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Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners

Technical Report
NREL/TP-6A2-46723
Revised February 2010

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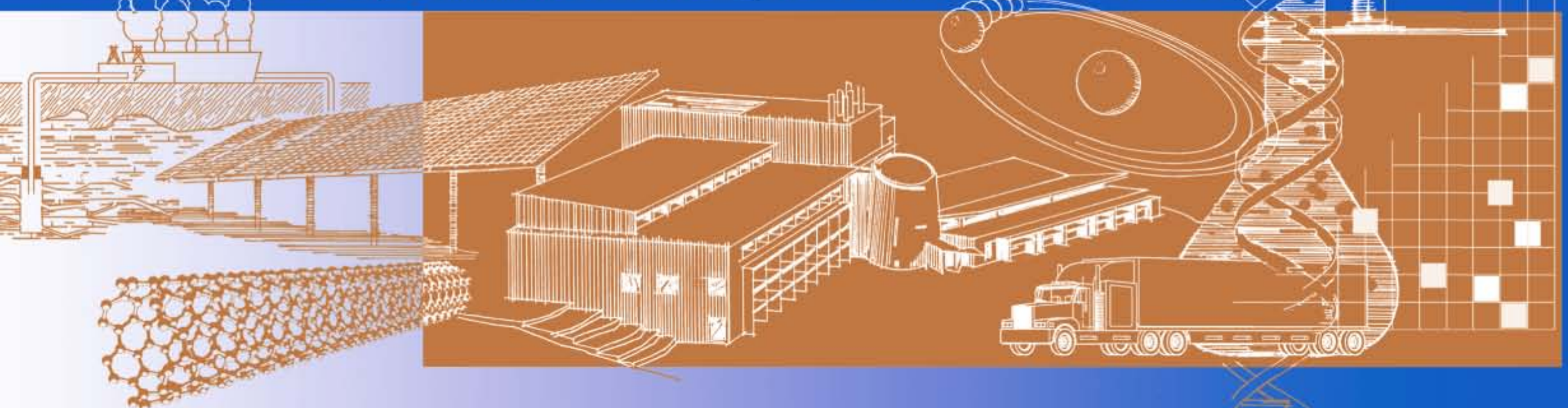

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Finally, the authors also offer their gratitude to Mike Meshek and Jim Leyshon of the NREL communications department for providing editorial support and graphics respectively.

A Note on the Revisions

This report, as originally published, contained editorial errors that have been corrected in this revision. No changes, except those noted here, changed the authors' intent.

- Page 8, last paragraph: Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are <u>not</u> subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption.
- Page 25, last paragraph: Under the most common of these, the solar lease, the customer does <u>not</u> pay for the equipment but receives the electricity generated from that equipment.
- Page 34, paragraph 5: However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to <u>the utility</u>.

List of Acronyms and Abbreviations

C&I	commercial and industrial
CPUC	Colorado Public Utilities Commission
CREB	clean renewable energy bond
CSI	California Solar Initiative
dba	doing business as
DG	distributed generation
DOE	U.S. Department of Energy
DSIRE	Database of State Incentives for Renewables and Efficiency
EIA	Energy Information Administration
ESS	electrical service supplier
FERC	Federal Energy Regulatory Commission
IOU	investor owned utility
IREC	Interstate Renewable Energy Council
IRS	Internal Revenue Service
ITC	investment tax credit
kWh	kilowatt-hour
LLC	limited liability company
LSE	load serving entity
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
OPUC	Oregon Public Utilities Commission
PPA	power purchase agreement
PUCN	Public Utilities Commission of Nevada
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
REC	renewable energy certificate
RES	renewable electricity standard
RPS	renewable portfolio standard
SREC	solar renewable energy certificate
SSA	solar services agreement
WAPA	Western Area Power Association

Executive Summary

Many end users of electricity would like to use on-site photovoltaic (PV) generation to hedge against volatile electric utility bills and reduce climate change impacts. However, PV systems have high initial costs, and they must be properly operated and maintained to deliver expected benefits.

Providing a potential solution to these cost challenges is a model in which a third-party owner uses a power purchase agreement (PPA) to finance an on-site PV system. This model—the third-party PPA model—allows a developer to build and own a PV system on the customer's property and sell the power back to the customer. In addition, the third-party PPA model enables the customer to support solar power while avoiding most or all initial costs as well as responsibilities for operations and maintenance, both of which typically transfer to the developer. These advantages appeal to owners of residential and commercial buildings who would like to obtain solar PV systems.

However, third-party electricity sales face regulatory and legislative challenges in some states and jurisdictions. Several of these challenges pertain to whether third-party owners are deemed to act as monopoly utilities, competitive service suppliers (competitive suppliers), or both depending on the degree of retail electricity market deregulation. If third-party owners are deemed to act similarly, according to state definitions or state public utility commission (PUC) definitions, the third-party owners may also need to be regulated by the state PUC. Third-party owners of solar PV systems face an additional challenge if they are not allowed to net meter,[1] as this is a significant financial incentive to owning these systems.

Legislative and Regulatory Challenges with Third-Party PPA Model

Five legislative and regulatory issues that challenge the third-party PPA model—and the solutions that several states have applied to them—are summarized below and in Table ES-1.

- **Challenge 1—Definition of Electric Utility as Seller of Electricity:** Because third-party owners sell electricity to site hosts or end users, their systems may require PUC regulation when the state defines a public electric utility (or electrical corporation in California) as a retail seller of electricity. Also, some municipal utilities prohibit others from selling power to their customers and require their customers to buy power exclusively from them.

  State Solutions: Colorado, New Mexico, and California determined that third-party owned systems are not utilities or electrical corporations and non-traditional power generators are not utilities, and are therefore exempt from PUC regulation.

[1] With net metering, an electric meter tracks net power usage—the difference in the amount of electricity provided by the utility and the amount generated by the PV system.

- **Challenge 2—Power Generation Equipment Included in Definition of Electric Utility:** When the definition of electric utilities includes power generation equipment (such as solar PV equipment), third-party owned systems may face regulatory challenges.

  State Solutions: Nevada and Oregon excluded third-party owned renewable energy systems (specifically solar and wind power in Oregon) from the definition of a public utility in PUC regulations.

- **Challenge 3—Definition of Provider of Electric Services:** Third-party owned systems in regulated or partially restructured ("hybrid") states may encounter challenges when legislation or regulation defines utilities or competitive suppliers in a way that includes those providing electric services. This is problematic for third-party owners who provide services to site hosts or end users.

  State Solutions: Oregon decided that third-party owned systems are not competitive suppliers (known as electricity service suppliers in Oregon) because they do not provide ancillary services.

- **Challenge 4—Muni and Co-op Concern over Opting into Deregulation of Electricity Generation:** Third-party ownership of systems is still an issue in Texas within municipal and co-op jurisdictions. Municipal utilities (munis) and rural cooperatives (co-ops) are concerned that by allowing a third party to sell power to customers within their service territory, the public utility commission would force them to allow customers to choose retail electricity service suppliers.

  State Solutions: Third-party ownership of systems remains an open issue in Texas within municipal and co-op jurisdictions.

- **Challenge 5—Determining Whether Third-Party Owned Systems May Net Meter:** Although net metering provides a significant financial incentive, it is not available in all states.

  State Solutions: According to legislation in New Jersey, qualifying facilities include customer-generators that use power from solar PV systems sited on their property (i.e., customer-generators do not have to own the solar PV system). However, this issue remains unresolved in Texas where there are no plans to address it via regulatory or legislative changes.

Alternatives to Third-Party PPA model

Although third-party owned systems have faced regulatory and legislative obstacles in several states, all states that have tried recently have overcome these challenges. Florida examined this situation in the late 1980s and did not develop a solution; but the issue has not been addressed recently. And, while the potential solutions described in this report are state-specific, they likely could be applied in other states that want to encourage solar PV deployment by allowing third-party owned systems. When legislative or regulatory solutions cannot be found, end-use electricity customers may pursue alternatives to the third-party PPA model, including:

- **Solar leases:** Under a solar lease, the customer does not purchase power from a third party but simply leases equipment and receives the power generated by that equipment. This solution has been used in Florida, which does not allow the third-party PPA model. Although it avoids the retail sale of electricity, the solar lease model creates challenges for the use of the federal tax credit and accelerated depreciation.
- **Utilities as Contractual Intermediaries:** A utility may act as a contractual intermediary. Under this arrangement, the third-party owner sells power from the solar PV system to the utility, which, in turn, sells the power back to the site host/end-user.
- **Standardized Contract Language:** Standardized third-party PPA contract language protects customers and reduces the likelihood the PUC will disallow the third-party PPA model or require future regulation.
- **Utility Ownership:** Utilities that own solar PV systems sited on customers' properties could take the federal investment tax credit (ITC) to reduce the capital costs of owning solar PV. However, this model is not as market oriented as others and could exclude third-party solar developers from the utility service territory.
- **CREBs:** For states and municipalities that want to install solar PV on government property, clean renewable energy bonds (CREBs)[2] offer an alternative financing mechanism to the third-party PPA model. However, some projects may be too large to qualify and project owners had to apply by August 2009 to secure a CREBs allocation.
- **Waived Monopoly Powers:** The state PUC and utility may work together to jointly waive the monopoly power rights of the incumbent utility. While this solution is not typical and less feasible than other alternatives, it was applied in Colorado until legislation was passed that replaced this arrangement. With consent from the PUC, the monopoly utility allowed projects financed under the third-party PPA model only when the projects provided renewable energy certificates (RECs) to the utility.

[2] The Internal Revenue Service (IRS) issues CREBs. They are an alternative to tax-exempt bonds that pay out as tax credits instead of interest payments. For more information, see Appendix D.

Table ES-1. Summary of Solutions to Third-Party PPA Model Regulatory Challenges

Solution \ Challenge	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4.Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
PPA Solutions					
Clarify third-party owned systems are *not* utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems *used* by customer-generators					NJ
Alternative Solutions					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds [a]	*	*	*	*	
Utility and PUC Waive Monopoly Rights [b]	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.
* Indicates a probable solution with no barriers identified.
** Indicates a possible solution that requires further investigation
[a] This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.
[b] This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

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1 Introduction

The third-party PPA model is quickly becoming the financing method of choice across a wide range of PV generation market segments (Frantzis et al. 2008) and is even finding a niche in the residential and federal markets. However, use of this finance model may be inhibited if it conflicts with state legislation and regulation that was established before third-party ownership was used to finance renewable energy projects.

State regulations and legislation concerning the electric generation sector often define utilities and competitive service suppliers (competitive suppliers), and these definitions often become the starting points for determining which entities require regulation by the state PUC.[3] However, many of these regulations were written when monopoly utilities or competitive electricity suppliers were the main providers in electricity markets. Thus, the regulations do not account for a finance model in which a non-utility entity owns power generation equipment and sells the power generated by this system to a customer. Therefore, in states where utilities or competitive suppliers are defined (a) as sellers of electricity, (b) owners of power generation equipment, or (c) providers of electricity services, the third-party owners that meet the State or PUC definition of utilities or electricity service suppliers may be interpreted as such. If third-party owners are interpreted as meeting these definitions, they might face regulation as a utility. In deregulated retail electricity markets where only munis and co-ops maintain monopoly rights over their service territories, these entities may not allow third-party owned systems if regulation does not clarify whether they would be opening themselves up to customer choice.

In addition to facing regulatory uncertainty, developers using the third-party PPA model may be disincentivized to install solar PV in states where systems using this finance model are not allowed to net meter. Thus, the deployment of solar PV may be hindered in states where third-party owners are uncertain if they will be regulated or allowed to net meter. This paper explores these regulatory conflicts between third-party ownership, state laws, and PUC decisions. It also looks at how particular states have dealt with these challenging issues and explores existing and potential ways to address them.

Section 1 introduces the third-party PPA model, regulation of electric markets, and the related legislative and regulatory challenges. Section 2 describes the third-party PPA model for financing PV projects at customer sites. Section 3 summarizes electricity markets in the United States and explains why markets are regulated and related issues. Section 4 explores in depth several legislative and regulatory challenges to using the third-party PPA model, using California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas as examples. This section also details solutions or answers to these challenges, including legislative and regulatory solutions, and suggests other situations in which these solutions could be applied. Additional solutions, including variations of the third-party PPA model and alternatives to the third-party PPA model, are given in section 5.

