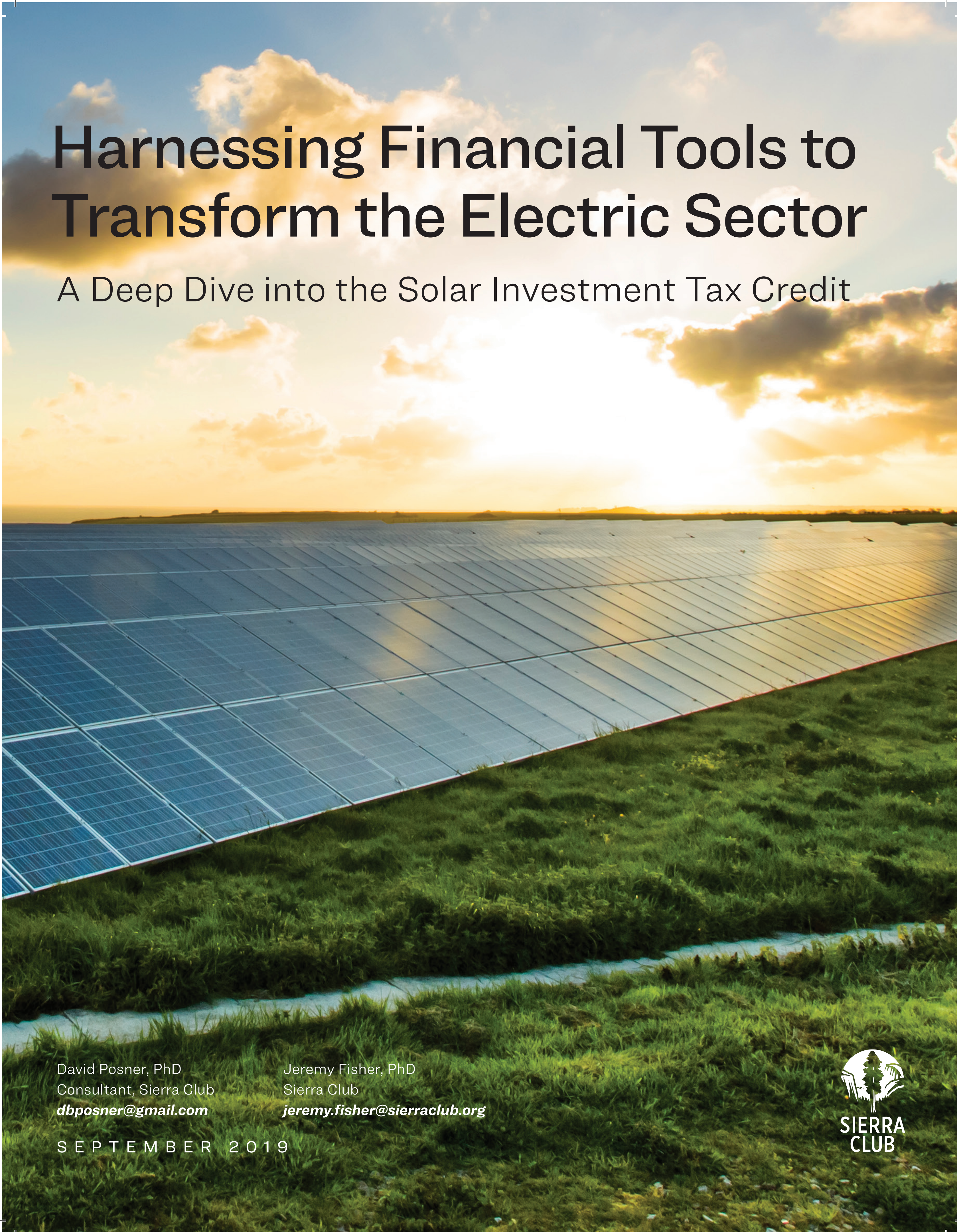

Harnessing Financial Tools to Transform the Electric Sector

A Deep Dive into the Solar Investment Tax Credit

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SIERRA CLUB

INTRODUCTION

Over the last decade, a combination of low market energy prices, rapid growth in renewable energy, and stricter environmental regulations have challenged the economics of coal-fired generation across the United States. In restructured regions with competitive markets, coal plants clear energy and capacity auctions less frequently, and have had to accept less favorable margins. Traditional vertically integrated utilities have faced increased regulatory scrutiny of coal plants whose operating costs alone often top the all-in cost of brand-new renewable facilities, and where the justification for continued operation has grown weaker. In response, since 2009, more than 80,000 megawatts of coal have retired,[1] and many more utilities have either announced retirements in coming years or are actively considering taking expensive and inefficient units offline. In the meantime, generation from renewable energy has surged. In June 2019, the U.S. Energy Information Administration announced that, for the first time, energy from renewable sources outpaced coal generation.[2]

The first wave of coal retirements focused on smaller and older units, and often units that would cost too much to retrofit with environmental equipment, like controls for toxic gasses. However, more recent retirements are a recognition that, even without a requirement for large capital investments, coal units simply can't compete in today's electricity market.

