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The Right Tone of VOS: Improving the Argument for Local Community Solar

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Abstract

This paper describes an alternative to the typical value-of-solar (VOS) analytic approach for supporting utility acquisition of local, distributed solar, relative to centralized solar resources. The specific context is resource acquisition for a community-solar program. The utility in this case could acquire (by ownership or power contract) solar from a centralized solar project for a relatively low cost, or it could include a portfolio of local, commercial-scale solar projects with higher "sticker price," but strategic benefits. This case sheds light on the utility's internal-stakeholder debate and on the limitations of detailed bottom-up VOS analysis for some kinds of utility solar decisions. The recommended approach involves building a qualitative, strategic argument, which focuses on relatively few calculated values—three in this case, including strategic-design improvement, reduced transmission costs, and customer-retention value. In other cases, other values or ranges of values might be used. The objective is to apply analytics sparingly, to facilitate better decision-making under highly changeable technology, market, and policy conditions.

Keywords: *Community solar, value of solar, VOS, DER, utility solar, distributed solar, strategic solar*

1. Introduction

The practice of distributed-solar value analysis began in earnest shortly after Small is Profitable (Lovins et al. 2002) cataloged 207 possible values of distributed generation. Today, solar-value analyses, commonly called value of solar (VOS) studies, have become ubiquitous in net energy metering (NEM) policy debates. Less often, these analyses have been adapted to utility-planning proceedings and to support new rates or projects. Rocky Mountain Institute tallied 16 major VOS studies in 2013 (Hansen et al. 2013), and since then, many more have been published. The North Carolina Clean Energy Technology Center (2016) notes that policymakers in 28 states were studying the costs and benefits of NEM or the value of distributed generation in early 2016.

Despite their growing role in state policy-making, current VOS methodologies have practical limitations. For example, Cliburn and Bourg (2013) worked with a diverse panel of NEM stakeholders convened by the Solar Electric Power Association (SEPA) to establish a baseline understanding of VOS and NEM-related issues.

Stakeholders from all sides generally agreed upon VOS terminology and even upon most aspects of methodology, but their different perspectives and assumptions led them to very different conclusions. In addition, we found that current VOS approaches often forced an incomplete or static view of the value of distributed solar (DPV), at odds with increasingly dynamic utilities and markets. In its broad study of methods for analyzing solar value, NREL (Denholm et al. 2014) has envisioned developing a comprehensive VOS methodology, while noting that in the meantime, "there are trade-offs between different approaches in terms of accuracy and appropriateness" to the task at hand. We are reminded that, as the saying goes, that the map is not the territory, and analysis does not necessarily equate with understanding.

2. Methodology

The authors' current work with the Community Solar Value Project (CSVP), funded by the U.S. Department of Energy SunShot program, has suggested the advantages of using VOS analytics sparingly to gain internal utility-stakeholder support for distributed-solar acquisitions. In short, it is the CSVP mission to work with utilities, including a working group that includes Sacramento Municipal Utility District (SMUD), Public Service of New Mexico (PNM), and six other mostly Western utilities, to increase the value of community solar programs. Approaches include strategic siting and design, integration with storage and demand-response, and procurement innovations, regardless of project ownership. Community solar lends itself well to such strategies. Yet, community-solar program design inevitably raises tensions in and among utility departments, where some individuals associate DPV with utility risk and change, and others associate it with risk-management and opportunity.

In working with utilities, the authors have learned that providing a compelling narrative can be more effective—especially early in a program-design process—than providing a full economic analysis. Beginning with a hypothetical case, instead of a specific one, allows individuals within the utility to see past their differences on particular numbers and engage directly in a discussion of strategic possibilities and attainable outcomes. The analytics follow, sometimes as a collaboration involving cross-departmental utility expertise and expertise in solar VOS analytics. In sum, the path for this methodology is marked by four milestones:

1. A sketch of the "realistic hypothetical" solar-program scenario, including relevant problems or challenges;

2. Discussion with utility staff, setting baseline CPV and DPV values (energy, capacity) and identifying a short list of relevant DPV benefit categories, for which net values or ranges of values could be calculated;

3. Selective VOS analysis, to show that the utility could reach the net levelized cost target, which is needed to "close the cost gap" with CPV and justify the DPV investment;

4. Inclusion of additional strategic benefits that could tip the balance if there is still a cost gap between the CPV program resource and a CPV-plus-DPV portfolio option. The overall approach should underscore the changeable nature of technologies, utilities, and markets, and the risk-management value of strategic decisions.

