IN THE MATTER OF AUSTIN ENERGY BASE RATE CASE FILING DATED APRIL 18, 2022	)))))	**BEFORE THE CITY OF AUSTIN HEARING EXAMINER**

DIRECT TESTIMONY OF KARL R. RÁBAGO

ON BEHALF OF

SIERRA CLUB, PUBLIC CITIZEN, AND SOLAR UNITED NEIGHBORS

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I. BACKGROUND AND INTRODUCTION

A. Qualifications

I am an expert in electric utility regulation, planning, investment, operations, and rate making. I am principal and sole employee of Rábago Energy LLC, a Colorado Limited Liability Company with a business address of 2025 East 24th Avenue, Denver, Colorado. Rábago Energy provides consulting, advisory, and expert witness services to a wide range of clients in the electric utility regulatory field.

My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, Executive Director of the Pace Energy and Climate Center, Managing Director with the Rocky Mountain Institute, and Director with AES Corporation, among others. I have earned a Bachelor of Business Administration in business management from Texas A&M University and a Juris Doctorate with honors from the University of Texas School of Law. I have Master of Laws degrees in military law from the U.S. Army Judge Advocate General's School and environmental law from the Pace University Elizabeth Haub School of Law. A copy of my CV is attached hereto as Rábago Exhibit 1.

I have been engaged as an advisor and expert witness in some 150 regulatory proceedings across the country, including many relating to distributed energy resources of all kinds, rates and tariffs, resource acquisition and development, low-income energy issues, grid modernization, return on equity, and other issues. Further description of my experience relating to solar energy is attached as Rábago Exhibit 2.

I have authored and co-authored a wide range of publications relating to utility regulatory issues, as listed in Exhibit 1. In particular, I co-authored publications relating to my leadership role in developing the Value of Solar Tariff ("VOST") and Value of Solar analysis as an approach for characterizing and quantifying the value to utilities and society that results from customer generation of electricity with solar technology. I also served as a contributing author and advisor in the writing and publication of the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM"), published by the National Energy Screening Project.[1] The NSPM sets out detailed guidance for establishing a benefit-cost analysis framework that can support jurisdictionally-specific evaluations of all manner of distributed energy resources ("DER"), which includes distributed generation ("DG"), demand response, energy efficiency, distributed storage, and others. The NSPM compiled best practices guidance through an intentionally inclusive process of drafting, commenting, and revising supported by a range of authors and reviewers.

B. Purpose of Report

The purpose of this expert report is to review and make recommendations regarding Austin Energy's proposed changes to its VOST for customer-generators. This review addresses not only the proposed changes from Austin Energy, but also the report of Austin Energy's Consultants, New Gen Strategies & Solutions ("NewGen"), which appears to be the source of several elements of the VOST proposals.

This report includes conclusions and recommendations based on those conclusions.

This report recommends that Austin Energy:

1. Suspend almost all proposed changes to the VOST.

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[1] T. Woolf, et al, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources,* National Energy Screening Project (Aug. 2020). Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/. While the NSPM-DER was published recently, it reflects best practices articulated in a prior NSPM for efficiency resources and generally recognized in the industry.

2. Evaluate how customer-sited generation rates impact solar generation investment in Austin.

3. Identify barriers and challenges to solar adoption by economically-disadvantaged customers and communities.

4. Conduct a comprehensive and transparent Value of Solar analysis using a Benefit-Cost Analysis framework developed in accordance with guidance provided in the NSPM.

5. Implement proxy values for reserve capacity and distribution capacity, and expand the environmental benefits credit to reflect avoided costs related to non-carbon emissions reductions. If Austin Energy is allowed to implement its proposed backward-looking rate values for some avoided costs, it should add VOST credit for avoided generation capacity.

6. Establish a concrete and actionable plan, with specific performance metrics for achieving the Austin Energy Resource, Generation and Climate Protection Plan to 2030[2] ("AE 2030 Plan") objective of 200 MW of customer-sited local solar capacity.