In an earlier paper, "Harnessing Financial Tools to Transform the Electric Sector,"[3] we focused on the capital recovery problem that investor-owned utilities face when deciding to retire a large existing power plant, and some of the emerging tools — like ratepayer-backed bonds, also called securitization — that utilities might use to get over that barrier. In the interim, states have begun looking more closely at these tools, in several cases enacting enabling legislation.[4] For utilities, one attractive element of securitization is if it is coupled to the opportunity for the utility to reinvest, called capital recycling. In our earlier paper, we noted that capital recycling is more difficult for utility-owned solar projects. In this paper, we explore the cost disadvantages utilities may face when building their own solar projects, and some of the proposed solutions.

In today's utility-scale market, solar is attractive if it's built by a third party and acquired under a power purchase agreement (PPA). But, as we show below, utilities may have a difficult time demonstrating that utility-built solar is cost competitive. As a result, even with emerging tools like securitization, utilities may oppose the clean energy transition, because they are unlikely to derive earnings from solar replacement resources.

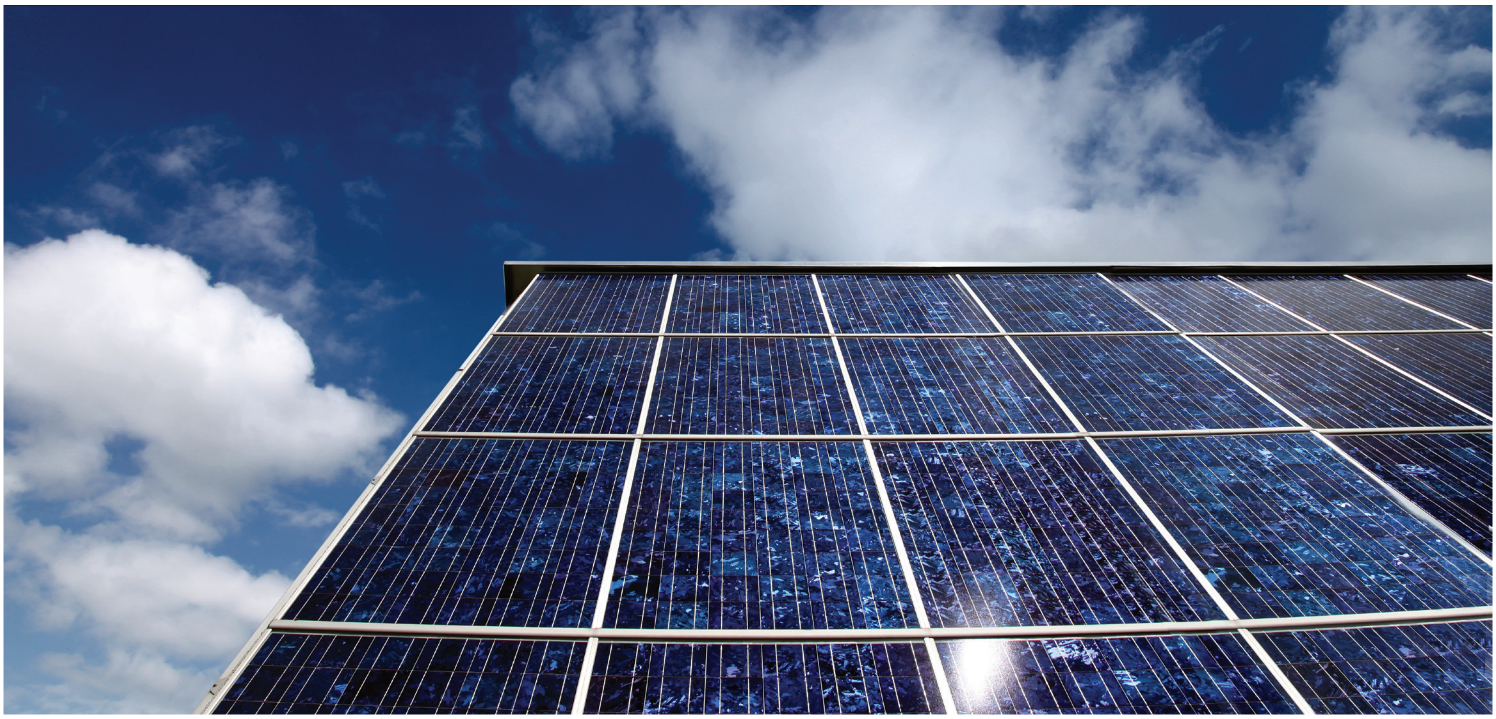
Here we explore the financing structure of solar projects, the basis of the barrier(s) faced by investor-owned utilities that want to own their own solar projects, and some of the methods states are exploring to overcome those barriers.

UTILITY RATEMAKING – THE THREE-PARAGRAPH PRIMER

Under traditional rate regulation, investor-owned utilities get reimbursed for all fuel, maintenance, operational, and PPA expenses — what we call "pass-through costs"— and earn a return on any capital they invest on behalf of their customers, for example by building transmission lines, upgrading existing infrastructure, or building new generation. This invested capital, called "rate base," is effectively a loan made by the utility to its customers. Over time, the utility recovers rate base plus a "return on" the capital, which is similar to interest payments that a consumer might make on a loan or mortgage. This return on investment is the primary way that regulated utilities make profits. For most utilities, about half of the invested capital comes from creditors (who issue relatively low-cost debt) and the other half from equity investors (i.e., shareholders).[5]

After the utility pays interest to its creditors on the money it borrowed, the profit that remains, called the "return on equity," goes to shareholders. In setting rates for investor-owned utilities, regulators prescribe an "authorized" return on equity, which in turn governs the amount of profit a utility can expect to earn.[6] Returns are not guaranteed, however, as regulators can also disallow costs they deem imprudent (i.e., not in the best interests of ratepayers). Disallowances primarily impact equity investors in their capacity as initial absorbers of loss. In short, utilities have a well-known incentive to build and hold capital projects, as these projects provide returns for shareholders.

