the same election, Proposition H was passed giving the City authority to issue additional revenue bonds with greater flexibility as to the issuer and the amount. To date, these bonds have never been issued for a number of reasons, including net metering issues between PG&E and the City of San Francisco,³⁷ and apparent creditworthiness concerns at Hetch Hetchy Water and Power.³⁸
- **Delaware.** In 2007, Delaware announced the creation of a Sustainable Energy Utility to promote energy efficiency, weatherization, and distributed renewable energy generation, including PV. Proposed funding for the Sustainable Energy Utility would come from a number of sources, including the issuance of special purpose, tax-exempt bonds up to the amount of \$30 million.³⁹ Energy savings are expected to generate funds to repay these bonds.

³⁵ “Annual Report 2005,” New Mexico Finance Authority, 2005, page 24, at <http://www.nmfa.net/uploads/document/Annual%20Report%202005.pdf>

³⁶ “Invested in New Mexico: 2007 Annual Report,” New Mexico Finance Authority, 2007, at http://www.nmfa.net/uploads/document/NMFA_2007_Report.pdf

³⁷ “Electricity: Hetch Hetchy Water and Power Solar Generation,” California Assembly Committee on Utility and Commerce, Lloyd E. Levine, chair, California Assembly AB 2573, hearing date: April 17, 2006. See page 7.

http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2551-2600/ab_2573_cfa_20060414_120324_asm_comm.html

³⁸ “1/27/05 & 1/28/05 Minutes SFPUC Commission,” San Francisco Public Utilities Commission meeting minutes published 3/10/2005, updated 3/14/2005, accessed March 2008, at

http://sfwater.org/detail.cfm/MC_ID/18/MSC_ID/113/MTO_ID/369/C_ID/2422/Keyword/Proposition%20B

³⁹ McDowell, Harris B., and John Byrne, “A Sustainable Energy Future for Delaware,” as chair and co-chair of the Sustainable Energy Utility Task Force, presented to the Delaware General Assembly on April 16, 2007. Accessed April 6, 2008, at http://www.seu-de.org/docs/fina_report_brief.pdf

4.0 Federal Incentives for Public-Sector PV

Among the programs that have been created by the federal government to promote renewable energy development, at least two are targeted to help state and local governments finance new renewable projects: the IRS' clean renewable energy bonds (CREBs) and DOE's Renewable Energy Production Incentives (REPI). The CREBs program is attracting significant interest from local governments. In contrast, REPIs are subject to annual congressional appropriations and to date have been unable to meet the total requests each year. These two factors mean that REPIs are not bankable in project financing.

4.1 Overview of CREBs

To participate in CREBs, a state or local government must apply to the IRS for a CREBs allocation. Upon receiving an allocation, the public entity can issue CREBs to finance a solar PV project.^{40, 41} Originally created in the 2005 Energy Tax Incentives Act, CREBs provide a federal tax credit to the bond owners in lieu of interest payments from the issuer.⁴² Because the issuer (in theory) does not have to make interest payments and only has to pay off the bond principal, this feature is attractive compared to tax-exempt municipal bonds.

The initial allocation for the CREBs program was \$800 million in 2005; legislation in 2006 increased this amount to \$1.2 billion dollars.⁴³ In total, the amount of CREBs allocations that can be awarded to public-sector projects can be up to 62.5% of the total allocations. In the first round, \$800 million of CREBs allocations went to 610 projects.⁴⁴ Figure 5 shows that 433 of these projects were for PV; of these, 93% were in the public sector.⁴⁵

The second round of CREBs applications were due in July 2007⁴⁶ and project awards were announced on February 8, 2008.⁴⁷ 312 projects received allocations totaling \$477 million dollars. Similar to the 2006 allocations, public-sector PV projects were awarded a significant percentage of the total allocations. In 2008, 55% of the total funds allocated were for public-sector PV.⁴⁸ As illustrated in Figure 6, 44% of the total number of allocations were for PV projects (includes both governments and cooperatives).

⁴⁰ Other qualified entities that can borrow money using CREBs include cooperatives, any political subdivision that can issue tax-free bonds, and tribal governments. All of these entities, including states and local governments, can actually issue the CREBs; in addition, qualified cooperative lenders can issue bonds.

⁴¹ CREBs can be used to help finance a number of renewable technologies, including wind, closed-loop biomass, open-loop biomass, geothermal, solar energy, irrigation power facilities, landfill gas, MSW, and hydropower

⁴² Section 1303 of the Energy Tax Incentives Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) (the "2005 Act") added section 54 to the Internal Revenue Code.

⁴³ IRS Bulletin No. 2007-14. April 2, 2007. pp. 870, at <http://www.irs.gov/pub/irs-irbs/irb07-14.pdf>

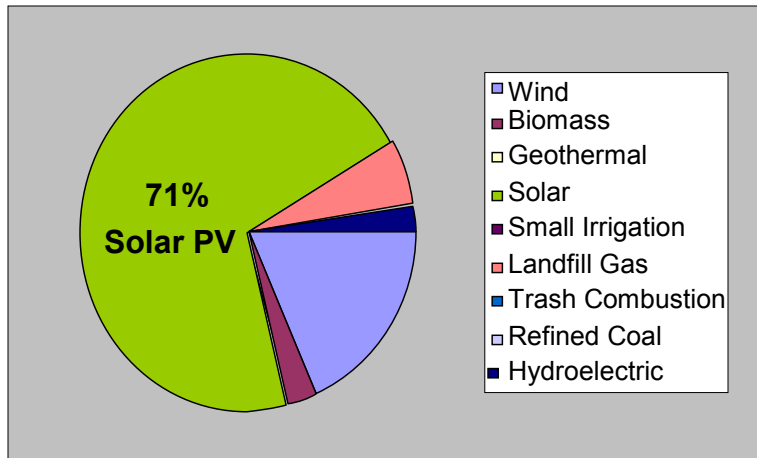
⁴⁴ "Clean Renewable Energy Bond Volume Cap Allocation Information," IRS News Release IR-2006-181, November 20, 2006, at <http://www.irs.gov/newsroom/article/0,,id=164423,00.html>

⁴⁵ Ibid.

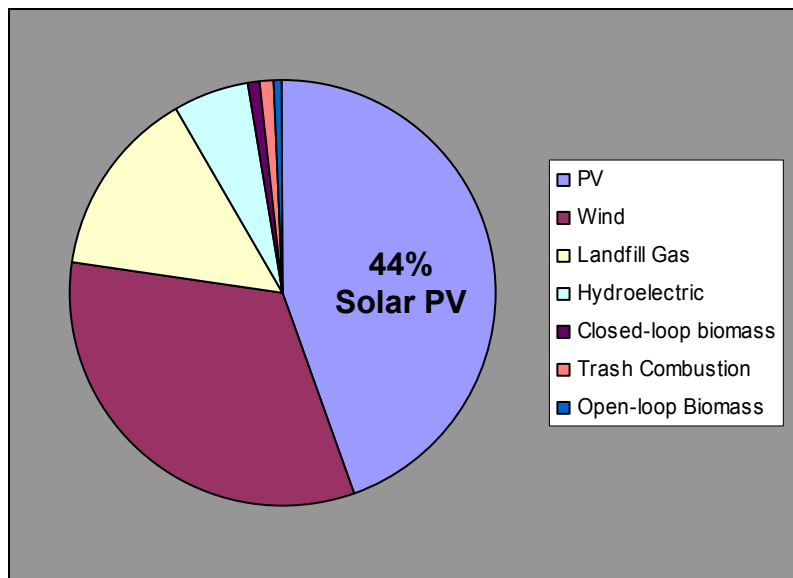
⁴⁶ "Clean Renewable Energy Bonds- July 13, 2007: Deadline for Second Round Allocation Applications and Updated IRS Guidance". Client Advisory by Hunton and Williams, March 2007, at http://www.hunton.com/files/tbl_s10News%5CFileUpload44%5C14044%5CCREB_Alert_March2007.pdf

⁴⁷ "IRS Announces Energy Bond Allocations," IRS News Release IR-2008-016, February 8, 2008, at <http://www.irs.gov/pub/irs-news/ir-08-016.pdf>

⁴⁸ Ibid.



**Figure 5. Allocation of 610 Round 1 CREBs projects:
Distributed by the number of projects per technology**
Source: Internal Revenue Service 2006



**Figure 6. Allocation of 312 Round 2 CREBs projects:
Distributed by the number of projects per technology**
Source: Internal Revenue Service 2008

Currently, the CREBs application process to apply for an IRS allocation is closed. Therefore, states and municipalities should not count on CREBs unless they currently have an allocation from the first or second rounds. There are legislative proposals to further expand the program, however, which are discussed in Section 4.4. At the end of the paper, Appendix 4 provides additional information on the critical steps necessary to apply for and issue a CREBs bond.

4.2 Basic Principles of CREBs

CREBs allocations are made by the Internal Revenue Service (IRS). The two times that Congress allocated money for the program, the IRS put out an announcement asking for applications from qualified projects. As shown in Figure 7, the structure is essentially the same as for the issuance

of a tax-exempt bond described in Appendix 5, except that the federal government provides the investor with a tax credit in lieu of interest payment from the project to the investor.

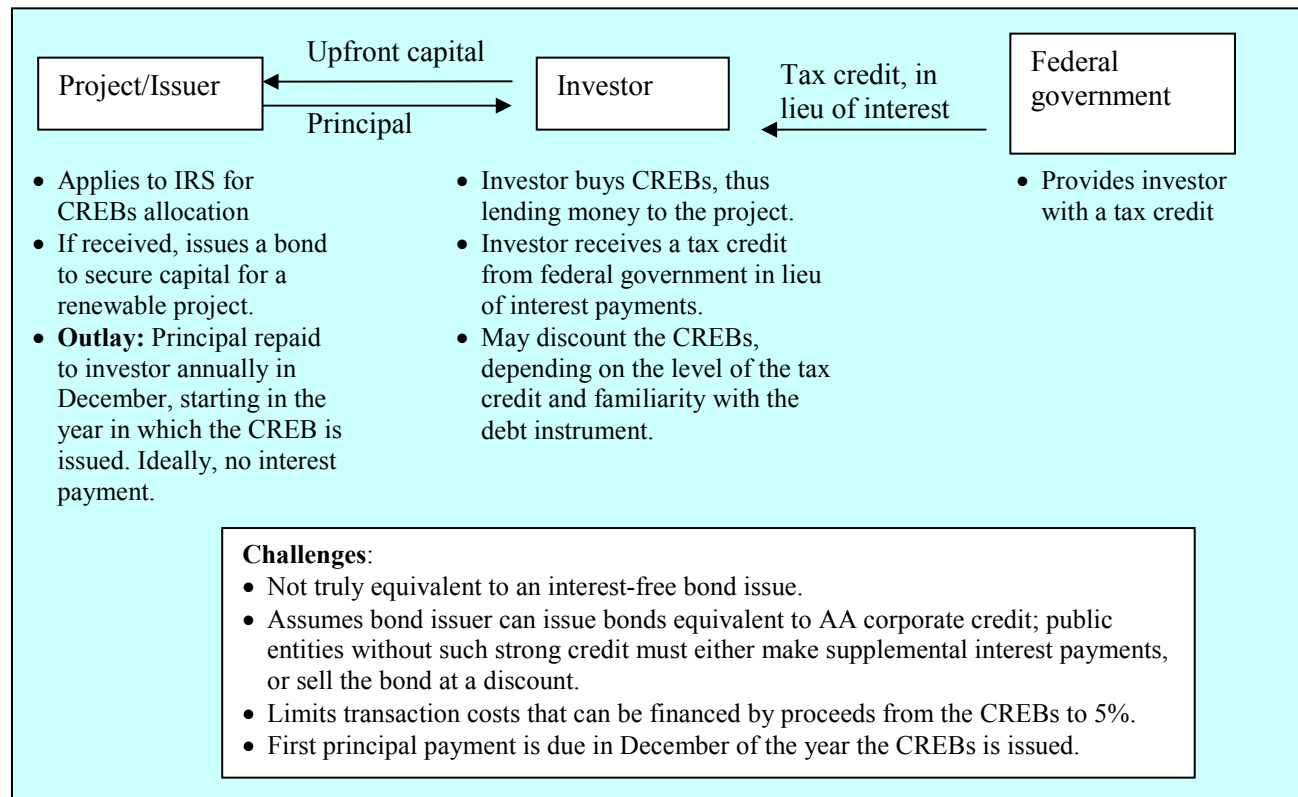


Figure 7. Clean renewable energy bonds

If a state or municipality has a CREBs allocation, specific requirements must be met. First, the bond must be issued before the end of 2008, or else the public entity forfeits the ability to secure the CREBs tax credits.⁴⁹ Second, the first payment for a CREB issued in 2008 must be considered in the financial planning as it will be due in December 2008.

There are several distinctions that should be understood with how CREBs are structured. For a typical bond issue, the shorter the term the lower the applicable interest rate. With CREBs, the longer the term, the longer the investor gets to benefit from the tax credit which increases the cost to the U.S. Treasury. As a result, the IRS limits the term of the bond; this limit is currently on the order of 15-16 years. In addition, the IRS uses the market rate for AA-rated corporate bonds to determine the tax credit to be offered investors. However, this can be challenging because not all public entities can borrow at this rate (this is explored in detail in section 4.3.2). Finally, each annual principal payment is treated as a separate bond with its own tax credit rate, rather than a single bond with one tax credit rate. This is different than how bonds are typically structured and it is taking some time for the market to get comfortable with this method.

⁴⁹ This deadline could be pushed back if the CREBs program receives an extension from Congress, but this should not be counted on.

4.3 Barriers to Using CREBs

Despite the significant number of CREBs allocations for PV projects, initial evidence indicates that the program has some significant challenges. When speaking to a few state and local officials, it was clear that the CREBs process is a frustrating one. The IRS awards allocations to projects from the smallest to the largest, which ends up maximizing the transaction costs per project. Additional issues include the fact that CREBs is often not true interest-free financing (based on federal government assumptions), and the challenging requirement to make the first bond principal payment in the same year the CREBs award was issued,⁵⁰ even if the system is not yet in service.

4.3.1 Transaction Costs

Administrative costs for CREBs are particularly problematic for smaller cities and towns that secure their own financing and tend to issue debt in modest amounts. As noted, to date the IRS has awarded allocations to projects going from the smallest qualified requests to the largest. While this ensures smaller projects are included, it can increase costs on a per-project basis since these are essentially fixed and not highly dependent on the size of the project.

In addition, the CREBs allocation has specific rules regarding how the proceeds can be spent. At least 95% of the CREBs allocation must be invested in capital expenditures on qualified project costs.⁵¹ Up to 5% of the proceeds can be used to cover non-qualified project costs, including transaction costs and a debt service reserve fund (which might be required by investors). The IRS requires that 95% of the net proceeds be used in the first five years of the project; if not, the IRS may require that the bond be redeemed early.

One interviewee (who wished to remain anonymous), in charge of managing renewable energy projects at a particular municipality, performed an analysis on CREBs to determine if it made sense to apply for an allocation. The results showed that a \$10 million allocation would cost \$3 million when transaction costs, the cost of getting voter approval, and the expected discount to par were taken into account. As such, this particular entity decided against applying for a CREBs allocation.

Bundling projects and issuing larger CREBs bonds can help reduce these transaction costs on a per-project basis. The state of Massachusetts bundled CREBs issuances together and were able to achieve notable transaction cost savings, as explained in Appendix 1.

4.3.2 Interest Rates

The combination of the term and the tax credit rate are not quite sufficient for the bonds to be truly equivalent to interest-free instruments. According to Bruce Serchuk at Nixon Peabody, to date most bonds have been issued at either a discount to par or with a supplemental interest payment. The tax credit earned by a buyer of a CREBs bond is based on the current market rate for AA corporate bonds.⁵² However, issuers are not assured of issuing at this rate for a number of reasons, including:

⁵⁰ “Part III – Administrative, Procedural, and Miscellaneous: Clean Renewable Energy Bonds,” Internal Revenue Service notification 2005-98, at <http://www.irs.gov/pub/irs-drop/n-05-98.pdf>

⁵¹ Ibid, pg 4.

