SOLAR PV FINANCING: POTENTIAL LEGAL CHALLENGES TO THE THIRD PARTY PPA MODEL

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Abstract

The third-party ownership PPA as a financing mechanism for solar PV has been increasing rapidly over the last few years. Its ability to dramatically lower or remove upfront costs has made it a popular way to obtain a solar PV system for both residential and commercial buildings. However, a number of states do not allow the third-party ownership PPA due to legislation language preventing competition with the monopoly utility or mandating that the third-party owner be regulated by the local public utility commission.

The third-party ownership PPA structure is a long-term contract between a customer and a third-party solar PV developer. The developer builds and owns a PV system on the customer's roof and sells all of the power to the customer. This allows the customer to support solar power while avoiding upfront costs as well as operations and maintenance.

In particular, third-party electricity sales have presented legal challenges in a number of regulated states and jurisdictions. These states may have issues with consumer protection, grid safety, or competition with the monopoly utility. A few states have already ruled on the issue (California, Oregon) and potentially provide some legislative guidance for those states looking to exempt third-party ownership PPA providers from regulation. Other states are actively dealing with the issue and have open dockets to determine legality (Nevada, Arizona).

Because legislative solutions may be difficult to obtain in some states, especially with the complex nature of PUC integration with state legislation, it is important to look at alternative solutions to the third-party ownership PPA. These include the solar lease, the utility acting as an intermediary, utility ownership of generating assets, the utility waiving monopoly power, registration of DG services providers, and Clean Renewable Energy Bonds.

Solar PV Financing: Potential Legal Challenges to the Third-Party PPA Model

Executive Summary

The third-party ownership power purchase agreement (PPA) is a financing mechanism for solar PV that has been spreading rapidly across the U.S. over the last few years. Its ability to dramatically lower or remove upfront costs has made it a popular way to obtain a solar PV system for both residential and commercial buildings. However, a number of states do not allow the third-party ownership PPA due to legislative language preventing competition with the monopoly utility or mandating that the third-party owner be regulated by the local public utility commission (PUC).

The third-party ownership PPA structure is a long-term contract between a customer and a third-party solar PV developer. The developer builds and owns a PV system on the customer's property and sells all of the power to the customer. This allows the customer to support solar power while avoiding upfront costs as well as operations and maintenance.

In order for PV to be effective and economic, there must be the appropriate logistical and financial incentives in place. A state's net metering and interconnection standards will either promote or hinder the development of customer-sited PV. Given the current cost of solar PV, government and utility financial incentives are still needed to make an installation economic. The federal solar investment tax credit, accelerated depreciation benefits, state cash and tax incentives, and local utility cash incentives all serve to promote solar and often determine the regions and jurisdictions where solar will be installed. State policies, especially renewable portfolio standards with solar or distribution set-asides, also serve to promote additional solar installations.

There are a number of ways that solar power can be financed depending on the type of customer and the market in which they are located. Some of the most relevant options explored include self-financing, the third-party ownership PPA, and the third-party solar lease. Recently, more and more non-residential systems (larger than 10 kW) are owned by third-party on the hosts' roofs.

However, third-party electricity sales can present legal challenges in a number of regulated states and jurisdictions. These states may have issues with consumer protection, grid safety, or competition with the monopoly utility. A few states have already ruled on the issue (e.g. California, Oregon) and may potentially provide some legislative guidance for those states looking to exempt third-party ownership PPA providers from regulation. Other states are actively dealing with the issue and have open dockets to determine legality (e.g. Nevada, Arizona).

Legislative solutions may be difficult to obtain in some states, especially with the complex nature of PUC integration with state legislation. There are however a number of alternative solutions when the third-party ownership PPA is not available. These include the solar lease, the utility acting as a contractual intermediary, utility ownership of generating assets, the utility waiving monopoly power, registration of DG services providers, and, for states and municipalities, Clean Renewable Energy Bonds.

This report explores the legal issues of the third-party ownership PPA model. The first section of the report presents an introduction to the third-party ownership PPA model for financing a PV project at a customer site. Section 2 explains the laws, incentives and policies in place at the state and federal level that promote PV. Many of these incentives and requirements are needed for solar projects to be economically competitive with the utility retail electricity rate paid by customers. Section 3 provides an overview of solar financing mechanisms with specific detail on two third-party ownership financing models: the third-party ownership PPA and the solar lease. Third-party ownership makes solar PV a viable option for many commercial and residential customers that would not otherwise utilize this resource due to the large up-front capital requirements. Section 4 discusses the legal opposition to the third-party ownership PPA, looking specifically at the case in Oregon, Nevada, Florida, Arizona, and Texas. Lastly, section 5 explores a number of solutions to the legal issue, including legislative and regulatory solutions, variations of the third-party ownership PPA, and alternatives to the third-party ownership PPA.

1.0 Introduction

The increase in federal and state incentives for solar power in recent years has significantly increased demand and spurred a number of new financing options to allow solar PV supply to keep pace with demand. In turn, these financing mechanisms have spurred new demand because of their low upfront costs and turn key approach. One of the more popular options, especially among commercial entities, has been the third-party ownership PPA. The third-party ownership PPA is quickly becoming the financing method of choice (Frantzis, 2008) and is even finding a niche in the residential market.

Important issues concerning legal implications with third-party ownership have recently been raised. Not all states or electricity markets can avail themselves of this financing model due to local legislation and regulation prohibiting electricity sales from anyone other than the regulated utility. This paper will explore the legal conflicts between third party ownership and monopoly utilities, look at how particular states have dealt with these issues, and explore both existing and potential solutions to the problem.

1.1 History of the 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 renewable generating assets under 80MW, known as qualifying facilities (QFs). The PPA was used by utilities to purchase from independent generators (the QFs) in a long-term stable-priced contract. With more recent FERC Orders weakening the utilities' mandate to buy from QFs and promoting wholesale electricity competition though opening transmission access, PPAs involving QFs are not as common.[1] In today's market when utilities choose not to own generation themselves, the utility signs a PPA with an independent power producer to deliver electricity from their generating plant (for example, renewable generation to meet a state Renewable Portfolio Standard (RPS)).

1.2 Introduction of the third-party ownership/PPA model

While the traditional PPA is still the mechanism of choice in the afore-mentioned situations, in 2005 a new structure developed that uses a PPA to cater to the distributed generation (DG) markets[2] - the third-party ownership PPA model. Some of the first companies to use this model for solar power financing were Sun Edison and MMA Renewable Ventures (Danielson, 2008). As shown in Figure 1, a customer interested in hosting solar panels on their building or land signs a PPA with a project developer who builds, owns, and operates a solar system on the customer's site, also known as the host