In addition to paying a return on investment, customers pay back the utility some of the rate base every year, over a lifetime. This "return of" capital, also called "depreciation," is like paying down the balance on a credit card over time. And like credit card users, ratepayers pay interest only on their outstanding balance (as rate base declines, the calculated amount of return on capital decreases as well). Utility accounting usually calls for straight-line depreciation — i.e., the amount getting paid back on a particular investment gets evenly split over the life of the asset. As an asset ages, customers pay back the same return of investment (i.e., the fraction of outstanding debt) each year, but pay a smaller return on investment (i.e., the interest payment).



COAL RETIREMENT AND THE SECURITIZATION PATHWAY

The coal plants of today were typically built for an approximately 40-year life, and in many cases initial depreciation was set based on that expectation. Today, we have numerous coal plants in operation built well before 1980, largely because utilities have refurbished or replaced original equipment such as boilers and turbines, or have added high-cost pollution control equipment. Every time such a capital investment was made at a coal plant, the plant's rate base was increased, and in some cases the expected lifetime of the plant was extended. So, while a 50-year-old coal plant may have depreciated its initial capital balance, its presence in rate base today may still be substantial. In fact, we estimate that the average coal plant has about $500/kW of remaining undepreciated capital balance almost irrespective of age or capacity — and some have much more.[7] And rather than the initial 40-year life, utilities may be banking on coal plants lasting until they're 80 years old or more.

For the vast majority of rate-based coal plants that operate above market costs or the cost of replacement generation, the utility owners still garner substantial profits even if the plant delivers no value to ratepayers.

What happens when a utility retires a coal plant with substantial remaining plant balance? Even if a plant has poor operational characteristics and poses substantial risks to ratepayers, retiring an existing coal plant deprives its utility owner of future profits, and puts the shareholders at risk for the recovery of the outstanding balance. If the utility isn't allowed to recover the remaining capital balance, shareholders are left holding that loss.

Utilities are likely to argue that investments that were deemed prudent by regulators when they were made should be recovered in full. In contrast, consumers and regulators may balk at repaying capital sunk into a plant that is no longer operating ("used and useful"). This tension between shareholder risk and ratepayer loss has quietly dominated the debate around economic clean energy transition.

Fearing disallowance of a balance associated with a retired plant, utilities will often request accelerated depreciation, so that they can recover all capital from ratepayers before the plant closes. Accelerating the return of capital over a shorter period than was originally planned for an asset causes sharp near-term rate spikes, similar to the effect of paying off a 20-year mortgage in three years.

Enter securitization, a financial tool that allows ratepayers to refinance what they still owe on a plant balance, swapping out a high return on capital[8] (effectively the interest rate charged by a utility) in exchange for low-interest bonds to be paid back over decades. By refinancing with lower cost bonds, paid for over a longer period of time, securitization avoids the rate spike associated with accelerated depreciation. Securitization also allows a utility to get its undepreciated capital balance back immediately. This capital can be returned to shareholders and corporate debt holders, or, if suitable opportunities exist, it can flow into new investments such as wind or solar, with their own profit potentials.

After securitization, ratepayers owe money to a new set of investors, not the utility.

No longer tied to an uneconomic plant, securitization bonds represent a claim on a bill charge that the ratepayers will pay off over terms up to 20 years. Backed by legislation that reduces risk to bondholders — for instance, by preventing future regulators from disrupting payments — these bonds receive very high investment-grade ratings from credit rating agencies and carry a low interest rate. For example, while the typical rate of return collected by utilities from ratepayers to compensate debt and equity is around 7 percent,[9] ratepayer-backed securitization bonds issued under today's conditions are likely to pay less than 4 percent per year in interest. Compared with accelerated depreciation, low-cost, long-term securitization bonds can significantly reduce the present value of payments made by ratepayers.[10]

HOW DOES SECURITIZATION AFFECT RATES?

Figure 1 below illustrates the ratepayer impacts of securitization. Imagine a coal plant with $430 million of remaining capital balance and annual fuel and operating expenses amounting to $34/MWh. In addition to those operating expenses, ratepayers are paying $9/MWh in depreciation expense (the payments for return of capital) and $12/MWh to cover the rate of return on the undepreciated capital, for a total of $55/MWh.

In our example, the utility has found an inexpensive wind power purchase agreement (PPA) at $20/MWh — far cheaper than the $34/MWh for the coal plant's pass-through costs alone. All the parties agree: the plant should be retired and replaced with the wind PPA. Without securitization, in order to get the plant offline and take the wind PPA, the utility might seek to accelerate depreciation, but this would ratchet up the next year's depreciation expense to $36/MWh plus $12/MWh in return on capital. Thus, in the first year of the switch from coal to wind, ratepayers would be paying $68/MWh (middle column), more than the $55/MWh they had been paying for uneconomic coal.

With securitization, however, the remaining $430 million asset base is paid off with the proceeds from a ratepayer-backed bond. The utility is paid back immediately and its risk for the plant goes to zero — it can retire the plant and won't risk a disallowance.