C. Overview of Austin Energy Value of Solar Tariff Proposal

In this proceeding, Austin Energy proposes to fundamentally change its VOST from a forward-looking tariff originally designed to capture the present value of energy and capacity from customer investments in long-lived solar generation facilities into a short-term backward-looking rate calibrated against energy prices in the previous year. Austin Energy proposes to characterize only a limited set of costs as "avoided costs" and externalizes incentives and environmental benefits for recovery as "policy-driven incentives" and "societal benefits" for recovery through the Community Benefits Charge ("CBC").

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[2] Exhibit KRR-8, Austin Energy Resource, Generation and Climate Protection Plan to 2030 (As Recommended for Action to Austin City Council by the EUC and RMC on March 09, 2020), available at: https://austinenergy.com/wcm/connect/6dd1c1c7-77e4-43e4-8789-838eb9f0790d/gen-res-climate-prot-plan-2030.pdf?MOD=AJPERES&CVID=n85G1po [hereinafter, "AE 2030 Plan"].

The City Council should require Austin Energy to base VOST change proposals on a comprehensive analysis, conducted within the context of all its base rate and revenue recovery change proposals. It is important to note that the CBC and full policy and ratemaking implications of the proposed changes in the VOST on the CBC are not evaluated in Austin Energy's application, creating a problem of piece-meal rate making. As a result, Austin Energy has effectively precluded the City Council and the community from seeing a comprehensive analysis of the total impacts of proposed rate changes and collection methods due to their segmentation among separate proceedings.

Key elements of the package of proposed VOST changes include:

- A new method of calculating the value of saved energy based on the previous year's average day-ahead price for ERCOT system energy.
- A new method of calculating the value of saved transmission based on the previous year's ERCOT so-called "postage stamp" rate for transmission services.
- A new method of calculating the value of saved ancillary services charges based on the previous year's ERCOT prices for four ancillary services products.
- An adjustment based on annual estimated average line losses, without regard for the fact that line losses increase during periods of peak energy consumption.
- A new classification of only saved ERCOT energy, transmission, and ancillary services as "avoided costs," and a new proposal that only those avoided costs would be recovered through the Power Supply Adjustment charge. Austin Energy proposes to exclude consideration of avoided generation capacity costs, reserve capacity costs, distribution capacity costs, operations and maintenance expenses, environmental costs not captured in the social cost of carbon, health liabilities, and of incremental benefits to the grid and the community like reliability and resilience benefits and job and economic benefits.
- A new proposal to treat the environmental performance benefits of customer-sited solar as a "societal benefit" and not as costs avoided when purchases from the ERCOT market are avoided.
- A proposal to base the avoided emissions benefits of customer-sited generation on Texas statewide carbon dioxide emissions rates reported by the U.S. Energy Information Administration in 2020 and an annually adjusted federal social cost of carbon value.
- A yet-to-be-developed or quantified proposal for a performance-based incentive that will replace the current Residential Solar Education Program and the current commercial incentive program.

It is also noteworthy that the Austin Energy VOST proposal does not assess the costs or benefits of customer-sited generation over the likely 25-plus years that a new solar generation system will operate, and without incremental financing, operating, or maintenance costs to the utility and non-solar customers. Nor does Austin Energy in its proposal or documentation include any assessment of the following impacts of customer-sited generation:

- Utility system impacts, including evaluation of costs and benefits related to: AE 2030 Plan achievement, market price effects, distribution capacity, peak system losses, distribution operations and maintenance, distribution voltage, administration, credit and collection, operating and capital risk, reliability, and resilience.
- Host customer impacts, including evaluation of costs and benefits related to: host customer investment, interconnection, risk, resilience, taxes, non-energy effects, and low- and moderate-income customer effects.
- Societal impacts, including evaluation of costs and benefits related to: resilience impacts beyond those experienced by the utility and host customers, non-CO2 air emissions, water, solid waste, other environmental impacts, incremental economic development and job impacts, health, productivity, environmental justice, reduced foreclosures, home maintenance, energy imports, and energy independence.