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[3] In addition to facing state regulation, the third party PPA model could be subject to regulation by the Federal Energy Regulatory Commission (FERC). However, in a recent declaratory order, FERC ruled that they do not have jurisdiction over behind-the-meter third-party PPA solar generating systems (FERC 2009a).

2 The Power Purchase Agreement (PPA)

Traditionally, the PPA was a vehicle for utilities to purchase energy from each other. With the dawn of the Public Utility Regulatory Policy Act (PURPA) in 1978, utilities were required to purchase all of the power from qualifying facilities (QFs) generating renewable assets under 80 MW (FERC 2009b). Utilities used the PPA to purchase from independent generators (the QFs) under long-term stable-priced contracts. PPAs involving QFs are not as common with recent Federal Energy Regulatory Commission (FERC) Orders weakening the utilities' mandate to buy power from QFs and promoting wholesale electricity competition through the opening of transmission access.[4] However, today utilities are signing PPAs with independent power producers for non-utility owned generating plants, for example to meet state renewable portfolio standards (RPS).

2.1 History and Explanation of the Third-Party PPA Model

While the traditional PPA is still the mechanism of choice for utility power purchases, in 2006 a new structure developed that uses a PPA to cater to the distributed generation (DG) markets.[5] SunEdison and Renewable Ventures (formerly MMA Renewable Ventures) pioneered this financing model (Johnson 2008; Renewable Ventures 2009), which was quickly employed by others developers. As Figure 1 indicates, the use of PPAs as a financing model for non-residential solar PV installations has grown rapidly since 2006, taking over other financing models in 2008; this trend is expected to continue through 2009 (Guice and King 2008).

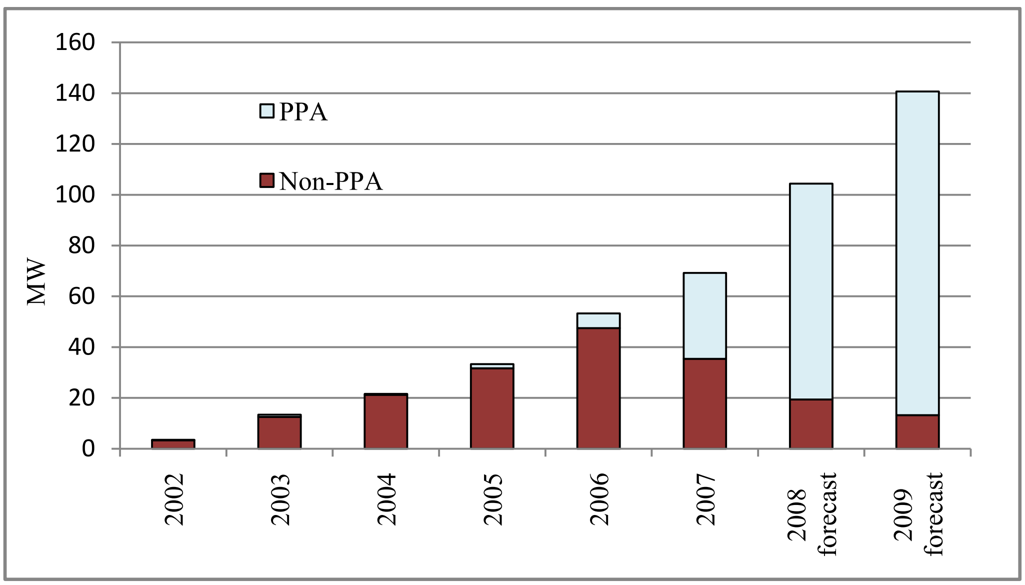

Figure 1. Use of PPAs for U.S. non-residential solar PV installations

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[4] The goals of FERC Order 888, issued in 1996, were "promoting wholesale competition through open access non-discriminatory transmission services by public utilities" and the "recovery of stranded costs by public utilities and transmitting utilities" (FERC 2006). These changes led to fewer PPAs (Stoel Rives 2006). FERC Order 688 also removed the mandate that utilities "must buy" the power from QFs if they were greater than 20 MW and have access to one of three major wholesale markets (Stoel Rives 2006).

[5] DG is meant to encompass a variety of sizes of projects located behind customer meters. The larger the customer and the more electricity demanded, the larger the DG system can be. While this can be as small as 2 kW for residential systems, it can be up to 2 MW for large commercial and industrial customers.

Figure 2 details the third-party PPA model where a customer interested in hosting solar panels signs a PPA with a project developer who builds, owns, and operates a solar energy system on the customer's site, also known as the host site. The developer then sells the electricity back to the customer via the long-term PPA. In effect, this allows the customer to have the benefits of solar power while transferring the up-front capital costs to an entity designed to capture available tax benefits (with a potentially lower cost of capital) and foregoing the logistics of financing, building, and maintaining the system. The third-party PPA model is depicted in Figure 2 and is described in detail in Appendix A.

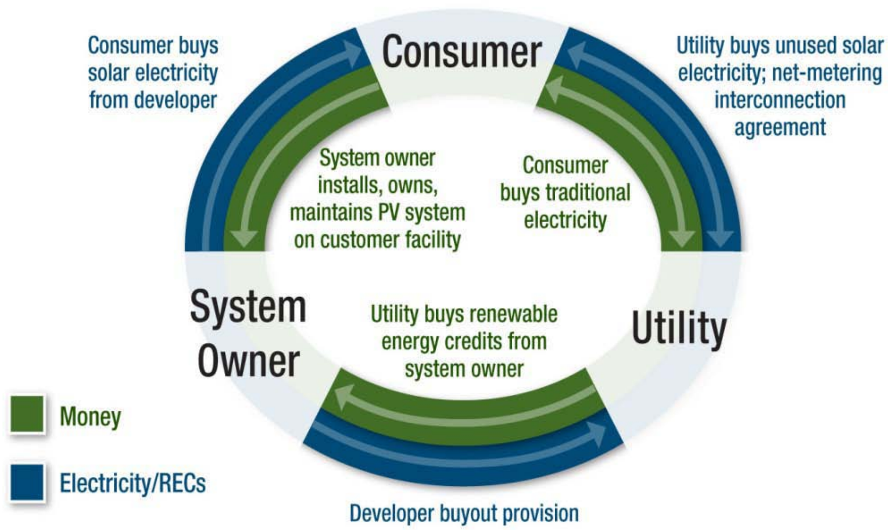

Figure 2. Third-party PPA model
(DOE Solar Energy Technologies Program)

In the PPA contract, a developer receives a combination of revenues and incentives that include electricity sales, sales of environmental attributes (RECs), cash incentives, and state and federal tax incentives in return for paying for the project up front. The customer and developer determine the right mix of up-front cost and payment for electricity sales to meet the developer's required rate of return. This means that customers who want to avoid paying any up-front costs will typically pay more for electricity.

2.2 The Benefits of the Third-Party PPA Model

One of the largest barriers to the deployment of solar energy systems is the high up-front cost. The recent emergences of financing structures that address this challenge have helped spur a significant increase in solar PV installations in the United States. In 2008, over 18,000 new PV systems were installed in the United States that generated 292 MW of the total 342 MW connected to the grid (SEIA 2009). The transfer of the up-front capital costs to an entity with greater access to capital, lower cost of capital, or greater ability to utilize tax specific incentives has been critical to commercial and industrial (C&I) customers adopting the technology. Although this financing model could be used for other installation types, it is primarily used for behind-the-meter installations (i.e., installations that affect only the use of the customer who hosts the installation) (Cory, Coughlin, and Coggeshall 2008).

3 U.S. Retail Electricity Markets and Third-Party PPA Model Interactions

Before examining the regulatory issues (Section 4), the context of state attempts to deregulate retail electricity generation markets must be understood. The level of restructuring in state retail electricity markets varies along a wide spectrum. While some states may be clearly defined as having traditionally regulated retail markets, other states may have “hybrid” markets that have characteristics of both regulated and deregulated electricity markets.[6] Examples of hybrid markets include California, New Jersey, and Oregon.

In states with regulated, vertically integrated utilities, third-party owners of PV must understand the regulatory framework within which they operate. First, the state’s definition of a utility may be problematic. In some states, selling power to an end-use customer may mean that the third-party provider would be considered a utility and therefore need to be regulated by the utility regulators. In a few states with ample incentives or REC markets, the third-party owners have tried to get the regulations or laws changed (examples are discussed below).

In states with deregulated retail electricity markets, third-party owners must be aware of the regulations faced by competitive suppliers. And where hybrid markets exist, third-party owners need to be knowledgeable of how utilities and competitive suppliers are defined and where they are active. Developers using the third-party model in hybrid states should investigate whether munis and co-ops will allow these systems, especially in states like Texas where these utilities are concerned that this could open their territories to deregulation of the generation market. Lastly and in all types of markets, states must address whether third-party owned systems are allowed to net meter if they want to encourage the deployment of solar PV projects using the third-party PPA model.

When assessing the feasibility of third-party ownership, PUCs must consider consumer protection and grid safety. PUCs must also consider the degree to which third-party PPA models should be regulated, if at all. This section looks at the pros and cons of allowing third-party ownership in regulated and hybrid retail electricity markets, and it details some state positions on this issue.

3.1 Why Retail Electricity Markets are Regulated

Retail electricity markets in the United States remain regulated in most states in part to protect consumers (rates and reliability) and to ensure a highly functioning electric grid. If anyone could freely connect a generator to the existing grid, the electricity supply could become volatile and unsafe, which could cause congestion, blackouts, and maintenance concerns. Additionally, regulation of these markets prevents unnecessary duplication of assets such as transmission and distribution facilities. Regulated investor-owned utilities are given monopoly status in most service territories to prevent such problems. By having a single entity control the system, a utility can balance constantly changing supply and demand to ensure reliability and keep the electricity flow on the grid optimized and safe.

[6] This is a simplifying assumption—that no market has fully achieved competition in the retail electricity generation markets—that could be debated. However, in many states, the default utilities are still serving substantial portions of the load, so it is difficult to say that any retail electricity generation market is truly deregulated.

States dealing with high power prices in the 1990s began considering deregulating retail electricity markets to lower prices by creating competition among generators supplying electricity (Borenstein 2000). With the relative success of deregulation in the wholesale electricity market, several states began to deregulate retail sales and allow customers to choose where and how they purchased their power. Throughout this electric system restructuring process, most municipal utilities (munis) and rural cooperatives (co-ops) remained regulated by their cities (i.e., by city council members) rather than opening up their territory to competition. Therefore, in most states that restructured, munis and co-ops continue to operate under different rules and regulations than do investor owned utilities (IOUs). Although views on the effectiveness of restructuring vary—and some states are taking steps to re-regulate generation—there are a number of states where customers (sometimes just non-residential customers) continue to choose their power providers.

3.2 Legislative Issues and Challenges with Regulated Retail Electricity Generation Markets

Generation deregulation can affect whether third-party owners are regulated. In electricity markets where the retail customer has consumer choice of their power provider, the third-party PPA model may pose fewer legislative issues. If the utility does not have monopoly power over a given customer base, the customer can choose to purchase power from a company that has placed a solar PV system on its roof or from a competitive supplier, or from both. However, even in a deregulated market, customers may not be incentivized to use the third-party PPA.

Notably, not all states have clearly regulated or deregulated retail electricity generation markets. In fact, some could be said to have "hybrid" markets with characteristics similar to both regulated and deregulated markets. Oregon is an example of a hybrid electricity market where third-party ownership is allowed and where a combination of IOUs, munis, and co-ops provide electricity to customers (State of Oregon 2007); the case of Oregon is discussed in further detail later. However, since most electricity markets in the United States have not restructured to allow customer choice (Showalter 2008; EIA 2008), any model in which an entity other than the monopoly utility sells electricity directly to customers may be prohibited. This legislative issue could significantly challenge third-party owned models.

3.3 Consumer Protection

Some state PUCs are asking if a third party owns a system and sells the power to a retail customer in the service territory of a regulated utility, does the utility commission need to regulate that entity to protect customers from fraud and to protect the security of the electric system? The same question could be posed if the third party owns a system and sells the power to a retail customer where markets are deregulated. In that case, the third-party owner may be considered a competitive supplier.