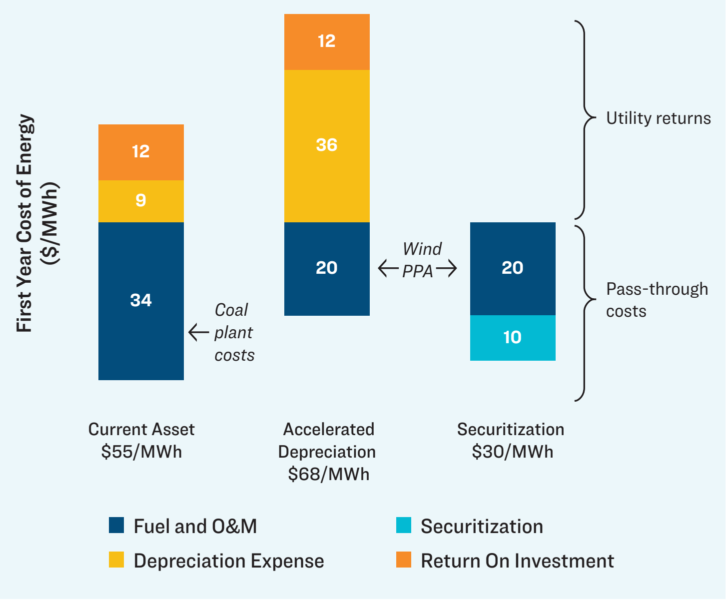


FIGURE 1. COMPARING RATEPAYER COSTS UNDER ACCELERATED DEPRECIATION AND SECURITIZATION

The utility still contracts for the low-cost wind PPA, and ratepayers start paying off the bond. However, rather than paying a combined $21/MWh for the depreciation and rate of return as they had been (or $48/MWh for these in the case of the accelerated depreciation), ratepayers pay just $10/MWh to cover the costs of the bond. Ratepayers have reduced their payment stack from $55/MWh for the coal plant to $30/MWh, unlocking the favorable economics of both renewables and securitization bonds while ensuring that the utility is fully compensated for its coal investment.

Securitization is not an earnings strategy for a regulated utility. The utility now has its cash back, but this means it has less capital in rate base earning a return. To earn in the future, the utility will want to seek regulatory approval to invest in new, renewable assets. If the utility can "recycle" its capital from the ratepayer bond back into rate base, it can maintain its level of earnings.

In our prior "Harnessing" paper, we described how utilities can own wind assets that may be cost competitive with third-party PPAs. However, it is more difficult for utilities to harness attractive earnings from solar, chiefly because U.S. tax regulations prevent utilities from efficiently capturing the value of the Investment Tax Credit (ITC) for ratepayers. The remainder of this document describes how tax rules make it difficult for utilities to build solar at a price that is competitive with PPAs and also examines solutions proposed by some states to remedy this problem.

TAX INCENTIVES FOR SOLAR

Solar energy has taken off in the last decade as the cost of solar panels and mounting hardware has fallen, and because of significant tax benefits to solar energy projects, the most important provided by the federal government. The two prominent federal tax benefits are direct tax credits and accelerated depreciation.

- **TAX CREDITS:** The Investment Tax Credit (ITC) is currently valued at 30 percent of a project's cost. Since the credit is claimed when a project is put into service, it essentially constitutes a 30 percent reduction in the cost of developing solar.[11] The credit is not refundable for cash, but if a company has tax due, the credit offers a dollar-for-dollar reduction.
- **ACCELERATED DEPRECIATION:** Solar projects may be depreciated over a 5-year period, so-called "Modified Accelerated Cost-Recovery System (MACRS)" depreciation.[12] Depreciation tax rules allow a business to deduct expenses to reflect how an investment is used up over time, thereby lowering taxes due to the government. Depreciation for tax is not to be confused with how utilities recover, or depreciate, rate base. In the default, the tax depreciation period accords with the expected life of the asset. However, under accelerated depreciation for tax purposes, deductions are front-loaded, reducing an investor's taxable "net income" in the near term (even to negative amounts), while its actual pre-tax cash flow is unchanged by depreciation. Effectively, this pushes taxable income out to a later year, which raises the present value of an investment. With a 30 percent ITC and a 21 percent Federal corporate tax rate, accelerated depreciation has a present value equal to 15 percent of the project's cost.[13]

In addition to being applicable to stand-alone solar projects, the solar ITC and accelerated depreciation benefits can be applied to solar-plus-storage projects in which batteries "behind the meter" are charged by solar projects. The full ITC is only available for the storage investment if charging relies completely on renewable energy. The ITC is scaled back if other charging is used and disappears completely if the renewable charging share goes below 75 percent.[14]

Solar developers are able to use both the ITC and accelerated depreciation to reduce the cost of projects, savings that are ultimately reflected in the cost of power to consumers. However, federal law requires public utilities to allocate the benefits of the ITC and accelerated depreciation to customers over the life of the asset. This requirement — known as "normalization" — reduces the present value of both tax benefits; the impact is greater for the ITC, since it is larger in value and, absent normalization, credited entirely in the project's first year of operation.

Utility-owned wind projects must also normalize their accelerated depreciation benefit. However, the "production tax credit," or PTC, that is available to wind projects (but not solar) is not subject to normalization.