Austin Energy's VOST proposal is not accompanied by a Value of Solar study, nor is it based on a cost of service study specific to customer-generators.[3]

D. Summary of Conclusions & Recommendations

Based on my review of the Austin Energy VOST proposals, I conclude that Austin Energy intends to terminate its VOST in almost everything but name, and to replace it with what is essentially a wholesale generation supply tariff for customer generation embedded in a buy-all-sell-all tariff structure. The Austin Energy proposal seeks to dis-integrate societal impact credits relating to avoided emissions from its VOST energy value calculation and treat such credits as unrelated to the generation, transmission, and distribution of electric energy. Coupled with its proposals to use rate redesign to encourage increased customer consumption of utility-

[3] Austin Energy RFP Ch. 9.

provided electricity, it appears that Austin Energy's VOST changes will economically disadvantage customer-generation in favor of utility generation, thereby increasing Austin Energy revenues.

Austin Energy proposes to shift to quantification of customer solar generation avoided cost benefits based on historical market costs, without regard for value of future avoided energy, capacity, transmission, and distribution costs resulting from customer investments in distributed generation. Austin Energy essentially proposes to credit long-term customer investments in distributed generation that provides long-term system resource value on the basis of short-run marginal costs, thereby violating best practices in comparably assessing customer-owned and utility-owned (or purchased) resource value. Austin Energy proposes to ignore entirely the contribution that customer generation makes to avoided distribution costs, despite operating its VOST for some ten years, during which it could have collected data and performed analysis to determine fair compensation rates to customer-generators for avoiding these costs. Austin Energy and its consultant appear to base their proposed changes on the unexamined assumption that customer-sited generation is worth less and costs more than utility-scale generation—an approach that replaces data-based evaluation of resources conducted in the context of value analysis with unsubstantiated assertion. Most troubling is language in Austin Energy's consultant report suggesting an abdication[4] of the utility's responsibility for ensuring that Austin meets its AE 2030 Plan target of achieving 200 MW of local, customer-sited solar.[5]

The City Council should not approve Austin Energy's VOST proposals. Nor should the Council approve altering solar compensation credits without a comprehensive, objective, transparent assessment of the costs and benefits—the value—of customer-sited solar generation. This was the approach used in creating the VOST a decade ago, and is the only way to anchor customer generation terms in just and reasonable rates.

Finally, the City Council should not approve Austin Energy's proposed restructuring of the revenue recovery methods for credits paid to customer-generators, in particular, the shifting of revenue requirements associated with VOST credits to the CBC. The CBC is managed as a budgetary matter separately from the PSA, and increasing the pool of revenue requirements in the CBC without a comprehensive and holistic review of the CBC and what it is created to accomplish is unreasonable. Adding revenue requirements to the CBC without such a review risks the fiscal undercutting of other programs and goals that the CBC is intended to accomplish, and would suffer from the same adverse consequences of other piece-meal rate making proposals from Austin Energy. Without this review, there is likely a violation of the well-recognized matching principle, which holds that costs and benefits to customers should reflect cost and benefit creation. Under Austin Energy's proposal to restructure revenue recovery there are some

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[4] "[I]n recognition that Austin Energy can more cost-effectively achieve the overall policy goal of increased solar generation by constructing or contracting for one or more utility-scale solar projects given the relative cost of such projects in the current environment (as compared to customer-sited installations and the corresponding VOS credit), Austin Energy may instead opt to procure utility-scale solar projects. This latter approach may result in Austin Energy meeting it system renewable energy goals at a lower cost to ratepayers, but falling short of the individual goal for customer-sited solar." NewGen Strategies & Solutions, Review of Austin Energy's Value of Solar at p. M-6 (Feb. 8, 2022) ["hereinafter, "NewGen VOS Review"].