⁵² “Part III – Administrative, Procedural, and Miscellaneous: Clean Renewable Energy Bonds,” Internal Revenue Service notification 2007-26. p14. <http://www.irs.gov/pub/irs-tege/n-07-26a.pdf>

- The state/municipality may not be able to borrow at a rate equivalent to the current AA corporate borrowing rate;
- Investor demand for CREBs may be limited given a lack of familiarity with the instrument. This may complicate the ability to sell the bonds at par; and/or
- The amount of the bond issue is small.

In 2006, Carbondale, Colorado, received a CREBs allocation of \$1.6 million to help finance 250 kW of solar electricity. On November 6, 2006, 80% of the voters in Carbondale approved a ballot initiative (2F) for the town to issue up to \$1.8 million in Energy Bonds to construct and operate two large-scale solar systems.⁵³ Xcel Energy agreed to provide \$1.5 million in the form of rebates and SREC purchases to lower the installed cost of the systems. The bonds were approved by voters as interest-free debt. Electricity sales and energy savings from the proposed solar projects would cover the amortization of the principal. Unfortunately, Carbondale would have had to issue the bonds at a discount to par, since their municipal borrowing rate is higher than an AA corporate borrowing rate. This discount to par, plus the transaction costs associated with issuing the debt, made the proposed Energy Bonds more expensive than initially expected and the town of Carbondale decided to abandon using CREBs.⁵⁴ The town is now pursuing other options to finance its solar projects, including partnering with private capital to take advantage of federal tax incentives.

4.3.3 Early First Payment

The requirement to make the first CREBs payment in the calendar year that the CREBs are issued can also be problematic. For example, if a CREB is issued in October, the first principal payment is due in December of the same year. Note that the principal payment is due whether the PV system begins to produce electricity or not. This structure is distinct from how the principal is typically repaid on bonds, where the interest might be paid annually, but the principal is usually paid fully at maturity (unless repaid early, as in the case of a callable bond).

Consequently, the issuer may need to be prepared to tap into other funds to make the first payment.

4.4 The Future of CREBs

Given the uncertainty surrounding the extension of the program, state and local governments should evaluate their proposed PV projects with the assumption that additional CREBs funding will not be available. However, if a new CREBs allocation is approved by Congress and signed by the President before a particular project is financed, and if the project meets eligibility requirements, an application can then be submitted to the IRS for a CREBs allocation. If the project has already been financed using other financial instruments, public entities should investigate whether or not the reauthorized CREBs program continues to allow for project refinancing. If so, depending on the current interest rate environment, it may make economic sense to consider refinancing outstanding debt with a CREBs issuance.

⁵³ Guarascio, Gina. "Carbondale pursues solar power, but unsure how much," *Post Independent* of Glenwood Springs, Colorado, January 19, 2007, at www.postindependent.com/article/20070119/VALLEYNEWS/101190052

⁵⁴ Personal communication with the Community Office for Resource Efficiency with Gary Goodson (new director) and Randy Udall (former director, as of April 2008, no longer with CORE), October and December 2008. For more information, see <http://www.aspencore.org/>.

There are proposals in the House and Senate to expand the CREBs program, often grouped with the reauthorization of production and investment tax credits. For example, the proposed Renewable Energy and Energy Conservation Tax Act of 2008 (H.R. 5351), which the House of Representatives passed in early 2008, was referred to the United States Senate. If passed and signed by the president, the bill would establish an additional \$2 billion for new CREB allocations.⁵⁵ If the CREBs program is expanded, an additional round of CREBs would likely be issued by the IRS soon thereafter, and applicants would have a few months to put together an application. It is also worthwhile to note that the second round of CREBs also included allocations that had been turned-in to the IRS from first-round awardees who decided to not use their CREBS allocation. A third round of CREBs allocations could include additional allocations that have since been surrenders to the IRS.

The proposed legislation may address a few other issues as well. For municipalities, the proposal shifts from making awards to the smallest projects first to issuing awards at a pro-rata share of the total funds available across all eligible projects that apply. It also proposes to eliminate the requirement to make the first principal repayment in the year that the bond is issued and to either allow for a grace period of some duration or a lump sum payment at maturity.

4.5 Federal Renewable Energy Production Incentive (REPI)

A second federal program, which was designed to assist municipalities finance new renewable energy projects, is called the Renewable Energy Production Incentive (REPI) Program. Authorized under the Energy Policy Act of 1992 and amended under the 2005 Energy Policy Act, REPI provides financial incentive payments as renewable electricity is generated. In other words, it is a production-based incentive program.⁵⁶

It is difficult for public entities to count on the availability of full REPI payments to help finance renewable projects for two main reasons. First, while the REPI program provides qualifying projects with incentives over a 10-year period, funding is subject to annual federal appropriations and is therefore uncertain every year.⁵⁷ This uncertainty is unacceptable to lenders, who will attribute no value to potential REPI payments, to reduce their risk of investment. Additionally, funding has been insufficient to meet 100% of the qualified REPI payments. For example, in 2007, only 25% of the amount requested by qualified producers was paid out (based on 2006 electricity production). Approximately \$20 million worth of REPI credits were requested in 2006, yet only \$4.9 million were allocated by Congress for the program.⁵⁸ Given that REPI payouts are production based, the amount can still be considerable for large producers of electricity. In 2007, a Nebraska wind project received a \$1.1 million REPI payment and a Washington wind project received a REPI payment of \$585,000.⁵⁹

⁵⁵ “Renewable Energy and Energy Conservation Tax Act of 2008 (Engrossed as Agreed to or Passed by House)” United States Congress proposed legislation [H.R.5351.EH], Title I, Subpart I, Section 54B New Clean Renewable Energy Bonds, at <http://thomas.loc.gov/cgi-bin/query/F?c110:4:./temp/~c110Z35Iae:e32849>:

⁵⁶ “Renewable Energy Production Incentive,” U.S. Department of Energy Web site, accessed April 6, 2008, at <http://www.eere.energy.gov/rep/rep/>

⁵⁷ “Renewable Energy Production Incentive: About the Program,” U.S. Department of Energy Web site, accessed April 6, 2008, at <http://www.eere.energy.gov/rep/about.cfm>

⁵⁸ Personal communication with Christine Carter and Chico Gonzalez, REPI program managers of the U.S. Department of Energy Golden (Colorado) Field Office in December 2008.

⁵⁹ Ibid.

However, for many projects, particularly solar, the REPI payout is very modest. The average allocation for the 25 solar projects that received REPI funds in 2007 was \$898.52.⁶⁰ Given this data and the fact that REPI rewards electricity already generated, it is not a significant driver of financing new public-sector PV. One local government REPI beneficiary (who did not wish to be cited), viewed REPI as an added bonus but not something to include in a project's justification or economic analysis. In this particular case, only 10% of the incentives earned by this district's qualifying projects had actually been paid out over the years.

⁶⁰ Ibid.

5.0 Federal and State Tax Incentives

The emergence of the third-party ownership model (described in Section 6) has created a mechanism whereby renewable projects on government property can benefit from federal and state tax incentives. These incentives provide tremendous value to the system owner, which can be passed on to the public host. For example, the federal investment tax credit (ITC) and Modified Accelerated Cost Recovery System (MACRS) can account for 40-60% of the installed cost of a PV system,⁶¹ which can dramatically alter the economic viability of installing solar. State tax incentives also provide benefits to tax paying entities. The value of these incentives can be passed on to public entities through the price of the power purchase agreement (PPA), which is typically at or below the utility's retail rate in the first year. This section explains the two primary federal tax incentives for solar, the ITC and MACRS, and also describes certain state tax incentives.

5.1 Investment Tax Credit (ITC)

For commercial entities, the federal government currently offers a 30% investment tax credit to partially offset the up-front installed cost of a PV system.⁶² This credit will revert back to 10% as of January 1st, 2009, if Congress does not reauthorize it. The system owner can use this credit to reduce his tax burden. For example, a PV system with an installed cost of \$1 million will qualify for a \$300,000 tax incentive. The rules associated with the ITC are complex and a tax lawyer should review its application. Certain incentives can reduce the ITC's value and can impact the depreciable basis of the underlying asset as well. The Solar Energy Industry Association's *Guide to Federal Tax Incentives for Solar Energy* provides good background information and incentive detail.⁶³

5.2. Modified Accelerated Cost Recovery System (MACRS) and Bonus Depreciation⁶⁴

As defined by the IRS, "depreciation is an income tax deduction that allows a taxpayer to recover the cost or other basis of certain property. It is an annual allowance for the wear and tear, deterioration, or obsolescence of the property."⁶⁵ Depreciation schedules can range from 3-50 years, depending on the asset.⁶⁶ It is a non-cash charge recorded as a depreciation expense for tax purposes, and most property today is depreciated using MACRS.⁶⁷ The IRS allows

⁶¹ Cory, Karlynn, Jason Coughlin, et al. "Innovations in Wind and Solar PV Financing," National Renewable Energy Laboratory technical report NREL/TP-670-42919, February 2008, at <http://www.nrel.gov/docs/fy08osti/42919.pdf>

⁶² See Section 48 (a) (3) (Investment Credit: Energy Credit) in the IRS tax code.

⁶³ Chadbourne & Parke, LLP. "Guide to Federal Tax Incentives for Solar Energy: Version 1.2," Solar Energy Industries Association, version 1.2 released May 26, 2006, at <http://seia.org/taxmanualdownload.php>

⁶⁴ "Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation," Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed February 27, 2008, accessed March 2008, at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=federal¤tpageid=1&ee=1&re=1

⁶⁵ "A Brief Overview of Depreciation," Internal Revenue Service Web site, accessed April 2008, at <http://www.irs.gov/businesses/small/article/0,,id=137026,00.html>

⁶⁶ "Modified Accelerated cost-Recovery system (MACRS) + Bonus Depreciation," Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed February 27, 2008, accessed March 2008, at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US06F&State=federal¤tpageid=1

⁶⁷ "Chapter 4. Figuring Depreciation Under MACRS," Internal Revenue Service publication 946, accessed March 2008, at <http://www.irs.gov/publications/p946/ch04.html>

commercial owners of PV systems (and most renewable systems) to use a five-year MACRS schedule.

Depreciation reduces an entity's taxable income and subsequently, its tax burden. The shorter the depreciation schedule, the greater the percentage of the asset that can be depreciated each year. So in the case of PV, five-year MACRS is more advantageous than longer depreciation schedules because shorter schedules allow businesses to accelerate the tax benefits of depreciating a particular asset.

The Economic Stimulus Act of 2008 (ESA08) contains bonus depreciation for qualifying assets placed in service in 2008. Renewable energy installations, including PV systems, may qualify for this bonus depreciation if certain criteria are met. Instead of the standard five-year MACRS schedule described in the preceding paragraph, under the ESA08, 50% of the installed cost of the PV system can be depreciated in the first year, with the remaining 50% to be depreciated over the original schedule. By accelerating the amount of depreciation in the first year, tax benefits will accrue more rapidly to investors, improving the return characteristics of the project. The requirement that the depreciable basis of the underlying asset be reduced by 50% of the federal investment tax credit did not change.

5.3 State Tax Credit Incentives

Individual states have a number of mechanisms at their disposal to support the development of renewable energy within their jurisdictions. The aforementioned RPS is one such mechanism, and state tax credits, sales tax exemptions, and property tax exemptions are three additional incentives that create value for corporate entities purchasing PV systems. According to the North Carolina Solar Center, more than 10 states offer some form of local tax relief to encourage renewable energy development.⁶⁸

The Oregon Business Energy Tax Credit (BETC) is noteworthy given its relevance to public-sector entities. The BETC is a state income tax credit up to 50% of the installed costs of a renewable energy system. The tax paying entity can apply the tax credit pro-rata over five years to lower its state income tax bill.⁶⁹ In recognition of the non-tax-paying status of governments and nonprofits, the Oregon Department of Energy created a "Pass-Through Option" where a government agency or a school, for example, can sell the present value of its tax credit to a tax paying entity and use the proceeds to defray the cost of its PV project.⁷⁰ For example, in 2002, the North Santiam School District in Oregon's Central Cascade Mountains sold its tax credits to the Nike Corporation and received \$129,000 to assist with the capital costs of its energy efficiency upgrades.⁷¹

⁶⁸ "Corporate Tax Incentives for Renewable Energy," Database of State Incentives for Renewables and Efficiency (DSIRE), last review depends on the state, accessed April 2008, at <http://www.dsireusa.org/library/includes/seeallincentivetype.cfm?type=Corporate¤tpageid=7&back=fintab&EE=0&RE=1>

⁶⁹ Ibid.

⁷⁰ "Business Energy Tax Credit Pass-Through," Oregon Department of Energy – Conservation Division, accessed April 2008, <http://egov.oregon.gov/ENERGY/CONS/BUS/tax/pass-through.shtml>

⁷¹ "Case Study: North Santiam School District: Homework pays off for North Santiam Schools," Oregon Department of Energy – Conservation Division, February 2008 at <http://egov.oregon.gov/ENERGY/CONS/SB1149/Schools/docs/NorthSantiam.PDF>

6.0 Third-Party Financier Model in the Public Sector

Now that the tax incentives have been described, this section turns to how public entities can finance on-site PV by working with partners to monetize the federal tax incentives.

6.1 Public-Sector Hosts, but Does Not Own PV

In the public-sector PV marketplace, public entities are moving away from direct ownership of PV systems and toward the use of partnering with third-party owners. While common in the private sector, the use of third-party ownership structures is still a relatively new phenomenon in the public sector. According to Greentech Media, in 2007, 50% of the growth in the commercial and institutional market for solar in the United States was carried out using the third-party owner model compared to just 10% in 2006.⁷² State and local governments see the third-party ownership model as a potential way to effectively monetize federal tax benefits, avoid paying the up-front cost of solar, more efficiently allocate public funds, and accelerate the deployment of solar PV.

Instead of owning the PV system, a public entity hosts a system that is paid for and owned by a taxable entity. The public entity enters into a long-term contract (the “PPA”) with a third party to purchase the electricity generated on its property. The electricity price is typically set at or below the host's current retail rate for the first year, and then will typically increase at a fixed percentage over time. The developer manages all aspects of system financing, installation, and maintenance, and bears all operating risks as illustrated in Figure 8.

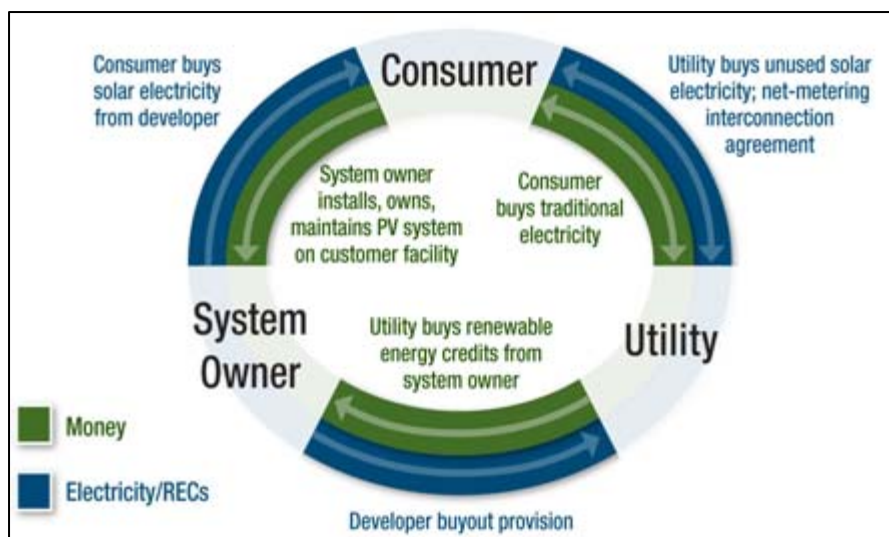


Figure 8. Contracts and cash flow in third-party ownership model

Source: Department of Energy Solar Program

Benefits of the third-party ownership structure include no up-front capital costs, known electricity prices purchased from the system for 20-25 years, no responsibility if the system does not perform over time (except to purchase more power from their utility), and a shift in the operating and maintenance (O&M) responsibility onto a qualified party. The details of the roles and responsibilities of different parties for one variation of the third-party ownership model are

⁷² Guice, Jon, and John D.H. King, “Solar Power Services: How PPAs are changing the PV Value Chain,” Greentech Media Inc., February 14, 2008.

shown in Figure 9. Examples of the third-party ownership structure in place in the public sector include PV facilities at an airport,⁷³ a water treatment plant,⁷⁴ and a port,⁷⁵ to name a few. These examples are explored in detail in Appendix 1.