THE ROLE OF TAX EQUITY

To maximize the value of the ITC and accelerated depreciation, a taxpayer needs to have enough income and associated tax liability to absorb these benefits when they first become available.[15] Because renewable energy developers typically lack tax capacity in the early years of a project, it is common for them to partner with a different set of investors seeking to offset other taxable income, so-called "tax equity" investors. In these partnerships, the energy revenues and the tax benefits stemming from a project can be allocated to the investor best able to use them; the allocations do not need to be in line with each investor's ownership share of the project. Thus, tax equity investors can receive most of their return in the form of tax credits and deductions, while developers receive cash.

Figure 2 shows a breakdown for an example $100 million project structured as a so-called "partnership flip." In this example, the tax equity investor puts in 35 percent of the project's capital ($35 million). In return, the tax equity investor receives 99 percent of the ITC and the net income for the first few years of the project's life.[16] In contrast, the developer (here called the "project sponsor") receives the majority of the cash income from the project. Once the tax equity investor has received the fully vested ITC and the benefits of accelerated depreciation, its share of net income and cash drops to only 5 percent. With the tax equity investor's role essentially complete, nearly all the remaining benefits (i.e., the project revenues) accrue to the developer. Without any depreciation left, the developer now realizes a positive net income, and pays income taxes on its revenues (unlike the tax equity investor, who realized a loss).

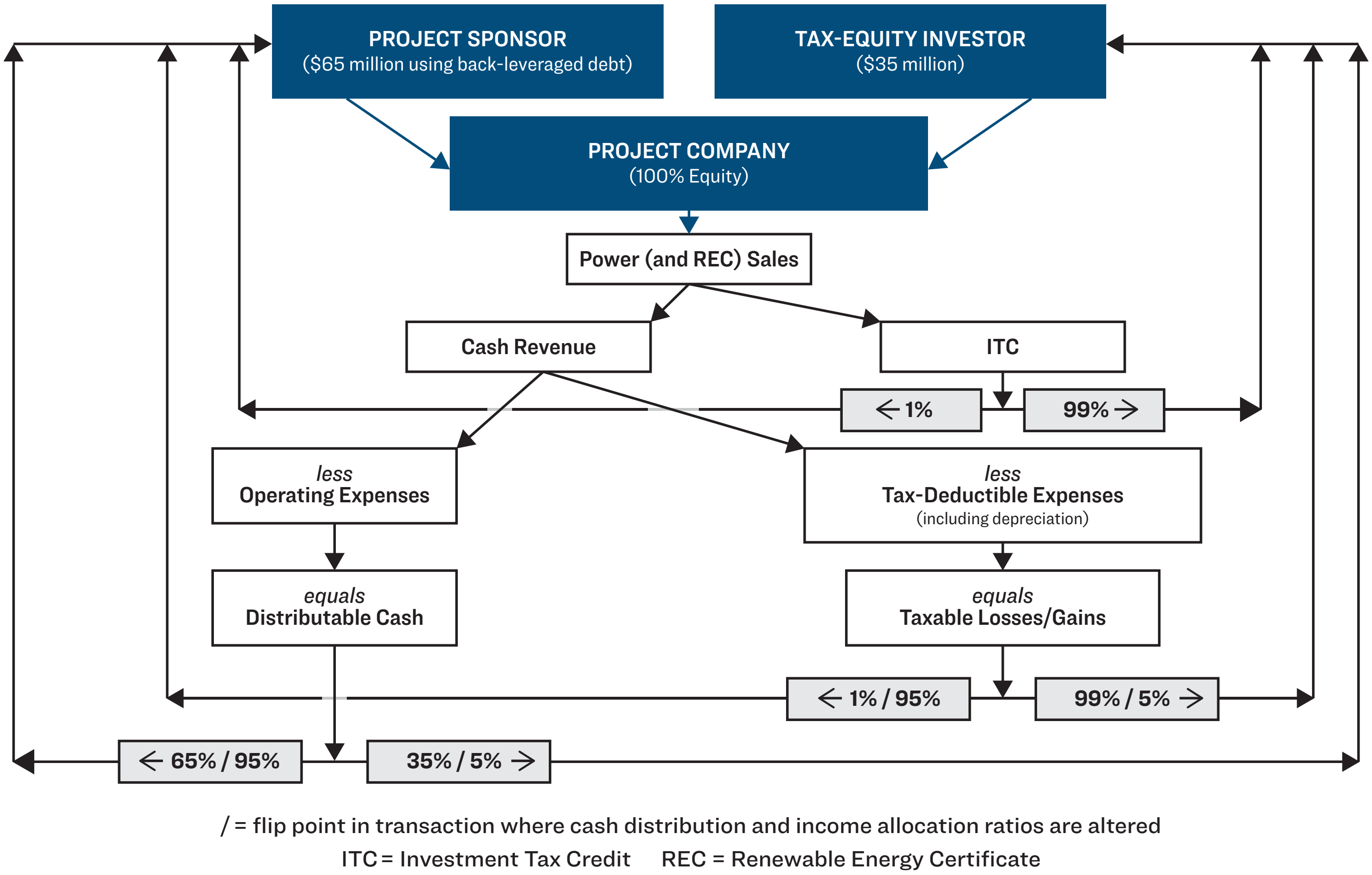


FIGURE 2. PARTNERSHIP FLIP STRUCTURE AND ALLOCATIONS SOURCE: NREL, Terms, Trends, and Insights on PV Project Finance in the United States, 2018

TAX BENEFITS LOWER THE COST OF PPAS

When a developer bids or sells a PPA to a utility, it weighs two key factors: the total costs to be incurred and the amount of energy expected to be produced by the facility. In general, total expected costs divided by the total expected energy to be sold is the price of the PPA. The total expected costs comprise the investment and its financing costs (e.g., debt or equity returns) plus the cost of maintenance, insurance, property and so on, minus the value of the tax benefits. Thus, more substantial tax benefits lower the price per MWh that must be charged to recoup all costs of the project.