[5] AE 2030 Plan at p. 3.

customers that would be eligible to receive VOST credits without ever contributing to the CBC account that funds some of those credits.[6]

For these reasons, this report recommends that Austin Energy take the following actions prior to developing and proposing any changes in the VOST:

1. Suspend almost all proposed changes to the VOST. As noted below, Austin Energy's recognition that environmental benefits assessment should be measured against emissions rates for ERCOT or all of Texas is sound, as is increased reliance on actual performance data for customer-sited generation.

2. Conduct a comprehensive program of research and engagement with customers, solar technology and service providers, and other key stakeholders to evaluate how customer-sited generation rates impact current and prospective solar customers.

3. Conduct a special evaluation of economically-disadvantaged customers and communities to determine barriers and challenges to solar adoption by these customers and in these communities.

4. Conduct a comprehensive and transparent Value of Solar analysis using a Benefit-Cost Analysis framework developed in accordance with guidance provided in the NSPM.

5. Until such time as Austin Energy completes a comprehensive and transparent Value of Solar study for Austin, it should implement proxy values based upon studies conducted in other jurisdictions and upon more complete environmental benefits data. In particular, Austin Energy should add to its current VOST credit for avoided reserved capacity costs ($0.0079/kWh) and for avoided distribution capacity cost ($0.0175/kWh). The environmental benefits credit should be

[6] I support Sierra Club witness Cyrus Reed's testimony in this proceeding on the issue of revenue recovery mechanisms.

increased to reflect the avoided social cost of not just carbon emissions, but also methane, nitrous oxide, and sulfur dioxide emissions (total $0.0365/kWh). If Austin Energy is allowed to implement its proposed backward-looking rate values, it should add to its proposal VOST credits for avoided generation capacity ($0.0302/kWh), avoided reserve capacity cost ($0.0079/kWh), and avoided distribution capacity cost ($0.0175/kWh). The environmental benefits credit should be increased for either the existing or proposed VOST to reflect the avoided social cost of not just carbon emissions, but also methane, nitrous oxide, and sulfur dioxide emissions (total $0.0365/kWh).

6. Establish a concrete and actionable plan, with specific performance metrics for achieving the AE 2030 Plan objective of 200 MW of customer-sited local solar capacity.

II. THE PURPOSE AND APPROACH OF THE VALUE OF SOLAR TARIFF

Austin Energy's proposed changes to the VOST must be evaluated in light of the City's intent in establishing the original tariff. Working with staff and consultants at Austin Energy, I developed the first VOST. The VOST had and should retain several key objectives and approach elements, all of which are consistent with sound rate making and best-practices valuation approaches.[7] These design elements include:

1. Treat customer-sited solar as a utility resource. The analysis and rate design approach should treat customer-sited generation as a resource. Customer-sited solar, once operational, will add value to the host property, for other customers, and to the utility system for twenty-five or more years. Like other resource options available to the utility in meeting demand for energy

[7] The key design elements and approaches to the VOST are documented in several published sources. These include: K. Rábago, *The Value of Solar Tariff: Net Metering 2.0,* ICER Chronicle (Ed. 1, Dec. 2013); K. Rábago, et al., *Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator,* paper prepared for World Renewable Energy Forum (2012); K. Rábago, *The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff,* Solar Industry, Vol. 6, No. 1 (Feb. 2013).

services, customer-sited generation can provide resource value—the ability to help the utility meet its service, supply, and planning goals in the near term and for many years into the future. Assessment of that resource value requires objective, comprehensive evaluation of benefits and costs to the utility, and because Austin Energy is a community-owned utility, to the people of the City of Austin including solar host and non-host customers.

Rates that fail to objectively capture resource value mean uneconomic investment and economic waste—there is a significant opportunity cost in artificially suppressing customer generation compensation and credit in order to enhance utility asset-based revenues, even and especially for a publicly-owned utility. Evaluation of customer-sited solar resource value must begin with recognition that the people of Austin have decided as a policy matter that a significant amount of customer-sited solar—at least 200 MW—must be developed to the meet the commitment in the AE 2030 Plan.

