A TIGER IN THE LIFEBOAT: MAKING THE MOST OF UTILITY SOLAR PV

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ABSTRACT

In papers presented to ASES in 2006 and '07, Cliburn and Robertson weighed the merits of direct utility investment in solar distributed PV, as a way to meet climate mitigation goals.[1] At the time, the thesis that utility PV could offer unique economic and societal benefits was a hard sell. Utilities were barely in the field, and the solar industry viewed them mostly as a barrier to getting PV on the grid. Yet policy and market forces have dramatically changed utility solar investment patterns. Utility solar, including PV, is the fastest-growing segment of the US solar market today. The title of this paper recalls a novel, *The Story of Pi*, to illustrate how a utility (cast in the role of the tiger) might be a dangerous but necessary partner for solar success, cast in the role of Pi, the adolescent hero.[2] (As a novel, the book is about a myriad of other things besides a boy and a tiger surviving a shipwreck together; among them, it suggests that dramatic images have a place in helping us grasp game-changing ideas.) Figuratively, utilities and solar stakeholders find themselves in the same lifeboat, heading for a high-tech, carbon-constrained future, while the role for solar PV in utilities and in our society is still undetermined.

This paper will review recent utility solar trends, drawing from ongoing work in three distinct markets: 1) Wisconsin, where regulatory intervention in 2008 led to a statewide Solar Collaborative to look at whether and how utilities should invest in PV, 2) New Mexico, where the major utility and stakeholders recently filed a stipulated agreement to conditionally restore and expand threatened solar incentives, and 3) the electric co-op market, where utilities are newly considering PV as a utility asset investment. The paper takes a high-level view, but highlight key issues and possible resolutions.

1. INTRODUCTION: UTILITIES AND SOLAR STAKEHOLDERS IN TRUCE

Despite the rapid pace of utility-solar development in the U.S. today, it has only been a few years since the solar industry and the utility industry seemed irrevocably at odds. The reasons for this were largely rooted in utility regulatory history. The commercial solar industry was born in the 1970s, coinciding with the post-embargo hey-day of energy self-reliance. The solar industry then reached its adolescence during the era of deregulation, when some policymakers envisioned utility and non-utility distributed generation sparking a revolution in the industry. Many solar advocates wanted to be a part of that revolution, challenging established utility practices. This model for solar development applied initially to do-it-yourself PV, but it soon drove PV investments for government entities, big retailers, and others. The solar energy services company Sun Edison, begun in 2004, embodied this trend, offering an alternative to utility-only service. Most utilities responded to distributed PV at first as an annoyance and then as a threat, and only recently as a potentially useful resource in the utility portfolio. At the same time, while many solar customers still value energy self-reliance, many also see the emerging importance of some utility functions, especially related to their market reach and grid services.

Utility solar has emerged as a powerful counterpoint to customer-driven solar, capable of driving gigawatts of development and appealing to the global solar industry as no other market-channel has. Regulated and consumer-owned utilities were initially conceived to serve community needs by orchestrating different technologies and unleashing economies of scale. The utility-solar vision emphasizes universal service, system reliability, and an ideal of equitable, cost-based rates. Studies, such as the Clean Edge Utility Solar Assessment, concur that utilities have a lead role in diversifying resource portfolios and modernizing the grid for the benefit of all Americans.[3] Yet, utilities, like the tiger in this paper's title, are mostly atavistic. Their solar plans trend toward scaling up and streamlining PV deployment, while adhering as much as possible to regulatory minimum requirements and standard utility economics, design, and operations. In 2007, Cliburn discussed how customer-driven and utility-driven solar express opposite, but equally important social values: first, the customer-driven solar Trailblazer, valuing courage, innovation, and independence, and then the utility-driven solar Wagon Train, which values inclusion, integration, and order.