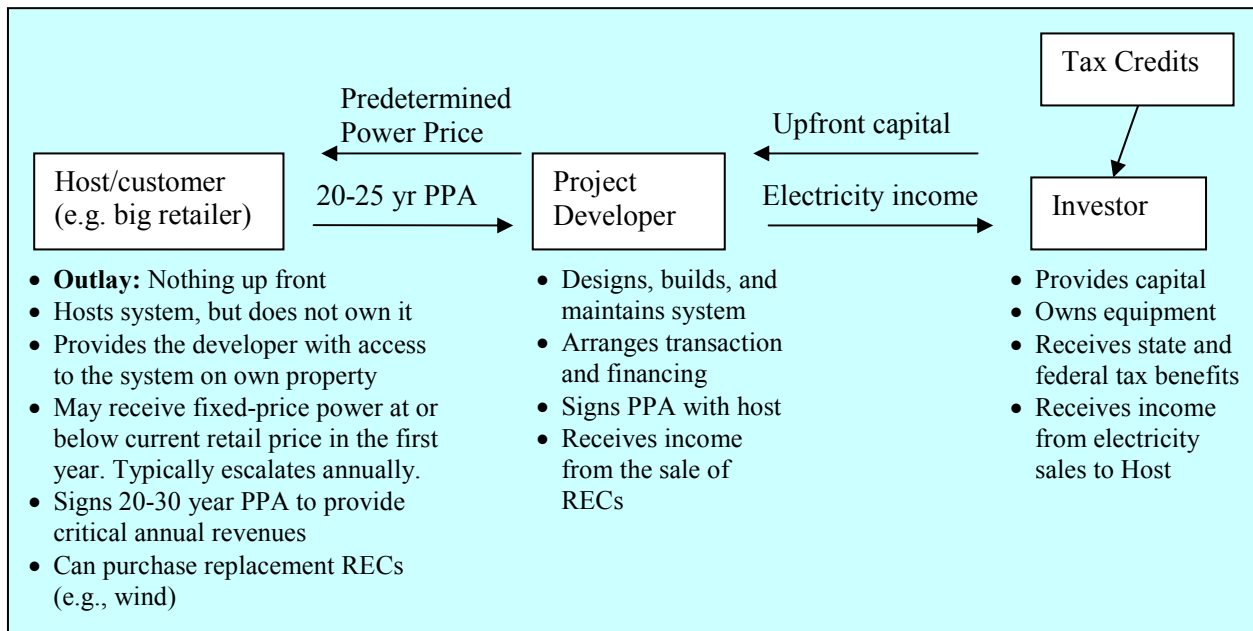


Figure 9. Third-party ownership model details (one variation)

While the third-party owner model is attractive, there are some important caveats—most notably, if the SRECs are sold, then the municipality cannot claim it is consuming green power unless it buys replacement RECs.⁷⁶ A second issue is that despite the fact that the public entity is hosting on-site PV, it still pays for all of its electricity needs. In addition to paying a fixed (and escalating) price for power generated on-site through the PPA, the public entity purchases its remaining electricity needs from the LSE at the current retail rate. Thirdly, the partners in the third-party ownership model must have access to the site where the PV system is located. Finally, transaction costs can be significant and there are some specific contracting issues that require attention. These challenges are explored in Section 6.3.

6.2 The Benefits of Third-Party Ownership

There are several key reasons why more state and local governments are considering the third-party PPA an integral component of their PV financing strategy.

- **Ability to Monetize Federal Tax Incentives.** As noted above, the federal ITC for commercial solar projects is 30% of the installed capital cost. In addition, businesses can accelerate the depreciation of the cost of a solar system using a five-year MACRS. Together, these two tax incentives have a tremendous impact on both the cost of and the financial returns on a project. However, as non-tax paying entities, state and local

⁷³ Denver International Airport

⁷⁴ San Diego's Alvarado Water Treatment Plant

⁷⁵ Port of Oakland, California

⁷⁶ When a renewable generation owner sells the RECs, it also sells the right to claim they are using renewable power. This is discussed in more detail in Section 6.3.

governments cannot benefit from these attractive incentives if they own PV systems. The third-party ownership model introduces a taxable entity into the structure that can benefit from the federal tax incentives, lowering the overall cost to the non-taxable entity.

- **Low/No Up-front Costs.** At \$9-10 per installed watt in parts of California,⁷⁷ public-sector PV systems (above 100 kW) can easily cost hundreds of thousands of dollars. Even with rebates and incentives to reduce this amount, the up-front cost is significant. Given budget constraints, committing to such a large initial investment is not always feasible, even if the long-run economics make sense. The third-party ownership structure pushes this initial cost on to the solar developer and its investors.
- **Predetermined Electricity Price for 20-25 years.** In today's volatile energy markets, a fixed-priced PPA (with a predetermined escalation rate) offers predictable electricity pricing for the portion of the entity's load served by the PV system. To make the third-party ownership model work, the price of electricity is usually set at or below the customer's current retail rate for the first year, and then escalates annually for 20-25 years. This structure provides a price hedge against the potential volatility of both fossil fuel and electricity markets. An annual price escalator of 3-3.5% is common in today's marketplace,⁷⁸ although smaller escalators are possible. For example, San Francisco's bus company, AC Transit, has signed a 20-year PPA with MMA Renewable Ventures with a 2.5% price escalator.⁷⁹
- **Shift O&M Responsibility to Qualified Third Party.** Owning a large PV system implies a certain degree of oversight and maintenance that a public entity may not want to be responsible for or have the expertise to carry out. One of the attractive features of the third-party ownership structure is the ability to assign the operation and maintenance of the PV system to more qualified counterparties. The third-party ownership model streamlines the number of counterparties that the public entity has to deal with down to basically one, the PPA provider/developer.
- **Path to Ownership.** It is possible for a local government to include a buyout option in the PPA. From a financial perspective, this option would likely take place after year six so that the original investors are able to capture all of the tax incentives. This buyout will likely represent a mutually agreed upon fair market value for the PV system. For example, the Denver International Airport (DIA) has entered into a 25-year PPA with MMA Renewable Ventures for a 2 MW PV system at the airport. This PPA contains an estimated \$8.1 million dollar buyout option after year six that will allow DIA to take ownership (the actual payment will be based on the fair market value of the system at the

⁷⁷ Phillips, Roy. "Solar Technology," presentation at the Solar Power Project Development and Finance Tutorial in San Diego, California, by the president of Marin Solar on November 14, 2007.

⁷⁸ Horsey, Ed. "Modeling Solar Projects," presentation at the Solar Power Project Development and Finance Tutorial in San Diego, California, by a principal of Enselle LLC on November 15, 2007.

⁷⁹ "Solar's Newest Resource: MMA Renewable brings together energy users, builders, and financiers to build mini-utilities," *BusinessWeek* article from www.businessweek.com, published December 12, 2007, at http://www.businessweek.com/magazine/content/07_49/b4061074.htm?chan=technology_technology+index+page_top+stories&chan=innovation_architecture_top+stories

time of purchase).⁸⁰ If a buyout option is not exercised prior to the end of the original PPA term, at the end of the term, the three likely scenarios for the host would be to: 1) extend the PPA agreement, 2) purchase the system, or 3) ask that the system be removed.⁸¹

6.3 Caveats with Third-Party Ownership

While the third-party ownership model can be attractive for state and local governments, it is not perfect. There are nuances to PPA agreements which must be understood before moving ahead with the third-party ownership structure.

- **Green versus Brown Energy.** It is common in third-party PPA agreements that ownership of the SRECs be transferred to the owner of the system (i.e., not the state/local government). If this is the case, state and local governments must be careful how they advertise the solar PV systems that they host. In the absence of REC ownership, it is not accurate to claim that the public agency is *powered* by clean or green energy. The owner of the SREC is the only entity that can claim the environmental attributes of the solar power. In essence, the host has sold the clean attributes of the system in the form of SRECs. Instead, what may be permissible is to say that the agency “hosts” solar panels on its property.⁸² The rationale is to avoid double-counting of renewable energy credits by more than one entity.⁸³ Therefore, if a particular agency wants to claim that they are powered by solar energy, it must either own the system or negotiate to retain ownership of the SRECs within the PPA. However, by retaining SREC ownership, the negotiated price of electricity plus SRECs in the PPA will be higher to compensate the third-party PPA provider for the loss of the SREC revenue stream. An alternative option is to replace the SRECs sold to the owner with lower-cost wind or biomass RECs purchased in the voluntary green market to claim they are supporting green power (but again, not solar power).
- **Ownership and Facility Access.** In some cases, ownership is important.
 - One of the concepts that can attract public entities to solar PV is the concept of a permanent reduction in electricity bill payments to their LSE. However, when the third-party ownership model is used, the host must still pay for the power generated on-site during the term of the PPA (albeit at a known rate that will not change with fossil fuel and electricity prices). While a third-party PPA can allow for system buyout options (generally after tax incentives are exhausted), in most

⁸⁰ Vuong, Andy. “Solar-energy system to land at DIA in 2008,” *The Denver Post*, October 1, 2007, at http://www.denverpost.com/ci_7056394?source=rss

⁸¹ Guice, Jon, and John D. H. King. “Solar Power Services: How PPAs are Changing the PV Value Chain,” Greentech Media, February 14, 2008.

⁸² The Federal Trade Commission (FTC) is currently investigating renewable energy certificates and carbon offsets (among other topics) and held a workshop on January 8, 2008, to discuss advertising claims. The FTC is planning to issue guidance in late 2008 or early 2009 that clarifies the claims that parties can make (as of early 2008), and they plan to include guidance about REC claims in the third-party ownership model. More information can be found at <http://www.ftc.gov/bcp/workshops/carbonoffsets/index.shtml>, or by contacting Hampton Newsome at 202-326-2889.

⁸³ Holt, Ed, Ryan Wiser, and Mark Bolinger, “Who Owns Renewable Energy Certificates? An Exploration of Policy Options and Practice,” Lawrence Berkeley National Laboratory technical report LBNL-59965, April 2006, at <http://eetd.lbl.gov/ea/emp/reports/59965.pdf>

cases, permanently lower electric bills must wait until the PPA expires and the host exercises the ownership option (during which the host will have to pay the fair market value of the system).

- Some government agency staff, particularly plant/facility managers and security staff, may not be comfortable with a third party having access to and installing equipment on their property. Ongoing site access is critical to the performance of the system and if that is not acceptable, the third-party ownership model will unlikely be a viable option.
- **Transaction Costs.** The third-party ownership model requires knowledgeable lawyers to assist with implementing the appropriate contracts so that the various federal tax incentives can be monetized. While the host is not involved with all of the contracts that need to be signed, it is involved with the PPA itself and must be ready to allocate resources to ensure its interests are represented in the final contract.
- **Municipal-Specific Contractual Issues.** Most state and local governments approve the funding of their operating obligations on an annual basis, so there is a question about the enforceability of a long-term PPA. This is typically addressed through two mechanisms:
 - Non-appropriation clause: A non-appropriation clause permits the hosting customer to terminate the PPA at the end of any appropriation period without further obligation or payment of any penalty, if and only if, the host was unable to obtain appropriation for funds to meet future scheduled payments and a formal resolution or ordinance is passed. Often, this type of clause will contain a "best efforts" requirement, i.e., the customer promises to use its best efforts to seek and obtain the necessary appropriation for payment. This provision is common in tax-exempt leases and is designed to enable the customer to account for the PPA obligation as a current expense instead of debt.
 - Non-substitution clause: In today's fast-evolving solar industry, non-substitution clauses are used to protect a project's viability. If a PPA is canceled due to non-appropriation, the clause prohibits the customer from replacing the hosted equipment supported by the PPA with equipment that performs the same or similar function. A non-substitution period of 365 days is common, and shorter time periods are also used. Decisions regarding the length of the non-substitution period are based partly on the perceived essential nature of the equipment. Generally, the more essential the equipment is, the shorter the non-substitution period will be. Given the host's right to cancel under the non-appropriation clause, the non-substitution clause is intended to provide some comfort to the investor and the project developer.
- **Legality Concerns.** In Nevada, there may be some question about the legality of using the third-party model for on-site projects. The argument is that by selling power to a host facility, the third-party PPA provider might be illegally competing with the utilities. The

Public Utilities Commission of Nevada is investigating these concerns and is expected to make a ruling later in 2008.⁸⁴

In the end, city and state program administrators will determine how best to tailor third-party ownership and the PPAs to meet their PV program goals and to capitalize on any incentives. Certainly, the promise of stable and predictable electricity prices for 20-25 years has value. However, the economic value can only be measured retroactively when the contracted PPA prices can be measured against actual market prices. While any realized electricity savings (or additional costs) can be calculated over time, the total net economic benefit (or cost) can only be determined at the end of the PPA.

6.4 Who is Using Third-Party Ownership in the Public Sector?

While there are many examples of individual public-sector projects that use a third-party ownership structure (many of which are in California), comprehensive programmatic approaches to third-party financing are relatively new. States such as Massachusetts⁸⁵ and Hawaii,⁸⁶ and local governments such as Boulder County, Colorado,⁸⁷ are among those pursuing more comprehensive third-party ownership models. In 2007, the San Francisco Public Utilities Commission⁸⁸ (SFPUC) and the Sacramento Municipal Utility District⁸⁹ (SMUD) issued a request for information and a request for offer, respectively, seeking PPA proposals for PV deployment. This trend is continuing into 2008; more cities have indicated an interest in issuing requests for proposals for solar PV PPAs. Recent examples of public-sector third-party owner projects are included in Appendix 1.

6.5 Sale-Leaseback and the Partnership-Flip Models⁹⁰

It is important for state and local governments to understand the dynamics between the solar developer and its tax-equity investors, because the agreement between these two parties will influence elements of the PPA, including the timing and the cost of any potential buyout options. Common system ownership structures include the sale-leaseback model and the partnership-flip model.

6.5.1 Sale-Leaseback Structure

The sale-leaseback structure is shown in Figure 10. Under the sale-leaseback arrangement, the tax-equity investor buys the PV system and leases it to the third-party PPA provider. The third-

⁸⁴ Lacey, Stephen. "Nevada Debates Third-Party Ownership of Renewable Energy Systems," *Renewable Energy World*, March 24, 2008, at <http://www.renewableenergyworld.com/rea/news/story?id=51908>.

⁸⁵ Personal communications with Jon Abe of the Massachusetts Technology Collaborative, December 2008.

⁸⁶ "Governor Lingle Announces Historic Plan to Utilize Solar Power at 12 Locations Around State: Plan highlights commitment to renewable energy, leading by example," Hawaii governor's news release, January 9, 2008, at http://hawaii.gov/gov/news/releases/2008/news_item.2008-01-09.3842330405

⁸⁷ "Boulder County Envisions Expansion of Solar Power on County Buildings," Boulder County Colorado, November 16, 2007, at <http://www.co.boulder.co.us/newsroom/templates/?a=976&z=1>

⁸⁸ "Request for Information: development of renewable power facilities within the city," San Francisco Public Utilities Commission, February 22, 2007, at http://www.fypower.org/pdf/SFPUC_Solar_RFI.pdf

⁸⁹ "SMUD to Release 2007 Renewable Energy RFO," Sacramento Municipal Utility District, news release on March 8, 2007, at http://www.smud.org/news/releases/07archive/03_08RenewableRFO.pdf

⁹⁰ Most of the information in this section was provided through several personal communications with Charles Jennings, of Financial Analytics Consulting Corporation, in February and March 2008. Additional input was provided from Mark Bolinger, Lawrence Berkeley National Laboratory, on March 30, 2008.

party PPA provider, in turn, signs a PPA with the state or local government agency that will host the PV system. At the end of the lease period, which likely will be after “year six” when the tax benefits have been exhausted, the third-party PPA provider can purchase the system. At that time, and at predetermined times throughout the remainder of the PPA, the municipality may have the option to purchase the system and take full ownership, if this was contractually arranged in the PPA. The sale-leaseback structure is subject to the same rules of any capital equipment lease, in that the tax investor must show a before-tax profit on the lease, net of the investment tax benefit. Therefore, the transaction must be structured so that it shows an economic benefit to the tax investor, other than merely the tax incentives.