2. Treat rooftop solar customers as generators "for use," not wholesale generators.[8] Customers that install and operate solar facilities are primarily customers of electricity services who seek one or more objectives through their investments. These customers seek, among other things, bill savings, environmental performance and leadership, a contribution to community improvements and plan achievement, and improved building performance and value. Few, if any, of these customer-generators seek to become wholesale generators of electricity for sale. Just and reasonable rates for the voluntary initiatives and investments undertaken by these customers

[8] Non-utility generators fall into two primary categories: Generators "for use" primarily operate their facilities to provide electric service at their home or business, and export energy incidental to that primary purpose. Wholesale generators, or generators "for sale for resale" operate their facilities to sell most or all of the output of their facilities to the local utility. Although the VOST provides a "credit" for all generation and charges customers for all use, whether or not offset by that generation, the tariff design has always been carefully constructed to avoid turning customer-generators into wholesale generators.

must be fair to those customers, to other customers on the system, and to the utility charged with providing electric service to all customers.

3. Align customer and utility interests. As resource providers, customer-generators bring long-lived generation-related non-utility capital, maintenance services, siting, and insurance services to the utility system as a whole. They can diversify the generation mix, enhance local system reliability and resilience, and mitigate the need for investments and spending by the utility. In fact, the more than 200 ways that distributed energy resources can provide economic, financial, operating, and engineering benefits to utilities and society have been extensively and comprehensively documented.[9] In short, customer-generators promote local economic benefit, meet policy goals, and align customer and utility interests for the benefit of all customers—and in far excess of their cost to the system. Those generators are entitled to just and reasonable rates for those well-documented benefits.

4. Use real-world data and analysis to establish rate elements. The "value" in value of solar analysis can only be rationally characterized after thorough, comprehensive evaluation of the resource value of customer-sited generation deployment and operation. Real-world data should be used, and if it is not readily available, the prudent utility bears a responsibility to collect the data it needs, preferably from actual customer-generators. An understanding of how the cost to serve customers changes when they become customer generators, and a corollary study of the value of energy produced at or near the site of distribution system load, is absolutely essential.

[9] Amory B. Lovins, et al., "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size,"* Rocky Mountain Institute (2003). Mr. Rábago was a contributing author.

5. Use billing determinants that encourage the generation of benefits. The original purpose and design of the VOST was to provide a rate that fairly compensates customers for bringing generation to the grid, retains a strong conservation incentive, encourages the injection of excess production into the grid (especially at high-cost times), supports long-lived investments by customers, reduces the total cost of generation to the utility (including present and future environmental costs), and is easily understood by solar customers and installers. In practical terms, this means that customer-generators should have clear, actionable economic rate "signals" that discourage excess or on-peak energy consumption, that encourage maintenance of generation facilities, and that provide customers (and installers) with clear visibility into reasonable payback rates and period. One key objective of the original VOST was to reduce dependence on incentive payments required to overcome and adjust for the externalization of distribution system benefits that occurs with wholesale-based generation pricing for distributed resources.

6. Strike an appropriate balance in addressing price signals, market price volatility, and regulatory lag. Customer-generators, even when assisted by solar installers, often lack the tools and sophistication to treat their rooftop solar investments in the same way a sophisticated, well-funded, and hedged wholesale market generator would. Minimizing potential subsidies in the short-run through short-term marginal cost pricing can undervalue capacity, as the ERCOT market has learned at the expense of millions of Texans. Paying rooftop solar generators based on short-term market prices ignores that the fact that market prices are an artifact of bidding practices, curtailment events, transmission constraints, and a host of other factors that do not fully or efficiently define the economic value of distributed generation. Market price volatility might be fun for traders, but it is inimical to private investments in rooftop solar by customers seeking primarily to manage rising electricity service costs. Cost and price factors can change many times over the useful life of a rooftop solar system, and rates, which should be forward-looking, should reflect the value that those systems bring in dampening the swings in prices, resource availability, and other factors.