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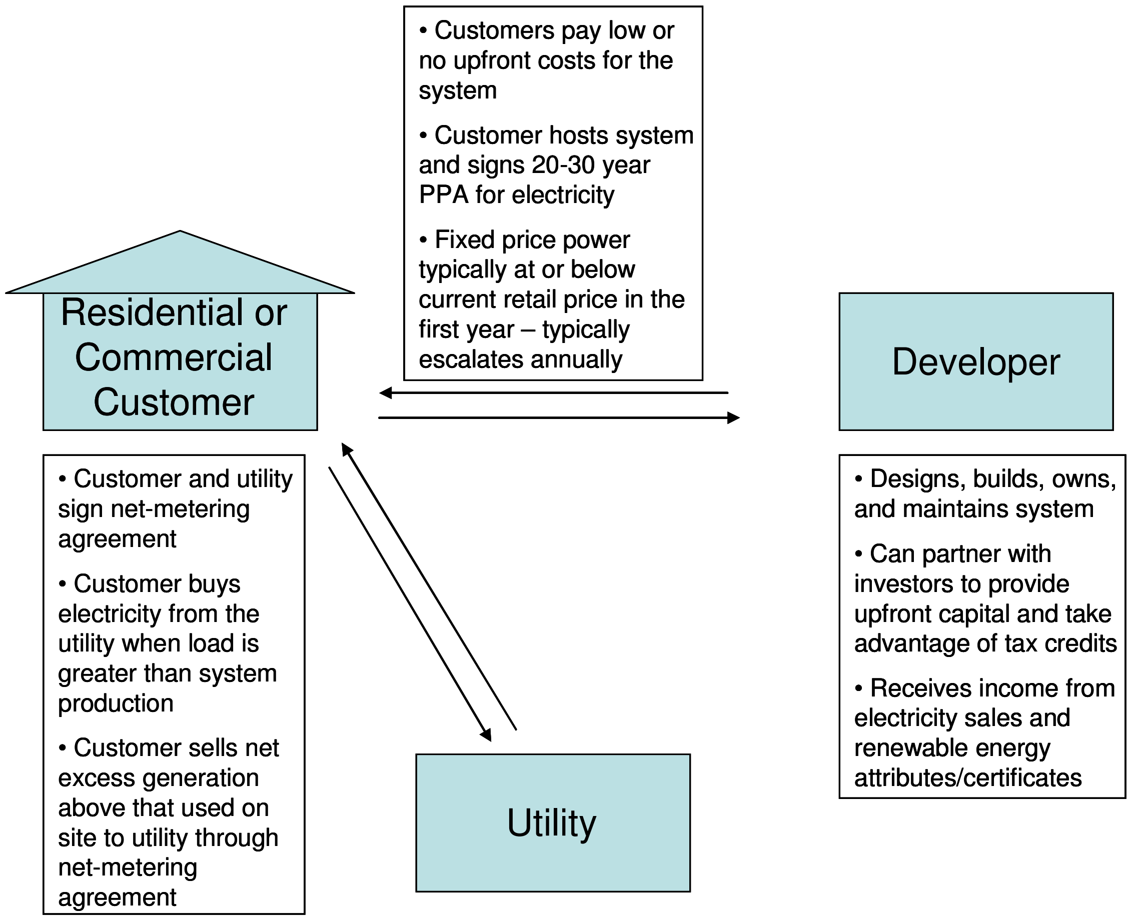
[1] The goal of FERC Order 888, issued in 1996, was to promote wholesale competition through open access, non-discriminatory transmission services offered by public utilities to all generators and recovery of stranded costs by public utilities and transmitting utilities (FERC, 2006). In 2006 FERC Order 688 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).

[2] DG is meant to encompass a variety of sizes of projects located behind a customer meter. The larger the customer and the more electricity demanded, the larger the DG system can be. While this can be as small as 2-10 kW for a residential system, it can be up to 1-2 MW for large commercial and industrial customers.

site. The developer then sells the electricity back to the customer in a long-term PPA. In effect, this allows the customer to have the benefits of solar power without the upfront costs and without the logistics of financing, building, and maintaining the system. The third-party ownership PPA model is depicted in Figure 1 and will be described in more detail later.

Figure 1. Third-Party Ownership PPA Structure



1.3 Why the Third-party PPA Ownership Model is Used for Solar

One of the largest barriers with solar systems is the high up-front cost. The recent emergence of good financing options for solar that address this challenge have helped to spur a significant increase in the growth of solar PV installations in the U.S. In 2007 alone, over 12,700 new grid-tied systems were installed in the U.S. with an annual capacity of nearly 150 MW-dc (SEIA, 2008). The reduction and removal of upfront costs through third-party ownership has been critical to residential, and commercial and industrial (C&I) customers adopting the technology. Although this financing model could be used for other technologies, currently it is primarily used for behind-the-meter solar (Cory, 2008). And the financing model is only being used in states with adequate incentives or enforceable mandates to help support PV, as explained in the next section.

2.0 Solar Laws, Incentives, and Policy Background

There are a number of prerequisites to a successful solar installation, both with regard to logistics and economics. This includes net metering laws, interconnection standards, financial incentives, and federal and state policies requiring incremental renewable generation[3]. It is necessary for all of these things to come together to ensure an economically viable project.

2.1 Connecting Solar Systems to the Grid

The financial incentives discussed later are only helpful if the state where the solar system is being installed has the appropriate net metering and interconnection standards. Net metering and interconnection ensure that systems can be adequately sized, safe and affordable. These items are discussed below and in detail in the Interstate Renewable Energy Council's (IREC) annual report, "Freeing the Grid" (NNEC, 2008). This report rates the effectiveness of state interconnection and net metering standards with the goal of displaying best practices and helping states to make incremental improvements to facilitate additional grid-tied solar development.

2.1.1 Interconnection Standards (NNEC, 2008)

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 (which is usually informed by the utility).

IREC notes that states with more progressive policies that aim to promote grid-tied solar development have technical standards that become more stringent as the system size is increased, and especially in the case of systems that serve multiple buildings (i.e. a large company's campus). IREC also recommends eliminating the need for an external disconnect switch since all modern grid-connected systems automatically shut down in the event of a grid failure. These improvements to interconnection standards will assist in removing logistical barriers for small systems and make larger systems operate safely within the grid.

2.1.2 Net Metering (NNEC, 2008)

Net metering is the billing arrangement the customer-generator has with the utility whereby any excess electricity that is generated by the customer and not used on-site, offsets electricity that the customer consumes from the utility. Net metering allows the customer to realize credit for net excess generation (NEG) produced by their system, sometimes at the utility's wholesale rate (or at the utility avoided cost) and sometimes at the customer's retail rate. Essentially, the customer can use credit obtained through past

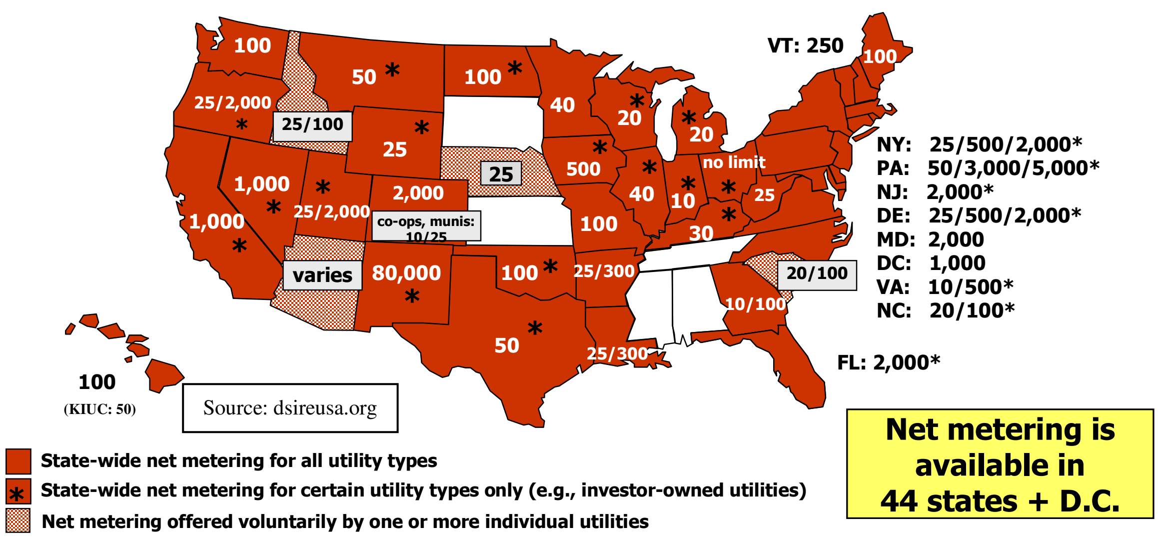
[3] The quality of the solar resource (i.e. location) is another critical element to PV projects. However, even in a location with an excellent resource incentives are needed for the project to be economic as of today. In fact, incentives can make up for the differential between poor to OK resources to help spur new development. Germany is a world leader in PV, and yet their solar resource is on par with Alaska; it is the government incentives that make the difference.