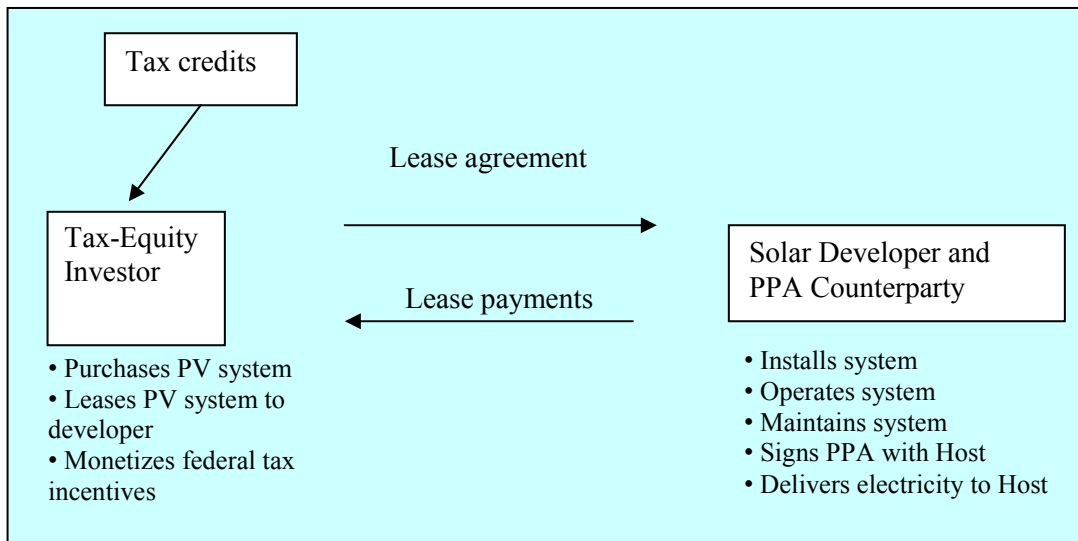


Figure 10. Sale-leaseback structure with PPA

6.5.2 Partnership-Flip Structure

The partnership-flip structure is borrowed from the wind industry and is shown in Figure 11. The solar developer and tax-equity investor(s) can form a partnership for the express purpose of installing and operating that system, usually in the form of a limited liability corporation or special purpose entity (SPE). The SPE then purchases the PV system and enters into a PPA with the public-sector host of the system. The SPE, or its affiliates, will install, operate, and maintain the PV system. The tax-equity investor will own a majority stake (nearly 100%) in the SPE in the early years of the project (through year six) to monetize the federal tax incentives. When these tax benefits are exhausted, majority ownership “flips” from the tax investor to the developer. At that time, and at predetermined times throughout the remainder of the PPA, the municipality may have the option to purchase the system and take full ownership, if the option was contractually arranged in the PPA.

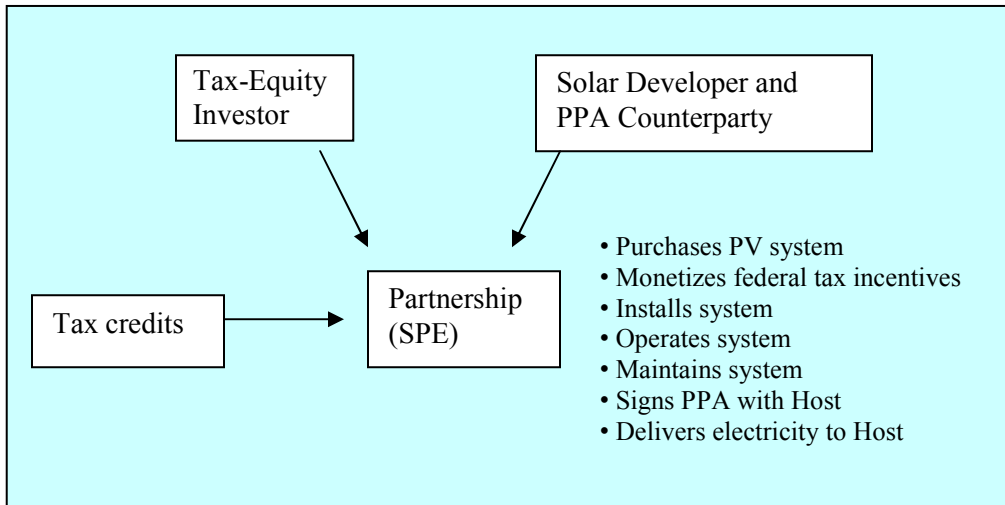


Figure 11. Partnership-flip structure with PPA

While the ownership requirements are not clear for solar facilities using the ITC, at the end of 2007, the IRS clarified the rules of the production tax credit (PTC) for wind energy deals under Revenue Procedure 2007-65.⁹¹ In this ruling, the IRS created a “safe harbor,” whereby if the ownership structure meets the entire set of key requirements, investors can be certain about the allocation of wind tax credits.⁹² While the IRS made it clear that this procedure does not apply to other technologies or other tax credits, the solar industry is using it as a guideline for how ITC ownership should be structured.

⁹¹ “Part III: Administrative, Procedural, and Miscellaneous: 26 CFR 601.105: Examination of returns and claims for refund, credit or abatement; determination of correct tax liability,” Internal Revenue Service, Revenue Procedure 2007-65, 2007, at http://www.novoco.com/energy/resource_files/irs_guidance/rulings/proc_07-65.pdf

⁹² “IRS Establishes Safe Harbor Provision for Investors Claiming Section 45 Wind Energy Credits,” Bracewell & Giuliani Update, October 29, 2007, at http://www.bracewellgiuliani.com/index.cfm/fa/news.advisory/item/0d77e273-7527-4f00-90d1-dc105955d58d/IRS_Establishes_Safe_Harbor_Provisions_for_Investors_Claiming_Section_45_Wind_Energy_Credits.cfm

7.0 Insurance and the Impact on PV Deployment

Insurance requirements can complicate the installation of PV systems on public buildings and lands. Depending on the state, utility companies, as part of the interconnection agreement, can require owners of PV systems to obtain additional general liability insurance whose cost can reduce the economic viability of the project.⁹³ Under the third-party PPA ownership structure, it is the third party that must obtain property insurance for the PV systems hosted by the public agency; but, as with other costs associated with the PPA, the customer/host will bear this cost. This insurance can be expensive and has the potential to result in higher-than-expected costs—and could potentially result in abandoning potential projects.

7.1 Self-Insuring Publicly Owned PV Systems

An issue for public entities in certain states is the insurance requirement mandated by the local utility as a prerequisite to interconnect a PV system to the grid.⁹⁴ Public entities traditionally self-insure property they own. However, local utilities in certain states might require that public entities obtain a separate policy, prior to interconnection. While utility interconnect agreements allow for self-insurance options,⁹⁵ minimum coverage requirements may exceed self-insurance levels. Depending on the cost of coverage, this insurance premium could materially impact the feasibility of the project. If insurance costs are high enough, it is possible that a PV system will be downsized or abandoned to avoid insurance requirements, instead of optimizing it for the host's load profile.

7.2 Massachusetts: Umbrella Insurance Policy Decreases Costs⁹⁶

If additional liability insurance requirements are unavoidable, anecdotal evidence from Massachusetts indicates that an umbrella policy may be a more cost-effective approach than one-off policies for each project. Net-metering laws in Massachusetts apply to systems up to 60 kW.⁹⁷ Additional insurance requirements are triggered for projects greater than 60 kW.⁹⁸ Of the 12 CREBs projects for public-sector PV installations that the state's Division of Energy Resources (DOER) is involved in (described in Appendix 1), nine of them are larger than 60 kW and, thus, require additional insurance. Of those, two already have policies for other power-generating assets, but the rest must obtain additional insurance. According to utility regulations, for projects in the 60-100 kW range, the insurance requirement is \$500,000 per project. Projects

⁹³ "Freeing the Grid: 2007 Edition," Network for New Energy Choices, Report No. 02-07, November 2007, at http://www.newenergychoices.org/uploads/FreeingTheGrid2007_report.pdf

⁹⁴ Shirley, Wayne. "Survey of Interconnection Rules," prepared for the Florida Public Service Commission Workshop on Interconnection of Distributed Generation, The Regulatory Assistance Project, August 27, 2007, at http://epa.gov/chp/documents/survey_interconnection_rules.pdf

⁹⁵ Ibid.

⁹⁶ Information in this section that is not attributed to other sources comes from various e-mail conversations with Meg Lusardi, Division of Energy Resources, Commonwealth of Massachusetts in October, November, and December 2007. (<http://www.mass.gov/doer/>)

⁹⁷ "Massachusetts Incentives for Renewables and Efficiency: Massachusetts – Net Metering," Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed 04/25/2007 and accessed April 2008, at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MA01R&state=MA&CurrentPageID=1&RE=1&EE=1

⁹⁸ Shirley, Wayne. "Survey of Interconnection Rules," prepared for the Florida Public Service Commission Workshop on Interconnection of Distributed Generation, The Regulatory Assistance Project, August 27, 2007, at http://epa.gov/chp/documents/survey_interconnection_rules.pdf

greater than 100 kW but less than 1 MW require \$1 million. Finally, for systems between 1 MW and 5 MW, the insurance requirement is \$2 million. Utility interconnection agreements in the state permit self-insurance if it is established in accordance with commercially acceptable risk management practices.⁹⁹ However, in the case of the aforementioned CREBs projects, the level of self-insurance does not meet the minimums stipulated by the insurance requirements listed above.

As a result, the DOER is exploring the concept of an umbrella policy for public-sector PV facilities as a way to lower insurance costs on a per-project basis. To provide a data point, one particular 425 kW PV project in Massachusetts triggered the need for a \$1 million insurance policy, which carries an annual premium of \$14,000 (\$33/kW). However, according to conversations that the DOER has had with various insurance agencies, if additional PV projects are aggregated under an umbrella policy, costs will decrease on a \$/kW basis.¹⁰⁰

7.3 Insurance and Third-Party PPA Providers

In conversations with two of the largest third-party PPA providers, MMA Renewable Ventures and SunEdison, there are "under-the-radar" issues such as insurance, property taxes, sales taxes, and other costs that impact project economics and the feasibility of entering into third-party ownership agreements. Some states waive certain taxes and fees, such as California, which waives property taxes for solar PV.¹⁰¹ A comprehensive list of these exemptions can be found on the Solar Energy Industries Association Web site.¹⁰²

However, insurance appears to be a particular issue for third-party PPA providers. From the interviews, it is apparent that insurance costs can stop a deal from moving forward. MMA has been quoted annual insurance rates as high as 0.5% of the installed project costs, or \$50,000 per year on a \$10 million dollar PV system. Insurance can be costly for a number of reasons, including:

- PV equipment and system integration is not well understood by the insurance industry.
- There is insufficient historical data on losses in the PV industry to appropriately price risk. Anecdotally, actual losses in the United States appear to be very minimal. However, the operating history for the majority of PV systems in the United States is not long enough to fully document what appear to be modest levels of risk.
- Insurance companies are being asked to provide coverage on expensive electrical equipment that is installed on someone else's property. This is not typical and can cause some concerns.

⁹⁹ Ibid.

¹⁰⁰ Personal communication with Meg Lusardi, Division of Energy Resources, Commonwealth of Massachusetts in October, November, and December 2007. (<http://www.mass.gov/doer/>)

¹⁰¹ "California's Incentives for Renewables and Efficiency: Property Tax Exemptions for Solar Systems," Database of State Incentives for Renewables and Efficiency (DSIRE), last DSIRE review on 03/05/2008, accessed April 2008, at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA25F&state=CA&CurrentPageID=1&RE=1&EE=1

¹⁰² Herig, Christy, and Susan Gouchoe. "State by State Incentives for Photovoltaic Projects," Seague Energy Consulting under subcontract to the National Renewable Energy Laboratory, August 2007, at http://www.seia.org/PV_Incentives_Aug07.doc

In addition to the initial premium, the PPA provider must also absorb the risk of annual premium increases despite locking in a fixed-price, 20-plus-year contract with the PV host. Annual premiums are most likely to fluctuate in markets where there is a greater potential for system damage due to issues outside of the project owner's control. For example, California has the potential for seismic activity, and the Gulf Coast has the potential for damaging hurricane activity. Floods, fires, and heavy winds are other weather-related risks that the insurance industry will severely scrutinize. Florida appears to be particularly problematic. While the state has recently announced an aggressive renewable energy plan, which includes promoting the use of PV,¹⁰³ it is unclear whether high insurance rates will be a major barrier for third-party providers and their ability to offer PPAs to public entities—and for PV deployment, in general.

One approach to lowering the cost of insurance on a project basis is for PPA providers to establish master policies (often on a state-by-state basis) that moderate the risk profile of PV systems in aggregate. Both third-party providers interviewed are doing this. The interviewees also suggested three specific activities that could begin to address the insurance challenges, including:

- Collaborate with the U.S. solar industry to compile actual loss data and demonstrate the true risks involved in PV. An agency such as the Department of Energy could work with solar associations to collect information from industry on a confidential basis and publish an annual report on claims made against insurance companies for damage to PV systems.
- Work with Europe and Japan to secure loss-history data because their systems have been operating longer than the systems in the United States. Provide an analysis of this data to educate U.S. insurance companies about actual PV risks.
- Conduct policy roundtables with representatives from the PV industry and the insurance industry, to bridge any existing knowledge gap and, potentially, reduce insurance premiums that currently inhibit PV deployment in certain instances.

¹⁰³ Crist, Charlie. "Establishing Immediate Actions to Reduce Greenhouse Gas Emissions within Florida," State of Florida: Office of the Governor, Executive Order Number 07-127, July 13, 2007, <http://www.fsec.ucf.edu/en/media/enews/2007/pdf/07-127-emissions.pdf>

8.0 Conclusions

Given the recent changes in the marketplace, many state and local governments are evaluating new strategies to deploy solar PV on public property. With payback periods longer than most public entities consider reasonable, state incentive programs have proven necessary to help support additional solar PV deployment. Appropriate policies and adequate financial incentives can motivate public-sector agencies to consider implementing PV on their sites. The goal of this report is to gauge the progress of public-sector PV deployment in select states and cities throughout the country, and determine what policies and programs are working and where there are barriers to deployment.

A significant source of funding for PV on public and private buildings comes from SBC funds. Enacted on a state-by-state or utility-specific basis, SBC funds can successfully support new PV projects on public buildings and lands in several ways. Rebates and subsidies can significantly reduce the up-front capital costs of a PV system. Funds also can be used to challenge the public to take in-kind action, as in Connecticut. Nonetheless, the remaining costs are large enough that SBC incentives are often bundled together with other financial incentives.

RECs have emerged as an important revenue stream for deploying renewables. The environmental attributes of renewable energy generation are captured in this tradable commodity and are critical to the success of many PV projects. SRECs provide the most revenue in states with specific RPS set-asides for solar. In Colorado, Xcel Energy purchases SRECs from the owners of qualified PV systems, in addition to providing an up-front cash rebate. New Jersey used to provide rebates, in combination with market-based SREC sales, but recently enacted changes to phase out those rebates. In the near future, developers must depend solely on SREC sales to utilities to get projects financed. The elimination of the up-front solar rebate may create additional financing hurdles for new PV projects, particularly for small projects.

In states with significant support for PV, state and local governments have recently been able to use the third-party ownership structure to monetize federal tax credits. Given their non-tax paying status, government agencies are traditionally unable to benefit from the generous federal tax incentives for PV such as the ITC and accelerated depreciation schedules. However, under a third-party PPA, the public entity hosts rather than owns the PV system. The host secures stable and predictable electricity prices over a 20- to 25-year period. The up-front capital investment and the ongoing operations and maintenance requirements of the PV system are transferred to the tax investor and developer, respectively, in exchange for the tax credit benefits. As a result, the third-party ownership model offers great promise to those state and local governments looking to install a significant number of PV systems in the most cost-efficient manner. Third-party ownership is not necessarily the solution for all public entities, especially those who want to reduce their annual electricity bills by taking immediate ownership of the PV system, or those who are reluctant to provide third parties access to their facilities.

In addition to tax incentives, there are other federal programs that provide subsidized financing for renewable energy owned by public entities. CREBs offer a new source of affordable financing for qualifying PV projects. CREBs provide a federal tax credit to investors in lieu of interest payments. Massachusetts successfully navigated the CREBs process by pooling together several projects to minimize transaction costs. However, in general, transaction costs appear to

be a significant barrier for local governments who want to finance small PV projects with CREBs. In addition to CREBs, the renewable energy production incentive (REPI) also provides a 10-year financial incentive for public renewable energy projects. However, it is apparent that this particular program does not promote significant new PV deployment because it is subject to annual congressional appropriations and has been unable to support a majority of eligible projects in the past.