The utility commissions serve to protect consumers' interests by regulating rates and service quality. Additionally, they serve as a clearinghouse for customer complaints and are charged with dealing effectively with these matters. However, in the case of third-party owners, the PUCs may have no oversight or control over these competitive suppliers. This lack of oversight may pose a challenge for customers. Developers maintain they must provide a quality product to retain customers and remain competitive, and that detailed contract language assures the customer of what can be expected from the system and its owner (Danielson 2008). Moreover, the third-party model aligns the interests of the customer and developer as the project is paid for performance and will not be successful if it underperforms. At a minimum, the customer is usually protected by state consumer protection laws.

3.4 Interconnection Standards

Utilities may use interconnection standards, which provide safety provisions to protect the grid and utility workers, to integrate non-utility owned DG systems. Best practice interconnection standards follow engineering standards and FERC technical screens that maintain the safety of the grid and give DG customers stable policies for interconnection (NNEC 2008).

Interconnection standards consider the effects of size and location of distributed resources on the electric grid. In addition, interconnection standards include provisions about maintenance and the utility's right to disconnect the system if it identifies a problem. Interconnection standards, net metering policies, and other incentives are discussed in detail in Appendix B.

4 Regulatory and Legislative Issues and Challenges to the Third-Party PPA Model

Most state laws and regulations that complicate third-party ownership in monopoly territories have been in place for decades and did not originate specifically to prevent the third-party PPA model. In general, the third-party PPA model is not specifically outlawed. Rather, any entity that sells power to retail customers has to be regulated by the utility commission. Because regulation adds substantial cost and delay, it effectively removes a developer's incentive to offer services in a state. The regulatory language, which is different in each state, gives an idea of the prohibitions on third-party ownership in these markets. This issue is not limited to regulated or hybrid states as some states that have deregulated with respect to customer choice still have sub-markets that remain monopoly utilities (such as the previously mentioned munis and co-ops). The challenge in this case is third-party owners who are allowed to sell retail power to customers might open municipal utilities and rural electric cooperatives up to competition, thereby subjecting them to regulation by the PUC, which these small utilities may not desire (Cory, Coggeshall, and Kollins 2008). Additionally, some munis and co-ops have ordinances that protect their monopoly and do not allow for third-party developers in their territory. Also, there may be regulatory issues for third-party owned systems within deregulated electricity markets where systems using this finance model must abide by the same legal and public utility commission regulation as competitive suppliers.

Interviews with PUC officials across the country were conducted to determine the third-party PPA legislative issues that challenge states, the arguments being presented, and the solutions that may exist. The following describes five legislative and regulatory issues that several states have recently addressed. A few of these challenges have subtleties that depend on state or PUC definitions of utilities or competitive suppliers. All regulatory challenges and their possible solutions, as well as alternative solutions, are summarized in Table 1. Appendix C summarizes the language surrounding third-party ownership, and the status of third-party PPA models, in California, Colorado, Florida, Arizona, Nevada, New Jersey, Oregon, and Texas.

4.1 Challenge 1: Definition of Electric Utility as Seller of Electricity

In regulated markets where utilities are granted monopoly rights for selling electricity, definitions of utilities in PUC regulations or state legislation may prohibit third-party owned solar power generation systems. Because third-party owners of PV systems sell power to the hosts/end-users via the power purchase agreement, the owners could be considered sellers of electricity and thus utilities. Being considered a utility presents a challenge for developers wanting to use the third-party PPA model, as it would require that they be regulated by the state PUC. Regulation of third-party owned systems would add administrative costs and development time to projects, making this finance model less economically appealing.

In California, Colorado, Florida, and Arizona, utilities were defined as sellers of electricity, which created regulatory uncertainty for developers using the third-party PPA model. Colorado and California found legislative solutions for excluding third-party owned systems from being considered utilities; Colorado codified a previous regulatory solution and California addressed regulation of third-party owned systems several years ago.

4.1.1 California—Legislative Solution

California allowed the third-party PPA model for a number of years via a legislative decision. California Public Utilities Code 218 specifically allows certain ownership and technologies, and it promotes a clear path for long-term, customer-sited energy development. In fact, the code's definition specifically exempts an "Electrical Corporation" from regulation:

> …a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for… the use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

This language first establishes solar as an option by stating that non-conventional power sources are exempt. The key for the third-party ownership model is that a corporation can sell electricity if it is used solely on the property where it is generated. In fact, the electricity can even be sold to two other corporations or persons who are also on that property, according to the legislation.

California's language has several interesting implications. First, it allows third-party owners to sell to residential customers on an individual basis. Also, the exemption presents the possibility of selling power to multi-family housing units, as well as multi-tenant commercial and industrial buildings that are net-metered (with restrictions on the pricing of the power). However, the issue of selling power to tenants when the system is not net-metered remains unsettled. The state requires third-party owners to set up new independent business units (such as LLCs, or limited liability companies) for each commercial system they install in order to comply with the rules and use/employ the third-party PPA model.

When deciding whether a competitive supplier is subject to regulation as a public utility, California applies a standard of "dedication to public service." While states have interpreted differently what it means to offer service "to or for the public," California has interpreted their statutes in a way that provides an exception for the provision of power sales to a subset of customers such as tenants. Although California has consistently used this standard when interpreting the intention of power providers, the issue is still officially open.

4.1.2 Colorado—Legislative and Regulatory Solutions

Unlike California, Colorado did not allow third-party owned solar PV systems until very recently, at least not without the threat of PUC regulation. It was not clear if systems under 10 kW that were owned by third parties on a customer site would require regulation. In fact, the temporary response to this challenge was to allow Xcel Energy (Xcel), the state's largest utility, to waive monopoly rights for these smaller systems. That was until a challenge surrounding the regulatory uncertainty of third-owned systems was brought to the Colorado Public Utilities Commission (CPUC) at the request of SunRun, a residential solar developer that uses the third-party PPA finance model. SunRun wanted clarification on whether third-party owned systems smaller than 10 kW would be allowed. In February 2009, the PUC released a recommended decision (08-R-424E) in regard to changes to the renewable electricity standard (RES) confirming that systems less than 10kW are allowed, are not defined as utilities, and therefore, do not require CPUC regulation.

In addition, Colorado Senate Bill 51, which outlined the State's Renewable Electricity Standard, passed in April 2009, clarified whether third-party owned systems should be regulated (State of

Colorado 2009). Like the CPUC-recommended decision, SB 51 confirmed that third-party owned systems of any size are not subject to regulation by the CPUC providing they do not generate more than 120% of the customer's average annual consumption. The bill's specific language is:

> The supply of electricity or heat to a consumer of the electricity or heat from solar generating equipment located on the site of the consumer's property, which equipment is owned or operated by an entity other than the consumer, shall not subject the owner or operator of the on-site solar generating equipment to regulation as a public utility by the commissions if the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.

Prior to the recent legislative and regulatory solutions, Xcel and the CPUC agreed to waive Xcel's monopoly rights on specific projects that provided it with RECs, thereby allowing it to comply with Colorado's RPS requirements, including a 4% solar set-aside. For systems over 100 kW, Xcel held a competitive solicitation for RECs generated from third-party owned PPA projects as well as selected winning proposals in order to meet Colorado's RPS solar set-aside mandate. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel found the third-party ownership structure to provide an effective way of meeting that goal. However, Xcel provided this waiver only for those projects selected in its solicitation.[7] This allowed the utility to decide which providers were allowed to serve the market for commercial-scale systems using the third-party PPA model. The recent state legislation and CPUC ruling provides stronger regulatory clarification, which is needed for the long-term development of third-party owned systems.

4.1.3 Florida—No Solution

Unlike Colorado and California, the third-party PPA model has not recently been debated formally in Florida. However, in 1987, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project for which PW Ventures, Inc. (PW Ventures) would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide most of their power needs (*PW Ventures v. Nichols*, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, Florida Power & Light. The definition of a "Public utility" as defined by Florida Statute 366.02 is:

> Every person, corporation, partnership, association, or other legal entity and their lessees, trustees, or receivers supplying electricity or gas…to or for the public within this state.

In their ruling on the issue, the FPSC focused on the definition of "to or for the public." PW Ventures argued that to be considered a utility they would have to sell their power to the general public to be considered a utility. However, the Commission determined that the definition of "to or for the public" could mean *one* customer, meaning that by selling only to Pratt and Whitney, PW Ventures was selling to the public and would be deemed a public utility. Without a change in

[7] Telephone conversation with Richard Mignogna, Professional Engineer, Colorado Public Utilities Commission, September 24, 2008.

statute, this ruling appears to eliminate the possibility of using the third-party PPA model in Florida without PUC regulation (FPSC 1987).

4.1.4 Arizona—No Solution

Arizona has not addressed the regulatory uncertainty about the third-party PPA model. As in Oregon, the retail electricity generation market in Arizona is a hybrid market where competitive suppliers are allowed to register and sell electricity within the utility's exclusive service territory, although no competitive suppliers are currently registered. However, according to the Arizona Corporation Commission, there are several solar PV projects that plan to use the third-party PPA model even though these project arrangements are not allowed.[8] Article 15 Section 2 of Arizona's Constitution defines a public utility as a corporation that "furnishes" electricity or power, requiring that any entity furnishing electricity be regulated in Arizona. Because the definition is part of the constitution, the issue would likely require a legislative solution rather than a regulatory one.

The Solar Alliance, a consortium of solar manufacturers, integrators, and financiers, in 2008 appealed to the Arizona Corporation Commission for a declaratory order in an attempt to resolve the third-party PPA model matter in the state. The Solar Alliance requested that providers of certain solar service agreements not be considered public service corporations (and therefore not be regulated by the Commission). The docket outlines the characteristics of these solar service agreements and argues they are not public service corporations because they are not "clothed with the public interest," which legal precedent has determined is a characteristic of an entity that requires regulation. The Solar Alliance argues that they therefore, do not require the Commission's economic regulation (Arizona Corporation Commission 2008).

Interestingly, in 2007 the Arizona legislature passed HB 2491 to make third-party financiers eligible for the Arizona corporate solar tax credits (State of Arizona 2007). It is to be determined whether the third-party owners will be able to take advantage of this legislation.

4.1.5 Applicability Elsewhere

California's legislative solution is applicable in fully regulated, hybrid, or deregulated power generation and supplier markets where third-party power suppliers are considered by definition to be electrical corporations. Of course, this type of legislative solution, in which renewable energy power suppliers are exempt from being regulated, requires the support of state lawmakers and their willingness to change state laws.

The recent solution applied in Colorado—clarifying in an RES bill that third-party owned systems are legal—could also be applied in other states with fully regulated electricity markets. This type of solution makes sense in states passing new RES legislation as both RESs and the allowance of third-party owned solar PV systems support renewable energy deployment.

The prior solution used in Colorado—allowing a utility to waive its monopoly rights—could be applied in other fully regulated or hybrid electricity markets. However, this solution is less feasible because a public utility commission may not always allow a utility simply to decide

[8] Telephone conversation with Ray Williamson, utilities division, Arizona Corporation Commission, September 23, 2008.

whether third-party owned systems should be allowed, and the utility may not agree to this policy. Nonetheless, this might be a solution in a state where the public utility commission or legislature has not established rules that clearly allow for third-party owned systems, but the utility and its regulators desire this option to meet an RPS requirement.

4.2 Challenge 2: Power Generation Equipment Included in Definition of Electric Utility

Third-party owned systems may fit the definition of a utility in states where regulations or legislation defines electric utilities as those that use power generation equipment for purposes other than personal use. This is because third-party developers own solar PV equipment that generates power sold to the site host. Developers who worry that third-party owned systems could be interpreted as utilities may choose not to install projects in these states.

Both Nevada and Oregon have dealt with the issue of third-party owned systems meeting the definition of public electric utilities, which included power generation equipment.

4.2.1 Oregon—Regulatory Solution

In Oregon, whether third-party owned systems should be considered public utilities came into question when third-party PPA model developers approached the PUC about net metering. The issue was brought to the Oregon Public Utilities Commission (OPUC) via a Petition for Declaratory Ruling pursuant to ORS 756.450 by Honeywell and PacifiCorp seeking clarity on Honeywell's use of the third-party PPA model. To clarify whether third-party owned systems could net meter, the OPUC considered the definition of public utilities. According to Oregon's net metering law, ORS 757.00, public utilities are defined as:

> any corporation, company, individual, association of individuals, or its lessees, trustees or receivers, that owns, operates, manages or controls all or a part of any plant or equipment in this state for the production, transmission, delivery or furnishing of heat, light, water or power, directly or indirectly to or for the public, whether or not such plant or equipment or part thereof is wholly within any town or city.