NEG, toward electricity needed when their system is generating less than they are consuming.

IREC's best practices with respect to net metering include removing size limits and customer classes from net metering, allowing monthly carryover of NEG credited at the utility's full retail rate, and standardizing net metering standards across the state without regard to the type of utility to make rules simpler and clear to all market participants. These suggestions are important as net metering rules can determine a project's size and economic feasibility in many cases.

Each state has different rules and requirements for net metering, some 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 system, which dictates whether or not a customer will be able to install a system that is 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 that doesn't have a limit (DSIRE, 2008a).

Figure 2. Map of States with Net Metering Standards



(Note: Numbers indicate individual system size limit in kilowatts (kW). Some states' limits vary by customer type, technology and/or system application. For complete details, see www.dsireusa.org.)

Although nearly all states have net metering size limits, they aren't actually necessary in most cases. Most states have financial mechanisms in place that discourage installation of systems that are larger than the customer's average load. For example, in many states, customer-generators are not paid for NEG held at the end of a twelve month period. This means 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). As such, Ohio regulators at the PUC ruled that "an implied limitation" is in effect because, by statute, a net-metered system must be "intended to offset part or all of the customer-generator's electricity requirements," rather than in place primarily as a business, to sell NEG to the utility (DSIRE, 2008b).

Other net metering provisions can discourage solar installations altogether. Solar energy production varies significantly based on the time of day, as well as by the season. This means that during the day of particularly sunny months, the system could produce more than the host site uses, 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 (and rather to just meet the peak demand). In some states customers are forced to pay net metering tariffs and standby charges.[4] These charges can negate some/all of the financial benefit the customer would receive from their solar system, while the utility would benefit when the solar system's peak generation coincides with the peak load of the utility.

2.2 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. Some of these critical financial incentives are detailed in the following section.

2.2.1 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 currently set at 30% of qualified expenses, and was recently extended through December 31, 2016. (WRI, 2008 and HR, 2008). While the commercial ITC has never had a maximum amount, the residential ITC had a cap of $2,000 until October 2008, when Congress removed the cap as of January 2009. Additionally, there are a limited number of entities that can take full advantage of the 30% credit. The requirement that the entity pays federal taxes eliminates not-for-profit businesses, state and federal government agencies, and any other business that does not earn accounting profits.[5] Finally, the October 2008 changes to the ITC also allow utilities to utilize the tax credit starting in 2009, which they were unable to do before.

2.2.2 Accelerated Depreciation

Another critical incentive for solar PV is the federal Modified Accelerated Cost-Recovery System (MACRS), which allows businesses[6] to recover investments in

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[4] Net metering tariffs and standby charges are fees the utility charges (approved by the state PUCs) to account for the fact that they must still provide back up power in the instance the customer generator's system does not perform.

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

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

property through accelerated asset depreciation, effectively reducing the entity's tax liability. Solar equipment can be depreciated over a five year period, allowing a business to take advantage of this tax deduction over a shorter time span, versus the actual lifetime of the equipment (20-30 years) (DSIRE, 2008c). On a percentage basis for a commercial entity, the MACRS provides about as much value as the ITC over the life of the project, towards reducing costs (Cory 2008/2009).

2.2.3 Cash Incentives

In addition to federal incentives, a large number of cash incentives are available to solar projects, through state, local and utility specific financial 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) database maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) found at www.dsireusa.org.

Some of these incentives are substantial enough to advance solar installations in their respective territories. Two state-specific examples are included below since state programs are the most widely available and tend to have the most funds available.

2.2.3.1 State of California Example (DSIRE, 2008d)

One example of a robust state incentive program is the California Solar Initiative (CSI). 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 is designed to offer higher incentive levels initially which are reduced over 10 years as utility-specific capacity targets are met.

Incentives received are based on the project's size. When the program began in 2007 buy-downs (rebates) for systems less than 50kW were $2.50/W AC for residential and commercial systems, and $3.25/W AC for government entities and nonprofits. These incentives are adjusted based on expected performance of the specific PV system at a particular site. For a system greater than 50kW, performance based incentives are paid for the first five years 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.

2.2.3.2 State of New York Example

The state of New York has encouraged solar PV installations through its state rebate program and personal tax credit program. The state rebate program is available to all customers of investor owned utilities, including residential, commercial, government, and schools. The incentive value ranges from $3-$5/watt DC, and varies by sector, total system installed capacity, and system type[7]. Residential incentives are capped at 10 kW and non-residential incentives are capped at 50 kW per site/meter (DSIRE, 2008e).

Through the personal tax credit program, residential purchasers of PV are also eligible for a tax credit equal to 25% of the cost of equipment and installation up to $5000 (DSIRE, 2007). If a PV system costs $8.30/Watt, then this incentive can cover the full 25% of the cost of a 2.4 kW system; for anything larger, the tax credit is capped at $5000.

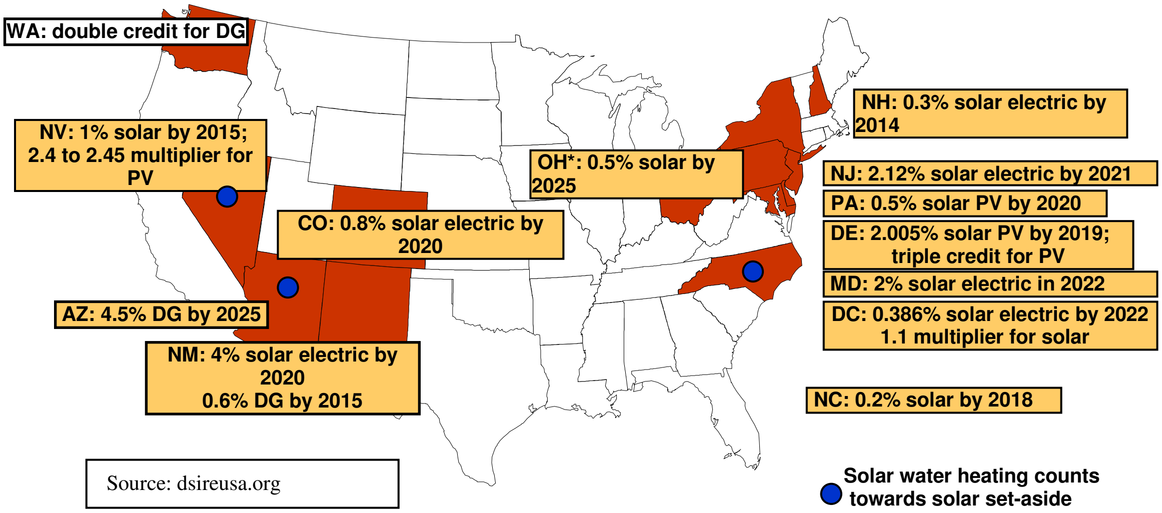
2.3 State Policies Encouraging Solar

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 in a particular state generate or purchase on behalf of their customers, a certain percentage of electricity from new renewable energy sources.

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 their RPS (shown in figure 3). The set-aside dictates the amount of power in that state that must be generated from solar resources, in particular. This solar specific requirement is important to help separate solar from other, less expensive forms of renewable generation such as wind and landfill gas. Note that there are direct solar set-asides as well as set-asides for renewable DG, which are 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. For example, if a 5kW solar PV system is installed in Delaware and has a capacity factor of 14%, it generates 6,132 kWh of power, and because the state has a triple credit for solar, it will count as 18,400 kWh towards the RPS requirement.