The realistic hypothetical scenario described here involves a generic Northern California municipal utility, which is interested in shared solar, using low-cost centralized solar (CPV) generation, but which also has interest in siting local shared-solar projects. In part, this hypothetical represents a voluntary municipal-utility response to California's Green Tariff Shared Renewables Program, introduced by SB43. In fact, many utilities in the West have been drawn to CPV resources. These resources can supply solar via familiar utility pathways for prices that Lawrence Berkeley National Laboratory (Bolinger and Seel, 2015) has estimated at \$0.05/kWh. Recent news indicates continued price declines, but this paper uses the \$0.05 benchmark for a Northern California project. While projects approaching 20-MW scale could be sited on the distribution grid, tapping in to the CPV cost advantage, the land requirement for such projects (averaging more than 8 acres per MW) is a limitation for most distribution utilities. Thus, the authors assume CPV is transmission-sited. Community-solar DPV is assumed to be distributed on sites that meet a basic grid-hosting requirement (with higher-value siting requirements to be explored later) and an average 2-MW DPV project scale. Designs include 2 MW of fixed-tilt rooftop solar, 2 MW of single-axis tracking (SAT) solar, and 2 MW of flat-roof carport-integrated solar. The latter two designs are modestly strategic. The average cost for this fleet is

$0.075/kWh, based on Lazard (2015) and discussions with other consultants working in the region.

Thus, on the face of it, there is a 2.5-cent per kWh cost gap between the all-CPV and all-DPV options. It is understandable that utility resource planners and program designers might be drawn to the all-CPV solution. The case presented here takes a realistic view of the utility's inclination toward cheaper, centralized resources, and it recalls a solution demonstrated in green-power programs (O'Shaughnnessy 2015), when utilities sometimes combine lower-cost wind power with a smaller amount of solar PV to reach a combined-price target. Here, we suggest a "fleet" approach, beginning with 20 MW of CPV, plus a total of 6 MW of DPV, as described above. The DPV fleet may grow to include more DPV or to add more innovations, as solar costs decline.

Note that the realistic hypothetical scenario should describe relevant problems or challenges. This scenario will address several, but primarily these two:

- A cost gap favoring centralized solar over DPV, despite a preference among many community-solar participants for DPV. Case studies and market research support this customer preference, but the utility sees the higher cost of DPV as a risk, if customers prove to be more driven by savings.
- A pricing gap between utility-based pricing and rooftop solar competitors. The CSVP (Romano 2016) has documented a utility preference for community solar that avoids virtual retail-NEM pricing, in favor of a cost-based $/kWh tariff or a charge per "block" of generation. This approach would reward customers for solar generation, while providing greater utility cost-recovery than NEM-based offers. The challenge is for utilities to keep community-solar pricing within range of third-party competitors. Can utilities achieve this without relying exclusively on low-cost CPV?

2.1 Baseline Values and Target Categories for Analysis

A typical VOS analysis quantifies monetary benefits that accrue to the utility through the deployment of DPV systems and/or project strategies. These benefits typically fall within the following general categories:

- Generation Level
- Transmission System Level
- Distribution System Level
- Societal Level

Within these four categories are numerous sub-categories of benefits. Unlike numerous prior studies, our process does not attempt to document all of the potential VOS benefits up and down the chain of monetizable categories. Nor is the purpose to see how high the benefits of DPV can stack. In working with utilities, the authors have recognized that any stacked-benefit graphic would draw utility stakeholders' attention away from the strategic argument, sparking debates over numerous specific values. An alternative approach begins with relatively straightforward agreement on wholesale energy and capacity values. This includes utility-provided hourly avoided energy and capacity costs for the hours of solar generation. Subsequently, we present a simple categorical listing of possible benefits, including measures that address the utility's strategic problems or challenges, and work to select which to explore. Here, we focus primarily on just three strategic values:

- Strategic-design aspects of the DPV fleet
- Avoided transmission costs
- Customer retention value of local vs. centralized community solar

2.2 Analysis of DPV strategic-design benefits

The approach to this analysis will focus on the levelized cost of energy (LCOE) metric, which is commonly used in VOS analyses and throughout the utility industry to make resource planning decisions. LCOE is defined as the costs of a project (fixed and variable) over its expected life divided by its energy production over the same period, on a discounted basis. In simple terms, the LCOE is the net present value (NPV) of the annual costs divided by the NPV of the project's annualized energy production. Note that the authors also introduce a refinement, specifically identifying a levelized net *benefit* of energy (LBOE) for DPV and incorporating it into the final, fleet net value.