Because third-party owned solar PV systems consist of equipment used within the state for the production of power, they may have to be considered as a utility in Oregon. However, whether third-party owned systems provide power "to or for the public" in Oregon is debatable because they would likely only provide power to one or two other users.

The Oregon legislature determined a solution prior to any PUC decision. PUC Order 08-388 found that according to ORS 757.005 a public utility does not include:

> …any corporation, company, individual or association of individuals providing heat, light or power…*from solar or wind resources* to any number of customers (Emphasis added).

Thus, a third-party owned solar PV systems may not be considered a public utility because solar and wind power generation systems are specifically exempt from the definition even though the definition of a utility includes generation equipment.

The OPUC also considered whether third-party owned systems may be considered competitive suppliers. This is discussed in section 4.3.

4.2.2 Nevada—Regulatory and Legislative Solutions

In Nevada, the question of whether third-party owned systems should be regulated came about because they fit the definition of an electric utility, according to Nevada Statute 704-020, which defined a utility as:

> any plant or equipment, or any part of a plant or equipment, within this State for the production, delivery or furnishing for or to other persons…. power in any form.

Thus, a third-party owned system could be deemed a utility because the equipment used to produce power is ultimately furnished "for or to other persons."

On November 20, 2008, the Public Utilities Commission of Nevada (PUCN) formally addressed the issue of third-party owned systems, ruling in favor of third-party ownership (IREC 2008a). According to the findings, which were a result of a PUCN vote to expand a net metering docket to include the issue of third-party ownership, third-party owned systems are not utilities even though they use power generation equipment. In addition, the PUCN found in their Report on Third Party Ownership of Net Metering Systems in Nevada, that third party owners of net-metered renewable energy systems are not public utilities and beyond the jurisdiction of the Commission. The PUCN noted in its comments that allowing third-party ownership of net-metered systems is consistent with state policy goals to encourage the development of, and private investment in, renewable energy resources, stimulate economic growth in Nevada, and enhance the diversification of energy resources (IREC 2008a).

Notably, Nellis Air Force Base in Nevada had the largest U.S. solar PV system to use a third-party PPA model even before third-party ownership was allowed without regulation in the state. Nellis contracted with MMA Renewable Ventures to provide a third-party PPA for a 14-MW solar PV array (WAPA 2008). According to conversations with the PUCN,[9] Nellis accomplished this because it is operated by a federal agency that has special exclusions in the state and as such can choose where to purchase electricity.

Finally, the 2009 Nevada legislature passed, and the Governor signed Assembly Bill 186, which, like Colorado's legislative regulatory solutions, codifies the exemption of third party developers from regulation. The pertinent language is as follows:

> Persons who for compensation own or operate individual systems which use renewable energy to generate electricity and sell the electricity generated from those systems to not more than one customer of a public utility per system if each individual system is:
>
> (a) Located on the premises of another person;

[9] Telephone conversation with Tammy Cordova, Assistant General Counsel, Public Utilities Commission of Nevada, September 23, 2008.

> (b) Used to produce not more than 150 percent of that other person's requirements for electricity on an annual basis for the premises on which the individual system is located; and
>
> (c) Not part of a larger system that aggregates electricity generated from renewable energy for resale or use on premises other than the premises on which the individual system is located As used in this subsection, "renewable energy" has the meaning ascribed to it in NRS 704.7811.

4.2.3 Applicability Elsewhere

Nevada's regulatory solution could be applied in states in which the definition of utility includes the use of power generation equipment to supply electricity to other persons or entities. Similar to Oregon's solution (discussed in section 4.4), Nevada also looked to state policy goals, which support renewable energy deployment, to guide their own regulatory decisions.

4.3 Challenge 3: Definitions and " Competitive Service Suppliers"

Regulatory uncertainty for third-party owned systems may arise when the definition of either "provider of electric services" or "public utility" does not explicitly exempt third-party owned PV systems. Competitive suppliers provide electricity to customers within deregulated or hybrid electricity markets, where customers can choose their electricity supplier. However, a vague definition of a competitive supplier may lead to confusion about whether third-party owned systems require regulation as they too provide some degree of service to the site host, usually in the form of operations and maintenance. Also, in regulated markets, the definition of public utility might not clearly exempt third-party owned systems. This is the case in New Mexico, which is examining the issue.

4.3.1 Oregon—Regulatory Solution

Oregon, which has a semi-regulated retail electricity market, addressed the issue of the regulatory uncertainty surrounding the use of third-party owned systems via a PUC decision. The question for Oregon was whether a third-party provider qualified as an electrical service supplier—Oregon's term for a competitive supplier. Oregon Legislative Statute 757.600 defines an "ESS" as:

> A person or entity that offers to sell electricity services available pursuant to direct access to more than one retail electricity consumer.

"Direct access" is defined as:

> The ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission . . . directly from an entity other than the distribution utility. (OPUC 2008)

Because third-party owners—who do sell electricity to hosts of solar PV systems and may sell to more than one retail electricity customer—would be considered electrical service suppliers under Oregon legislation and would need to be regulated by the state's public utilities commission. As discussed previously, the regulation as an ESS (or utility) is a disincentive to develop third-party owned systems.

In Order 08-338 entered on July 31, 2008, the OPUC interpreted the definitions and statutes in a manner they felt met the legislation's intent (OPUC 2008), especially because the legislation was designed to increase renewable energy generation. To be considered an ESS in Oregon, the entity must provide "direct access" and use the utilities' distribution system. Entities are considered to provide "direct access" if they provide both electricity *and* "ancillary services," which are defined as:

> Services necessary or incidental to the transmission and delivery of electricity from generating facilities to retail electricity consumers, including but not limited to scheduling, load shaping, reactive power, voltage control and energy balancing services. (OPUC 2008)

The OPUC recognized that ancillary services—which relate to the management of electric power delivered through the transmission and distribution grid—did not apply to the third-party owners who generated power on the customer's side of the meter and did not use the distribution system (OPUC 2008).

Even though most third-party owned PV systems participate in net metering in Oregon, DG systems there usually generate between 0.05% and 18% of the total electricity used in the state (OPUC 2008)."As such, the third-party owned PV systems are not intended to be annual net generators and are thus not considered energy wholesalers, which would require the ancillary services of the distribution system (OPUC 2008). Systems typically produce less than the customer's annual electricity use because any net excess generation will not be credited to the site host. Rather, it is credited to the utility's low-income assistance program. In addition, the net metering limit on a project is 25kW for residential systems and 2MW for commercial systems.

4.3.2 Applicability Elsewhere

Oregon's solution has the potential to be applied in other electricity generator and supplier markets in which third-party owned systems are in conflict with the definition of a competitive supplier or public utility. Clarification that third-party owned systems are not considered competitive suppliers or utilities is important as both are regulated by the state PUC making doing business too difficult for third-party providers. In Oregon, public utility officials were supported by legislation that guided state policy on renewable energy generation. Having state legislation that explicitly encourages the deployment of renewable energy could help steer regulatory decisions made by utility commissions.

4.4 Challenge 4: Munis and Co-ops Resisting Opting into Deregulation of Electricity Generation

As discussed earlier, many of the challenging issues surrounding the regulation of third-party owned systems arises in regulated retail electricity markets, where they could be viewed as being in competition with monopoly utilities. However, in some deregulated retail electricity markets, municipal utilities and cooperatives were not required to deregulate. Thus, within the service districts of those munis and co-ops, third-party owned systems could be seen as being in competition with these local, smaller utilities. This is the case in Texas, which has not attempted to address the issue.

4.4.1 Texas—No Solution

Texas presents an interesting case regarding the regulation of third-party owned systems within the jurisdiction of municipal utilities and co-ops that, per usual, were not required to deregulate. Thus, in most of Texas, the third-party PPA model can be used as a financing mechanism. However, this financing mechanism only makes sense when the third-party PPA owner is not producing more electricity than it consumes, as net metering is not allowed anywhere in the state. In addition, in jurisdictions such as Austin and San Antonio where municipal utilities supply the electricity, third-party PPAs may not be an option (Cory, Coggeshall, and Kollins 2008).

The Texas Utilities Code Section 40.053(a) says:

> If a municipally owned utility chooses to participate in consumer choice, after that choice all retail customers served by the municipally owned utility within the certificated retail service area of the municipally owned utility shall have the right of customer choice …, and the municipally owned utility shall provide open access for retail service.

Though the Texas PUC has made no formal statement on the matter, municipal utilities are concerned they might open themselves to competition if they allow generators to sell electricity to their customers. Even though these utilities may want to allow the third-party PPA model to facilitate the adoption of solar power, they will not risk inadvertently exposing themselves to deregulation and competition in their service territory.

However, the third-party PPA developer could create a contract with the utility that would effectively allow the utility to buy the electricity and resell it to the site host. This solution, which is described in detail in section 5.2.1, requires that utilities work with customers and developers on a project basis. It also requires that utilities act as silent intermediaries and do not create administrative or cost barriers that might reduce the appeal of using the third-party model.

4.4.2 Applicability Elsewhere

Although no solution has been found, this challenge could arise in other states that have fully or partially deregulated electricity markets and where munis and co-ops worry that by allowing for third-party owned systems, they will open themselves up to competitive suppliers. However, the municipal utility regulators (usually the city council, which is often also the utility's board of directors), state regulators, or state legislators could make a regulatory or legal exception for using the third-party PPA model. And as discussed previously, alternative solutions such as using the utility as a contractual intermediary might be an option for developers wanting to use the third-party PPA model in Texas or other states in similar situations.

4.5 Challenge 5: Net Metering

Allowing third-party owned systems to net meter could facilitate the deployment of solar PV systems because the on-site generation reduces electricity purchased from the utility and any excess is credited to the customer bill. However, in some states, third-party owned systems may not meet the definition of facilities or customers that are allowed to net meter. Net metering has been problematic for third-party owned systems in at least two states, New Jersey and Texas, and only New Jersey offers a (somewhat vague) solution.

Neither New Jersey nor Texas has explicitly addressed whether third-party owned systems are allowed to net meter; however, both states demonstrate how the interpretation of regulations or legislation can alter whether third-party owned systems are allowed to net meter.

4.5.1 New Jersey—Legislative Solution

New Jersey does not have legislative or regulatory language that determines whether third-party owned systems are allowed to net meter. However, New Jersey Administrative Code 14:8-4.2 and 4.3, which outline changes to net metering and interconnection rules, (Docket #: EX08070548) define a "customer-generator facility" as:

> …the equipment *used* [italics added] by a customer-generator to generate, manage, and/or monitor electricity. A customer-generator facility typically includes an electric generator and/or an equipment package.

New Jersey's definition stipulates that the equipment need only be used by the customer; i.e., a customer-generator allowed to net meter is not required to own the generation equipment, and third-party owners are allowed to net meter (Keyes 2008).

4.5.2 Texas—No Solution

In Texas, where the retail electricity generation market is deregulated, the PUC claimed that *requiring* net metering is incompatible with deregulation, thus making the third-party PPA model financially less attractive as carrying excess generation forward would not be possible.

4.5.3 Applicability Elsewhere

New Jersey's regulatory solution in which the PUC determined eligible customers only need to use the power generated by the facilities (regardless of ownership) could be applied in any state determining which kind of facilities are eligible to net meter. However, as noted previously, New Jersey was able to look to state legislation that clearly supports renewable energy deployment and make decisions in a consistent manner with the legislation. Thus, having state legislation that can serve as a guideline for PUC officials may help to create state regulations that support net metering for third-party owned/PPA financed systems.

Overall, implementing third-party PPA model financing is difficult in states where unclear legislation or regulations could result in the regulation of third-party PPA owners. Munis and co-ops might be concerned that allowing third-party owned systems to sell power to their customers will open their service territories to deregulation. The third-party PPA model is also problematic in states that do not explicitly allow net metering of third-party owned systems. Finding a one-size-fits-all policy solution is not possible when states not only define differently utilities and other competitive supplier, but also put in place different rules about what they can legally supply or how many customers they can serve. However, more parties are seeking resolution to these issues as evidenced by recent rulings in Colorado and Nevada, and a docket filing in Arizona.

See Appendix C for a summary of all the language variations explored in this section.