[7] Residential incentives are $4.00/W up to 5W, $4.50/W for NY Energy Star Homes up to 5W, $4.50/W for all building integrated PV systems up to 5 kW, and for additional capacity between 5-10 kW, all residential incentives will be reduced by $1.00/watt. Non-residential systems receive $4.00/W up to 25 kW, $4.50/W for all building integrated PV systems up to 25 kW, $5.00/W for schools, non for profit organizations, and municipalities up to 25 kW. All non-residential incentives will be reduced by $1.00 per watt for additional capacity above 25 kW. Non-residential incentives will be capped at 50 kW per site/meter (DSIRE, 2008e).

Figure 3. Map of Solar and DG Provisions in RPS Policies



Renewable Energy Credits (RECs) have become the dominant mechanism for compliance with RPS policies.[8] RECs are tradable commodities, separate from the electricity produced, that bundle the non-electricity "attributes" of renewable electricity generation. The definition of "attributes" can vary across contracts, but will likely include any future carbon trading credits, emission reduction credits, and emission allowances (Cory, 2008).

Solar RECs (SRECs) are generated exclusively by solar projects and have the potential to demand a higher price in markets with a solar set aside or tier in their RPS. Several states have instituted penalty prices on utilities or load serving entities (LSE) for not meeting their specified share of the RPS. They are designed to be high enough to encourage the utility to obtain generation from renewable energy sources, rather than paying them. These penalties can come in the form of alternative compliance payments, explicit financial penalties (can be on a per MWh basis or fixed), or discretionary financial penalties (Wiser, 2008). The more concrete the penalty, the more it helps to establish a cap for RECs and SRECs in that particular state by letting utilities and developers know what the "alternative" payment would be if not enough RECs 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 traded at a weighted average monthly price between $197-$246/MWh from July 2007 through August 2008 (NJ Clean Energy, 2008). RPS compliance year 2009 started in July 2008, and a new penalty price of $711/Mwh was instituted (NJ Clean Energy, 2007). As a result, SREC prices traded at a weighted average monthly price between $308-$345/MWh from July 2008 – September 2008, reaching a monthly high of $560/MWh (NJ Clean Energy, 2008).

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

In order to make solar PV expansion viable in any given state, solid interconnection and net metering standards must be in place. These should serve to allow DG technologies to connect to the grid, receive a fair price for the value they provide to the electrical system, and reduce barriers to installation. Federal incentives have provided solar a boost in recent years, but state financial incentives as well as state policies encouraging solar truly drive the adoption of solar PV as noted by significant penetration levels in California and New Jersey.

3.0 Overview of Solar Financing Mechanisms

If the necessary financial incentives, interconnection standards, and net-metering rules are in place, and a project makes economic sense, financing the solar equipment is the final step.

3.1 Self-financing

Historically the electricity consumer has been the dominant owner of solar PV systems. Commercial, industrial and residential consumers self-financed their systems either through cash, bank loans, home equity loans, and sometimes mortgages. These early-adopters were motivated to purchase solar generation systems for non-economic reasons such as the desire for clean energy or grid/utility independence (Frantzis, 2008). In the case of companies, they wanted to limit their environmental footprint and reduce their carbon emissions especially in anticipation of carbon regulations. For example, Johnson and Johnson was one of the early adopters of solar, installing a 500 kW system in February of 2003 atop one of their New Jersey offices, even though it did not meet the company's minimum rate of return for capital expenditures (WRI, 2003).

3.2 Third-Party Ownership PPA

There are a number of attributes that have recently made the third-party ownership PPA a popular model for financing new PV installations. These benefits (and challenges) outlined below apply to both residential and commercial customers, but do have some varying implications depending on customer type.

3.2.1 Minimal Upfront Costs

One of the primary benefits of the third-party PPA is that it dramatically reduces or eliminates up-front costs for the commercial, industrial and residential customers. The developer can eliminate the need for the customer to provide this upfront capital by finding capital to buy the system; either by purchasing it outright or securing financing for most of the capital cost. The amount, if any, of upfront cost to the customer is determined by the PPA contract between the customer and developer. This contract is a mechanism for the developer to earn their necessary rate of return, which they can do through a combination of electricity and SREC revenues, cash incentives, state and federal tax incentives, and an upfront payment. If a customer wants to avoid paying any upfront cost, he will typically pay more for electricity.

3.2.2 Project Financing Expertise

Solar developers participate in the niche tax equity financing market and form relationships with banks that have tax equity financing divisions. This requires that the bank have large enough profits to take advantage of depreciation benefits (MACRS) and tax credits. Because this is the developer's line of business, they are well equipped to manage the process and can usually find cheaper sources of capital compared to homeowners or businesses. However, the recent financial crisis in the U.S. seems to have constrained the tax equity market, potentially severely.

3.2.3 Efficient Use of Tax Credits

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

The most salient example, the ITC, is only available to a homeowner or business with taxable profits. Therefore, if a homeowner or commercial entity does not have a high enough tax bill to absorb the entire tax credit, they can not take advantage of an incentive that potentially offsets 30% of the upfront capital cost. The residential and non-tax paying customers are also at a disadvantage since neither can use the MACRS depreciation tax benefit.

By contracting with a developer who can take advantage of these various incentives and credits, certain customers can now realize these cost savings that would have been foregone if they purchased and owned the system themselves. The cost savings are subsequently passed from the developer to the customer in the form of lower electricity rates (equivalent to the system output).

3.2.4 Removes Maintenance Responsibilities

For the most part, the businesses and residences that are installing PV do not have an expertise in solar maintenance and operations. With the third-party ownership model, the ownership and responsibility of the system can be placed on the developer, and not the customer. The customer only pays for the electricity that is generated. Therefore if the system is not functioning properly, the customer does not have to pay for repairs or for the electricity. Ultimately, the customer just purchases more electricity from the utility. This provides a revenue incentive for the developer to maintain the system, since they are not paid unless the system is producing power.

3.2.5 Predictable Cost in a Volatile Electricity Market

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

When businesses with large power needs are looking at how they can 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 at or below the current utility retail rate for that customer and may remain constant or contain an annual escalation factor of 3-3.5% (Cory, 2008). This stability can be comforting to businesses who can plan out a portion of their energy expenses with certainty, as well as to project investors who can count on a revenue stream, as long as they maintain system performance.

3.3 Challenges with the Third-Party Ownership PPA

The main challenge with third-party ownership is determining whether or not the utility has entitlement 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. NEG). However, if the utility contributes financial incentives or rebates to a project, most utilities require the RECs be transferred to them in exchange (Holt, 2006).

In the case of the third-party ownership PPA model, the developer typically sells the electricity to the customer and retains the SRECs for sale into the RPS market. The sale of SRECs helps the project make the necessary returns and allows the developer to offer the customer a price competitive with traditional generation. If the customer is interested in claiming that they are "solar powered" they must purchase the SRECs from the developer. This will result in a much higher PPA price. One option in regions with active REC markets is for the customer to buy cheaper wind or landfill gas RECs on the open market. This allows the customer to retain the renewable energy claim (not solar), for their own system, while taking advantage of high SREC prices (Cory, 2008).

In the case that a customer moves, the contract states the options available to the customer. Because the third-party has taken on credit risk of the customer, the new occupant is not automatically entitled to assume the terms of the contract; they often must meet a credit check. Some contracts will have buy-out clauses so that the customer can buy the system and sell it with the building.