In 2010, the tension between customer-driven and utility-driven PV is still important. But perhaps a new metaphor applies—the utility as a tiger in the lifeboat. The utility might be necessary to achieving climate mitigation and other societal goals, but only if it is understood—and often warily. The premise of regulation is that monopoly utilities are going to act in their own self-interest, unless their attention is deliberately trained on serving the public good. Utility solar is not necessarily compatible with public policy goals, and conversely some public policies and established regulatory tactics will need innovation, to get the most public benefit from utility solar.

The authors cannot predict the ultimate role of solar PV within or beyond the utility. What we can identify now are a number of ways in which utility solar strategies need improvement, and a number of ways in which customer-owned solar strategies continue to offer unique and important benefits.

2. LIMITATIONS OF UTILITY-PV ECONOMICS

A 2008 report from the Solar Electric Power Association on solar business models addressed four utility-solar stakeholder groups: utility owners, customers, society, and the solar industry, and it assessed solar business models in an attempt to identify win/win approaches from all stakeholder perspectives.[4] That study was beneficial in giving the utility perspective at-least-equal weight. Until that time, there had been little about utility solar in the literature. However, in practice, the utility perspective almost always trumps other perspectives in determining whether and how utility solar moves forward. Another 2008 report, for the National Renewable Energy Laboratory recognized this, concluding, "The full benefits of an extensive distributed PV resource are not likely to be realized without some degree of utility control and possibly ownership."[5] The downside of that realization is that unless the utilities' limitations are addressed, they may hold solar progress back.

The utility perspective encompasses not only shareholder or consumer/owner interests, but also operational interests—a broad set of practical and cultural concerns. Confronted with a list of some 40 distributed solar benefits, utility leaders typically ask, first, whether solar is being required, then which of these solar benefits could the utility monetize, and its third, how might the effort to capture these benefits upset other, ongoing utility operations? For example, in 2008 testimony supporting solar as an alternative to repeated utility rate hikes in Wisconsin, the authors pointed out that Wisconsin Power and Light and Wisconsin Public Service each could retire numerous outdated, inefficient natural gas peakers by making a significant investment in solar PV.[6] The utilities' initial response was that since the Midwest Independent System Operator (MISO) controlled the regional loading order, no one utility had much influence on wholesale operations or costs. Reframed, the question became, how might solar on the distribution side of the grid help these utilities to purchase less wholesale power at high locational marginal prices (LMPs)? From the utility's perspective, the retirement of inefficient plants was only secondary to this immediate benefit. The utility value proposition must be stated in a way that is economically and practically meaningful.

Conversely, state and national policymakers are just beginning to understand the new regional markets that they created. Policymakers in ISO regions need to find new ways (for example, ordering development of equitable solar capacity credits) to transform generation portfolios.

A range of limitations of utility solar is discussed below.

2.1 Effects of Restructuring. As just described, a simple description of the utility solar value proposition does not map onto most utilities today. They are no longer vertically integrated, and must find ways to capture benefits that do not flow directly to them.

- The challenge facing regions with Independent System Operators is described above. Solar strategies must be refocused on reducing wholesale power bills, or by directly incentivizing ISOs to quickly, cost-effectively displace natural gas use and replace outdated turbines with integrated renewable energy strategies.

- The structure of the consumer-owned utility sector provides a similar challenge. Many electric co-ops and municipal utilities are under all-requirements contracts from their power suppliers; they do not have much local generation. Some wholesale providers now allow a small amount (typically up to 5%) of the local utilities' portfolio to be locally owned DG. This does not begin to address planning and operations for growing customer-owned PV on local distribution lines. In some cases, a significant peak load reduction from solar in one distribution territory *could* shift costs to other members of the G&T co-op or joint action power supplier. The current response is to treat PV-friendly local utilities as outliers, to be discouraged. An alternative might be for suppliers to encourage that PV market growth, but regionwide, through leadership and coordination. In fact, there may be solar operational benefits for wholesale suppliers who encourage geographic distribution of PV regionwide.
- Some IOUs argue that corporate restructuring has created firewalls, which prevent them from realizing the full economic benefits of solar. A distribution utility cannot directly realize transmission loss savings, for example. The authors encountered this as a serious barrier four or five years ago. Interestingly, as solar becomes more economically attractive, utilities seem to be finding ways to account for indirect savings.