5 Alternatives to the Third-Party PPA Model

In cases where states have ruled against the third-party PPA model or where legislative change or PUC decisions are not feasible, the following alternative solutions may be applicable. Additionally, Clean Renewable Energy Bonds (CREBs) provide a potential alternative for munis and co-ops and are discussed in Appendix D.

5.1 Third-Party Ownership Solar Leases

The third-party solar lease model is sometimes called the solar services agreement (SSA) model. Like the third-party PPA model, it benefits from having a third party finance and own the solar energy system.

The solar lease is a relatively new way to provide customers access to on-site solar energy systems, however, the concept is the same as traditional equipment leases. Instead of purchasing a PV system, the customer enters into a service contract with a lessor (the owner) of a PV system and agrees to make fixed monthly lease payments (regardless of system generation) over time (Coughlin and Cory 2009). The customer consumes whatever electricity the leased system generates, net meters any excess or pays the utility rate for any additional electricity it requires.

5.1.1 Benefits of the Solar Lease

The benefits of the solar lease mirror most of those associated with the third-party PPA model, including transferring most or all of the up-front cost, using a developer who can partner with a tax equity investor to take advantage of federal tax incentives, and if indicated in the contract, transferring maintenance responsibilities to a qualified party. However, the price of electricity will differ somewhat because the customer effectively pays a set price for the equipment (and sometimes maintenance) and not the electricity itself. Ideally, monthly electric bill savings will equal, if not exceed the lease payments (which take into account available state and federal incentives) to create a cash neutral or cash positive transaction. Figure 3 presents the parties involved in the solar lease.

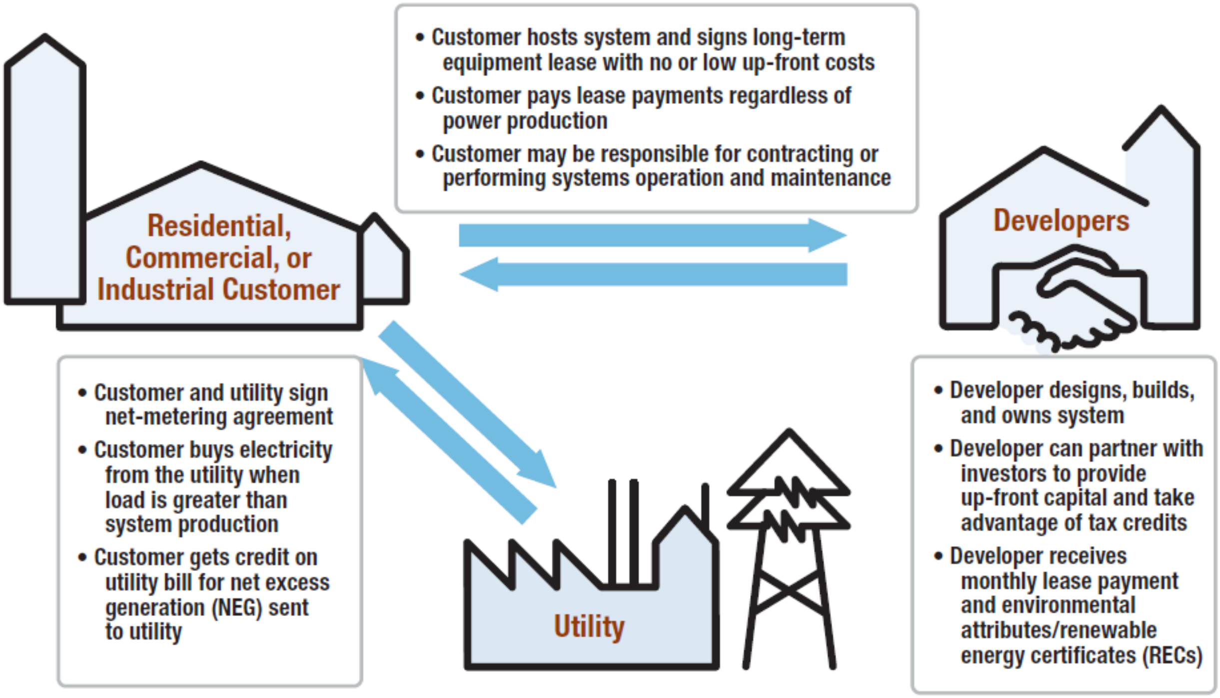

Figure 3. Solar lease structure (aka solar services agreement)

If the customer purchases a maintenance package, the solar leasing company may monitor the systems in real-time to detect issues and provide prompt resolution. Additionally, a solar lease may come with a performance guarantee to make the customer more comfortable with the arrangement (SolarCity 2008).

To make the projects economic (with lease payment levels close to the customer's retail utility rate), developers typically require that either they receive the RECs or that the RECs are sold to the utility (which may have an RPS requirement). As previously mentioned, many utilities mandate that they receive the RECs from those projects where they have contributed rebates and financial incentives (Holt et al. 2006). These up-front cash incentives exchanged for the environmental attributes generated by the PV system can be an important revenue stream to make the project economic. This is especially true with smaller residential projects.

5.1.2 Challenges with the Solar Lease

Under the solar lease model, more risk may be transferred to the customer and away from the developer compared to the third-party PPA model. The developer receives a fixed lease payment regardless of whether the system is operational and independent of the electricity produced. Operations and maintenance risks are therefore transferred to the customer unless maintenance services or operational guarantees can be procured from the developer or another provider. The customer may be responsible for property insurance for the system, which could be added to homeowner's insurance or an existing property policy. The developer, on the other hand, is responsible for insuring the construction and operation of the system; their policies may include workers' compensation and auto, business interruption, and liability insurance. Because large developers have established insurance relationships, they receive more favorable rates than do onetime residential or commercial customers looking for solar PV insurance.

In addition to taking on the previously mentioned risks, some types of customers also face more financial challenges with solar leases than they do with the third-party PPA model. Owners of systems sited on property owned by governmental entities or non-profits, including schools, are not eligible for the ITC (SEIA 2008). This removes a large incentive to the developer and in turn raises required lease payments for the customer. Another important financial challenge for the solar lease model regards the estimation of a system's electricity production. If estimates of solar PV system production are not accurate, the customer may pay more for the electricity on a levelized basis ($/kWh) than if had they entered into a PPA.

Notably, the solar lease (solar services agreement) model involves a traditional sale/leaseback arrangement between the developer/operator of the system and the tax equity partnership established to monetize the federal tax credits and use the accelerated depreciation. For the investor to receive the tax benefits, the agreement between its lessee and the host customer must be a *service* agreement (hence, the SSA), and the recipient of the service agreement cannot operate the system or stand to face significant financial loss or gain in case the system does not perform as predicted. Were the host customer to sublease the system, it would arguably be taking on the operation of the system (the definition of lease tends to include the lessee's "control" of the leased asset). Moreover, because lease payments are typically fixed, the host would either gain if the system overproduced or lose if the system under produced.

A direct lease—under which the solar developer owns the system and leases it to the host customer—is not feasible for most developers because neither the developer nor the host/lessee would be able to fully realize the benefits of the federal incentives. Solar developers, as system owners, typically do not have the tax appetite to realize the benefit of either the ITC or accelerated depreciation. The solar developer could pass the ITC (but not the accelerated depreciation) through to the host/lessee, but one-half of the ITC would be treated as taxable income to the host. Even in this pass-through scenario, the developer still holds the essentially worthless depreciation benefit. Thus, most of the benefit of the incentives would be lost making the project more costly or economically unreasonable.

It should be noted that, like the third-party ownership/PPA model, the solar lease could also face regulatory challenges. However, this appears not to be as common of a challenge as it is for the third-party PPA model. An example of the solar lease facing regulatory changes occurred in Nevada, where the Public Utility Commission of Nevada did not believe that the third-party PPA model or the solar lease structures are legal under Nevada law. The staff was also concerned with consumer protection if these third parties were not regulated. Further, they felt the Commission should implement rules that govern rates and fees as well as contractual obligations (PUCN 2008).

5.1.3 Applicability of the Solar Lease: Florida and Texas

The solar lease appears to be acceptable in those states that define a utility or load serving entity (LSE) as an entity that sells "electricity." With a solar lease, the owner leases the equipment and does not sell the electricity, which most states find to be an acceptable arrangement.

In Florida, the FPSC went so far as to rule in favor of a solar lease structure in the Monsanto case of 1987 (FPSC 1987). In that case, the Commission stated that there was no *sale of electricity* because Monsanto was leasing equipment that produced electricity rather than buying electricity that the equipment generated. The terms of the lease were the most important factor in this ruling:

> The lease payments would be fixed throughout the term of the lease. These payments, based on a negotiated rate of return on the lessor's investment, would be independent of electric generation, production rates, or any other operational variable of the facility. Thus, lease payments would continue to be due during either planned or unplanned outages of the facility.

This puts the operating risk on the customer instead of the third party, which the FPSC found to be a completely different transaction than the third-party PPA model where the risk was born by the third-party. Although this operational risk requirement is applicable in Florida, other states do not carry this stipulation, and O&M can be performed by the third-party owner, often with some sort of performance guarantee.

For the financial challenges with the federal tax credit and accelerated depreciation, the solar lease may be a good option in electricity markets where the legality of third-party owned systems is uncertain. However, it is not an option for projects on government or non-profit property (including schools) as the benefits of the ITC cannot be realized. In places such as Florida and possibly Texas where the third-party owned systems are not legal or cannot net meter, the solar lease may be a good financial alternative because the lease finance structure does not appear to face the same legislative barriers (specific situations should be checked with legal counsel). Because the solar lease is competitive cost-wise with the third-party model, it does not pose a real loss to those looking to install solar PV systems on property located in electricity markets where the third-party PPA model cannot be used.

Table 1. Incentives and Project Responsibilities for Solar Financing Mechanisms

Financing Mechanisms	**Self-Financing**	**Third-Party Ownership PPA**	**Solar Lease**
Incentives			
State Cash Incentive (production-based or upfront)	Yes	Yes	Yes
Use of Federal ITC	Requires large tax liability	Yes	Yes, except on government or non-profit property
Accelerated Depreciation	Yes	Yes	Yes, except on government or non-profit property
State Tax Credits	Yes**	Yes**	Yes**
Responsibilities			
Upfront Costs	Yes	No*	No
O&M	Yes	No	Yes, unless contracted to the developer

* The lower the up-front costs, the higher the price of electricity, therefore up-front costs depend on the contract arrangement between the third-party owner and the customer to meet the goals of both parties.
** Requires a larger tax liability within the state the system is located.

5.2 Other Alternative Solutions

When statutory interpretation is unclear with regard to third-party PPA models, it might make sense to consider variations of this model or alternative arrangements. Customers interested in solar PV systems and developers looking to enter new markets can explore the following alternatives to the standard third-party PPA model.[10]

5.2.1 Utilities as Silent Contractual Intermediaries:

If the utility is willing to work with customers and developers on a project-by-project basis, the project developer may sign a PPA with the customer's *utility* then have the utility sell the electricity back to the customer. With this potential solution, the utility is a silent intermediary in the third-party PPA model and only transfers the sales and purchases on paper, while the actual electricity is used directly by the customer. This process would likely require some standardization within the utility if it were to be deployed for more than a few projects. One potential concern with this model is that it turns the developer into the wholesaler of electricity, which could subject the developer to FERC regulation. While this regulation is workable and

[10] This does not constitute legal advice, and it should not be considered as such; a full legal opinion from your attorney, specific to your situation, should be obtained.

common in many states, it puts additional responsibility on the developer. Moreover, the retail transaction between the utility and the customer could be subject to regulation.

This solution, which clearly requires that the utility be interested in promoting solar resource development, is an important potential option for a regulated utility concerned about opening themselves to competition, as is the case for municipal utilities in Texas. Because of increased transaction costs, the structure may not come with pricing as favorable as the third party PPA model, but it could be an important solution when legal questions surround the third-party PPA model.

5.2.2 Standardized Third-Party PPA Contract Language

Many states noted that it would be in the customer's best interest to have standard rules and contract clauses in place that must be part of the third-party PPA. This would help ensure that customers receive a fair deal and are not paying hidden fees or signing up for services of which they are not aware. A standard contract approved by the PUC would leave less room for interpretation of legality down the road, but developers and their bankers might view it as a form of regulation.