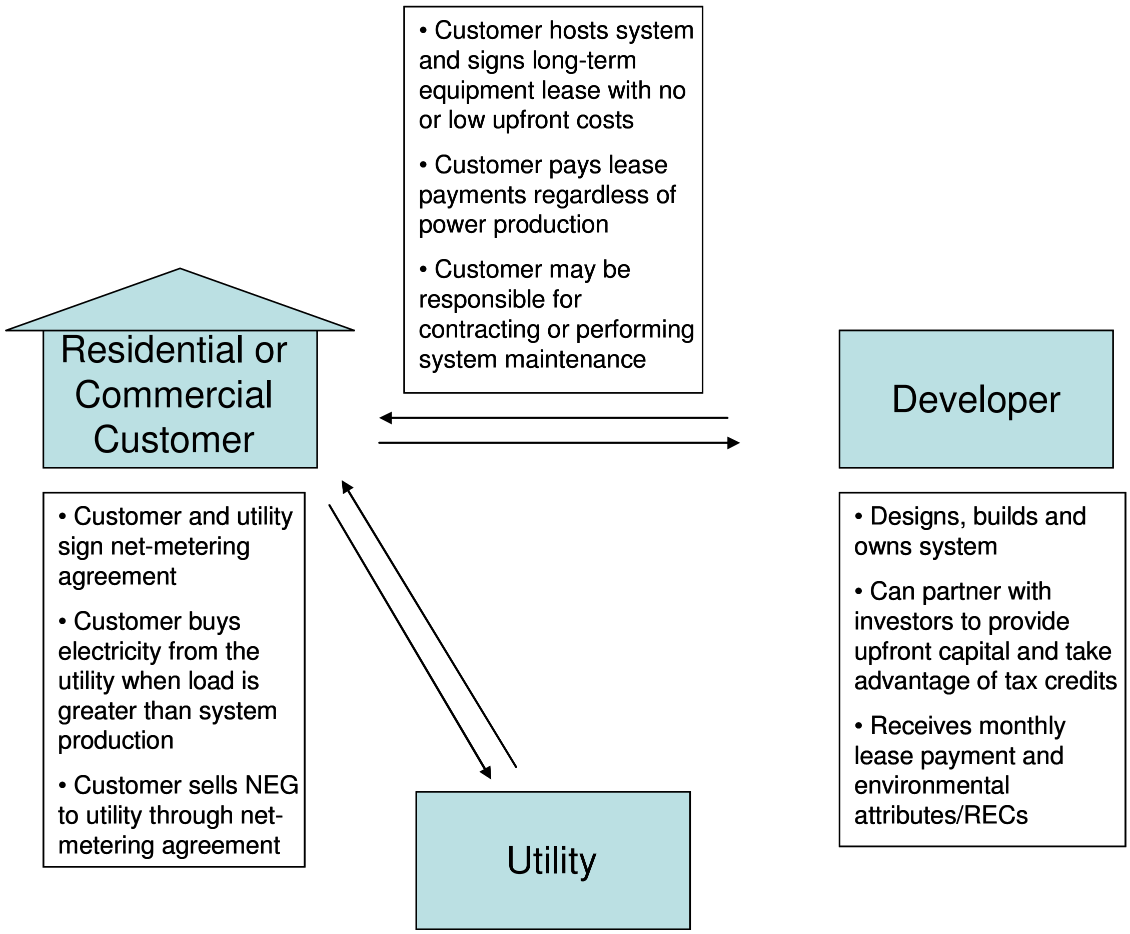
3.4 Third-Party Ownership Solar Lease (Coughlin, 2008/2009)

Like the third-party ownership PPA model, the third-party solar lease model utilizes the benefits of having a third party finance and own the solar system. The solar lease is a relatively new way to provide customers access to on-site solar systems, however the concept is the same as traditional equipment leases. Instead of purchasing a PV system, the customer enters into a contract with a lessor (the owner) of a PV system and agrees to make fixed monthly lease payments (regardless of system generation), over a set period of time. The customer consumes whatever electricity the leased system generates, net meters any excess, and pays the utility rate for any additional electricity demand.

3.4.1 Benefits of the Solar Lease

The benefits of the solar lease mirror most of those associated with the third-party ownership PPA including reducing or removing the upfront cost, utilizing a developer who can take advantage of federal tax incentives, and if indicated in the contract, the transfer of maintenance responsibilities to a qualified party. However, the price of electricity will differ somewhat because the customer is effectively paying a set price for the equipment (and sometimes maintenance), and not the electricity itself. Ideally, monthly utility 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 4 below is a graphical representation of the parties involved in the solar lease.

Figure 4. Solar Lease Structure



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

In order to make the projects economic (i.e. with prices close to or below the customer's retail utility rate), developers typically require that they receive the RECs from the project. As previously mentioned, many utilities mandate that they receive the RECs from those projects where they have contributed rebates and financial incentives (Holt, 2006). The developers are willing to receive up-front cash or tax credits in return for an environmental attribute they may otherwise have trouble monetizing. This is especially true with smaller residential projects.

3.4.2 Challenges with the Solar Lease

Under the solar lease model, more of the risk may be transferred to the customer instead of the developer. The developer receives a fixed lease payment regardless of whether the system is operational and independent of the electricity produced. In other words the monthly payments continue, even if the system is off-line and not producing electricity. Maintenance and operational risk are therefore transferred to the customer unless maintenance services or operational guarantees can be procured from the developer or another provider.

The customer is also responsible for insuring the system. Since large developers have established insurance relationships, they receive favorable rates as compared to a one time residential or commercial customer looking for solar PV insurance.

If estimates of how much energy the solar PV system will produce are not accurate, the customer could end up paying more for the lease, and thus the electricity on a levelized basis ($/kWh) than if had they entered into a PPA.

Table 1. Overview of Solar Financing Mechanisms

Sources of Financing	Self-Financing	Third-Party Ownership PPA	Solar Lease
Upfront Costs	yes	unlikely*	unlikely*
O&M	yes	no	unless contracted
Use of Federal ITC	requires large tax liability	yes	yes
Use of State Incentives	requires adequate tax liability; bigger systems require larger liability	yes	yes

* The lower the upfront costs, the higher the price of electricity, therefore upfront costs depend on the contract arrangement between the third-party owner and the customer to meet the goals of both parties

A number of financing options exist for businesses and residential customers looking to utilize solar PV, with the third-party ownership model becoming popular in recent years due to its low upfront costs, ease of use for customers, and stable power price. Third-party owners are strategically financed to take advantage of numerous tax credits and incentives available, making power prices to their customers competitive with traditional generation in many cases.

4.0 Potential Legal Issues

In states with regulated, vertically integrated utilities, third-party owners must work within the current utility framework and be cognizant of PUC regulation and the existing monopoly utilities. These utilities have been granted monopoly status and are not always amenable to third-party sales in their territory. Additionally, third-party providers are often restricted from particular markets due to the state's definition of a utility. If the third-party provider is considered an entity that requires regulation, they will choose not to operate in that state.

PUCs must also consider consumer protection and grid safety when assessing the legality and feasibility of third-party ownership. This section will look at the pros and cons of allowing third-party ownership in regulated territories and detail some state positions on this issue.

4.1 Background: Why Electricity Markets are Regulated

Electricity in the U.S. remains regulated in many states in order to protect consumers and to ensure a highly functioning electric grid. If anyone could connect a generator to the existing grid at will, the electricity supply would be incredibly volatile and unsafe, which could cause congestion, blackouts, and maintenance issues. To prevent such issues, regulated investor-owned utilities were created as monopoly providers to customers in specific service territories. By having a single entity control the system, the utility can balance constantly changing supply and demand in order to ensure reliability and keep the electricity flow on the grid optimized and safe.

States dealing with high power prices in the 1990s began to look at deregulation of electricity markets as a way to create competition among generators supplying electricity and to hopefully lower prices (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 who they purchased their power from and how. Throughout this electric system restructuring process, most municipal utilities (munis) and rural cooperatives (coops) remained regulated by their cities and members, rather than opening up their territory to competition. Therefore, in most states that restructured, munis and coops continue to operate under different rules and regulations than the investor owned utilities (IOUs). Although there are differing views on the effectiveness of restructuring, and some states are taking steps to go back to regulate generation, there are a number of states where customers continue to choose their power provider.