The range of strategic benefits associated with improved DPV project design is great—from the benefits of optimized inverter specification to the benefits of designing for resilience in case of prolonged emergency outages. However, for this hypothetical case, we simply consider how three generic DPV system designs (fixed-tilt rooftop, single-axis tracking and flat-mount carports) impact the need to purchase energy and capacity from wholesale markets or via existing PPAs. Then we derive the benefit of each design, relative to the typical fixed-tilt CPV system. Of course, there was no incremental value associated with the fixed tilt rooftop design, as its design was assumed to be similar to that of the typical CPV system. The flat-mount carport, while generating 12% less energy than a fixed-tilt system on an annual basis, had an incremental avoided cost (0.41-cents/kWh) above the fixed-tilt system. That is because it generates much more power in the summer months, coincident with higher wholesale energy and capacity purchases in Northern California. In fact, this configuration yields 4.2 times the monthly energy production in the peak summer month than in the lowest winter month. Finally, the single-axis tracking system had a higher incremental avoided cost value (1.33-cents/kWh) than the CPV system, since it generates 24% more annual energy on an annual basis than a fixed tilt system of the same size, and its output profile is highly coincident with the highest wholesale hourly power costs.

Combining these strategic-design values in an analysis of the entire 6-MW DPV fleet, the incremental LBOE associated with wholesale power cost savings is 0.64-cents/kWh. In other words, this 6-MW fleet would have avoided wholesale power cost savings that are of 0.64-cents/kWh higher, relative to a typical fixed-tilt CPV project. This savings will contribute to filling the cost gap of 2.5 cents between the CPV-only and DPV-only resource options. Figure 1, below, demonstrates the individual and aggregate generate profiles of the DPV fleet.

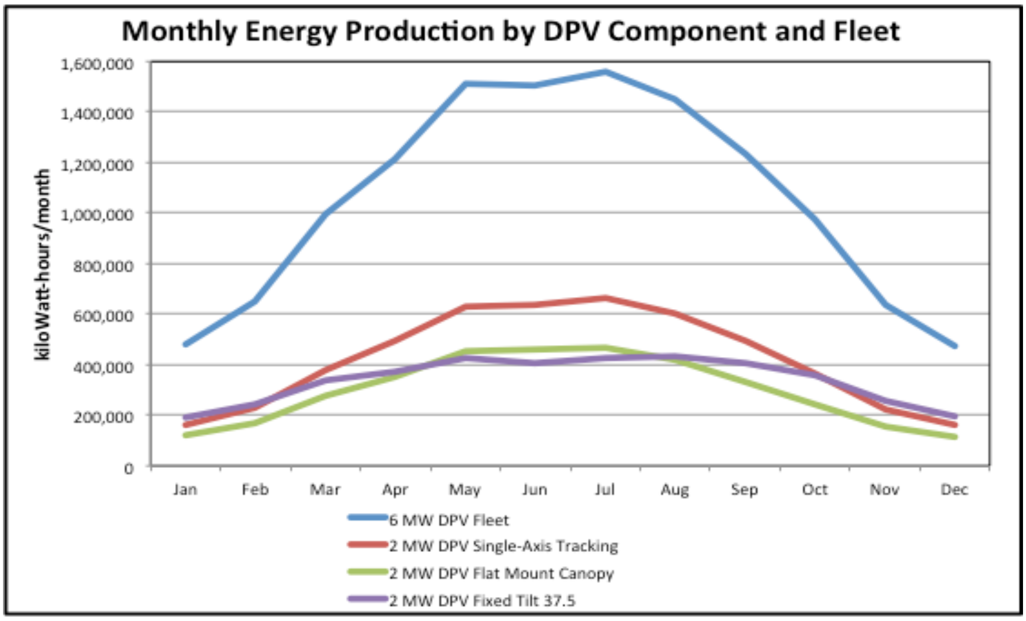

Fig. 1. Monthly energy production by DPV component project-design and by the fleet.