5.2.3 Utility Owns Customer Sited Generation Assets

With the recent change to the federal ITC that allow utilities to take the 30% up-front PV tax credit (H.R. 2008), more tax-paying utilities may choose to own PV. Although these utilities may choose to build and own large-scale solar plants, they can also finance customer-sited DG and sell the power back to host customers. In this instance, the utility effectively takes the place of the third party in the third-party owned PPA model. If the model is properly structured, the customer can enjoy the same benefits of fixed-price power at or below utility retail rates, and the utility can take advantage of the tax credits. However, some argue that utility costs of developing customer-sited solar projects could be higher than costs available in the competitive marketplace. In addition, some suggest it is not fair or efficient to allow a utility to be the sole provider of a service that is a competitive offering in many states.

5.2.4 Utility- and PUC-Waived Monopoly Rights for Distributed Generation (DG)

Although not typical, monopoly utilities might be able to waive their monopoly rights and allow third-party owners to participate in their service territories if their regulators support this structure. Xcel Energy and their regulators in Colorado used this as an interim measure before the legislature passed a law allowing the third-party PPA ownership model.

To meet Colorado's RPS requirements, including the 4% solar set-aside, Xcel Energy (in agreement with their regulators) waived their monopoly rights on specific projects that provide it with RECs for compliance. For systems over 100 kW, Xcel holds a competitive solicitation and selects winning proposals in order to comply with the Colorado RPS solar set-aside. Colorado also requires that 50% of the solar set-aside be customer-sited (DSIRE 2008a), and Xcel has found the third-party ownership structure to be an effective way of meeting that goal. However, Xcel provides this waiver for only those projects that are selected in its solicitation and that provide it with RECs for its compliance obligations (Mignogna 2008). This makes the utility the absolute power and "sole arbiter" of which providers are allowed to serve the market for commercial-scale systems using the third-party PPA model. For projects from 10kW to 100kW, Xcel has a standard rebate offer but only for projects that supply it with RECs. For the under 10-

kW "residential" segment, Xcel runs another standard rebate offer but requires that the customer own the system.

Table 2 illustrates the wide range of solutions previously discussed. Legislative or regulatory changes to allow the third-party PPA model might be out of the control of third-party developers or the customers who desire their services, but both variations to the traditional model or entirely different alternatives are possible. Some of the variations will require a ruling by a governing body (registration of DG service providers and standardized third-party PPA contracts), while others can be implemented in many jurisdictions without any legal issues.

Table 2. Summary of Attributes of Alternative Solutions to Third-Party PPAs

Attributes of Alternative Solutions	**PPA Parties**	**Low/No Up-front Costs**	**System Maintenance Responsibilities**	**Monthly Payments**
Solar Lease	No PPA, just flat lease fee	Yes	Customer, unless contracted to the developer	Fixed
Developer Sells Power to Utility	Third-party sells to the utility, which sells to the end-use customer	Yes	Third party	Based on electricity usage
Utility Owns Customer Sited Assets	Utility sells to end-use customer	Yes	Utility	Based on electricity usage
Standardized Third-Party PPA Contracts	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Clean Renewable Energy Bonds (Municipal utilities)	Customer (govt. entity) owns the system	Must pay issuing costs	Customer, unless contracted	None *

* Annual principal payments were required for CREBs before 2009.

Table 3 indicates in which states the five major regulatory challenges to the third-party ownership/PPA model have occurred, as discussed in Section 4, and the solutions that have been applied or are possible.

Table 3: Summary of Solutions to Third-Party Ownership Regulatory Challenges

Challenge / Solutions	1. Definition of Electric Utility Includes Seller of Electricity	2. Definition of Electric Utility Includes Power Generation Equipment	3. Definition of Competitive Supplier or Utility Includes Provider of Electric Services	4.Munis and Co-ops Concerned with Opting into Deregulation of Retail Electricity Generation Markets	5. Third-Party Owned Systems May Not Net Meter
PPA Solutions					
Clarify third-party owned systems are *not* utilities or competitive service suppliers	CO	NV		**	
Exempt non-conventional generation (including solar) from definition of electrical corporation or public utility	CA	OR (solar and wind only)			
Rule third-party owned systems are legal and do not require PUC regulation	CO	NV		**	
Decide third-party owned systems do not provide direct ancillary services			OR		
Allow net metering for systems *used* by customer-generators					NJ
Alternative Solutions					
Solar Lease (except for government or non-profit entities)	*	*	*	*	*
Developer Sells Power to Utility	*			*	*
Utility Owns Customer Sited Assets	*	*	*	*	*
Clean Renewable Energy Bonds [a]	*	*	*	*	
Utility and PUC Waive Monopoly Rights [b]	*	*	*		
Waiving of DG registration	*	*	*	*	

State abbreviations indicate that this solution has been applied there.
* Indicates a probable solution with no barriers identified.
** Indicates a possible solution that requires further investigation
[a] This solution is only applicable for state and municipal solar PV installations that apply to the IRS for an allocation.
[b] This solution, which requires PUC and utility approval, is possible but not as feasible as other alternatives.

6 Summary

Of the states that have examined the legislative and regulatory issues with the third-party PPA model in recent years, most have accepted the structure as sound and clear of conflict with utility rights. This is true whether states deregulated their retail electric generation market or not. However, most states have not clarified the use of this model, and therefore it may not be clear whether this structure can be used. Of the cases investigated, no two states have had the same specific situation (language and regulating body, for example) regarding the regulation of third-party owners, which defies a single solution that will work everywhere. However, lessons from the examples in this report could be used in other states that wish to address the issue of regulation of the third-party PPA model.

Several regulatory challenges exist for the third-party PPA model. The first challenge occurred when state legislation or regulations defined electric utilities as sellers of electricity. Because the owners of third-party systems using a PPA sell their electricity to site hosts, these systems may be interpreted as being electric utilities and would therefore require PUC regulation. This issue has arisen in Colorado, Florida, and Arizona. However, Colorado and California determined that third-party owned systems using PPAs are not utilities or electrical corporations, and that non-traditional sources of power generation are exempt from being considered as utilities. Florida's ruling, which occurred in 1987, has not been revisited. The second challenge occurred when the definition of electric utilities included power generation equipment, such as solar PV, and thus required regulation. Solar developers in Nevada and Oregon who were using the third-party PPA model encountered this challenge, but PUC regulators in those states clarified that third-party owned renewable energy generation systems (solar and wind only, in the case of Oregon) using a PPA are not considered to be public utilities.

A third type of challenge occurred in Oregon, where the definition of competitive service suppliers (or ESS under Oregon's definition) and utilities came into conflict with third-party ownership. Oregon legislation defined an ESS as a seller of electricity that provides direct access and ancillary services. Nonetheless, the State of Oregon determined that third-party owned systems using a PPA are not electrical service suppliers because they do not provide ancillary services. The fourth challenge occurred when munis and co-ops were concerned they would open their service territories to deregulation of electricity markets if they allowed the third-party PPA model. This challenge has occurred only in Texas where the remainder of electricity markets is deregulated. Texas has not addressed this issue and has no plans to do so. The fifth and final challenge, which has been identified in New Jersey and Texas, occurred when third-party owned systems were not allowed to net meter. Texas has not resolved this issue, but New Jersey regulations allow net metering for all systems "used" by customer-generators, thus they do not have to be owned by the customers.

All of the solutions found here could be applied in regulated, hybrid, or deregulated markets. The solutions could be applied to a number of challenges. Lastly, in a few cases, PUC officials looked to their state's policies/goals for renewable energy deployment when making regulations favorable to third-party owned systems.

Other solutions include variations of the third-party PPA model, many of which also require legislative or regulatory approval. For example, states can allow a standardized third-party PPA contract. Other variations of the third-party PPA model do not require legislative approval but focus on the utility. For example, a developer may sell power to the end user via the utility as a contractual intermediary, allowing the utility to remain the only seller of electricity. In addition to these other regulatory solutions, effective financing mechanisms can be employed in jurisdictions where the third-party PPA model is unavailable. Under the most common of these, the solar lease, the customer does not pay for the equipment but receives the electricity generated from that equipment. However, this option is not available to government or non-profit entities. CREBs are available to state and local governments including co-ops and munis, that apply for and receive an allocation from the IRS, which allows them to finance and own solar PV without major up-front costs.

States that want to support renewable energy—and feel that adequate consumer protection provisions are in place—might want to consider explicitly allowing third-party owners using PPAs to be unregulated. The third-party PPA model provides benefits to customers who are interested in solar PV but do not want the up-front costs or maintenance responsibilities. The third-party PPA model can be an attractive financing option, and it has spurred solar PV growth in states where it is available. It also promotes market discipline and is instrumental in driving the cost of solar energy down. For these reasons, states may consider allowing third-party electricity sales as one way to meet their renewable energy, solar, and distributed generation mandates and goals.

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Appendix A: Overview of Third-Party PPA Model

Recently, attributes of the third-party PPA have popularized this model for financing new PV installations. The benefits (and challenges) of this model, which are outlined below, apply to both residential and commercial customers. Implications of using the model vary and depend on customer type.

Minimal Up-Front Costs

A primary benefit of the third-party PPA is that it dramatically reduces or eliminates up-front costs for commercial, industrial, and residential customers by transferring the up-front capital costs of the solar PV system to entities set up to use numerous revenue streams from the system; and, the third-party PPA potentially does this with lower costs of capital. Developers can eliminate the need for customers to provide up-front capital by finding capital to buy the systems, by either purchasing them outright or securing financing for most of their capital costs. The PPA contract payment level established by the customer and developer determines the amount of up-front cost, if any to the customer.

Project Financing Expertise

Solar energy developers participate in the niche tax equity financing market and form relationships with banks that have tax equity financing divisions. Because this is the developer's line of business, they are well equipped to manage the process and can usually find capital at lower costs than homeowners can or businesses can. However, the recent financial crisis in the United States has consolidated or eliminated many participants in the tax equity market, while others have scaled back as they have less taxable income to offset. Therefore, there are fewer tax equity investors in renewable project financing than before. The remaining players in the tax equity market are increasing their return on capital requirements and focusing on projects with low counterparty risk (Chadbourne & Parke 2009).

Efficient Use of Tax Credits

As mentioned earlier, a number of available tax credits encourage the installation of solar PV. However, only certain entities can take advantage of these financial incentives, and commercial businesses with taxable profits often have the most to gain. Third-party developers are set up to allow investors in their business to take advantage of incentives in the form of tax credits, thereby allowing them to use both more and higher-value incentives than traditional businesses or homeowners are able to use.

The most salient examples, the ITC and the residential tax credit, are only available to a homeowner or business with taxable income. A homeowner or commercial entity whose tax bill is not large enough to absorb the entire tax credit—even with the credit carried forward—cannot take advantage of an incentive that potentially offsets 30% of the up-front capital cost. The residential and non-tax paying customers are at a disadvantage because neither can use the Modified Accelerated Cost-Recovery System (MACRS) depreciation tax benefit. This means that the project owner must have predictable profits large enough to offset the depreciation benefits (MACRS) and tax credits they receive from the project.

By contracting with developers who can take advantage of these incentives and credits, certain customers can now realize cost savings that would have not been possible had they themselves purchased and owned the systems. The cost savings are subsequently passed from developers to customers in the form of lower electricity rates (equivalent to the system output).

Removal of Maintenance Responsibilities

For the most part, the businesses and residences that are installing PV do not have expertise in solar array maintenance and operations. With the third-party PPA model, the ownership and responsibility of the system is placed on the developer and not on the customer, who pays only for the electricity generated. If the system does not function properly, the customer does not pay for repairs or for the electricity. Ultimately, the customer just purchases more electricity from the utility. This arrangement provides a revenue incentive for developers to maintain their system because they are not paid unless the system produces power.

Predictable Costs in Volatile Electricity Markets

Both residential and business customers are looking at ways to reduce electricity costs and incorporate predictability in their future electricity expenditures. The third-party PPA model allows a customer to avoid some of the large rate increases seen across the nation in recent years (Smith 2008) by providing a contract with a pre-determined price for 20 to 25 years.

When businesses with large power needs are considering ways to reduce expenditure risk, locking in prices with suppliers via long-term contracts is an excellent way to manage this line item. Often these contracts start with electricity rates that are competitive with the utility retail rate for that customer and may remain constant or contain an annual escalation factor of 3 to 3.5% (Cory, Coughlin, and Coggeshall 2008). With this stability, businesses can plan a portion of their energy expenses with certainty, and project investors can count on a revenue stream as long as they maintain system performance.