4.2 Third-Party Ownership and Regulated Markets

The significance of electric generation deregulation is critical to the legal issues with the third-party ownership PPA. In electricity markets where the retail customer has consumer choice of their power provider, the third-party ownership PPA model does not appear to pose any legal issues. If the utility does not have monopoly power over a given customer base, that 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, since most electricity markets in the U.S. have not gone through restructuring to allow customer choice (Showalter, 2008 and EIA, 2008) any model where an entity other than the monopoly utility sells electricity directly to customers may be prohibited. This legal issue could pose a significant challenge to third-party owned models.

4.3 Third-Party Ownership and Consumer Protection

The question raised by some state PUCs is if a third-party owns a system and sells the power to a retail customer in the service territory of a regulated utility, does that entity then need to be regulated by the utility commission, in order to protect customers from fraud and to protect the security of the electric system? The commissions serve to protect consumer's interests by regulating rates and service quality. They also serve as a clearing house for customer complaints and are charged with dealing effectively with these matters.

In the case of third-party owners, the PUCs would have no oversight or control over these electricity providers. Some have suggested that this lack of oversight over third-party power providers could pose a problem for customers. The developers maintain that like any business, they must provide a quality product to their customers to retain customers and remain competitive, and that detailed language in their contracts assures customers of what they can expect from the system and its owner (Danielson, 2008).

4.4 Third-Party Ownership and Interconnection Standards

One way that utilities currently deal with integrating non-utility owned DG systems is through interconnection standards, which provide safety provisions to protect the grid and the utility workers. It is feasible for interconnection standards to follow engineering standards and FERC technical screens that maintain both the safety of the grid and give DG customers stable policies for interconnection (NNEC, 2008). Interconnection standards also maintain careful planning of projects to allow power to enter the grid when and where it is needed. However, such standards only protect the grid at the time of connection and do not ensure the system is maintained and operated appropriately over time. Hence, the utility is needed to perform real-time balancing to protect the grid's safety.

4.5 Examples of Third-Party Ownership Legality Issues: Competition with the Monopoly Utility

Most of the state laws and regulations that prohibit third-party ownership in monopoly territory have been in place for decades and were not originated specifically to prevent the third-party ownership PPA model. In general, the third-party owner is not specifically outlawed, but rather, any entity that sells power to retail customers would have to be regulated by the Utility Commission. Because this is counter to the business model of these developers, it effectively removes the option for them to offer services in that state. The specific language, which is different in each state, gives an idea of the prohibitions on third-party ownership in these markets. Note that this issue is not limited to regulated states, as even 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 coops). The challenge in this case is that allowing third-party owners to sell retail power to customers might open muni and coops up to competition and subject them to regulation by the PUC, which may not be desired by these small utilities.

A number of interviews were conducted with PUC officials across the country to determine how states are currently dealing with third-party PPA legal issues, what the arguments on each side are, and what solutions exist. Five states that are actively dealing or have previously delt with this issue will be highlighted: Oregon (which already has a ruling), Nevada, Florida, Arizona, and Texas (a muni/coop issue in a restructured state). Appendix A contains a table listing each of the states with a summary of their language surrounding third-party ownership and the status of third-party ownership PPAs in the state.

4.5.1 Oregon

Oregon has been the poster child for the third-party ownership issue in recent months as one of the only states that has addressed the issue directly. Oregon is a regulated state with monopoly utilities, and the Oregon PUC (OPUC) ruled in favor of third-party ownership.

The question for Oregon was whether or not a third-party provider qualified as either an electricity service supplier (ESS), or a Public Utility. 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).

In Order 08-338 entered on July 31, 2008, the OPUC determined that third-party owners are not considered an ESS because in order to participate in direct access the ESS must use the utility’s distribution system. Even though most third-party owned PV systems participate in net metering in Oregon, the DG systems usually generate between 0.05% and 18% of total electricity use and are not intended to be net generators, sending power to the grid (i.e. using the utility’s distribution system) (OPUC, 2008). Systems are typically below the size of customer generation because any NEG above the customer’s average annual load is credited to the utility’s low-income assistance program (vs. paying the customer for the generation). In addition, the net metering limit on a project size is 25kW for residential and 2MW for commercial, as shown earlier in Figure 3.

The second question the PUC addressed was whether or not a third-party provider was a public utility. This term would also require the third-party be regulated by the PUC. This was a more straightforward decision, as Oregon law specifically exempts wind and solar providers from being a “public utility.” The OPUC has noted that other renewable generating sources will need to be written into legislation if they are to be allowed as third-party generators as well.

4.5.2 Nevada

On August 20, 2008, the Public Utilities Commission of Nevada (PUCN) voted to expand a net metering docket to include the issue of third-party ownership. Currently the Nevada Statute 704-020 defines 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." PUCN Staff do not believe that the third-party ownership PPA or the solar lease structures are legal under Nevada law. The solar lease exclusion differs from the other states mentioned in this paper due to Nevada defining a utility as the "equipment" in addition to the seller of electricity. Staff is also concerned with consumer protection if these third-parties are not regulated and believes the Commission should implement rules which govern rates and fees as well as contractual obligations (PUCN, 2008).

According to comments filed by Nevada Power and Sierra Pacific power on September 24, 2008, these parties are amenable to the third-party ownership structure as a way to help the state and its regulated utilities meet the Nevada RPS and promote renewable energy. They do recognize that legislation must be changed and recommend additional consumer protection rules specific to using third-party ownership.

The PUCN has an open rule making where this issue could be addressed. If not addressed by the PUCN, there is speculation that it may likely be addressed in the Nevada legislative session that runs from February until June 2009 (Cordova, 2008).

It is interesting to note that even with these issues at hand, Nevada has the largest U.S. solar PV system that utilized a third-party ownership PPA, to date. Nellis Air Force Base 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, Nellis was able to accomplish this because it is operated by a federal agency that has special exclusions in the state and as such, it has a choice of where to purchase electricity.

4.5.3 Florida

Florida does not allow the third-party ownership PPA model and the situation is not currently under debate in any formal process. That said, the state of Florida has a long history with the third-party PPA issue. The definition of a "Public utility" as defined by Florida Statute 366.02 means:

> 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 1981, the Florida Public Service Commission (FPSC) considered a proposed cogeneration project where PW Ventures would have sold electricity from their plant exclusively to Pratt and Whitney (the customer) to provide for most of the company's power needs (*PW Ventures v. Nichols*, 533 So. 2d 281). Supplementary power needs and emergency backup power would have come from the local utility, FPL. When the FPSC ruled on the issue, it came down to the definition of "to or for the public." PW Ventures argued that they would have to sell their power to the general public in order to be considered a utility. However, the Commission determined that the definition of "to or for the public" could be *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 statute, this ruling appears to have eliminated the possibility of using the third-party ownership PPA in the state of Florida. It is important to note this does not exclude all other forms of third-party ownership, just those where the sale of electricity based on consumption is involved (FPSC, 1987).

In 2007 the Florida Energy Commission (FEC), which became part of the Florida Energy and Climate Commission within the Executive Office of the Governor in 2008, made the recommendation to the legislature to allow third-party PPAs (FEC, 2007). Specifically, the FEC recommended changing:

> Florida Statutes to allow, without incurring regulatory jurisdiction of the Florida Public Service Commission, third party ownership of new renewable generation facilities located on the site of an electric energy customer and sale of up to 5 MW of renewable electricity to a single customer provided the facilities are located on the customer's premises.

Even though this was a formal recommendation, this action never materialized (Miller, 2008).

4.5.4 Arizona

Arizona has a number of recently announced solar PV projects that plan to use the third-party ownership PPA, however, according to the Arizona Corporation Commission, these project arrangements are not currently legal (Williamson, 2008). Article 15 Section 2 of the state 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. Since the definition is part of the constitution the issue is likely a legal one as opposed to a policy issue.

The Solar Alliance, a consortium of solar manufacturers, integrators and financiers, recently filed a docket with the Commission in an attempt to resolve the third-party ownership PPA matter in the state. The Solar Alliance has requested that providers of certain solar service agreements not be considered public service corporations (and therefore should not be regulated by the Commission). The docket outlines the characteristics of these solar service agreements and argues that 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. Therefore, they argue that they do not require the Commission's economic regulation (AZ, 2008).