At the state and local level, governments continue to explore bond-related instruments to finance PV projects with mixed success. General obligation bonds supported by a government's taxing authority provide greater security to investors, but revenue bonds repaid by energy savings appeal to local governments managing their debt burden. During the past several years, voters, city council representatives, and state legislatures have approved solar PV bonds in several states and one city. However, of the four cases examined, only Honolulu has successfully issued these bonds. It appears that getting approval to issue renewable energy bonds, in general, may be easier than issuing them to finance projects.

The third-party ownership structures are financed using either the sale-leaseback structure or the partnership-flip model. While these structures are independent from the PPA that is signed by the host and the project developer, they do influence the language in the PPA, in particular, the buyout clauses. Both of these third-party structures have complex tax issues associated with their use. To the extent the tax issues can be addressed efficiently, these innovative financing structures may begin to propagate in the public sector.

Insurance can be a "below-the-radar" issue in the PV industry. For public agencies accustomed to self-insuring their facilities, it is important to determine whether they need to contract for third-party insurance to comply with interconnection requirements. It can be costly to insure PV systems on a one-off basis. Therefore, Massachusetts is exploring an umbrella insurance policy to cover multiple systems and, ultimately, reduce costs on a per-project basis. Aside from new insurance requirements for public systems, third-party PPA providers also grapple with the high cost of insuring the large-scale systems they own as they pursue PPA opportunities. In certain states such as Florida, the high cost of insurance may actually prevent a project from going forward.

Appendices

Appendix 1. Examples of Public-Sector PV Deployment, by State and Project

Note: This page provides an overview of the public-sector PV project examples detailed in this appendix and shows which aspects our examples highlight. It is not intended to be comprehensive, and the authors recognize that each state/city may offer many more programs and other states/cities may offer programs not included here.

Table 2. Examples of Public-Sector PV Deployment, by State and Project

Examples by State and Project*									
State	RECs	CREBs	SBC	Energy Bonds	PPA	Energy Efficiency	Emergency Power	Insurance	PBI
California			X						X
Santa Rita Jail			X			X			
Moscone Center			X			X			
Alvarado Water Treatment Facility			X		X				
Port of Oakland			X		X				
Fresno State University			X		X				
San Francisco				X**					
Colorado	X		X						
Denver International Airport	X		X		X				
Boulder County					X				
Connecticut			X						
Clean Energy Campaign			X						
Delaware				X**					
Hawaii					X				
Honolulu				X**					
Massachusetts		X	X					X	
Montana			X				X		
New Jersey	X								
Atlantic County Utilities Authority	X		X						
New York			X						
New Paltz			X						
Ohio			X						
Center for Nature Photography			X						
New Mexico									
Finance Authority				X**					

* The examples highlight particular aspects of each state's programs - that each program may offer more than what is listed in the table.

X** - These four examples are found in the text in Section 4.2.2.

California

*California Solar Initiative*¹⁰⁴

California is a leader when it comes to public-sector PV programs. San Francisco, Sacramento, Berkeley, Los Angeles, and San Jose are just a sample of the many California cities that have taken a progressive attitude toward public-sector PV deployment for a number of years. As a result, many of the public-sector PV examples are in California. Generous state and utility incentives and widespread public support have contributed to the state's impressive demand for PV systems. From 1981-2006, 198 MW of grid-connected PV was installed in California.¹⁰⁵ In 2007, 7,541 applications, requesting \$558 million in incentives, were submitted for a total of 209 additional MW of PV.¹⁰⁶ Out of these totals, the government and nonprofit sector (the two sectors are reported on a combined basis) accounted for 197 applications for 33.4 MW.¹⁰⁷ 18 MW of new PV was actually installed in the state in 2007, partly financed by \$46 million in rebates.¹⁰⁸

In January 2006, the California Public Utilities Commission (CPUC) approved the landmark California Solar Initiative (CSI), which authorizes the state to invest \$3.2 billion in small-scale solar electric systems.¹⁰⁹ The California Solar Initiative, funded by a system benefit charge, is tasked with developing 3,000 MW of new solar generated electricity by 2017. The CPUC and the California Energy Commission (CEC) have joint oversight over the CSI, whereas the utilities administer the program. The initiative was complimented in August 2006 when Gov. Arnold Schwarzenegger signed the Million Solar Roofs Bill (SB1). The bill created state-level policies that reinforced the California Solar Initiative, something that the CPUC was unable to establish on its own.¹¹⁰ CSI was officially launched on January 1, 2007, and it is currently administered by the utilities in their respective service territories.¹¹¹

¹⁰⁴ "The California Solar Initiative – CSI: About the California Solar Initiative," Go Solar California Web site, accessed April, 2008, at <http://www.gosolarcalifornia.ca.gov/csi/index.html>

¹⁰⁵ "California Solar Initiative: California Public Utilities Commission: Staff Progress Report," California Public Utilities Commission, September 2007, at <http://www.energy.ca.gov/2007publications/CPUC-1000-2007-011/CPUC-1000-2007-011.PDF>

¹⁰⁶ "California Solar Initiative: California Public Utilities Commission: Staff Progress Report," California Public Utilities Commission, January 2008, at http://www.cpuc.ca.gov/NR/rdonlyres/5C9DDC79-3E96-4241-BEEC-46D3F34254F4/0/080117_Jan_ED_CSI_Staff_Progress_Report.pdf

¹⁰⁷ "California Solar Initiative Public Forum," presentation for a meeting hosted by PG&E on January 17, 2008, at http://www.cpuc.ca.gov/NR/rdonlyres/ADF0C249-959A-4D17-A242-58C51E499C4C/0/080117_CSIForummaster.pdf

¹⁰⁸ "California Solar Initiative: California Public Utilities Commission: Staff Progress Report," California Public Utilities Commission, January 2008, at http://www.cpuc.ca.gov/NR/rdonlyres/5C9DDC79-3E96-4241-BEEC-46D3F34254F4/0/080117_Jan_ED_CSI_Staff_Progress_Report.pdf

¹⁰⁹ "The California Solar Initiative – CSI: About the California Solar Initiative," Go Solar California Web site, accessed April 2008, at <http://www.gosolarcalifornia.ca.gov/csi/index.html>

¹¹⁰ Ibid.

¹¹¹ The three California utilities are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Note that SDG&E hired a contractor, the California Center for Sustainable Energy (CCSE), to manage its program.

Similar to other states with SBC-funded programs, California initially developed a system of capacity-based incentives.¹¹² This capacity-based incentive program was labeled an expected performance-based buy-down (EPBB), resulting in an up-front payment based on the expected performance of the PV system.¹¹³ However, in 2007, with the implementation of the CSI, the state began the transition away from up-front EPBB payments to a performance-based incentive (PBI) program.¹¹⁴ Under the PBI system, monthly payments based on actual performance are paid out over a five-year period.

In 2007, PV systems that were greater than 100 kW were required to participate in the PBI program. As of January 1, 2008, PV projects that are 50 kW or greater will be included in the PBI program. This threshold will drop to 30 kW in 2010. Therefore, state and local governments currently contemplating PV systems of less than 50 kW can still benefit from up-front incentives at a rate of \$2.30/watt to \$2.65/watt (depending on the utility).¹¹⁵ Public PV systems that exceed 50 kW can earn \$0.32/kWh – \$0.37/kWh generated under the new PBI program.¹¹⁶ California does provide a higher per watt rebate to non-tax-paying entities to compensate for their inability to take advantage of tax incentives. However, both of these incentives step down over time as more solar projects are installed and megawatt milestones are achieved.

Using Energy Efficiency with Solar Projects

Energy efficiency should not be forgotten when a public agency is considering PV. In addition to the cost savings from energy efficiency retrofits, which can have very attractive payback periods on their own, there are direct benefits related to the installation of a PV system. If the energy consumption of a facility is reduced as a result of energy efficiency investments, the PV system can offset a larger portion of the total load of the facility, or the size of the PV facility (and the cost) can be reduced. In addition, energy savings resulting from energy efficiency investments can help defray the cost of owning and maintaining a PV system. The California Solar Initiative now requires that all existing customers applying for a solar incentive must first conduct an energy audit, unless 1) they have done an acceptable energy audit in the past three years, 2) have proof of Title 24 Compliance,¹¹⁷ or 3) have either Leadership in Energy and Environmental Design (LEED) or Energy Star certification.¹¹⁸ Even prior to the introduction of the California Solar Initiative, California was paying attention to energy efficiency as the following two examples illustrate.

¹¹² “Performance-Based Incentives and New Incentive Levels Starting in 2007,” Go Solar California! Web site, accessed April 2008, at http://www.gosolarcalifornia.ca.gov/csi/performance_based.html

¹¹³ “California Solar Initiative: Program Handbook,” California Public Utilities Commission, January 2008, at http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF

¹¹⁴ Ibid.

¹¹⁵ “California Solar Initiative: Statewide Trigger Point Tracker,” developed by PG&E, Southern California Edison and the Center for Sustainable Energy California, last accessed on April 18, 2008, at <http://www.sqip-ca.com/> The price will ramp down as the next trigger point is reached.

¹¹⁶ Ibid.

¹¹⁷ “California’s Energy Efficiency Standards for Residential and Nonresidential Buildings,” California Energy Commission, Title 24, Part 6, of the California Code of Regulations, October 1, 2005, as amended September 11, 2006, at <http://www.energy.ca.gov/title24/>

¹¹⁸ “California Solar Initiative: Program Handbook,” California Public Utilities Commission, January 2008, at http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF

Santa Rita Jail

Alameda County installed a 1.18 MW system on the Santa Rita Jail in 2001-2002. The system produces 2.4 million kWh of annual electricity, meeting approximately 30% of the jail's daytime energy needs.¹¹⁹ The project cost approximately \$9 million but was offset by nearly \$5 million in incentives from the following sources:¹²⁰

- California Energy Commission's Emerging Renewable Buy-down program
- California PUC Self Generation Program (through PG&E)
- Energy efficiency incentive programs
- Low interest-rate energy efficiency loan from CEC that will be repaid using the project's energy savings.

This project occurred in tandem with an elaborate energy efficiency retrofit. The combined savings from this retrofit and the solar installation was \$400,000 in the first year of operation, and it's expected to save \$15 million during the 25-year life of both projects.¹²¹

Moscone Center¹²²

At the end of 2001, the San Francisco Mayor's Energy Conservation Account (MECA) funded an \$8.1 million solar and energy efficiency project at the Moscone Center. The project consisted of \$4.5 million for a 675 kW solar installation and \$3.6 million for investments in energy efficiency. These costs were offset by the public utility commission's "self-generation" subsidy of \$2.3 million, as well as a California Energy Commission (CEC) Incentive for energy efficiency of \$186,000. As with the Santa Rita Jail, the success of the Moscone project is attributed to the energy efficiency upgrades that were executed in connection with the solar PV installation. It is estimated that the efficiency measures taken, including upgrades to lighting equipment, and building controls, reduces the annual energy needs for the center by more than 20%.

California Third-Party Ownership Examples

San Diego's Alvarado Water Treatment Plant¹²³

San Diego's Water Department has entered into a PPA with SunEdison for 1 MW of solar PV at its Alvarado Water Treatment Plant. According to the city's news release, \$6.5 million in up-front installation costs were avoided by signing the PPA with SunEdison (as opposed to buying the system). Once installed, the PV system will cover 20% of the plant's power needs.

Port of Oakland¹²⁴

On November 8, 2007, the Port of Oakland inaugurated its 4,000-panel, 756 kW, ground-mounted PV system. SunEdison financed, built, and will own and operate the system. The Port

¹¹⁹ Gouchoe, Susan, Lynne Gillette, and Christy Herig. "Solar Cities: Local Government & Utility Leaders in Solar Deployment," Seague Energy Consulting and Million Solar Roofs Program, March 15, 2004, page 6, at http://www.dsireusa.org/documents/PolicyPublications/Solar_Cities_Report_fnl1_3_22_04.pdf

¹²⁰ Ibid.

¹²¹ Ibid.

¹²² "Moscone Featured at World Environment Day," Moscone Center news release, June 1, 2005, at <http://www.moscone.com/site/do/news/view?id=6>

¹²³ "Mayor Sanders Unveils Solar Power System At Alvarado Water Treatment Plant," City of San Diego news release, March 1, 2007, at <http://www.sandiego.gov/environmental-services/energy/news/pdf/070301.pdf>

¹²⁴ "Port of Oakland and SunEdison Flip the Switch on New Zero Emission Solar Power System," Port of Oakland news release, November 7, 2007, at <http://www.portofoakland.com/newsroom/pressrel/view.asp?id=82>

of Oakland signed a PPA with SunEdison to purchase “clean and predictably priced electricity” for 20 years at a cost of approximately \$4.1 million.¹²⁵

Fresno State University¹²⁶

On November 9, 2007, Fresno State University and Chevron Energy Solutions completed the installation of a 1.1 MW PV system that will provide the university with 20% of its annual electricity needs. The project cost approximately \$12 million; an amount that was partly offset by a \$2.8 million rebate from PG&E under California’s Self-Generation Incentive Program. Chevron Energy Solutions installed the PV system and Fresno State signed a 20-year PPA with MMA Renewable Ventures. MMA financed and will own the system. The university expects to save \$13 million in avoided electricity costs over a 30-year period.

Colorado

Colorado RECs: Meeting Xcel Energy’s RPS Requirement

Colorado's Renewable Energy Standard requires that investor-owned utilities of a certain size meet 20% of their energy sales with renewable sources by 2020.¹²⁷ Four percent of this 20% must be solar, and 50% of this solar requirement (or 2%) must be generated on their customers' sites.¹²⁸ Additionally, renewable energy that is generated in Colorado receives a 1.25x multiplier toward their RPS, so that for every 1 kWh generated, 1.25 may be claimed toward compliance.¹²⁹ Community-based systems in the service territory of Colorado electric cooperatives and eligible municipal utilities that are less than 30 MW receive a 1.5x credit toward RPS compliance purposes. Community-based system refers to a system owned collectively by residents of a community, by a local nonprofit organization, by a cooperative, by a local government agency, or by a tribal council.¹³⁰ Renewable energy certificates (RECs) may be used to satisfy compliance with the renewable standard. Utilities that do not generate the required amount of electricity from renewable energy sources may purchase RECs from other utilities that exceed the requirement or from independent renewable energy producers.

As an example, Xcel Energy, Colorado’s largest electricity provider, has established the Xcel Energy Solar*Rewards program. Xcel will provide a rebate for the installation of a PV system and also purchase the RECs generated by the system. A 20-year contract is signed with Xcel when the REC agreement is negotiated.¹³¹ These REC purchases help Xcel meet its solar

¹²⁵ “Oakland Board of Port Commissioners Authorized Port of Oakland’s First Solar Energy Agreement,” Port of Oakland news release, June 6, 2006, at <http://www.portofoakland.com/newsroom/pressrel/view.asp?id=28>

¹²⁶ “Fresno State, Chevron Energy Solutions Complete Solar Parking Project Largest at US University,” *Fresno State News* article, November 9, 2007, at <http://www.fresnostatenews.com/2007/11/solarwrapup2.htm>

¹²⁷ Subject to an overall retail rate cap of 1.7% on Colorado ratepayers.

¹²⁸ “Colorado Incentives for Renewable Energy: Renewable Energy Standard,” Database of State Incentives for Renewables and Efficiency (DSIRE), accessed April 2008, at http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=CO24R&state=CO¤tpageid=2&search=State&EE=0&RE=1

¹²⁹ Ibid.

¹³⁰ Ibid.

¹³¹ “Solar*Rewards,” Xcel Energy Web site, accessed April 2008, at http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-2_41004_43476-23075-2_171_256-0,00.html

obligations under the renewable energy standard while lowering the cost of the system for the end user.