2.3 Analysis of Avoided Transmission Costs

The second category analyzed to fill the cost gap is the incremental value of avoided transmission costs, associated with DPV resources. Avoided transmission cost sub-categories include avoided transmission line losses, avoided ancillary service costs, avoided or deferred transmission capacity investments, and avoided transmission service charges (i.e., firm or non-firm transmission reservation charges). Not all transmission costs are avoided on a 1:1 basis as a result of DPV generation. A robust analytic approach today would require site-specific hourly transmission-cost modeling and additional considerations; in the foreseeable future, researchers at the National Renewable Energy Laboratory and other institutions expect to understand

DER/transmission interactions better and to develop analytic tools to assess DER/transmission values (Palmintier et al. 2016). Yet clearly, significant transmission-related costs would be avoided by DPV, compared to transmission-sited CPV resources.

In order to estimate the potential savings, the authors conducted a literature review. In the literature, transmission-related benefits are treated differently in different studies—often combining transmission system benefits with distribution system benefits as one T&D category, or referring generally to "transmission benefits," when only one benefit, e.g., the value of capacity deferrals from DPV, is being counted. For example, the U.S. Energy Information Administration (U.S. EIA 2015), suggests transmission cost "based on the average cost to build, operate and maintain these systems using a cost of service regulation model" averaging $0.0184/kWh (on a levelized basis) for the California market. EIA does not provide detail on the its transmission costs, but is assumed to be drawn from the "postage stamp" rate—the flat Transmission Access Charges (TACs) in the California ISO market (CAISO) for delivery of energy from the point of generation to the utility distribution system. One study, completed for the California Energy Commission by the Clean Coalition (Clean Coalition 2015), is more inclusive, and estimates transmission avoided-cost DPV benefits on the CAISO market totaling $0.03/kWh. The difference between the EIA and Clean Coalition estimates is the escalation rate of future TACs in the CAISO. Both start at the same 2015 TAC value of $0.018/kWh, but EIA assumes a relatively flat escalation rate in TACs over the next 20-plus years. The Clean Coalition study utilizes the CAISO's projected average future estimate of 7% nominal escalation (5% real) over the next 20 years, to arrive at its levelized value of $0.03/kWh. While this value may seem high, a 7% annual escalation rate is less than half of the historical escalation rate (15%) since 2005. It should also be noted that neither the EIA or Clean Coalition studies incorporate the value of line losses in their TAC-based analyses, underscoring that $0.03/kWh is most likely conservative.

Accepting that arguments for additional avoided-cost benefits can be contentious, the authors note that several other recent sources have found transmission avoided-cost benefits in the same range or higher. For example, the Crossborder study (Beach and McGuire, 2013) submitted to the Arizona Public Service Commission, estimated transmission benefits of DPV in the $0.021 to $0.023/kWh range with an additional $0.015 cents/kWh in savings attributed to ancillary services and capacity-reserve savings, for a total range of $0.036 to $0.038/kWh. A recent VOS study in Vermont by the Acadia Center (Acadia 2015) valued the avoided transmission costs for DPV between $0.027 and $0.030/kWh on a levelized basis. These studies focus on different regions; they are not perfectly comparable. Yet, such robust DPV benefits strengthen the case for considering some significant range of avoided transmission costs..

This paper's suggested methodology has an element of negotiation—posing the question, "What is the likely range of values for this benefit?" Rather than assuming there is one true number, we suggest that there is at least one *better* number, which reflects a better understanding of DPV value under likely technical and market conditions. In this case, we assume a LBOE value of $0.01/kWh for transmission benefits in this analysis—a conservative number from our perspective, but one which can be applied to the DPV portion of this community solar fleet, to help create cost-parity with the all-CPV option.

2.4 Derivation of Revenue-Retention Value

As noted above, this realistic hypothetical case is not intended to be all-inclusive of local solar DPV benefits. The authors are aware of many more benefits that could be added to a considerable stack. However, a first consideration is that, in order to differentiate DPV from this hypothetical utility's low-cost CPV option, we focus only on values that are *uniquely characteristic of DPV*. Thus, for example, environmental benefits that could be monetized from either a DPV or CPV resource are not considered here. There are other benefits that would likely be on the list—for example, locational distribution-grid benefits that could be introduced if strategic siting were part of the community-solar program design.