2.2 Resource Match and Impacts on Generation Utility planners often take interest in the match between the solar resource supply curve and the load curve, on both an annual and peak-day basis. Yet if the match is imperfect, they greatly discount or dismiss solar value. This is arguable in some cases (for example in assessing distribution investment deferral value, as discussed below), but often the utility dismisses intermediate and peak solar resource value unnecessarily.

For example, electric co-ops and other utilities nationwide may experience summer peaks in the early evening, when solar resources are falling off. Some utilities may site their PV slightly toward the west to capture more of that late-day sun, and they may create incentives for their solar customers to do the same. They could also use time of use rates or load control strategies to move or suppress the late afternoon peak. In our experience, utilities have not yet embraced such options. There has been an increase in use of solar tracking systems, with market observers predicting that 85% of solar projects of 1 MW or more, built between 2009 and 2012, will use tracking technology.[7] But utilities find other steps harder to take.

Solar advocates' focus on the match with system peaks may be backfiring a bit, as utilities push back with arguments about their "mismatch." In fact, the value of natural gas savings (and other resource savings and PV market-penetration increases) from diminishing most if not the entire system peak is potentially great. Further, in ISO regions, the appropriate focus is not on "attacking the peak" per se, but rather on reducing wholesale purchases from the market at high-cost LMP nodes.

As researchers anticipate greater PV market penetration, their models suggest changes in regional utility system operations. Denholm, Margolis and Milford have modeled increasing penetration of PV—up to 10 percent—in Western markets, and recognized a need for increased natural gas plant cycling, with a decrease in gas fleet operating efficiency.[8] A similar study by Lew and Milligan, looked at high penetration of a wind, solar, and CSP portfolio in the West and noted that on a given day in April, at 35% renewables, "the combined cycle units are almost completely off, gas (peaker) turbine output has increased, and the coal plants are cycling significantly. Even the nuclear units are trying to cycle some, which more likely would indicate a need to spill some of the wind generation."[9]In practice, utilities are likely to balk at such high penetration of renewables, as it runs against their ingrained understanding of how to run generation fleets efficiently. Undoubtedly, they would also balk at the erosion in cost-effectiveness—from additional plant cycling or actually dumping generation. To overcome such resistance, solar advocates should prepare now to refocus utility attention on integrated resource planning, *overall* system operating costs, and new performance metrics, such as greenhouse gas emissions reductions. They should expect to make quicker progress where regional system operators are in charge than where local utility operators dispatch their own generation.

2.3 Problems with Distribution Investment Deferral In the authors' experience, utilities in every sector and region have trouble capturing the potentially enormous solar savings from distribution system infrastructure deferral. One reason is a lack of good data on marginal distribution deferral costs in specific locations. The range of utility-reported marginal costs has been reported at anywhere between $127 to more than $3,000 per kW. A 2007 assessment of different methods of calculating deferral value pointed to field data from DTE and a refined study from Oak Ridge National Labs, that put a likely maximum value at $400/kW or less.[10] Few utilities have methodologies for identifying high-value load pockets. But it is not the lack of data on potential deferral values that really concerns utilities; it is the lack of real data to prove that PV can meet availability, reliability, and power-quality requirements for a deferral. The risk of uncontrolled two-way power flows from increasing penetration of rooftop PV is a particular concern cited by co-op distribution engineers.