For example, consider an 810 MW solar facility. At $1,100/kW, the upfront cost of the project is $890 million. Offered as a twenty-year PPA, and including the benefits of a 30 percent ITC ($267 million) and accelerated depreciation, consumers would end up paying an all-in cost of about $804 million on a present value basis,[17] or a levelized PPA price of $38.24/MWh.[18] For simplicity, we have ignored residual value for energy sales after the expiration of the PPA in year 20. In practice, however, the owner of the project would assume some residual value, allowing it to offer a lower price for the 20-year PPA.

UTILITY-OWNED SOLAR IS DISADVANTAGED BY NORMALIZATION RULES

From the ratepayer perspective, the project described above does not realize equal tax benefits if completed by a utility as a rate-based asset. Under IRS rules,[19] the utility must normalize the ITC benefit when setting rates. This lowers the present value of the tax benefit for ratepayers and correspondingly increases their costs.

If the ITC is thought about as a pot of money provided to solar project developers, the treatment difference becomes clearer:

- A private developer (or tax equity investor) can tap the ITC pot of money immediately and return a significant share of project's upfront costs to investors, lowering the total cost of the project (which includes financing charges) that must be recouped from energy consumers.
- The utility also gets the ITC pot of money paid by the U.S. taxpayers in the first year, but, for ratemaking purposes, it does not permanently lower the rate base to be recovered from ratepayers. Instead, the utility essentially claws back the benefit from ratepayers over time. In year 1, ratepayers are credited with the full amount of the ITC as an offset to rate base, reducing the amount they must pay to the utility as a return on capital. In year 2, however, the offset is reduced by a fraction of the ITC amount, taking back from ratepayers some of the previously shared benefit. In year 3, another reduction occurs, further lowering the benefit for ratepayers. And so on and so on, until the rate base offset has been reduced to zero. To be clear, the fact that ratepayers have received less value does not mean that utility shareholders have suffered. They received the full amount of the ITC in year 1 from the federal government (assuming the company had sufficient tax liabilities) but have, as required by law, shared only a lesser amount with ratepayers.

Using the same 810 MW, 20-year solar project example as before, the utility's ratepayers face an all-in present value cost of $866 million, or 7 percent higher than the private developer's $804 million cost, even though we assume that the utility can tap lower cost debt and equity for a 6.57 percent weighted cost of capital, or WACC (as opposed to a 7 percent WACC for the private developer). Levelized per unit of energy, ratepayers will have to pay $41/MWh, while the private developer could offer a $38/MWh PPA.

Normalization:
An accounting method that legally requires regulated utilizes to spread tax benefits such as credits and accelerated depreciation over the regulatory life of *public utility property.* This increases the cost of energy from utility-owned projects relative to third-party projects.

Regulators and ratepayers might rationally favor a third-party developer able to offer the same beneficial solar project at a relative savings. In this case, utility shareholders lose out on the earnings opportunity altogether.

NORMALIZATION ALSO DEVALUES DEPRECIATION

Normalization also lowers the benefit of accelerated depreciation for utility-owned investments.[20]

For tax purposes, the utility uses the accelerated depreciation to lower its tax burden, similar to a tax equity investor. However, for ratemaking purposes the utility collects funds to cover income taxes from ratepayers as if it were using straight-line depreciation (i.e., not accelerated). This disconnect between the benefit the utility receives from the U.S. government (in the form of accelerated depreciation) and the charge passed onto ratepayers effectively results in a loan from ratepayers to the utility — in other words, the fact that the utility realizes depreciation faster than ratepayers means that ratepayers are over-charged in early years.

The disconnect between tax depreciation and rate base depreciation is not new, and utilities have developed a way to ensure that ratepayers are compensated for the loan made to the utility. The utility tracks excess revenues collected in a balance known as Accumulated Deferred Income Taxes, or ADIT. ADIT is used to offset rate base, which means ratepayers effectively get interest on this money, but of course they lose the opportunity to invest it themselves.

In early years, the ADIT account increases as ratepayers pay more taxes to the utility than are actually owed to government. In later years, after accelerated depreciation has exhausted depreciation for tax purposes, the amount paid by ratepayers to cover taxes is less than what is owed to the government. At that point, the utility starts drawing from the ADIT account to pay taxes. At the end of the project life, the ADIT account will have returned to zero, ending the loan from ratepayers.

Normalization of accelerated depreciation shifts tax benefits into the future. In the early years of the project, ratepayers pay more taxes than they would have if the full benefit of accelerated depreciation were flowed through to them immediately, while future ratepayers will pay less. This shifting lowers the present value of the benefit.