The manner in which the contract with Xcel is structured, as well as the price paid for RECs, depends on the size of the system. Small systems (0.5 kW to 10 kW) located on Xcel's Colorado customers' sites¹³² get an installation rebate (currently \$2/watt) and an up-front REC payment equal to \$2.50/watt as a way to defray installation costs. Mid-sized systems (10 kW to 100 kW) get an up-front installation rebate of \$2/watt as well as a monthly REC payment of \$115/MWh. Large systems (100 kW to 2 MW) must bid for monthly REC payments based on the economics of the projects involved. Successful bidders receive their monthly REC price over a 20-year period, based on actual generation as well as a \$200,000 up-front rebate. For those paid monthly for their RECs, there are financial penalties if their PV systems do not generate the expected amount of electricity. For the large systems, the winning REC bids (and hence the average REC price) are not publicly available. However, NREL calculated an approximate range of \$205-265/MWh based on data from the Xcel 2008 RPS compliance filing, as well as a number of assumptions (see footnote).¹³³

Colorado Third-Party Ownership Examples **Denver International Airport (DIA)**¹³⁴

In 2007, the Denver International Airport (DIA) announced that it had signed a 25-year PPA with MMA Renewable Ventures for a 2 MW solar PV system, which will produce 3.5 million kWh per year. The total cost of power to be purchased under the PPA was reported to be \$10.9 million or roughly 12.5c/kWh. Xcel Energy will provide a \$200,000 rebate to partially offset the project's initial costs. While not stated in the news release, it is also reasonable to assume that MMA sold solar RECs to Xcel Energy as part of the project's financing. The system is expected to begin producing electricity in 2008. Built into the agreement is an \$8.1 million buyout option after five years, allowing DIA to assume ownership of the system. The structure of this project is creative and should be of interest to municipalities interested in owning PV systems on their property. First, it allows the city to leverage the federal tax incentives through a third party, thus reducing the need to secure up-front capital for the system. And yet, once the tax incentives are fully monetized by the original investors, the City of Denver has the option to ultimately purchase the system.

¹³² Including residences, businesses, and public buildings.

¹³³ See Section 5 of "Renewable Energy Standard Compliance Plan," Xcel Energy filed with the Colorado Public Utilities Commission on November 23, 2007, at: http://www.xcelenergy.com/XLWEB/CDA/0,3080,1-1-1_41994_45696-27104-2_171_282-0,00.html. In particular, see Table 1 in Section 5, on page 14 (http://www.xcelenergy.com/docs/Section5-Acquisition_Plans_Final.pdf). This table shows that their 2008 installations are expected to produce 16,129 MWh annually and cost \$8.4 million. To find the REC price, subtract out the \$200,000 rebate for each of the 20 installations (\$4 million), as well as an assumed 9% administrative costs (\$760,000 – which is less than the 10% required by law), there is \$3.7 million remaining. Divide by the expected generation (16,129 MWh) to get an estimated approximate average REC price of \$230/MWh. Xcel states that they assume large projects will have an estimated 16% capacity factor. If the PV systems have 14-18% capacity factors, then the range is between \$205/MWh and \$265/MWh.

¹³⁴ Vuong, Andy. "Solar-energy system to land at DIA in 2008," *The Denver Post*, October 1, 2007, at http://www.denverpost.com/ci_7056394?source=rss

Boulder County Buildings, Colorado¹³⁵

Boulder County has set an aggressive goal to reduce GHG emissions 7% below 1990 levels by 2012. PV will play an important role in meeting this target. In August 2007, Boulder County installed a 10 kW system on its courthouse, which will initially offset electricity consumption at the building. However, the ultimate goal is to use it to power four plug-in hybrids that the county plans to purchase in 2008. Xcel Energy, the utility serving Boulder County, provided a rebate of \$44,500 for this project, roughly 50% of the total cost of the system. On November 16, 2007, the county announced a plan to expand PV on public buildings using the PPA structure.¹³⁶ The Boulder County Office of Sustainability has hired a solar consulting firm, Bella Energy, to analyze the feasibility of third-party, PV deployment on public buildings as a way to limit the up-front costs of solar installations and to leverage tax incentives unavailable to the county on a stand-alone basis.

Connecticut

Connecticut: Challenges to Create Clean Energy Communities

In 1998, Connecticut passed electric-utility restructuring legislation that included the creation of the Connecticut Clean Energy Fund (CCEF) to support the growth of renewable energy in the state. Investor-owned utilities—Connecticut Light & Power (CL&P) and United Illuminating (UI)—within the state are required to add a surcharge to ratepayers' utility bills of no less than \$.001 per kilowatt hour.¹³⁷ The CCEF receives approximately \$20 million annually as a result of this charge. The CCEF develops and administers programs that provide grants, rebates, and other financing mechanisms to promote and subsidize the expansion of renewable energy technologies. One such program is the Connecticut Clean Energy Communities Program, under which the CCEF provides solar PV systems to qualifying municipalities who encourage resident participation in voluntary “green power” programs, and who meet the following requirements:

- The city or town must commit to the *SmartPower 20% by 2010* Clean Energy Campaign. The 2010 Campaign is a voluntary pledge by local governments to obtain 20% of the electricity for all municipal facilities (including schools) from clean, renewable sources by 2010. A town may satisfy the goal by enrolling in the CT Clean Energy Options program, purchasing renewable energy certificates, or installing on-site renewable power systems.
- A certain minimum number of local residents, schools, and businesses must sign up for CT Clean Energy Options,¹³⁸ a green power program approved by the Department of Public Utilities Control (DPUC). It allows any CL&P or UI customer to support clean energy produced from approved renewable resources such as wind, small hydro, and landfill gas. Customers who enroll in the program continue to receive electric delivery

¹³⁵ “Boulder County Envisions Expansion of Solar Power on County Buildings,” Boulder County, Colorado, news release, November 16, 2007, at <http://www.co.boulder.co.us/newsroom/templates/?a=976&z=1>

¹³⁶ Ibid.

¹³⁷ “Connecticut Incentives for Renewable Energy: Connecticut Clean Energy Fund,” Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed August 29, 2007, accessed April 2008, at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CT03R&state=CT&CurrentPageID=1&RE=1&EE=1

¹³⁸ “Connecticut Clean Energy Communities,” Connecticut Clean Energy Fund, accessed April 2008, at <http://www.ctcleanenergyoptions.com/>

service from their utility and pay a small clean energy surcharge. The surcharge is either \$0.011 (Community Energy) or \$0.0115 (Sterling Planet) per kWh for 100% clean energy (customers may also choose to offset 50% of their electricity use at 50% of the aforementioned rates, respectively). The average Connecticut home uses 700 kWh per month, which would result in an additional cost of approximately \$8 per month for the 100% renewable option.

- The city or town must make a municipal clean energy purchase using the electricity savings generated by any systems they received for free from the program.

When these obligations have been met, the city or town will receive a 1 kW solar PV system (towns located in the southwest Connecticut congested grid zone receive a 2 kW system.). Each system is accompanied by Fat Spaniel's monitoring software that enables students and residents to log on to the Internet and examine electricity generation, emissions avoided, and costs saved in real time. There is no limit to the number of systems that a town or city can earn. A town can secure additional PV systems for each threshold met, if the funding is available. Bob Wall, of the CT Clean Energy Fund, said that 62 out of 169 eligible towns and cities in the state have committed to the program, and that at least 23 have met the requirements for receiving a solar installation.

New Haven was the first city to commit to 20% by 2010. Since joining the Clean Energy Communities Program, New Haven has recruited more than 900 customers to sign on to the Clean Energy Options program, and has earned 20 kW of solar installations for the city. The first system New Haven installed was 2 kW on the Common Ground Environmental High School. The city announced that it will put some of the additional systems on low-income "green" housing projects.

The town of West Hartford is approaching 900 participants and has earned 11 kW of free solar. West Hartford installed a 3 kW system on its Town Hall. The city has plans to put 3 kW systems on each of the two local high schools.

Hawaii

Hawaii Department of Transportation¹³⁹

On January 9, 2008, the Governor of Hawaii, Linda Lingle, announced that the state was issuing a request for proposals for up to 34 MW of PV on 11 Department of Transportation sites as well as one downtown Honolulu site. According to the governor's news release, the plan is to finance these PV systems using the PPA model.

Massachusetts

Successfully Addressing CREBs Transaction Costs in Massachusetts

Despite the barriers involved with CREBs, there are success stories. Massachusetts was one state that successfully navigated the CREBs process.¹⁴⁰ Of the 13 CREBs projects that were awarded

¹³⁹ "Governor Lingle Announces Historic Plan to Utilize Solar Power at 12 Locations Around State: Plan highlights commitment to renewable energy, leading by example," Hawaii governor's news release, January 9, 2008, at http://hawaii.gov/gov/news/releases/2008/news_item.2008-01-09.3842330405

to the State of Massachusetts for solar PV installations in 2006, 12 of them were creatively bundled together into one financing package to streamline project costs. The state's "Leading by Example" program in collaboration with MassDevelopment (MassDev) and the Massachusetts Technology Collaborative (MTC), assembled 1 MW worth of PV projects at state colleges, prisons, a water treatment facility, and a veterans home, creating a critical mass for CREBs funding. By bundling the projects together, Massachusetts was able to minimize overall transaction costs.

Once installed, these 12 projects will represent a fivefold increase in PV-generated electricity at public facilities throughout Massachusetts.¹⁴¹ The 1 MW of new capacity also will represent a 20-25% increase in the total amount of PV in the entire state, and is part of an expanded solar PV program, whose goal is to achieve 250 MW of new capacity installed by 2017.¹⁴²

Together, the 12 projects will cost approximately \$8,500,000. The total CREBs allocation was \$3,129,300. The MTC and the state provided the remaining funds in the form of grants. While each project received its own CREBs allocation, only by bundling the projects into one MassDev bond issuance of \$3,129,300, was it cost-effective. Not only did bundling the 12 projects lower the transaction costs related to the CREBs financing, it also lowered procurement costs. To facilitate repayment of the debt, the CREBs financing for each project was intentionally sized so that expected annual energy savings was at least equivalent to the annual bond payment. The following excerpt from the MassDev news release summarizes the achievement:

Given the comparatively small bond amounts and unique funding structure, many states around the country are finding it difficult to bring CREB issues to market and realize the benefit of zero-interest financing for their solar power projects," said Robert L. Culver, MassDevelopment president/CEO. "That's why it made sense for the state's multi-agency energy team to partner with MassDevelopment – one of the Commonwealth's primary bonding authorities – to unify these twelve important projects and get the critical mass needed to attract investor interest and reduce issuance costs."¹⁴³

The structure of CREBs can present some particular challenges that may seem daunting. However, creative bundling of projects can help capture the value of CREBs.

Montana

Backup Emergency PV Power for Montana's Fire Stations

Montana restructured its legislation in 1997 to include a Universal Systems Benefit Program (USBP). The USBP requires all of the state's utilities, including cooperative utilities, to contribute an amount equivalent to 2.4% of their 1995 revenues each year to the program. This

¹⁴⁰ Personal communications with Ian Finlayson at the Massachusetts Division of Energy Resources in October and November 2008.

¹⁴¹ "\$3.1 Million MassDevelopment Bond Supports Twelve Solar Power Projects Across Massachusetts," MassDevelopment news release, November 13, 2007, at <http://www.massdevelopment.com/press/11132007-01.aspx>

¹⁴² Ibid.

¹⁴³ Ibid.

amounts to a combined annual contribution of \$14.9 million.¹⁴⁴ The utilities are required to invest these funds in “cost-effective energy conservation, low-income customer weatherization, renewable-energy projects and applications, research and development programs related to energy conservation and renewables, market transformation designed to encourage competitive markets for public purpose programs, and low-income energy assistance.”¹⁴⁵

Will Rosquist, of the Montana Public Service Commission, states that the only mandate for spending the money is that at least 17% of each utility’s fund has to be allocated to programs assisting low-income families. The utilities can spend the remaining 83% as they want, as long as it falls into the categories listed above. The largest Montana utility, Northwestern Energy (which meets two-thirds of the state's electricity demand), is the only energy provider in the state that has used these funds for renewable energy projects. Northwestern Energy has implemented a \$.001/kWh surcharge to meet its USBP requirement. When interviewed, John Campbell, of Northwestern Energy, stated that \$1 million of the \$9 million generated by the USBP went toward renewable energy projects in 2005. In 2006, this figure declined to \$850,000.

Northwestern Energy has used some of the USBP fund for solar PV projects on fire stations. The principle reason for the fire station focus is to provide emergency backup power. As of October 2007, 20 fire stations within the state have been outfitted with emergency power backup PV installations (including battery storage). Total capacity for these 20 systems is 47.5 kW. This represents 8 percent of total solar PV capacity in the state of Montana.¹⁴⁶ Campbell explained that 100% of the costs of these projects were covered by Northwestern Energy’s USBP.

New Jersey

New Jersey’s On-Site Rebate Program

New Jersey’s Clean Energy Program (NJCEP) is consistently highlighted as an example of a successful program that has encouraged significant solar PV deployment. New Jersey has a 2% solar RPS set-aside that must be met in 2020, which could result in 1,500 MW of new solar capacity. To help meet that goal, NJCEP created the Customer On-Site Renewable Energy (CORE) Program to provide an up-front rebate for PV in New Jersey, on the order of \$3-5/watt. The remaining costs of the system are recovered by a combination of attractive net-metering retail rates, avoided energy costs, and solar RECs (SRECs) sales to utilities with solar RPS obligations. New Jersey SREC prices started out in the range of \$160-\$200/MWh and have increased to as much as \$230/MWh at the end of 2007 and beginning of 2008.¹⁴⁷

¹⁴⁴ “Public Benefits Fund: Universal System Benefits Program for Montana,” Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed March 14, 2007, accessed April 2008, at http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=MT01R&Search=Type&type=PBF&CurrentPageID=2&EE=0&RE=1

¹⁴⁵ Rickerson, William, and Christopher Colson. “Montana Firefighters See Benefit of PV,” *Renewable Energy Focus*, November/December 2007, page 51, at <http://www.rickersonenergy.com/pdfs/renewableenergyfocus.pdf>

¹⁴⁶ Ibid.

¹⁴⁷ “SREC Pricing: SREC Trading Statistics,” New Jersey Clean Energy Program Web site, showing data through February 2008, accessed April 11, 2008, at <http://www.njcleanenergy.com/renewable-energy/programs/solar-renewable-energy-certificates-srec/pricing/pricing>

Demand for solar rebates was so tremendous that it exceeded the state's CORE budget. As of August 2007, all funding for the CORE solar electric rebate program had been allocated, and new projects were placed into a queue to wait for additional funding.¹⁴⁸ In late December 2007, the New Jersey Board of Public Utilities (NJBPU) approved another funding allocation that will include CORE, but it won't fully fund the projects in the queue. This same NJBPU order mandated that no additional private-sector applications will be accepted as of December 20, 2007, and that public-sector applications will be accepted only through April 1, 2008.¹⁴⁹ It is unclear whether projects remaining in the queue will receive any funding in the future.