New projects, such as an Arizona Public Service project initiated in 2009 to test utility-PV on a single feeder near Flagstaff, may raise distribution engineers' confidence that deferral values for PV are real. Anecdotal reports from electric co-op engineers suggest that regardless of positive results from a few field studies, individual utilities probably will insist on running their own pilot projects, beginning with more controllable substation-based PV, before they will be ready to bank on PV for distribution deferral.
A related need for field data, worth noting here, lies in the hypothetical value of using demand response to increase PV capacity value. Perez, among others, has made a strong case for coupling demand-response and PV.[11] Proven load control techniques may accomplish many of the same results as costly storage batteries, but utility engineers remain skeptical until many more PV/smart grid studies, such as the APS study or studies underway in Boulder, San Diego, and Marshfield (MA) are widely accepted.

2.4 Economic Methodologies That Favor Fuel-based Generation The electricity grid in the US was built on an infrastructure of generating fossil fuel-based electricity in one location, and transporting that electricity to the point of use. The overall utility regulatory regime, and specifically ratemaking methodologies, were also structured around this fuel-based generation model. Today, this regime imposes a strong bias towards maintaining the status quo of electricity resource options, and it discriminates against renewable resources that do not have fuel costs. This is a fundamental problem that underlies the limitations of utility-PV economics discussed above, as well as the rate issues discussed in Section 3, below.

A central flaw in the economic methodology of utility resource selection is the discriminatory nature of poorly applied discount rates. For example, in determining the Net Present Value (NPV) of a natural gas turbine versus a solar plant, the cost of natural gas over the expected 30+ year life of the plant is discounted at the utility weighted cost of capital. Natural gas plants are not capital-intensive, with only about 15% of the lifecycle costs realized as capital costs in Year 1, and the remaining 85% of its costs realized as fuel costs which are heavily discounted into the future. A typical 9% discount rate values the future cost of natural gas at less than 18 cents on the dollar in Year 20 in a discounted cash flow model. Moreover, this analysis would not include any "beta" factor to account for fuel price volatility.

By contrast, a PV plant is highly capital intensive, with nearly 95% of its lifecycle costs occurring during Year 1, with only 5% of its remaining costs, primarily operations and maintenance, discounted over the its expected life (30 years, or another long-term standard). Under this current methodology, solar would not receive any benefit from discounting future costs, since it has virtually none. Thus, fossil-based generating resources typically pencil out with a much lower NPV and levelized cost of energy (LCOE) than do solar resources.

In a figurative attempt to avoid the jaws of this tiger, one solution to this problem would be reformulation of the utility resource evaluation methodology. A better methodology would incorporate lower, risk-adjusted discount rates. Since fossil fuel costs are a pass through costs to utilities, so they should not be discounted at the utility weighted cost of capital. Instead they should incorporate a lower value, reflecting the benefit provided by the solar resource in reducing the impact and risks of highly volatile fuel costs, which have been a historic truth for decades.

One proxy for an appropriate risk-adjusted discount rate has been suggested by Hoff, et al, stating that the discount rate should be set according to the US Treasury Yield Curve, with a term equal to the expected system life.[12] Currently this equates to about a 4.5% discount rate for a 30-year PV system life. The incorporation of risk-differentiated discount rates into the regulatory framework would mark a fundamental shift away from a fossil-era utility economics, ushering in a new era of fairness in how utility economics are calculated and generation resources are selected.

3. RATE IMPACTS AND ISSUES

In considering the inadequacies of the standard analysis of renewable energy rate impacts, Wisconsin Public Service Commissioner Lauren Azar questioned the standard approach to assessing rate increases related to renewable energy investments:

"… should our definition for the cost of a renewable project recognize that renewables provide hedges against the cost of carbon, the cost of fuel, and the cost of transporting fuel? The tensions among the RPS, CA and Energy Priorities Statutes demonstrate that our old models will not work well. We must develop a new framework to evaluate renewables…"[13]

As discussed above, a change in the discount rate for comparative analyses in utility planning and ratemaking, would lay a foundation for this new framework.