Interestingly, in 2007 the Arizona legislature passed HB2491, the Solar Energy Tax Credit Application, to make third-party financiers eligible for the Arizona corporate solar tax credits (AZ, 2007). It is to be determined whether or not the third-party owners will actually be able to take advantage of this legislation.

4.5.5 Texas

The state of Texas presents an interesting case, as they are a deregulated state with respect to customer choice. However, the municipal utilities and co-ops were not required to deregulate . This means that in most of Texas the third-party ownership PPA model can be used as a financing mechanism, but in jurisdictions such as Austin and San Antonio, where municipal utilities supply the electricity, third-party PPAs may not currently be an option.

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 there has been no formal statement from the Texas PUC on the matter, the municipal utilities are concerned that they will open themselves up to competition if they allow any generator to sell electricity to their customers. Even though these utilities may want to allow the third-party ownership PPA to help facilitate the adoption of solar power, they will not do so at the risk of inadvertently setting themselves up for deregulation and competition in their service territory.

This matter is one that will likely need to be clarified as Texas has good solar resources. Also, the cities of San Antonio and Austin were selected by DOE to be part of the Solar America Cities program, one of the goals of which is to eliminate market barriers to solar PV deployment.

Overall the third-party ownership PPA is difficult in a number of states due to specific language mandating that providers of electricity be regulated entities. The issue appears to be gaining momentum with more parties seeking a resolution as evidenced by recent docket filings in Nevada and Arizona. With each state having different language regarding the definition of a utility, an energy services provider, etc., as well as different rules about what they can legally supply or how many customers they can serve, it makes it difficult to find a one-size-fits-all policy solution.

5.0 Potential solutions

A number of existing and potential solutions are emerging that could allow solar developers to participate in states that do not allow third-party ownership PPAs. Alternative financing options that still contain some of the same benefits of the third-party ownership model are also possible in some cases.

5.1 Third-party Ownership PPA Policy Solutions

As states begin to seek additional solar resources to diversify generation sources, meet peak loads, and comply with RPS requirements, they may choose to allow third-party ownership PPAs to help customers find turn-key solutions at competitive prices. This will require either a ruling by the State PUC or in some cases, a change in legislation. This paper will look at two states that present examples of regulatory or legislative changes: Oregon and California.

5.1.1 Oregon's Regulatory Solution

As previously mentioned, Oregon brought this issue to the OPUC for a decision, and the ruling was in favor of allowing third-party PPAs. Oregon had to decide if the third-party owner was subject to regulation as either an ESS or a public utility. Since earlier legislation ruled out wind and solar providers as public utilities, the main question was regarding ESS status.

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 in the state. To be considered an ESS in Oregon, the entity must provide "direct access" as well as use the utilities' distribution system. Entities are considered to provide "direct access" if they provide both electricity *and* "additional services." The OPUC recognized that these additional services were related to the management of electric power delivered through the transmission and distribution grid. This was not applicable to the third-party owners, because all of the power they generated was on the customer's side of the meter and would not be utilizing the distribution system (OPUC, 2008).

On a broader level, Oregon is looking at the third-party owner as a DG services provider vs. selling retail power to customers. Due to the nature of the mechanism, the intent is an alternative financing scheme, not to sell power in the same manner as a utility or to use the utility distribution system. In fact, the third-party ownership PPA does not seek to sell retail power to customers, but rather provides DG services by allowing customers to generate their own power.

5.1.2 California's Legislative Solution

California has allowed the third-party ownership PPA model for a number of years through state legislation. California Public Utilities Code 218 is very specific in the kinds of ownership and technologies that are allowed, promoting a clear path for long-term, customer-sited energy development. In fact, the code specifically <u>exempts</u> from the definition of an Electrical Corporation:

> …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 lies in that fact that a corporation can sell electricity if it is used solely on the property where it is generated. In fact, the legislation goes so far as to say that the electricity can be sold to two other corporations or persons who are also on that property.

California's language has several interesting implications. First, it allows third-parties owners to sell to residential customers on an individual basis. Also, the exemption opens up the possibility of selling power to multi-family housing units, as well as multi-tenant commercial and industrial buildings, as long as the owners of those buildings do not directly re-sell the power to their tenants (it is possible to raise the rent price, but not to charge directly for power). The state requires third-party owners to set up new independent business units (such as an LLC) for each commercial system they install in order to comply with the rules and utilize the third-party ownership PPA.

5.2 Variations on the Third-Party Ownership PPA

A number of states do not currently allow the third-party ownership PPA. While this can be changed with legislation or PUC decisions described above, these changes can be difficult and time consuming to obtain. It therefore might make sense to consider acceptable variations of the third-party ownership PPA 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 ownership PPA model. It is important to note that this does not and should not constitute legal advice; a full legal opinion from your attorney, specific to your situation, should be obtained.

5.2.1 Utility Waives Monopoly Rights for DG

If allowed by the PUC, monopoly utilities can waive their monopoly rights and allow third-party owners to participate in their service territory. Xcel Energy in Colorado is a primary example of this solution.

In order to meet Colorado's RPS requirements including the 4% solar set-aside, Xcel Energy has 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, 2008f), and Xcel has found the third-party ownership structure to be an effective way of meeting that goal. However, Xcel provides this waiver only for those projects selected in its solicitation and which provide it with RECs for compliance (Mignogna, 2008). This gives the utility absolute power by making them the "sole arbiter" over which providers are allowed to serve the market for commercial scale systems using the third-party ownership PPA model. For projects from 10kW to 100kW, Xcel has a standard rebate offer, but again only for projects that supply it with RECs. For the under 10kW "residential" segment, Xcel runs another standard rebate offer but requires that the customer own the system.

5.2.2 Developer Sells Power Directly to Utility

If the utility is willing to work with customers and developers on a project by project basis, one potential solution is for the project developer to sign a PPA with the customer's *utility*, and then have the utility sell the power back to the customer. The utility would be a silent intermediary in the third-party ownership PPA model, really only transferring the sales and purchases on paper, while the actual electricity would be 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.

This solution clearly requires that the utility be interested in promoting solar resources. It is an important potential solution for a regulated utility that is concerned about opening themselves up to competition, as is the case for the municipal utilities in Texas. The structure does add another step to the transaction and may not come with as favorable pricing due to increased transaction prices. But it could be an important solution in areas where there are legal questions surrounding the third-party PPA model.

5.2.3 Systems Sized Well Below Customer Load

Many utilities and state PUCs look at distributed generation services as a loss of income or a system that is going to put uncertainty into the grid. However, many of these systems are sized to be much smaller than the customer's load and will rarely, if ever need to put excess power back onto the system through net metering. In other words, they may not need to use the distribution system, as all the power is used on-site. In a sense, this is the same concept as energy efficiency or reducing a certain customer's load from the utility.

One potential option is for states to allow certain sizes of DG (as a percentage of customer load) to participate in third-party ownership models. On-site generation that would have no or limited effect on the grid and that would not use the distribution system could be allowed into third-party arrangements. Under this scenario, the third-party is truly providing the equivalent of an energy efficiency service; because all that the utility sees is that a particular customer's load has decreased.

5.2.4 Registration of DG service providers

One of the main concerns from many of the state regulatory commissions about allowing third-party power sales is oversight and customer protection. Therefore, it may make sense to have an official process where these owners communicate with the PUC. One way to do this might be by having the third-party owners (both PPA and solar lease providers) register with the PUC, but not be regulated by the PUC. Individual states would need to determine that registration could provide accountability of the service provider by charging the PUC to deal with customer complaints. At this time, there is civil recourse available to customers working within the third-party ownership structure, but adding registration could avoid issues with which civil courts may not be as familiar.