As of August 2007, only 40.9 MW had been installed in the state,¹⁵⁰ and more solar generation is needed to meet the state's aggressive solar RPS requirement in 2020. However, the state does not want to increase the customer's Clean Energy Fund rate to secure the necessary funds to achieve the 1,500 MW requirement, which could be billions of dollars (estimated to be \$500 million each year).¹⁵¹ Therefore, New Jersey decided to implement a system that relies entirely on market-based SRECs, rather than a combination of up-front state rebates and SRECs.¹⁵² On September 12, 2007, the New Jersey PUC voted to transition to a system without state-provided rebates and where LSEs with a solar RPS requirement pay the market rate for SRECs.¹⁵³ The expectation is that the cost the state would have had to pay through rebates will now be rolled into the price of SRECs. To accommodate higher SREC prices, the state raised the effective price cap for SRECs (called the alternative compliance payment), up to \$711/MWh in 2009. The solar alternative compliance payment declines at an annual rate of approximately 2.5%, down to \$594/MWh by 2016. The regulators hope that the market will be able to cover the total above-market cost using SRECs.¹⁵⁴

This new structure means that solar PV projects in the state will need to finance more of the project's costs up-front. While this new structure may not impact the installation of solar on large commercial, industrial, and public sites who use the PPA model, it could have a significant

¹⁴⁸ "Customer On-Site Renewable Energy (CORE) Program," New Jersey Clean Energy Program Web site accessed April 7, 2008, at <http://www.njcleanenergy.com/renewable-energy/programs/core-rebate-program/incentives/core-rebate-program>

¹⁴⁹ "Clean Energy Order: Suspension of Acceptance and Processing of New Solar Applications in CORE Rebate Program," State of New Jersey Board of Public Utilities, Docket No. EO07100773, accessed April 7, 2008, at <http://www.njcleanenergy.com/files/file/Core-Suspension-12-20-07-8E.pdf>

¹⁵⁰ "Core Activity: Renewable Energy Systems Completed," New Jersey Clean Energy Program Web site, accessed April 7, 2007, at <http://www.njcleanenergy.com/renewable-energy/program-updates/core-activity/core-activity>

¹⁵¹ "Frequently Asked Questions: New Jersey's Solar Market: Transition to Market-based REC Financing System," New Jersey Clean Energy Web site, estimated to be written in 2006, accessed April 7, 2008, at <http://www.njcleanenergy.com/files/file/FINALSolarTransitionFAQ4.pdf>

¹⁵² Wobus, Nicole, Kevin Cooney, and John Anderson. "Preliminary Review of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives," prepared for the New Jersey Board of Public Utilities by Summit Blue Consulting and the Rocky Mountain Institute, March 15, 2007, at http://www.njcleanenergy.com/files/file/NJ-BPU_Market_Transition_Interim_Report_0315076.pdf

¹⁵³ "New Jersey Board of Public Utilities Approves Transformation of New Jersey's Solar Market," Statement of the New Jersey Board of Public Utilities, September 12, 2007, at <http://www.njcleanenergy.com/files/file/STATEMENT%20On%209%2012%2007%20BPU%20Statement%20Solar%20Transition%20FINAL.pdf>

¹⁵⁴ "New Jersey's Solar Financing Program: as Approved by the Board September 12, 2007," New Jersey Clean Energy Program frequently asked questions, September 12, 2007, at http://www.cleanenergyfunds.org/library/nj/NJ_SOLAR-Transition_FAQs_091207.pdf

impact for small solar systems (residential and public) that would have to bear the burden of increased up-front, capital costs.

SRECs for Atlantic County Utilities Authority (New Jersey)

The Atlantic County Utilities Authority (ACUA) in New Jersey owns a wastewater treatment facility, on which 500 kW of solar PV was installed at five locations. Both the solar rebate and SRECs were important revenue streams to help the project be economically viable. The total initial capital cost of the project was \$3.25 million and was funded by a 57% CORE rebate and a \$1.5 million, 20-year low-interest loan from the New Jersey Environmental Infrastructure Trust Program.¹⁵⁵ Revenue from the SREC is assumed to start at \$238/MWh and decline 3% annually to \$114/MWh by the 25th year. This revenue is expected to exceed the cost of debt service, periodic replacement of the solar inverters, and system insurance. Combined with the avoided electricity costs (at the utility's retail rate), the total net present value of savings are expected to be more than \$1.8 million over a 25-year period.¹⁵⁶

New York

NYSERDA Funding for Municipal PV Systems

The New York State Energy Research and Development Authority (NYSERDA) was established in 1975, initially as a research and development organization focused on reducing New York State's fossil fuel consumption.¹⁵⁷ In 1996, the New York system benefit charge was created and the funds were directed to NYSERDA for a wide range of energy-related programs.¹⁵⁸

Municipal projects in New York are often financed with straightforward structures. Generally, a municipality receives an incentive from NYSERDA and covers the remaining costs out of local funds. For example, the Village and Town of New Paltz installed a 14.85 kW PV system with a solar battery backup at a cost of \$143,380. NYSERDA provided an incentive of \$96,200 and New Paltz covered the difference.¹⁵⁹

NYSERDA has also created the New York Energy SmartSM Program,¹⁶⁰ which is a portfolio of initiatives designed to promote energy efficiency products and services, and renewable energy technologies.¹⁶¹ One of these initiatives is the PV System Incentive Program, which provides

¹⁵⁵ "Solar Array Project: Fact Sheet," Atlantic County Utilities Authority, August 2007, at <http://www.acua.com/files/Solar%20Array%20Project1.pdf>

¹⁵⁶ "Solar Generation System 500 kW: project details," Atlantic County Utilities Authority, accessed April 18, 2008, at <http://www.acua.com/files/chartsmall06o6.pdf>

¹⁵⁷ "About NYSERDA," New York State Energy Research and Development Authority (NYSERDA) Web site, accessed April 7, 2008, at <http://nysesda.org/About/default.asp>

¹⁵⁸ In 2004, NYSERDA received additional funding from the settlement of a lawsuit with the Virginia Electric Power Company (VEPCO), according to "PV for Peak Load Reduction on Municipal Buildings," New York State Energy Research and Development Authority (NYSERDA), Program Opportunity Notice No. 843, at <http://www.nysesda.org/Funding/843PON.html>

¹⁵⁹ "Village and Town of New Paltz," New York State Energy Research and Development Authority (NYSERDA), case study for the New York Energy Smart program, accessed April 7, 2008, at <http://www.powernaturally.com/About/documents/newPaltz.pdf>

¹⁶⁰ Ibid.

¹⁶¹ "New York Energy SmartSM Program," New York State Energy Research and Development Authority (NYSERDA) Web site, accessed April 7, 2008, at http://www.nysesda.org/ny_energy_smart.asp

incentives for PV systems up to 50 kW per site and 100 kW per customer for nonresidential beneficiaries, including municipal governments.¹⁶² The incentive is \$5/watt for the first 25 kW and \$4/watt for the balance of the system up to 100 kW.¹⁶³

Many municipalities have taken advantage of the EnergySmartSM programs. One PV design and installation firm, Hudson Valley Clean Energy (HVCE), has installed at least five municipal PV projects itself.¹⁶⁴ According to the company's president, Jeff Irish, because these systems are often in highly visible areas of town, there are important educational and marketing benefits to PV system designers and installers who work on such projects. HVCE can trace numerous residential projects directly back to its public-sector projects. Public systems lend credibility to both the installer and to the concept of "going solar". However, there are elements of municipal projects in New York that increase the cost of installed PV systems.

- Prevailing Wages: Hourly wages on a residential job may be in the \$18-25/hour range. Prevailing wage rules for municipal projects can be as high as \$90/hour when social security and liability insurance are included.
- The Bid Process: Projects that require municipalities to spend \$10,000 or more trigger a bid process. This process often includes the need to hire an engineering consulting firm to review the bids, which adds to project costs. A project often will be scaled down so that the municipal portion is less than \$10,000 to avoid the costs involved in the bid process.
- Performance Bonds and Paperwork: Municipal projects may require both bid bonds and performance bonds. In addition, notarized forms, manuals, and drawings are required, none of which is standard in the residential sector.

These nuances of installing municipal PV systems in the State of New York can have a significant impact on costs. According to Jeff Irish, a residential PV project may cost \$8/watt, whereas a municipal project of the same size can cost 25% more or \$10/watt.

Ohio

Ohio's Advanced Energy Fund

In 1999, Ohio authorized the creation of the Advanced Energy Fund, to be managed by the Ohio Department of Development's Office of Energy Efficiency (OEE) during a restructuring of the state's electric utility sector.

The fund is designed to generate \$100 million over 10 years. To achieve this goal, investor-owned utilities (participation by municipal utilities and electric cooperatives is voluntary) are

¹⁶² "PV Incentives: PON 1050 Solar Electric Incentive Program," New York State Energy Research and Development Authority (NYSERDA), Program Opportunity Notice 1050, accessed April 7, 2008, at <http://www.powernaturally.com/Programs/Solar/incentives.asp>

¹⁶³ Ibid.

¹⁶⁴ Based on e-mail and phone conversations with Jeff Irish, president of Hudson Valley Clean Energy on December 3, 2008.

required to generate \$15 million per year from 2001-05 and \$5 million per year from 2006-11.¹⁶⁵ The utilities collected .00010758 per kWh for the first five years to meet the annual \$15 million target, and now collect a flat fee of 9 cents per monthly bill to raise \$5 million per annum.

The fund supports both the Advanced Energy Program and the Energy Loan Fund's low-interest loan program. State and local governments in Ohio use a combination of the grant program and their own bonding authority to finance solar PV. Participation in the loan fund is not common. Recently, the Metropolitan Park District of Toledo, Ohio, took advantage of a grant offered by the Advanced Energy Program to install a 6.48 kW solar PV system on the Center for Nature Photography. The total cost of the installation was \$63,400. The Metropolitan Park District paid the total cost of the system and then received a rebate of \$31,700 from the Advanced Energy Program. The 6.48 kW system generates nearly 100% of the electricity consumed at the center.

¹⁶⁵ "Public Benefits Funds: Advanced Energy Fund of Ohio," Database of State Incentives for Renewables and Efficiency (DSIRE), last reviewed September 12, 2007, accessed April 7, 2008, at http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=OH11R&Search=Type&type=PBF&CurrentPageID=2&EE=0&RE=1

Appendix 2. Critical Steps when Issuing a CREBs Bond

Applying for and issuing a bond supported by a clean renewable energy bonds (CREBs) allocation involves a number of steps. The key tasks and information regarding the CREBs process are summarized below.

Step 1 – Application to IRS

The IRS application must include the entity that will issue the bond, the borrower if distinct from the issuer, the nature of the project (size, technology, location, etc.), the regulatory approvals needed, and a financing plan. Unlike tax-exempt financing, CREBs also require certification from an independent licensed engineer that the project will meet the requirements and is technically viable (an additional step that adds to transaction costs).

CREBs allocations can be used only for projects that meet specific criteria. CREBs are primarily intended to finance the deployment of new facilities and cannot be used for existing facilities, except for renovation activities. The allocations also can be used to refinance a new project for which debt incurred after August 8, 2005. CREBs can be used for jointly owned projects, where the municipality or a cooperative uses it as their ownership contribution to the partnership with a utility, a municipality, or cooperative not using CREBs. The CREBs allocation is for a designated project at a specific location; if there is a change in the use of the project, or a change in ownership, the project may lose its qualified status forcing the issuer to undertake remedial action, which could include redeeming the bond.

For the first round, it took the IRS approximately five-six months to qualify projects and make allocations. The second round took six months and was announced on February 12, 2008. As of April 2008, all CREBs allocations have been made. If the CREBs program is expanded, it is expected that future allocations would go more quickly because the IRS can benefit from previous experience.

Step 2 – IRS makes allocations

In the first two rounds, CREBs were allocated using a simple process. The IRS would take all of the municipal projects that met the qualifications and put them in rank order from smallest to largest. The allocations were given to the smallest projects first, and then given out to increasingly larger projects until the allocations were exhausted. Therefore, many municipalities that wanted to do larger projects did not secure a CREBs allocation.

Step 3 – Work with the financial team to issue the CREBs

The process is the same as for the tax-exempt bond, except that the federal government provides a tax credit to the investor instead of the issuer making interest payments. The tax credit from the federal government and the tenor are predetermined using data published by the U.S. Treasury on a daily basis, at its Web site, <http://www.TreasuryDirect.gov>. For example, if a CREB had been issued on April 18, 2008, the maximum allowable tenor would have been 15 years with an allowable tax credit in the first year equivalent to 5.83%.¹⁶⁶

¹⁶⁶ “Clean Renewable Energy Bonds Rates,” U.S. Department of Treasury Web site, accessed April 18, 2008, at <https://www.treasurydirect.gov/SZ/SPESRates?type=CREBS>

Appendix 3. Critical Steps in the Structure of Third-Party Ownership Model

In Section 6.1, Figure 8 shows one variation of how a third-party ownership model can be used to help public entities own renewable projects—there are many others. To execute this model using a PPA for the power (and/or SRECs), the steps listed below are recommended. These were adapted from a report by GreenTech Media¹⁶⁷ and from conversations with Bob Westby at NREL, who has been actively involved in the PPA negotiations for several NREL PV projects. While the steps are presented in linear fashion, many are concurrent activities.

Steps to executing a third-party ownership model

Step 1 – Identify potential location(s)

Identify the buildings or land on which to install a solar PV system. In preparation for the next step, it is a good idea to characterize the site or sites that you would like to consider developing by gathering and providing detailed information. Characterizing the potential solar resource using PVWatts¹⁶⁸ also is recommended; you will be required to enter longitude and latitude, the PV technology of interest, and the tilt and azimuth angles. It also would be useful to characterize other site-specific characteristics, including potential for shading (e.g., buildings, trees, and other structures), distance to nearest substation, overall site load, average electricity prices paid, etc. Using available information, including expected REC prices and rebates, do a “back of the envelope” calculation to see if the economics make sense.

Determine whether an environmental impact assessment is going to be necessary, especially as it relates to ground-mounted systems. Finally, address both safety and security issues with the appropriate internal parties to make sure these two topics do not present barriers later in the process.

Step 2 – Identify developer

States and municipalities must comply with local and state rules of procurement. If the site is big enough (can support a project of a minimum size of approximately 1 MW), consider releasing a request for qualifications (RFQ) followed up with a request for proposals (RFP) once the number of potential vendors has been narrowed. If the site can only support a smaller system, developers may not respond to a formal RFP and might have to be contacted individually to gauge potential interest.

The potential developers will request the information developed in Step 1 so that they can make their own initial assessment of the feasibility of the project. Additional information that the developers may require include the utility's interconnection requirements, confirmation of access to the site, and information on the soil if the system is a ground-mounted one.

Step 3 – Site assessment and term-sheet development

Based on the preliminary information provided by the state/municipality and its own research, the developer will conduct a high-level site assessment that will include electricity needs, solar

¹⁶⁷ Guice, Jon, and John D.H. King, “Solar Power Services: How PPAs are changing the PV Value Chain,” Greentech Media Inc., February 14, 2008.

¹⁶⁸ “PVWATTS: A Performance Calculator for Grid-Connected PV Systems,” National Renewable Energy Laboratory Web site, accessed April 2008, at http://rredc.nrel.gov/solar/codes_algs/PVWATTS/

generation potential, financial incentives, and engineering issues. This will be an initial proposal to determine the feasibility of the project. Based on this assessment, a term sheet will be drafted that will include the estimated output of a solar project, the price of electricity and term. If a tentative agreement can be reached on the term sheet, then the project can move forward.

Step 4 – Contract development

The contracts are negotiated and signed. There are multiple contracts involved in the PPA process. There is the PPA agreement between the public entity and the PPA provider. There may be a separate agreement between these same two parties related to the easement or lease which provides access to the property. The PPA provider and the utility may sign a separate agreement for the solar RECs.

Step 5 – Rebate processing

If the state or utility offers incentives, the application to request them should be filed at this point. Note that in some states, there might be a limited window when incentives are awarded to qualifying projects. Depending on the state, in some cases, the rebate may go to the host who must endorse it over to the PPA provider. The utility will pay the PPA provider directly for the RECs.

Step 6 – Project design and financing

A detailed project engineering analysis is performed and the system is designed, based on more precise measurements that are specific to the site. Using the term sheet and the intent to enter into a contract, project financing also is arranged.

Step 7 – Permitting

Local regulatory agencies require appropriate documentation to receive a building permit. It might be useful to see whether there is a backlog of permits and when the project needs to be in the queue for this step to be completed, aiming for approximately the same time that the contract is signed.

Step 8 – Procurement, construction, and commissioning

The developer will arrange for the components and equipment to be supplied to the site, at which point the system is installed and tested. At commissioning, there is a final confirmation test to prove system performance to the utility, so that it will interconnect the system and allow for system activation.

Step 9 – Monitoring and maintenance

The host must allow the developer and the owner access to the site for maintenance activities for the life of the project. The system is monitored through a combination of automatic (and remote) readings of power performance and other indicators, and can include manual readings (on-site) of performance indicators as well. If there is an anomaly, then the system is accessed on the host's site for repair and any equipment replacement that is needed.

Appendix 4. Critical Steps to Issue a Tax-Exempt Bond

The information in this section is largely taken from “Anatomy of a Bond” by David Unkovic of Saul Ewing, LLP,¹⁶⁹ “The Basics of Municipal Bonds,” by Jim McWhinney on Investopedia,¹⁷⁰ and “Basics of Federal Bond Issues” by Jason Van Bergen on Investopedia¹⁷¹

This section explains the players and steps needed to issue a municipal tax-exempt bond. The roles and activities of each participant are described in detail, including how the participants interact and work together. Following this description, the steps for issuing a municipal security are described sequentially.