In addition, regulators might consider using scenario analyses, which would compare the rate impacts from solar investments to the rate impacts from business-as-usual utility operations years into the future. Solar advocates often ask, "How much would you pay for a 30-year contract for natural gas, and how would that impact utility rates?" While the question is realistically unanswerable, it suggests the usefulness of testing different rate-impact scenarios. This would include not only testing the net cost of solar against different future gas costs, but also adding to the scenario rising infrastructure commodity costs, environmental costs, etc. The notion that business-as-usual utility planning protects the average ratepayer from future increases is plainly false.

In many states, solar advocates face a stiff challenge in making this case with consumer advocates, including state Attorneys General. These advocates often characterize solar as a luxury item, which pushes rates higher for average ratepayers. Yet these advocates return year after year, to deny progressive solutions, even as rates invariably continue to rise.

One limitation that is often unanticipated is that utility-owned solar, with its embedded 30-year fuel costs, appears to have a greater rate impact than solar kWh acquired through a developer PPA or from customers through a utility solar incentive program. True, a utility-scale PPA provides reliable solar resources and RECs, but utilities consider PPA cost as imputed debt, in contrast to a utility-owned solar plant, which would be rate-based long-term asset. Incentivized customer solar is even less desirable, according to most utilities. It is in many ways like a PPA, but its operation and maintenance are less certain. Thus, when utility-owned solar fails to win regulatory support, the result is not only less utility-owned solar (on a scale that could drive solar market transformation), but little or no substitution of third-party solar contracts or customer incentives. The authors believe each approach to acquiring solar resources has unique merits, but these merits have little to do with the current approach to comparing their rate impacts.

One example where this situation has played out began with Duke Energy's announcement in May 2008 that it would lease customer roofspace for 20 MW of utility solar, at a cost of $100 million. While this marked a turning point in utility's willingness to invest in solar, the plan was opposed by consumer advocates as too costly. After long delays, the plan was cut in half.

Some utilities (notably PSE&G, through it's customer solar loan plus "Solar 4 All" program) are beginning to embrace a mixed solar portfolio of utility-owned, third-party, and customer-owned solar. Yet most utilities have only made gestures, and policy makers have generally put off the need to establish a new framework for assessing the benefits and rate impacts of a range of solar procurement strategies.

4. LIMITATIONS OF FINANCIAL INCENTIVES

Federal tax incentives and accelerated depreciation (MACRS and bonus depreciation) have become central to significant PV development strategies. In October 2008, Congress extended the 30% Solar Investment Tax Credit (ITC) and accelerated depreciation for eight years. The new rules also allow utilities to directly benefit from these incentives. However, the calculation of the actual benefit to utilities may be complicated.

For one thing, many utilities do not have significant tax liabilities. This includes many for-profit IOUS. These entities must work with solar development partners who have an appetite for tax credits. Obviously, COUs, which are non-taxable, have a more complicated problem. They have no alternative than to work with solar developers through a power purchase agreement (PPA) or via a lease with a solar developer that uses the Treasury Grant in Lieu of Tax Credit program (at least through 2010). Electric cooperatives and municipal utilities have struggled with alternatives to the ITC—notably the Clean Renewable Energy Bond program (CREBs)—finding that these alternatives are less certain and less advantageous than the ITC and MACRS. COUs have proposed versions of a tradable ITC, but such alternatives are unlikely ever to be enacted.

A little understood problem for IOUs that are eligible to use the ITC is the requirement that they will have to normalize the benefit. In other words, IOUs must share the ITC benefit back with ratepayers. The required method and speed of normalization determines whether the utility shareholders benefit at all, or whether the ITC must be treated simply as pass-through. If the utility receives the credit as a lump sum, but passes it through to ratepayers on a level basis over the life of the asset, then the benefit—while reduced by as much as half—might still be useful. Otherwise, the utility is better off to continuing working with solar developers, using a PPA approach. As noted in the discussion above, PPAs have a limited appeal to most utilities. Thus, to improve the utility's ability to deliver solar benefits, stakeholders might recommend the elimination of this normalization rule.