However, for this paper, we wish to confront a seldom-recognized benefit, which, if included, would help to create a win-win for the utility and the customer. That is, the need to find acceptable alternatives to retail NEM, as it is commonly used today. The aim would not be to limit customer choice, but to introduce an additional choice, with similar bottom-line pricing, other program-defined benefits, and less erosion of utility wires-charge revenue. Even utilities that accept the value of solar have noted how the very rise of NEM could create a utility cash crunch, because solar benefits materialize over the long term of the VOS analysis, while funding for grid maintenance and improvements are needed now. This is especially true in today's solar market, where the amount of residential DPV (mostly net metered) has about doubled in two years, 2014-2016 nationwide, bringing California to a total of more than 3,000 MW of DPV by yearend 2015, according to U.S. EIA. Utilities know they are experiencing impacts of a solar market transformation; many now are focusing less on stopping it, and more on a smoother transition, where community solar (possibly including PPA providers and other non-utility partners) could play a role. Utilities are learning that customers might exit any over-priced community-solar program, and turn to a rooftop lease or purchase, while the utility picks up the remaining years on an under-subscribed PPA. Is there a solution that could slow NEM-related revenue loss, while increasing the amount of DPV and improving community-solar pricing?

Our analysis begins with understanding the hypothetical utility's current residential rate tariff. In this scenario, the residential retail rate is $0.12/kWh. Half of this retail rate represents the value of (standard portfolio) energy, and the other half represents a non-bypassable wires charge. When a customer switches to full-retail NEM for solar on its own property, the associated non-bypassable wires charge ($0.06/kwh) is entirely lost to the utility. By contrast, a tariff-based community-solar model, similar to one that already exists in California, could include a more strategic, lower non-bypassable wires charge, reflecting the benefit of retaining the community-solar customers who pay it.

In practice, it would be reasonable to negotiate a lower wires-charge burden for all community-solar customers, because the net grid-impact per kWh of generation from a community-solar project is likely to be less than the net grid-impact per kWh of generation from randomly sited and variously oriented rooftop projects. That is part of the often-cited community-solar value proposition. However, for the sake of simplicity, we will examine the $0.06/kWh non-bypassable charge before any other value-related discounts.

To set the revenue-retention benefit for this hypothetical case, we first need to assess to what extent customers who choose community solar might alternatively opt for NEM rooftop solar. One can assume that customer-rooftop solar, community solar via a CPV tariff, and community solar via local DPV all draw from the pool 50-65% of all electricity customers, identified by a range of studies, who say they are interested in going solar. According to research (Shelton 2016) for SEPA, about 60% of residential customers are interested in solar power, and about 34% of these are seriously considering options. Before receiving any detailed information about options, the breakdown of that 34% includes about 16% who are primarily considering rooftop solar and 14% primarily considering community-solar (4% not reported). Are these groups interchangeable? Another research track in the Shelton work followed the customer decision process and found that indeed, there is movement in customer preference in both directions. For example, Shelton divided a large group of residential customers interested in solar into those initially likely/very likely to choose rooftop and those not likely to choose rooftop. Then each group was presented with information on actual solar options and pricing, for both rooftop and community solar. After two rounds of polling, 45% of the group initially favoring rooftop switched to a preference for community solar, and 35% of those initially disinterested in rooftop switched to the rooftop preference. Pricing was a major factor, but not the only factor in this shift. Reports from existing community-solar programs also suggest the market is somewhat fluid in both directions between rooftop solar and current community-solar options.

If the community solar option were not available or were not competitive, would as many as one-third of customers, who are currently considering solar, choose a rooftop option? We believe the evidence available today is not strong enough to confirm that. But a significant percentage of customers likely would migrate, and at an accelerating rate in places where rooftop solar (with or without NEM) is near retail parity.