The financial efficiency of the third-party model greatly increases opportunities for commercial, industrial, and government customers to use solar resources on-site. As a result of this expansive market, solar energy costs are driven down through volume purchases of equipment and efficient construction and installation methods.

Non-regulatory Challenges with the Third-Party PPA Model

Some challenges with the third-party PPA model are beyond the regulatory challenges examined in the body of this paper. One such challenge is determining whether the utility is entitled to the RECs. In net metering situations, some states have pre-determined whether the customer or the utility has rights to the RECs. The majority side in favor of the customer retaining the RECs, especially for generation associated with the customer’s load (vs. net excess generation). However, if the utility contributes financial incentives or rebates to a project, the utility or their regulator might require the RECs to be transferred to the utility (Holt 2006). One exception is the California Solar Initiative (CSI), which does not require the surrendering of RECs as a condition for receiving financial incentives or rebates (California Public Utilities Commission 2009, DSIRE 2009).

In the case of the third-party PPA model, the developer typically sells the electricity to the customer and retains the RECs or more valuable solar RECs (SRECs) for sale into the REC market. The sale of SRECs helps the project make the necessary returns and allows the developer to offer the customer a price competitive with grid-supplied electricity. To claim they are “solar powered," customers must purchase all or a portion of the SRECs from developers. In states with an RPS with a solar set-aside, which usually significantly increases the value of SRECs, the removal of SRECs from the deal can make the project uneconomic. However, customers do have other options in some cases. For example, federal agencies in regions with active REC markets often buy wind or landfill gas RECs for less on the open market, which allows them to retain the renewable energy claim (just not a "solar" energy claim) while taking advantage of high SREC prices (Cory, Coughlin, and Coggeshall 2008).

The contract states the customer's options in the event they sell their property. Because the third party has taken on the credit risk of the initial customer, the new occupant is not automatically entitled to assume the terms of the contract; the new occupant often must meet a credit check and other requirements. In addition, some contracts have buy-out clauses that allow the customer to buy the system and sell it with the building. Some jurisdictions, such as Colorado, are beginning to address these issues in their rules governing customer-sited solar resources.

Appendix B: Solar Laws, Financial Incentives, and Policy Background

A successful solar installation involves logistical and economic prerequisites, including net metering laws, interconnection standards, financial incentives, and federal and state policies requiring incremental renewable generation.[11] All these must come together to ensure an economically viable project.

Connecting Solar Energy Systems to the Grid

The financial incentives discussed in the body of this paper help only when the state where the solar energy system is installed has the appropriate net metering and interconnection standards. Net metering and interconnection, which ensure that systems are adequately sized, safe, and affordable, are discussed below and in detail in the Interstate Renewable Energy Council's (IREC) 2008 annual report and in "Freeing the Grid" (NNEC 2008).[12]

Interconnection Standards

Interconnection standards govern the technical and procedural process by which an electric customer connects an electric-generating system to the grid. Generally, the distribution utility assesses and approves the customer-generator within the rules established by the public utilities commission based on input from utilities and other stakeholders.

IREC also recommends eliminating any requirement for external disconnect switches because all modern grid-connected systems automatically shut down in the event of a grid failure (NNEC 2008). Such improvements to interconnection standards will remove logistical barriers for small systems and make larger systems operate safely within the grid.

Net Metering

Net metering is the billing arrangement between customer-generators and utilities whereby the customer is credited by the utility for excess electricity that the customer generates. Typically, net metering allows a customer to earn a credit for net excess generation (NEG) produced by the customer's system over a billing period at the utility's wholesale rate, the utility's avoided cost, or the customer's retail rate. Essentially, the customer can use credit obtained through past NEG in one billing period toward electricity consumed in future billing periods.

IREC's best practices with respect to net metering include (1) removing size limits and customer classes from net metering, (2) allowing monthly carryover of NEG credited at the utility's full retail rate, and (3) standardizing net metering standards across the state without regard to the type of utility to make rules simpler and clear to all market participants (NNEC 2008). These

[11] The quality of the solar resource (i.e., location) is another critical element to PV projects. However, even in a location with excellent resource, incentives are needed for the project to be economic under current conditions. In fact, incentives can compensate for the differential between poor and great resources to help spur new development. Germany is a world leader in PV despite having a solar resource on par with Alaska's; government incentives make the difference.

[12] *Freeing the Grid* rates and reports the effectiveness of state interconnection standards and net metering standards with the goal of displaying best practices and helping states make incremental improvements and facilitating additional grid-tied solar development.

practices are important as net metering rules can determine a project's size and economic feasibility in many cases.

States' rules and requirements for net metering differ based on whether the customer is a commercial or industrial customer versus a residential customer. The primary element in net metering rules is the allowable size of the systems, which dictate whether customers can install systems large enough to (approximately) meet their load and realize economies of scale. Allowable size varies greatly from state to state—the range stretches from six states that have no net metering laws to New Mexico, which allows up to 80MW, and Ohio, which does not have a limit (DSIRE 2008b). Arizona now allows net-metered systems sized to 125% of the customer's "connected load."[13] The net metering limit in Colorado is 120% of consumption, for the first time breaking from a capacity-based limitation. Figure B_1 shows the states with net metering standards and the allowed system capacity in kilowatts.

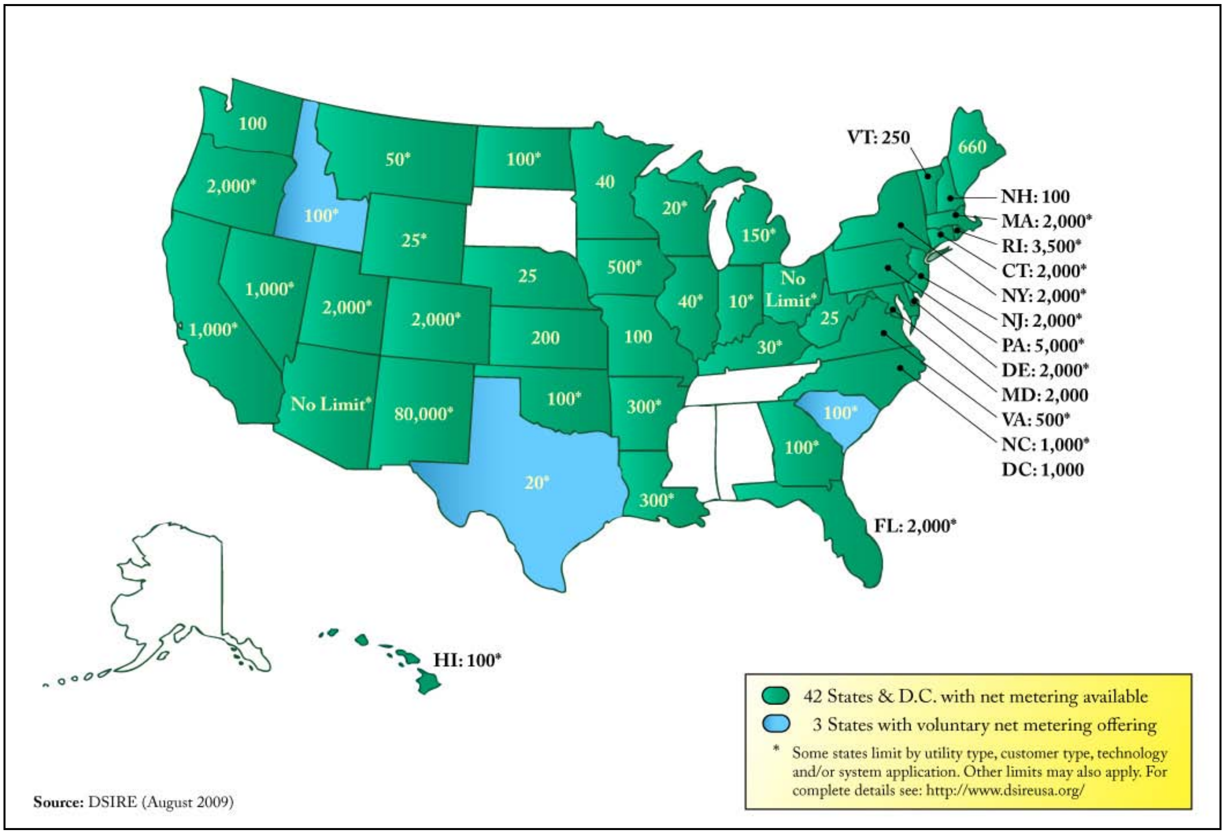

Figure B-1. Map of states with net metering standards (August 2009)

Although many states have net metering limits, they are generally unnecessary because financial mechanisms in most states discourage installation of systems larger than a customer's average load. For example, in many states, customer-generators are not paid for NEG held at the end of a 12-month period. This means that if a customer installs a system that produces more than their average load over the course of one year, they will not receive a financial benefit for overproduction (NNEC 2008).

[13] Connected load means the theoretical maximum a customer could load if all electrical devices were operating concurrently.

Other net metering provisions can discourage solar installations altogether. Because solar energy production varies significantly based on the time of day and the season, a system can produce more than the host site uses—particularly during the day and in sunny months—thereby creating a need for the NEG to rollover into the next month to average out over the course of a year. However, some state's net metering provisions do not allow rollover of NEG each month, thereby reducing the financial incentive to build a system sized to meet the customer's average load over the course of a year (rather than building a system to meet just peak demand). In some states, the customer is forced to pay an overlaying premium on a retail tariff for electricity purchased.[14] These charges can negate some or all of the financial benefit the customer would receive from the solar energy system even though the utility would benefit when the system's peak generation coincided with the utility's peak load.

Financial Incentives

With the proper net metering and interconnection standards in place, financial incentives from federal, state, and local governments, as well as utilities, can make solar power an economically attractive option.

Federal Investment Tax Credit

One of the most important incentives for solar PV is the federal investment tax credit (ITC). The ITC reduces federal income taxes for qualified tax-paying owners based on the capital investment of the solar project. The ITC is set at 30% of qualified expenses and was recently extended through December 31, 2016 (WRI 2008; H.R. 2008, Sec. 103). While the commercial ITC has never had a maximum amount, the 30% residential tax credit had a cap of $2,000 until October 2008 when Congress removed the cap as of January 2009. Additionally, a limited number of entities can take full advantage of the 30% credit. Because the entities must pay federal taxes, not-for-profit businesses, state and federal government agencies, and any other business that do not earn accounting profits are not eligible.[15] Finally, the October 2008 changes to the ITC now allow investor-owned utilities to use the tax credit starting in October 2008, which they were unable to do before.

Accelerated Depreciation

Another critical incentive for solar PV is the federal Modified Accelerated Cost-Recovery System (MACRS), which allows a business[16] to recover investments in property through accelerated asset depreciation, effectively reducing its tax liability. A business can depreciate solar equipment over a five-year period and thereby use this deduction over a time span that is less than the economic life of the equipment (20-30 years) (DSIRE 2008c).

Accelerated tax depreciation provides an incremental benefit equal to about 12% of system cost on a present value basis (assuming a 40% combined effective state and federal tax bracket and a

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[14] This additional premium for net metering, which the state PUC must approve, goes to the utility because they must provide backup power when the customer generator's system does not perform.

[15] Accounting profits refer to the financial statements that companies submit to the IRS. These are different from the statements of cash transactions, which recognize revenue when the service is performed (not when the cash is obtained) and include non-cash expenses like depreciation. As a result, the business may earn a cash profit but have enough taxable expenses (such as depreciation) in a given year to offset taxable income, thereby eliminating profits on an accounting basis even though the business is cash positive.

[16] MACRS is only available to businesses, not residential customers.

10% nominal discount rate). Together then, the 30% ITC and accelerated depreciation provide a combined tax benefit equal to about 42% of the installed cost of a commercial PV system (Bolinger 2009).

Cash Incentives

In addition to federal incentives, a large number of cash incentives are available to solar projects through state, local, and utility-specific financing programs. These programs can be very creative with their incentives, which include grants, loans, income tax and property tax incentives, sales-tax exemptions, and more. The incentives are detailed in the Database of State Incentives for Renewables and Efficiency (DSIRE) maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC), which can be found at http:/www.dsireusa.org/. Some of these incentives are substantial enough to advance solar installations in their respective territories. Because state programs are the most widely available programs and tend to have the most funds available, a state-specific example is presented.