5. RECASTING RPS AS A MINIMUM STANDARD

In testimony on behalf of the Sierra Club, intervening in two Wisconsin utility rate cases, the authors asserted that the utilities should invest in solar resources to a level that would match their load growth, as a way of moderating future rate increases.[14] The argument hinged on savings that PV could trigger in utility generation capacity, generation reserve, purchased power, line losses, and distribution investment deferral, as well benefits from capturing financial incentives, anticipating modest carbon regulation, and generating Renewable Energy Certificates (RECS) for compliance or sale. Meeting the state Renewable Portfolio

Standard (RPS) was explicitly not one of the benefits considered, because the utilities in question were already meeting their RPS goals. Ironically, current RPS law is, in effect, an impediment to adding more solar resources in Wisconsin.

Today, an ongoing Wisconsin Utility Solar Collaborative has added to its agenda a review of the state RPS statute that forbids the Public Utilities Commission from ordering utilities to invest in renewables so long as they are on schedule in meeting the RPS. A utility may voluntarily include additional renewable resources in its resource acquisition plans, but the rate impact of that resource acquisition would be subject to conventional scrutiny. As a result, Wisconsin utilities have invested in renewables only to keep pace with the RPS. As suggested earlier in this paper, the utilities first question about solar often remains, whether it is required.

In fact, nationwide, RPS guidelines are viewed erroneously as a "cap" for renewable resource development. According to the National Database of State Incentives for Renewables and Efficiency (DSIRE), the projected installed solar capacity for the US by 2025 will be about 8,450 MW, based on state solar RPS requirements. Solar industry marketing materials often cite this market projection. This seemed more than adequate for the fledgling solar industry, but with PV costs coming down and a need for bigger, faster emissions reductions, the implication of a cap on solar development is counterproductive.

States like Wisconsin need to consider if their regulators have adequate power to prompt utilities to add renewables that are cost-effective, even if those acquisitions outpace the RPS or are not least-cost resources. Some states, like California, are moving toward a "clean energy loading order" criteria to insure that energy efficiency and distributed renewables get fully deployed.

A new trend toward solar feed-in tariffs (FITs) might also push utilities to put more than a minimum amount of solar on their systems, except that the rate impacts of FITs might be even higher than the rate impacts of a solar RPS.

6. CUSTOMERS ARGUE FOR THEIR ROLE

As enthusiasm builds for the solar gigawatts that US utilities have begun to deploy, it might be tempting to forget that utilities are driven by profit and a competitive appetite. They can deploy the smart grid and prompt solar economies of scale, bringing strong benefits to all, but they need firm guidance in order to support broadly focused public policy. Policy leaders who put too much faith in utilities might be inviting an unbridled tiger into the lifeboat—with costly consequences.

There is a good case to be made for continuing support for customer-owned, grid-connected solar. In this paper, the authors can only introduce some high points from the customer perspective. Many of these have been documented in detail in regulatory proceedings nationwide. This includes recently in the course of two ongoing regulatory proceedings in New Mexico. [15] In the first of these, New Mexico utilities challenged the legality of third-party financing (PPAs) for customer-owned solar systems. In the second, New Mexico's leading utility, Public Service of New Mexico (PNM) submitted a mandated renewable energy plan to meet the state RPS, which was challenged on numerous grounds, including its proposed cutback or elimination of customer solar programs. PNM had proposed utility-owned solar, among other utility renewable strategies, but asserted that customer-owned solar was too expensive.