TOOLS TO HELP UTILITIES COMPETE WITH PRIVATE DEVELOPERS

EXTENDED SOLAR LIFE

One way in which utilities can compete with solar developers is by building solar projects with relatively longer asset lives. From a practical perspective, this may not mean a substantively different project, only that utilities and regulators agree to recoup investment over an extended period — longer, for instance, than is currently available in PPA market. In the commercial PPA market, terms have been shrinking as off-takers (i.e., purchasers) who are expecting continued renewable energy price declines grow increasingly reluctant to lock in contracts for extended periods. While a private developer might expect to recoup all costs (and profit) over a 20-year PPA life, and assign a very low residual value to post-PPA energy sales, a utility might seek to simply establish a project with a 30-year life. In our example, allowing customers to benefit from, and pay for, the asset of ten additional years depresses the price per MWh to $34.78. Of course, if regulators also expect future solar price declines, they may be reluctant to saddle ratepayers in the distant future with relatively expensive energy payments contracted today.

However, crediting a utility-owned asset with a longer life only masks the impact of normalization. If the utility's customers were to lock in a PPA priced without normalization for 30 years, enabling a true apples-to-apples comparison of energy delivered, they would pay only $33.41, despite a higher underlying cost of capital paid by the private developer.

MARKET-INDEXING OF SOLAR

Several states have recently enacted legislation to help counter the normalization handicap for utility-owned solar. In 2015 and 2018, Virginia and Utah, respectively, enacted laws designed to provide alternative financing routes to utilities for solar projects.[21] Both laws allow regulated utilities to price solar energy for ratepayers based on a "market-index" rather than traditional utility accounting with the normalization requirement. Effectively, these laws allow the utility to act as a private developer, build solar, and then offer it to ratepayers as a PPA; rather than the utility collecting a rate of return on rate base, it bakes a return into the cost of the PPA. In doing so, the utility can harness the full benefit of the ITC and accelerated depreciation and offer a price to ratepayers that is equivalent to third-party offerings. Potentially, utilities could even undercut third-party PPA prices by leveraging their lower costs of debt and equity. Normally, utilities would be restricted from doing so because these practices circumvent traditional regulatory review of items in rate base. These laws seek to provide a safeguard to ratepayers by compelling utilities to subject their proposed PPAs to a market test, and only accepting the lowest cost purchase agreements.

> ***Market-Indexing of Solar:***
> Legislation recently adopted in several states allows utility to own, and profit on, solar assets without the property being treated by the IRS as public utility property requiring normalization of tax benefits. Ratepayers are charged a per price MWh set competitively in line with third-party PPA offerings.

In a private letter ruling released in June 2019, the Internal Revenue Service ruled that a solar project whose energy is priced in market-indexed fashion does not constitute public utility property and is therefore not subject to normalization.[22]

IMPENDING PHASEDOWN OF THE ITC

The Consolidated Appropriations Act of 2016 extended the 30 percent solar ITC through 2019, to be followed by a step-wise phasedown of the credit to 26 percent in 2020 and 22 percent in 2021 (see Table 1). Beginning in 2022, individual taxpayers will be ineligible for any ITC. Business taxpayers, however, will continue to qualify for a 10 percent credit in 2022 and beyond.

	Individual Taxpayers	Business Taxpayers
Through 2019	30%	30%
Through 2020	26%	26%
Through 2021	22%	22%
2022 and onward	No Credit	10%

TABLE 1. PHASEDOWN OF THE SOLAR INVESTMENT TAX CREDIT

Adjustments to tax code in 2018 made it easier for developers to claim the ITC by shifting eligibility deadlines to the "beginning of construction" rather than when a project is placed in service.[23] In effect, a developer can now make an initial "safe harbor" investment to capture the ITC at the level available in that year, even if the project will enter service only several years later when the ITC percentage has declined. Under this new requirement, the IRS provided guidance to determine the criteria of the safe harbor provisions.[24]

The beginning of construction can be demonstrated by either the "Physical Work Test"[25] or the "Five Percent Safe Harbor."[26] The taxpayer must be able to show that work efforts on the project were continuous after the start of construction, but this requirement is assumed to have been met if the project is completed within four calendar years after the year in which beginning of construction is claimed. In the most favorable possible exploitation approach, systems that are recognized as having begun construction before January 1st 2020 would still be eligible for the undiminished 30 percent credit so long as they began operations before January 1st 2024. Regardless of when construction begins, no project entering operational service on or after January 1st 2024 will receive more than a 10 percent ITC.

With a 10 percent ITC, the PPA's price advantage over utility-owned solar with normalized tax benefits disappears, assuming costs of capital — WACCs — remain the same; for our 810 MW example, ratepayer costs would rise to just north of $45/MWh. However, with fewer tax benefits available, tax equity would form less of the capital stack in third-party projects; in all likelihood, debt would take tax equity's place, lowering the WACC (albeit on a larger balance net of the smaller tax credit).

CONCLUSION AND SUMMARY

Securitization is an important financing tool that can help overcome some of the risks and costs impeding the retirement of uneconomic coal-fired power plants. Utilities can recover undepreciated capital immediately, escaping the danger of disallowance. Consumers can avoid near-term rate spikes that follow from accelerated (regulatory) depreciation of plant balances by taking advantage of long-term, highly rated bonds that carry a low interest charge; in today's financial markets, institutional investors such as insurance companies and pension plans provide considerable demand for these debt instruments.

But securitization alone will not deliver a clean energy future. Unless securitization legislation requires renewables as replacement resources for retired plants, new assets could still be carbon emitting. And since securitization does not provide utility earnings (and, indeed, reduces them), the tool alone may be less attractive to utilities, unless otherwise faced with a risk of disallowance. For many utilities, securitization may need to be part of a package that facilitates new investment/earnings opportunities.