The next relevant question is, Does the customer-retention benefit differ for DPV compared to CPV within a community solar program? Anecdotally, the preference for locally-sited projects is strong, but some analysts have cautioned that early-adopters could be a special group. The recent Shelton work addresses this uncertainty, confirming that customers generally prefer local community solar, meaning "solar you can see on a short drive, in your community." This preference is very strong—even at a higher price. But in the context of subscription-based community solar, Shelton links this preference with other aspects of a competitive program offer, including that any premium should under $0.03/kWh over the retail rate. If other aspects of the program offer are held constant, there is significant value in keeping community solar local.

In this hypothetical case, the authors recommend incorporating a DPV benefit that reflects the impact specifically of local community solar on customer acquisition and revenue retention. Our methodology would ask the utility to review ranges of likely impacts, settling for this hypothetical on an assumption that *at least* 15% of those interested in solar could go to either community-solar or rooftop options, but would choose community solar, so long as it affordable and includes visible, local projects. Thus, 15% of the of the non-bypassable wires charges in the retail rate can be assigned as a customer-retention value for including a significant DPV in the community solar program. Based on the hypothetical \$0.06/kWh charge, this results in a first-year customer-retention value of 0.9-cents per kWh and an LBOE of 1.17-cents per kWh when levelized over the 30-year term of the solar investment, using a 6.5% discount rate and a 2.5% annual retail rate escalation factor.

The authors concede that this customer-retention analysis is preliminary. In the discussion below, we suggest ways to improve this analysis, including a call for more detailed market research. We assume any offer—rooftop or community solar—could be made more competitive, with resulting impacts on the market. However, in discussing this hypothetical case with utilities (especially in California where solar growth is strong), we found little resistance to the concept that "there is a significant cost to doing nothing." The recommended process is effective for engaging utilities on their need to offer a better community-solar product at a better price. Incorporating this fairly conservative local-solar benefit on the DPV 6-MW fleet allows the analysis to fill the cost gap between all-CPV and a fleet with significant local solar.

3. Results

A major goal of this paper is to demonstrate that in selecting solar resources for utility-driven community solar, DPV resources can economically compete with CPV projects. This was accomplished through a simplified VOS-type analysis. Calculations were performed to determine the base-case values for CPV and DPV in terms of their gross LCOE, in simple terms, the levelized "sticker price." Then, a select few high-value incremental benefits of DPV were analyzed to calculate a net LCOE of DPV resources. arriving at a net LCOE for DPV. This net LCOE accounts for a short list of incremental DPV benefits (three in this case) that are not found in CPV. These are expressed in aggregate as the levelized benefit of energy (LBOE) of DPV, as shown in Equation 2. The focus on select benefits that are uniquely characteristic of DPV is a much simpler approach than reviewing all the values of CPV and DPV, and then subtracting the gross benefits of CPV from DPV to calculate the incremental benefits of DPV.

$LCOE_{DPV\ NET} = LCOE_{DPV\ GROSS} - LBOE_{DPV\ GROSS}$ (Eq. 1), where

$LBOE_{DPV\ GROSS} = 0.64$ cents + 1.0 cent + 1.17 cents (Eq. 2)

$LBOE_{DPV\ GROSS} = 2.81$-cents/kWh (Eq. 3)

Incorporating those benefits, a side-by-side comparison of LCOE values emerges, as presented below.

Tab. 1. Gross Costs for Centralized and Distributed PV, in Comparison With Net Cost of DPV Incorporating Three DPV-Characteristic Benefits

$LCOE_{GROSS\ CPV}$	$LCOE_{GROSS\ DPV}$	$LCOE_{NET\ DPV}$
\$0.0500/kWh	\$0.0750/kWh	\$0.0469/kWh

The results of these analyses show that the difference in "sticker price" between CPV and DPV dissolves into economic equivalence of these resources. The net LCOE of the value-enhanced hybrid solar fleet is virtually the same as the gross LCOE of the baseline CPV plant. As shown in Table 2, the hypothetical 26 MW fleet, including 20 MW of CPV and 6 MW DPV (rooftop, SAT, and flat-mount carports) has a sticker price that is just over one-half cent more than the CPV alone. Considering available market-research on customer willingness-to-pay for local community solar, one wonders whether to increase the amount of DPV in this fleet, since the cost premium, even before counting DPV benefits, would be quite low. Assuming our hypothetical hybrid fleet, with DPV benefits counted (on a net LCOE basis), there is practically no economic difference between CPV alone and CPV-plus-DPV in a 26-MW fleet.