The challenge to third-party financing and the defensive response is important, because PPAs have been a primary driver of commercial-scale solar development. The approach accounts for more than 80% of non-residential solar development today, and it is especially important as a way for non-taxable entities to share in the benefits of tax incentives. Nevertheless, PPAs have been challenged in at least eight states. A legislative resolution with limitations recently passed in New Mexico, but the issue remains unsettled in Arizona, and other states are likely to face it in coming years. In arguing for PPAs, solar advocates have pointed to the contributions of customer-owned solar, including stimulating a broad-based and innovative solar industry, developing and maintaining a growing solar workforce, preparing officials who work with zoning, codes and standards, fostering marketing innovation, educating utility staff and the public about solar, and supporting policy dialog. Other solar advocates argue that customers want and possibly deserve to play a direct role in shaping the utility of the future. The potential for customer-owned solar is vast, even if utilities step up their efforts to directly develop and own distributed PV. A 2004 Energy Foundation study projected market potential for rooftop PV by 2025 at more than 45 GW. That study did not consider the utility market at all.[16] Certainly some gigawatts of customer-owned solar would create yardstick competition for utilities and to help drive the nation toward aggressive climate mitigation goals.

In a stipulated agreement on the PNM Renewable Energy Plan (submitted and pending hearings as of March 2010), the utility agreed that customer-owned solar contributes strategic economic value to the utility. These values are summarized in Table 1. Based on these values, the utility proposed a Solar Performance Program with a per kWh incentive—a modified FIT that has varying and gradually declining values for different solar economies of scale. Arizona and other states have similar plans in place.

While the values would be different for every utility, this approach suggests that customer solar would have value for most, if not all utilities. A productive next-step would be for utilities and stakeholders to work together to develop utility programs and incentives that could confirm and *increase* the value of both utility-owned and customer-owned solar.

Table 1. Customer-Installed Solar Values, Proposed in PNM Stipulated Agreement (Case No. 09-00260-UT) for Solar Performance Program.

Size Solar Installation, kW_{AC}	1-100	101-1000
Avoided Costs (2010)/kWh*		
Fuel	5.42	5.632
Capacity	3.041	3.041
Losses fuel	0.381	0.305
Losses CO2	0.063	0.05
CO2 credit	0.898	0.932
Avoided T&D	0.2	0.2
Total Avoided Costs/kWh	**10.003**	**10.16**

* The stipulated agreement includes references for the sources and terms for each value. The total solar avoided cost would be added to a REC-related incentive payment with a first-year value ranging between 13 to 18 cents to arrive at a total Program incentive.

7. CONCLUSION

Returning to the image of the tiger in our lifeboat, it is important to note that customer-utility collaboration on solar development is still a rare and risky situation. As customer-solar market penetration continues to build, the authors suggest that the next tussle may involve growing interest among utilities in reducing their cost of retail net metering. Solar advocates roundly defeated an attempt in 2009 by Excel in Colorado to introduce a solar facilities charge (essentially a standby charge) on net metered customers. However, electric co-ops, as well as some other IOUs and municipal utilities nationwide are currently examining options for similar solar-customer facilities charges.

In New Mexico, a plan to introduce that charge became part of the bargain in legislation to allow third-party solar financing. Legislation passed in 2010 calls for determining solar-customer facilities charges in rate case proceedings beginning in 2011. Most solar stakeholder groups, including the New Mexico Renewable Energy Industries Association, supported the legislation after fairly agonizing deliberations. According to NM REIA President Brian Cassutt, the process of establishing a fair charge will be challenging, but the concept—that customers should support a strong, modern grid—matches most REIA members' vision for a diverse, clean energy future.[17] A concern, raised by the authors, is that the cost of researching, developing, and implementing an equitable facilities charge might be beyond the means of solar advocates (working without regulatory intervener compensation) today. The result could be less diversity and slower growth for the solar market, just as it has begun to take off.

The market improvements and cautious collaborations outlined in this paper are priority items on an agenda for immediate utility and stakeholder action. Equitable models for facilities charges might well follow. It will be a fantastic journey in pursuit of all the technical, economic, and regulatory strategies needed to comprise a new framework for maximizing solar PV benefits within the utility and beyond it.

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