The California Solar Initiative (CSI) is a robust state incentive program. Adopted in January 2006 by the California Public Utilities Commission, the CSI is designed to provide more than $3 billion in incentives for solar energy projects with the objective of providing 3,000 megawatts (MW) of solar capacity by 2016. The program initially offers higher incentive levels, which are reduced over 10 years as utility-specific capacity targets are met.

Incentives are based on project size. When the program began in 2007, “buy downs” (rebates) for systems less than 50 kW were $2.50/W AC for residential and commercial systems, and $3.25/W AC for government entities and nonprofits. Incentives are adjusted based on expected performance of the specific PV system at a particular site. For a system greater than 50 kW, performance-based incentives are paid for the first five years starting at $0.39/kWh for taxable entities and $0.50/kWh for government entities and nonprofits. These incentives ramp down as state-level PV capacity is reached in each California utility’s service territory.

On top of the generous state incentives, numerous utilities in the state offer grants, loans, and rebates to make solar PV even more financially attractive.

State Policies Encouraging Solar

State policies requiring renewable generation known as renewable portfolio standards (RPSs) play a major role in the development of new renewable energy generating assets. Most RPS policies mandate that utilities generate or purchase a certain percentage of electricity from new renewable energy sources on behalf of their customers. States looking specifically to encourage solar power can do so in a number of ways.

The most frequently implemented is a solar set-aside within the RPS (shown in Figure 3). The set-aside dictates the amount of power that must be generated from solar resources in particular. This solar-specific requirement fundamentally helps separate solar from less expensive forms of renewable generation, such as wind and landfill gas. Also, direct solar set-asides and set-asides for renewable DG are available and primarily fulfilled using customer-sited solar.

The “multiplier” is another mechanism to encourage specific types of generation. For each kWh of solar power generated, the utility gets bonus credit towards meeting the RPS requirement.

A number of states have tried multipliers, but they have not resulted in viable solar markets. In fact, many states that tried multipliers have switched to set-asides.

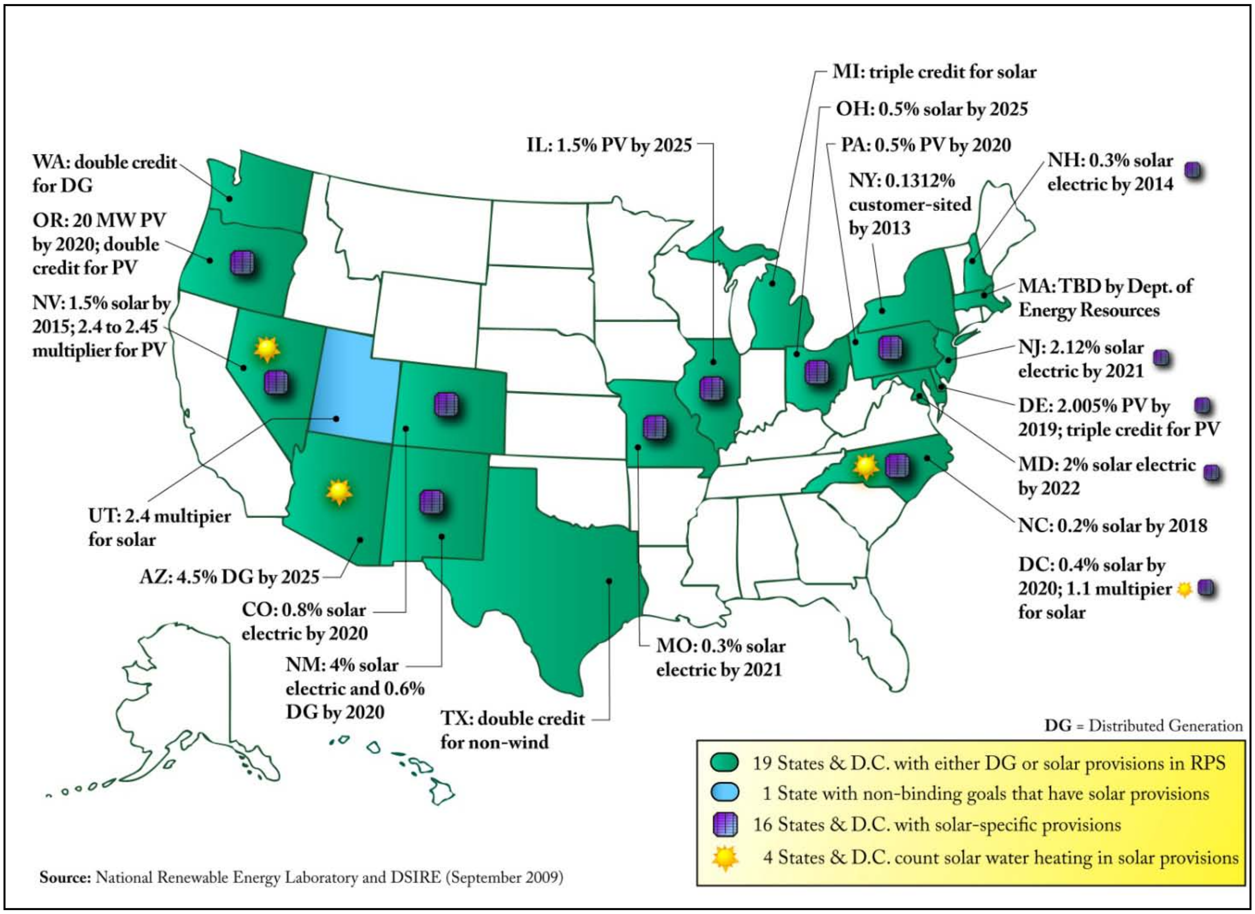

Figure C-1. Map of solar and DG provisions in RPS policies (August 2009)

Renewable energy certificates (RECs) have become the dominant mechanism for compliance with RPS policies.[17] RECs are tradable commodities separate from the electricity produced, meaning that the non-electricity "attributes" of renewable electricity generation are not bundled or sold with the electricity (although they can be if a contract provides for this). Definitions of "attributes" vary across contracts but typically include future carbon trading credits, emission reduction credits, and emission allowances (Cory, Coughlin, and Coggeshall 2008).

Solar RECs (SRECs) are generated exclusively by solar projects and have the potential to demand higher prices in markets with solar set-asides or tiers in their RPSs. Several states have instituted penalty prices on utilities or load serving entities (LSE) for not meeting their specified share of the RPS. The penalties are designed to be high enough to encourage utilities to obtain generation from renewable energy sources. The penalties come in the form of alternative compliance payments, explicit financial penalties (can be on a per MWh basis or fixed), and discretionary financial penalties (Wiser and Barbose 2008). The more concrete the penalty, the more it helps encourage utilities and developers to meet the RPS by letting them know what the

[17] RECs are not used for RPS compliance in Arizona, California, Hawaii, or Iowa (Wiser and Barbose 2008).

"alternative" payments will be if too few RECs or SRECs are generated or purchased. For example, New Jersey has a solar tier in its RPS and high penalties for non-compliance. Previously, New Jersey's penalty price was set at $300/MWh (Corbin Solar 2007), and SRECs for compliance year 2008 (July 2007–August 2008) traded at a weighted average monthly price between $197 and $246/MWh (NJ Clean Energy 2009). When the RPS compliance year 2009 started in July 2008, the penalty price was set to $711/MWh (NJ Clean Energy 2007). As a result of the increase in penalty price, SREC prices traded at a weighted average monthly price between $308 and $513/MWh from July 2008 to June 2009 reaching a monthly high of $695/MWh (NJ Clean Energy 2009).

Best practice interconnection and net metering standards—which allow DG technologies to connect to the grid, bring about a fair price for generators, and reduce barriers to installation—can make solar PV expansion viable. Federal incentives have boosted solar energy systems in recent years, but state financial incentives and state policies encouraging solar truly drive the adoption of solar PV as indicated by significant penetration levels in California, Colorado, and New Jersey.

Appendix C: State Third-Party Language Summaries

Table C-1. Summary of State Third-Party Language

State	Are 3rd Party PPAs Allowed without Regulation?	Where is the Language?	What is the Language?	Status and Solutions
OR	Yes	PUC Decision: Order 08-388	Customer is not an Energy Services Supplier because they are not using the utility's distribution system (i.e., generation is less than load). Oregon Law exempts solar and wind from being "Public Utilities."	PUC made a Decision to allow the third-party PPA model.
NV	Yes	Legislation; Docket 07-06024	Third-party ownership of net-metered systems does not qualify as a utility, is legal, and is not under the jurisdiction of the Commission.	PUC found that the third-party PPA model should be allowed.
FL	No, except leases are okay	PUC Decision: Docket 860725-EU; Order 17009	Every legal entity supplying "electricity to or for the public" was determined by legal precedent that "to or for the public" could be just ONE customer	No current attempts to change
AZ	Yes, but must be regulated	State Constitution: Article 15 Section 2	Anyone who furnishes electricity shall be deemed a public service corporation.	Solar Alliance filed a Docket with the PUC to exempt third-party PPAs from regulation
CO	Yes	SB 51	Third-party owned systems are not subject to regulation so long as the solar generating equipment is sized to supply no more than one hundred twenty percent of the average annual consumption of electricity by the consumer of that site.	RES bill SB 51 passed with supporting PUC recommended decision 08-R-424E
TX – Munis	Unclear	Legislation: Texas Utilities Code Section 40.053	By allowing someone else to sell to muni customers, the muni could be opening themselves up to competition	Munis are exploring alternative solutions (e.g. solar leasing and utility as the intermediary)
CA	Yes	Legislation: California Public Utilities Code 218	Utility Code states that if the system generates non-conventional energy and if you serve two or fewer customers on that property, you are not considered an LSE or ESP	Legislation was used to make third-party PPAs allowable
NJ	Yes	BPU Docket EX08070548	Customer generators may "use" a "customer-generator facility" and are thus not required to own the facility.	No current attempts to change

Appendix D: Clean Renewable Energy Bonds

One major reason to consider the third-party PPA model is that it helps get projects financed economically without large up-front payments from the end-user. For munis and co-ops, customer-sited projects can be financed in another way as long as the projects are not too large to qualify.

Munis and co-ops may apply to the Internal Revenue Service (IRS) for clean renewable energy bonds (CREBs) to help finance renewable projects, which have traditionally been smaller projects. CREBs, an alternative to tax-exempt bonds, are a financing instrument with a structure similar to a tax-exempt bond except that the federal government provides the investor with a tax credit in lieu of an interest payment (Cory, Coughlin, and Coggeshall 2008). A recent allocation and authorization of $800 million in CREBs funding (H.R. 2008) makes this option again available to state and local governments, co-ops, and munis, each of which receives one third of the allocation.[18] While this structure has some challenges (Cory, Coughlin, and Coggeshall 2008), Congress updated the CREBs structure in October 2008 in an attempt to address a number of the drawbacks. More information about these updates is explained in the IRS guidance, which can be found at http://www.irs.gov/taxexemptbond/article/0,,id=206034,00.html.

[18] Munis and co-ops are eligible for CREBs, but approved systems are likely to be small based on how the IRS has traditionally allocated CREBs (from smallest to largest). New CREBs allow municipal utilities to get a pro rata share of $800M, which means that even large projects can take advantage of CREBs.

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14. ABSTRACT *(Maximum 200 Words)*
Residential and commercial end users of electricity who want to generate electricity using on-site solar photovoltaic (PV) systems face challenging initial and O&M costs. The third-party ownership power purchase agreement (PPA) finance model addresses these and other challenges. It allows developers to build and own PV systems on customers' properties and sell power back to customers. However, third-party electricity sales commonly face five regulatory challenges. The first three challenges involve legislative or regulatory definitions of electric utilities, power generation equipment, and providers of electric services. These definitions may compel third-party owners of solar PV systems to comply with regulations that may be cost prohibitive. Third-party owners face an additional challenge if they may not net meter, a practice that provides significant financial incentive to owning solar PV systems. Finally, municipalities and cooperatives worry about the regulatory implications of allowing an entity to sell electricity within their service territories. This paper summarizes these challenges, when they occur, and how they have been addressed in five states. This paper also presents alternative to the third-party ownership PPA finance model, including solar leases, contractual intermediaries, standardized contract language, federal investment tax credits, clean renewable energy bonds, and waived monopoly powers.

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