Tab. 2. Economic Analysis for a Hybrid Community-Solar Fleet

20 MW CPV $LCOE_{GROSS}$	6 MW DPV $LCOE_{GROSS}$	26 MW Hybrid Fleet $LCOE_{GROSS}$	26 MW Hybrid Fleet $LCOE_{NET}$
$0.0500/kWh	$0.0750/kWh	$0.0556/kWh	$0.0493/kWh

A second goal for this process was also achieved. These results demonstrate the value of community solar to competitively retain some customers who would otherwise choose to own or lease NEM-based systems. This is shown in reviewing the net LCOE of the community solar fleet versus the LCOE to the utility customer of a NEM system. One California utility consulted for this study indicated that the average offer from third parties to its utility customers for a NEM residential system on a 20-year PPA was $0.1090/kWh with a 2.9% annual escalation factor. This equates to a customer LCOE of $0.1323/kWh. With a hybrid fleet average of the net LCOE at just under $0.05/kWh, the utility has considerable opportunity to recover valid wires charges in community solar pricing, while still offering a competitive product to its customers.

4. Discussion

As noted above, the goal of this methodology is not to build a bottom-up stack of solar benefit values, but rather to work directly with utility staff to build a bridge, to close the perceived cost-gap between CPV and DPV. That goal has been achieved by using only three categories of solar value. The authors could adjust the average LCOE of the fleet either by working with utility stakeholders to count more DPV benefits, or by adjusting the balance between amounts of CPV and DPV in the fleet resource mix. Another option might be for the utility to offer an all-DPV option, keeping the premium within a modest range, as demonstrated by incorporating these three categories of benefits, or by incorporating a subset of other characteristic DPV benefits. One of the main takeaways of this analysis is that utilities have good reason to consider deployment of at least some DPV resources in the community solar resource mix.

In addition to the customer acquisition and retention drivers, there is notable risk-management value in pursuing a diverse resource strategy during these times of change. Risk-management is a key category of strategic value, which our methodology suggests adding to the case narrative, just as prominently as the LCOEs and LBOEs. For example, some utilities are concerned that community solar offers a shorter term for participation and an "easy exit option." What if the declining cost of solar leads to newer, cheaper third-party offers? A project-fleet solution underscores the risk management value of DPV, as projects can be added incrementally, keeping pace with participation and putting downward pressure on average fleet-based pricing. This strategy leads to other technical and socio-economic benefits, too, of a distributed-fleet approach.

In reviewing the results of this methodology, it is important to underscore the importance of facilitating utilities' internal-stakeholder processes and building support for local solar, in order to speed much needed clean energy and grid-flexibility advances. The authors have long recognized the inherent conflicts between utilities and stakeholders, especially regarding solar advances (Cliburn and Bourg 2010). The contributions of non-utility innovators in the changing utility landscape are needed, but they will not fully replace utility functions—or certainly not immediately or without utility collaboration. The necessary change in utility mindset from relying on centralized, remote generation resources to working with centralized *plus* local distributed energy resources (DERs) on an increasingly flexible grid is difficult for anyone coming from established utility culture. By using a simplified, solution-oriented approach to VOS, applied to a realistic hypothetical case, utility groups can feel freer to consider new solutions. As noted above, they would not be pressed into agreement on the one *best* number for each incremental DPV value in the stack; they would only work with a short list of values and agree upon one *better* number for each, representing the range of possibilities and dynamics that they must consider. If a short list of agreeable DPV benefits can close a "cost gap," then implementation of community solar (or other strategic DPV options) can advance quickly, and on a larger cumulative scale.

To be sure, this paper includes preliminary analyses; continued research is needed on several fronts. The scarcity of market research on community solar and on customer preferences among all kinds of PV needs a lot of work. Nevertheless, the authors present what we know so far, because we hope to prompt a more substantive discussion. A hypothetical municipal utility may have the leeway to employ a customer-retention benefit fairly quickly, but we recognize that other utilities could face tough regulatory scrutiny. At minimum, those utilities that cannot monetize this a customer-retention benefit explicitly may be more open to an equivalent sum of other DPV values to help meet the DPV-benefits target. Further, the authors are currently engaged in developing out a more complete pricing proposal, urging utilities, regulators, and advocates alike to advance strategic, significant, and growing fleets of solar DPV.

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