5.2.5 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 customers receive a fair deal and are not paying hidden fees or signing up for services of which they are not aware.

5.3 Alternatives to the Third-Party Ownership PPA
In cases where states have previously ruled against the third-party ownership PPA model or where legislative change or PUC decisions are not feasible, the following alternative solutions may be applicable.

5.3.1 Third-Party Ownership: Solar Lease
From conversations with a few state utility commissions, it appears that the solar lease is being used as a financing mechanism in many states that do not allow third-party ownership PPAs. The solar lease appears to be acceptable in those states that define a utility or LSE as an entity that sells "electricity." With a solar lease, the owner is leasing the equipment, not the electricity, which most states find to be an acceptable arrangement. One exception is the state of Nevada which characterizes a public utility as any plant or *equipment* that delivers power, which could have the effect of ruling out the solar lease in this state.

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

> 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 ownership PPA 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.

5.3.2 Utility Owns Customer Sited Generation Assets
With the recent change to the federal ITC, allowing utilities to take the 30% upfront PV tax credit (HR, 2008), it is possible that more tax-paying utilities will choose to own PV generation assets than before. Although these utilities may choose to build and own

large-scale solar plants, they also have the option to finance customer sited DG and sell the power back to the host customer. In this instance, the utility would effective take the place of the third-party in the current third-party owned PPA structure. If properly structured, the customer could enjoy the same benefits of fixed-price power at or below utility retail rates, and the utility could take advantage of the tax credits.

5.3.3 Clean Renewable Energy Bonds

One main reason to consider the third-party ownership PPA structure is to help get projects financed economically, without making an upfront payment. For munis and coops in states with retail competition, there is another way to structure financing for customer-sited projects that doesn't involve becoming a contractual intermediary.

Munis and coops have the opportunity to apply to the Internal Revenue Service (IRS) for clean renewable energy bonds (CREBs). CREBs are a financing instrument with the same structure as a tax exempt bond, except that in lieu of an interest payment, the federal government provides the investor with a tax credit (Cory, 2008). A recent allocation of $800 million in CREBs funding was authorized (HR, 2008) making this option once again available to state and local governments. While this structure has some challenges. (see Cory, 2008), in October, Congress updated the CREBs structure in an attempt to address a number of the drawbacks. More information about these updates should become clear once the IRS issues their guidance about CREBs and the application process; such an announcement is expected in early 2009.

The following table illustrates the wide range of solutions previously discussed. Legislative or regulatory changes to allow the third-party ownership model may 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. Many of the variations also require some type of ruling by a governing body (systems sized well below customer load, registration of DG services providers, and standardized third-party PPA contracts). The alternative solutions can currently be implemented in numerous jurisdictions without any legal issues.

Table 2. Summary of Solutions

Third-Party PPA Solutions	Parties Involved in the Transaction	Low/No Upfront Costs to the Site Host	System Maintenance Responsibilities	Monthly Payments
Legislative or Regulatory Change	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Utility Waives Monopoly Rights for DG	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Developer Sells Power to Utility (Contractural Intermediary)	Third-party sells to the utility	Yes	Third party	Based on electricity generated
Systems Sized Well Below Customer Load	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Registration of DG Services Providers	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Standardized Third-Party PPA Contracts	Third-party sells to end-use customer	Yes	Third party	Based on electricity generated
Solar Lease	No PPA, just flat lease fee	Yes	Customer, unless contracted	Fixed
Utility Owns Customer Sited Assets	Utility sells to end-use customer	Yes	Utility	Based on electricity usage
Clean Renewable Energy Bonds	Customer (govt. entity) owns the system	Must pay issuing costs	Customer, unless contracted	Principal is repaid in annual installments

6.0 Conclusions

Solar power installations are expected to continue to penetrate the U.S. market due to favorable state and federal government incentives and tax credits, as well as technology cost reductions. Therefore, it is important for customers to have a clear understanding of available financing options. This can be difficult with energy laws and regulation being primarily state driven and therefore different depending on where the system is being installed.

Third-party ownership is becoming a popular method of financing solar installations in the few states where incentives are high enough to make the systems economically viable. The primary advantages of third-party ownership are reducing or removing the upfront costs, as well as giving the customer a set power price in a long-term contract. Due to the combination of monetary incentives the system owner receives, the power price to the end use customer can be competitive with conventional retail power generation. Additionally, the system maintenance responsibility and operational risk are transferred to a company with solar expertise and constitute a financial incentive for keeping the system performing optimally.

Although the third-party ownership PPA is popular in states that allow its use (including competitive electricity markets), there are a number of regulated states and other jurisdictions that do not allow third-parties to own and sell electricity to the customers of regulated utilities. States interested in promoting solar PV should actively determine if action is necessary to remove barriers to third-party ownership. Of the cases investigated, no two states have the same specific situation (language, regulating body, etc.) that prohibits or allows third-party ownership PPAs. Therefore, it is impossible to recommend a single solution that will work everywhere.

However, a number of solutions were identified – either directly making the third-party model legal, working through variations of the third-party ownership PPA, or using alternative structures. The state of Oregon is one of the few that has ruled specifically on the issue of the third-party ownership PPA. The OPUC's decision was in favor of the financing mechanism as a way to meet the state's renewable energy goals. California also has state legislation that allows for the third-party ownership PPA to be used in residential and commercial applications.

Other solutions include variations of the third-party ownership model, many of which also require legislative or regulatory approval. For example, states can categorically allow systems sized well below a building's overall electricity use (set at a certain percentage), register DG providers, or allow a standardized third-party PPA contract. Other variations of the third-party ownership PPA do not necessarily require legislative approval, but focus on the utility. This includes the utility waiving their monopoly rights in certain cases or a developer selling power to the end use customer via the utility as a contractual intermediary, allowing the utility to remain the only seller of electricity.

There are other effective financing mechanisms being employed in jurisdictions where the third-party ownership PPA is not available. The most common is known as the solar lease, where the customer pays for the equipment but receives the electricity generated from that equipment. CREBs are available to state and local governments, including coops and munis, allowing them to finance and own solar PV without major upfront costs.

As the popularity of the third-party PPA grows, more and more states will be looking at their policies on this issue, with a number of states already in the process of making a ruling. The third-party ownership PPA provides numerous benefits to customers who are interested in solar PV, but don't want the upfront costs or maintenance responsibilities. It can be an attractive financing option that has spurred solar PV growth in the states where it is available. It is therefore important that states consider the pros and cons of allowing third-party electricity sales as one way to meet their renewable energy, solar, and distributed generation mandates and goals.

Appendix A: State Summaries

State	Is 3rd Party Ownership Legal?	Where is the Language?	What is the language?	Status and Solutions
OR	Yes	PUC Decision	Customer is NOT an Energy Services Supplier because they are not using the utility's distribution system (generation is less than load). Oregon Law exempts solar and wind from being "Public Utilities"	PUC made a Decision to allow third-party ownership PPA
NV	No	Legislation	Utility is entity that owns any plant or <u>equipment</u> that delivers power – appears to affect both third-party PPAs and leases	Docket is open at the PUC to determine legality
FL	No	PUC Decision	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	No	State Constitution	Anyone who furnishes electricity shall be deemed public service corporations	Solar Alliance filed a Docket with the Commission to exempt from regulation
CO	Determined by the utility	Utility	XCEL will sign a monopoly waiver for projects they approve under the condition that they can buy the RECs	XCEL is allowing multiple projects at their discretion
TX - Munis	No	Legislation	By allowing someone else to sell to their customers they could be opening themselves up to competition	Munis are exploring alternative solutions (e.g. solar leasing and utility as the intermediary)
CA	Yes	Legislation	Utility Code states that in some cases (non-conventional energy) and if you serve two or fewer customers you are not considered an LSE or ESP	Legislation was used to make third-party ownership allowable

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