Capital-intensive renewable assets can provide significant earnings potential to utilities, and at least for wind assets, utility financing with efficient use of the PTC is highly competitive with third-party PPAs. By combining tax incentivized new wind with securitization in appropriate situations,

- utilities can recover exposed capital from coal plants and actually boost earnings for shareholders,
- while ratepayers get clean energy and a financially robust utility partner for a per MWh cost that is far lower than what they would pay for continued operation of uneconomic coal.

For solar, an attractive utility-ratepayer package is currently more difficult to achieve, in large part because of the way normalization tax rules disadvantage utility ownership of solar assets. Legislative examples set by Virginia and Utah demonstrate a possible mechanism for overcoming this disadvantage.

More generally, clean energy advocates should reconsider the value of normalization requirements. Ostensibly designed to provide fairness to investors and future ratepayers, normalization as applied to the tax benefits currently available for solar projects may well be preventing utilities from accelerating the clean energy transition. That acceleration is arguably the most valuable benefit today's stakeholders can provide to generations to come.

ENDNOTES

1 EIA Form 860M, April 2019.

2 EIA, June 26, 2019. U.S. electricity generation from renewables surpassed coal in April: https://www.eia.gov/todayinenergy/detail.php?id=39992.

3 sc.org/financial.

4 For instance, in New Mexico SB 489 (2019) and Colorado SB 19-236 (2019).

5 The exact split between debt and equity is determined by regulators, who seek to balance the cost benefits of debt with the need to incentivize equity investors who receive their return after creditors. For their part, creditors typically seek to limit their exposure by demanding the utility have sufficient equity participation to absorb losses. If a utility under-collects, faces a disallowance, or is compelled to accept a lower equity return, losses are first absorbed by shareholders, rather than creditors.

6 As a practical matter, the actual return received by a utility will not exactly match the authorized return. When a commission sets an authorized return, the utility adjusts its customers' rates accordingly. If the utility's projections are correct, after accounting for expenses and debt payments, the utility should be left with an amount of money that reflects its expected return. However, many other factors, such as changes in demand and adjustments to spending may leave the utility with a higher or lower return than "authorized."

7 As context, new fossil power plants are estimated to have an overnight cost of about $750-$1,000/kW (see Assumptions to the Annual Energy Outlook 2019, Electricity Market Module, Table 2). An old existing coal-fired power plant therefore may have as much debt on the books as a new plant would cost to build outright.

8 The utility's rate of return, or weighted average cost of capital (WACC) is comprised of relatively low-cost financing from corporate debt and high-cost financing from equity investors.

9 This 7 percent rate of return reflects a blend of corporate bonds (4-6 percent interest) and high-cost equity (9-11 percent return).

10 By "present value" we mean the overall cost of an investment expressed in today's dollar terms from an investor's standpoint. The present value of a future cost is usually smaller today because we can invest (and hence grow) today's dollars until that future date. For utilities, we typically "discount" back to today's present value at the utility's WACC.

11 The ITC vests ratably over 5 years. If the project ceases operations before then, the unvested portion is subject to recapture by the IRS.

12 In fact, through 2022, developers, but not public utilities, can fully expense all investments in the first year of operations. But IRS rules prevent partners from absorbing more tax benefits than they have in so-called outside basis, a figure that is increased by investment and income and decreased by losses and cash distributions. In practice, investors have not shown much interest in immediate 100% expensing.

13 The recently lowered Federal corporate tax rate lowered the value of the depreciation, which is a deduction to income. The value of the ITC, a credit, remained unchanged. If the ITC is claimed, then the total amount available for depreciation (the "basis") is reduced by half the amount of the ITC.

14 An annual requirement that also vests over 5 years.

15 A taxpayer, or developer, that isn't able to use all of its credits or losses immediately can carry those credits or losses forward, but the present value of any delayed benefits is lower.

16 In a partnership, the IRS requires that the tax equity investor receive no more than 99 percent and no less than 5 percent of the tax benefits. To help ensure that they pass IRS muster, most deals also provide the tax equity investor with at least a 2 percent pretax return.

17 The present value of the project includes the upfront, financing, and operating costs over a twenty-year period, discounted back to the present day at an assumed after-tax WACC of 7%.

18 Assumptions: Capacity factor of 30%, resulting in 1,985,676 MWh per year.

19 Under Section 50 of the Internal Revenue Code (IRC).

20 Required under IRC Section 168.

21 Virginia 2015 House Bill 2237: Electric Utility Ratemaking; Recovery of Costs of Solar Energy Facilities; Utah 2018 House Bill 261.

22 See PLR 201923019, available at https://www.irs.gov/pub/irs-wd/201923019.pdf.

23 Bipartisan Budget Act of 2018.

24 IRS Notice 2018-59.

25 The physical work test requires that "a taxpayer begin physical work of a significant nature." No specific cost amounts or percentages are required and off-site work, say, at a factory is acceptable, provided separate business entities carrying out the work are subject to binding contracts and the items worked on are not part of vendor's typical inventory such as solar panels. Installation of racks on-site would constitute suitable physical work, as would off-site manufacture of a transformer.

26 The five percent safe harbor establishes that the beginning of work occurs when a developer has paid or incurred five percent of the total project cost. Only costs "integral" to the production of electricity are eligible, thereby excluding items such as the value of real estate or equipment for transmission. Paying for items such as panels that are typically held in a vendor's inventory does count toward the five-percent threshold.

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