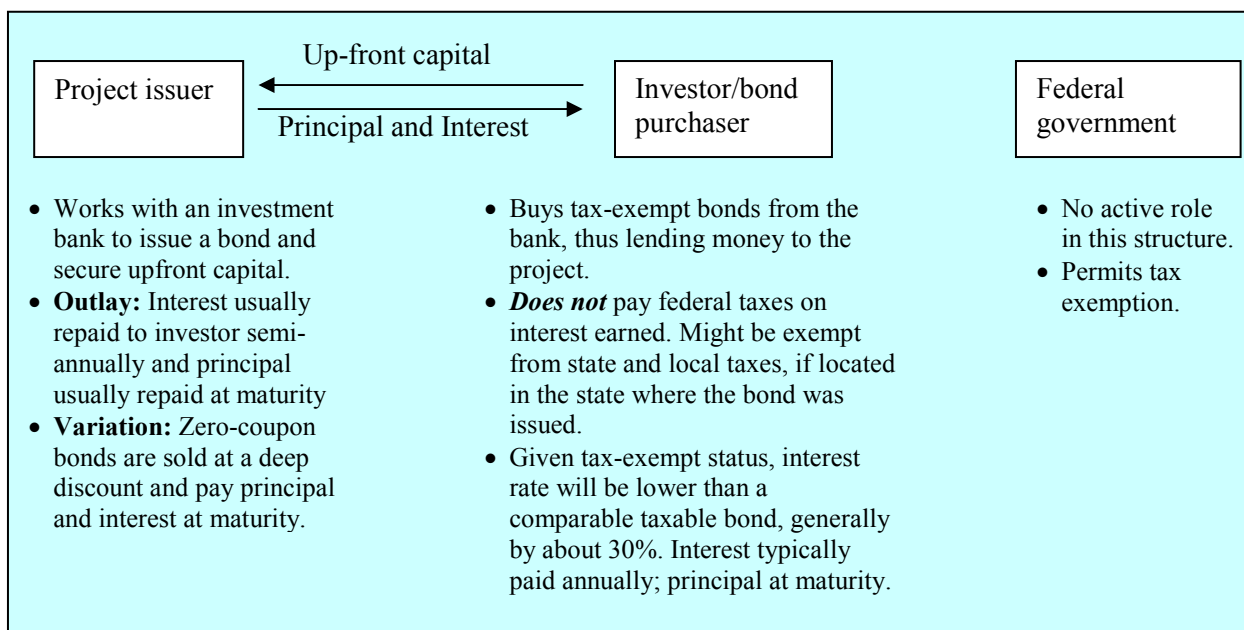


Figure 12. Tax-exempt bonds

Participants in Issuing a Bond

As with all bond issues, a bond to finance a renewable energy project will involve a number of different partners who must work together. Figure 12 shows the roles and describes the cash flow between the primary participants. The full list of participants and their roles are described below:

1. Issuer of the bond. The bond issuer needs capital to invest in a renewable energy project.
2. Investment banker/underwriter. Buys the bonds from the issuer at a discount, markets them to the public and resells them to investors. Often helps structure the bond issue and prepare the disclosure document. Sometimes purchases the entire bond issue without

¹⁶⁹ Unkovic, David. “Anatomy of a Bond Issue,” copyright Saul Ewing, posted on the Web site FindLaw for Legal Professionals in March 2000, accessed February 15, 2008, at <http://library.findlaw.com/2000/Mar/1/130778.html>

¹⁷⁰ McWhinney, Jim. “The Basics of Municipal Bonds,” posted on Web site of Investopedia: A Forbes Media Company, in February 2005, accessed February 15, 2008, at <http://www.investopedia.com/articles/bonds/05/022805.asp>

¹⁷¹ Van Bergen, Jason. “Basics of Federal Bond Issues,” posted on Web site of Investopedia: A Forbes Media Company, in May 2004, accessed February 15, 2008, at <http://www.investopedia.com/articles/basics/04/052104.asp>

proceeding to a public offering to resell it (e.g., for its own account or on behalf of its own clients).

3. Financial adviser. Participates in some bond issues to help the issuer structure the bond, prepare the disclosure document, and solicit bids from various investment bankers. Sometimes the investment bank/underwriter plays this role.
4. Lawyers. Each lawyer delivers an opinion at the bond issue closing
 - a. Solicitor. Validates the issuer and the bond issue.
 - b. Bond counsel. Focuses on the legal aspects of financing and helps structure the transaction with regard to state law approvals and compliance with federal tax laws related to bond issues. For funding of a capital project, the funds must serve the purpose of taxpayers and the greater good.
5. Trustee/paying agent. Bond issuer will choose a bank that will make debt service payments on its behalf to the bondholders and represent the bondholders in the event of default.
6. Bond guarantor. Provides credit enhancement to the bond issuer, either through an insurance policy secured from an insurance company (guaranteeing payment) or a letter of credit from a bank. A guarantor is not always included in transactions.
7. Ratings agency. Municipal bonds are rated by an independent ratings agency to provide guidance to potential investors as to the creditworthiness of the bond.
8. Investor/bond purchaser. Ultimate investor in the bond issue.

Steps for Issuing a Bond

Step 1 – Select financial team

The bond issuer selects a bond counsel and an underwriter/financial adviser to work with the issuer and the solicitor to structure financing.

Step 2 – Work with financial team to address details

Some basic questions must be answered:

1. What are the legal parameters that must be addressed (e.g., can debt be refunded under the federal tax rules?)
2. Should bonds be sold to one underwriter, or competed among multiple underwriters (e.g., does a relationship already exist with a single firm, and is the denomination small enough that it would be less hassle and cost to deal with one underwriter)?
3. Is the cost of credit enhancement (insurance or letter of credit) less than the resulting debt service savings to the issuer?

Step 3 – Select trustee and credit enhancer

The trustee is selected and possibly a counterparty to provide additional support for the issue if it makes sense to secure credit enhancement. Given the current creditworthiness concerns of the primary municipal bond insurance companies, credit enhancement may be less valuable than in the past.

Step 4 – Prepare required documentation

The underwriter prepares the disclosure document (also called the preliminary official statement) that provides the details of the bond issue. Bond counsel prepares legal documentation that is

specific to the bond issue. During the documentation phase, the lawyers make sure that state and federal legal procedures are followed.

Step 5 – Marketing

The bond is marketed to one or more potential purchasers, usually for about a week. During this time, the disclosure document is scrutinized by the potential purchaser(s).

Step 6 – Bond sale at public meeting

At the end of the marketing period, the bonds are sold at a public meeting. Terms of the purchase proposal include the principal amount of the bond, interest rates, amortization schedule, and details about prepayment provisions.

Single underwriter/negotiated offer

The underwriter that was preselected will come to the public meeting with a firm purchase proposal, containing the specific terms of the bond issue. These details can be negotiated further at the public meeting and approval by both sides at the meeting results in confirmation of the terms.

Multiple underwriters/competitive offer

If several underwriters were invited, the multiple bids are collected by the financial adviser the day of the bond sale and public meeting. The auction proceeds until all the bonds are distributed.

Step 7 – Prepare for Closing

Once agreement has been reached on the terms, the bond counsel prepares a package to be filed with the state, which approves the bond issue. The closing takes place about a month after the bond sale. Prior to the closing, the bond counsel distributes the necessary draft legal documents.

Step 8 – Closing

At the closing, all parties of the bond issue execute the various closing documents. The underwriter(s) wires the approved purchase price for the bonds to the trustee. The trustee ensures that funds are properly distributed according to the intended purpose of the bond issue. At the direction of the bond issuer, the trustee pays the cost of issuance and applies the balance to the construction project's accounts. After the closing, the bond counsel distributes copies of the executed documents to the bond participants.

Appendix 5. The Department of Energy's Solar America Cities and Showcases

The U.S. Department of Energy is supporting two significant developments at the local government level: Solar America Cities and the Solar America Showcases. In the 2006 State of the Union Address, President Bush announced the creation of the Advanced Energy Initiative (AEI). Within the AEI, the Department of Energy launched the Solar America Initiative (SAI) with the goal of making solar energy cost-competitive with conventional forms of electricity production by 2015.

One of the projects for the Solar America Initiative is Solar America Cities (SAC) (details can be found at <http://www.solaramericacities.org/>). The DOE initially offered approximately \$2.5 million to the Solar America Cities initiative in support of 13 cities (population must be at least 100,000). The cities approved to participate were judged on their “plans to build a sustainable solar infrastructure, streamline city-level regulations, and promote the adoption of mainstream solar technology among residents and businesses.”¹⁷² In addition to the combined \$2.5 million in federal financing to the 13 cities, the DOE will offer on-site technical and policy assistance for implementation of solar deployment. The 2007 Solar America Cities are:

Table 3. 2007 Solar America Cities

Ann Arbor, Michigan	Pittsburgh, Pennsylvania
Austin, Texas	Portland, Oregon
Berkeley, California	Salt Lake City, Utah
Boston, Massachusetts	San Diego, California
Madison, Wisconsin	San Francisco, California
New Orleans, Louisiana	Tucson, Arizona
New York, New York	

A second group of Solar America Cities was announced on March 27, 2008, bringing the total to 25.¹⁷³ The 2008 Solar America Cities are:

Table 4. 2008 Solar America Cities

Denver, Colorado	Philadelphia, Pennsylvania
Houston, Texas	Sacramento, California
Knoxville, Tennessee	San Antonio, Texas
Milwaukee, Wisconsin	San Jose, California
Minneapolis-St. Paul, Minnesota	Santa Rosa, California
Orlando, Florida	Seattle, Washington

In addition to Solar America Cities, the DOE also offers the Solar America Showcase (SAS). The DOE selects individual public projects that involve large-scale solar installations as additional support for the Solar America Initiative. SAS does not provide financial assistance for

¹⁷² “The 2007 Solar America Cities Awards,” U.S. Department of Energy Solar America Initiative Fact Sheet, June 2007, at http://www1.eere.energy.gov/solar/solar_america/pdfs/41760.pdf

¹⁷³ “U.S. Department of Energy to Provide up to \$2.4 Million to Advance Solar Energy in 12 U.S. Cities,” U.S. Department of Energy news release, March 28, 2008, at <http://energy.gov/news/6099.htm>

these projects; instead, it provides technical assistance to approved applicants through teams of DOE-funded solar experts. As of October 2007, the following five projects had been identified:^{174, 175}

- “Residential Hybrid Solar Electric and Thermal Systems in Hawaii” – Forest City Military Communities are seeking DOE assistance for the feasibility of incorporating hybrid solar-thermal electric systems into a large military residential project in Oahu, Hawaii.
- “Photovoltaic Demonstration and Research Facility and Family Learning Center” – Orange County, Florida, is seeking DOE assistance in evaluating the technical feasibility of placing an 800 kW photovoltaic system on the Orange County Convention Center.
- “Smart Solar Initiative” – City of San Jose, California, is seeking DOE assistance in evaluating the potential of multiple large buildings and complexes in San Jose for solar photovoltaic and thermal applications.
- Northeast Denver Housing Center – DOE will assist in overcoming barriers to the installation of solar photovoltaics on 80 permanently affordable housing units in Denver, Colorado.
- Montclair State University will receive technical assistance in support of a 280 kW “solar farm” at its New Jersey School of Conservation.

¹⁷⁴ “Solar America Initiative: Solar America Showcases,” accessed April 2008, at http://www1.eere.energy.gov/solar/solar_america/solar_america_showcases.html

¹⁷⁵ “DOE Announces Solicitation for 2008 Solar America Cities,” U.S. Department of Energy Progress Alert, October 30, 2007, accessed April 2008, at http://www1.eere.energy.gov/news/progress_alerts/progress_alert.asp?aid=252

Appendix 6. Useful Reference Documents and Internet Resources

California Solar Initiative Handbook 2007

http://www.gosolarcalifornia.ca.gov/documents/CSI_HANDBOOK.PDF

Database of State Incentives for Renewables and Efficiency (DSIRE)

<http://www.dsireusa.org/>

Energy Information Administration. 2003.

Commercial Buildings Energy Consumption Survey

<http://www.eia.doe.gov/emeu/cbecs/>

EPA. 2004. "Guide to Purchasing Green Power."

http://www.epa.gov/greenpower/documents/purchasing_guide_for_web.pdf

Interstate Renewable Energy Choices (IREC) and the North Carolina Solar Center. 2007

"Connecting to the Grid: A Guide to Distributed Generation Interconnect Issues," 5th Edition.

http://www.irecusa.org/fileadmin/user_upload/ConnectDocs/IC_Guide.pdf

Network for New Energy Choices, Interstate Renewable Energy Choices, Vote Solar Initiative and the Solar Alliance. 2007. "Freeing the Grid" Net Metering and Interconnection Report

http://www.newenergychoices.org/uploads/FreeingTheGrid2007_report.pdf

Shirley, W. 2006. "Survey of Interconnection Rules."

The Regulatory Assistance Project

Prepared for the Florida Public Service Commission

http://epa.gov/chp/documents/survey_interconnection_rules.pdf

Solar Energy Industry Association. 2006. "Guide to Federal to Federal Tax Incentives for Solar Energy (Version 1.2)"

<http://www.seia.org/SEIAManualversion1point2.pdf>

State Solar Power Rebates, Incentives, and Tax Credits

<http://www.solarpowerrocks.com/solar-politics/solar-cities/>

Wiser, R. and M. Bolinger. 2006. "Federal Tax Incentives for PV: Potential Implications for Program Design." Lawrence Berkeley National Laboratory.

<http://repositories.cdlib.org/lbnl/LBNL-60193/>

Appendix 7. Useful Contacts

State and Local Governments

California

- California Energy Commission
<http://www.energy.ca.gov/>
 - Virginia Lew
Vlew@energy.state.ca.us

- Department of General Services
<http://www.dgs.ca.gov/default.htm>
 - Pat McCoy
Patrick.McCoy@dgs.ca.gov

- New Solar Home Partnership
<http://www.gosolarcalifornia.ca.gov/nshp/>
 - Sanford Miller
Smiller@energy.state.ca.us

Colorado

- The County of Boulder
<http://www.co.boulder.co.us/>
 - Ann Livingston
Sustainability Coordinator
alivingston@co.boulder.co.us

- Public Utilities Commission
<http://www.dora.state.co.us/PUC>
 - Richard Mignogna
richard.mignogna@dora.state.co.us

Connecticut

- The Connecticut Clean Energy Fund
www.ctcleanenergy.com
 - Lise Dondy
President
lise.dondy@ctinnovations.com
 - Dale Hedman
Director of Project Development
dale.hedman@ctinnovations.com
 - Bob Wall
Bob.Wall@ctinnovations.com

Massachusetts

- Massachusetts Division of Energy Resources
<http://www.mass.gov/doer/>
 - Ian Finlayson
Ian.Finlayson@state.ma.us
 - Meg Lusardi
Meg.Lusardi@state.ma.us
- Massachusetts Technology Collaborative
<http://masstech.org/>
 - Jonathan Abe
Sr. Project Manager, Renewable Energy Trust
abe@masstech.org

Montana

- Montana Public Service Commission
<http://www.psc.state.mt.us>
 - Will Rosquist
wrosquist@mt.gov

New Jersey

- New Jersey Board of Public Utilities
<http://www.bpu.state.nj.us>
 - Scott Hunter
benjamin.hunter@bpu.state.nj.us

New York

- New York State Energy Research and Development Authority
<http://www.nyserda.org/>
 - Adele Ferranti
Sr. Project Manager
af1@nyserda.org
 - Heather Hammond
Project Coordinator - Loan Fund
hsh@nyserda.org

Ohio

- Ohio Department of Development
<http://www.odod.state.oh.us/cdd/oe/>
 - Judy Pacifico
jpacifico@odod.state.oh.us

Nonprofit Organizations

CESA – Clean Energy States Alliance

<http://www.cleanenergystates.org/>

- Mark Sinclair
MSinclair@cleanegroup.org

Community Office for Resource Efficiency (CORE)

<http://www.aspencore.org/>

- Gary Goodson
gary@aspencore.org

The Vote Solar Initiative

<http://www.votesolar.org/>

- Adam Browning
abrowning@votesolar.org

U.S. Department of Energy

Golden Field Office

Golden, Colorado

- REPI Program Administration
 - Christine Carter
christine.Carter@go.doe.gov
 - Chico Gonzalez
chico.gonzalez@go.doe.gov

REPORT DOCUMENTATION PAGE

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