7. Move Austin's solar industry toward self-sustaining markets. Solar incentives and even solar rates have a role in compensating for market failures and market inefficiencies in emerging markets, including markets for distributed solar resources. The fix is not to force distributed resources to operate like wholesale generators and institute extra-market adjustments for the externalization of value that wholesale markets operate with. Rather, just and reasonable rates for customer-generators should seek efficient internalization of all the costs and benefits of this unique resource. This was a fundamental objective in the design of Austin's VOST, and should again be a major design element in the VOST design.

III. EVALUATION OF THE AUSTIN ENERGY PROPOSAL

A. Austin Energy Failed to Meet its Burdens of Production and Proof

As the proponent of new and changed rates for customer-generators, Austin Energy bears the burden under commonly-accepted regulatory law and process to provide the City Council, as its regulatory authority with competent, relevant, and substantive evidence to support those rate proposals and that establishes those proposals as just and reasonable. Austin Energy has failed to meet its burdens in this proceeding.

Austin Energy developed its proposed VOST changes based on input from its consultant, NewGen, and without soliciting input or feedback from any stakeholders, including the Electric Utility Commission, the Resource Management Commission, solar installers, or current or potential solar customers.[10] The lack of engagement and inquiry weakens the proposal and is contrary to best practices for a publicly-owned municipal utility. This process failure is unjustified and in itself justifies a rejection of the proposed VOST changes.

Austin Energy's consultant, NewGen has never conducted a Value of Solar study,[11] and the neither the solicitation nor the response from NewGen specifically addressed experience and qualifications relating to Value of Solar studies or rates.[12]

Austin Energy also proposed changes in the VOST without regard for its obligations under the AE 2030 Plan and does not view customer-sited generation as a resource.[13] Austin Energy has not evaluated how the VOST proposals will impact achievement of the customer-sited solar target in the AE 2030 Plan.[14] A simple analysis of a hypothetical average solar customer, however, shows that the electric bill would double under the proposed base and VOST rate changes.[15] Moreover, Austin Energy did not perform a bill impact analysis concerning how its proposed VOST changes would impact customer-generators,[16] or any analysis or forecasts of future solar credits under its VOST proposals.[17] Austin Energy's VOST proposals are not grounded in a cost of service study for customer-generators,[18] and the utility did not conduct any analysis of how exports from customer-generators would impact grid operations.[19] Austin Energy did not analyze data on customer consumption levels prior to their investment in solar

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[10] Austin Energy responses to SUN 1-3, 1-5, 1-6, 1-7.
[11] Austin Energy responses to SUN 1-10, 1-12.
[12] Austin Energy response to SUN 1-8.
[13] Austin Energy response to SUN 1-16, 1-17, 1-18, 1-19.
[14] Austin Energy responses to SUN 1-26, 1-32.
[15] Austin Energy found that for a customer consuming 860 kWh and generating 725 kWh in a month, the bill would increase from $14.23 to $28.18. Austin Energy response to SUN 1-32.
[16] Austin Energy response to SUN 1-25.
[17] Austin Energy response to SUN 1-24.
[18] Austin Energy response to SUN 1-37.
[19] Austin Energy response to SUN 1-38.

facilities to determine how solar-generation changed their cost of service.[20] Austin Energy's proposals did not benefit from widespread analysis of feeder hosting capacity,[21] or marginal cost analysis,[22] even though such information would inform locational value of customer-sited solar. Austin Energy did not rely on best practices guidance relating to benefit-cost assessment for DERs available in the NSPM.[23]

B. Other Generally-Accepted Rate Making Principles That Offer Guidance

For nearly 60 years, James Bonbright's treatise entitled "Principles of Public Utility Rates" has stood as a foundational reference for evaluation of rate making proposals and approaches.[24] A review of Austin Energy's VOS proposal against Bonbright's principles serves a useful framework. The following articulation of the Bonbright principles[25] is useful in general and in reviewing Austin Energy's VOST proposals:

- Rates should be characterized by simplicity, understandability, public acceptability, and feasibility of application and interpretation.
- Rates should be effective in yielding total revenue requirements.
- Rates should support revenue and cash flow stability from year to year.
- Rate levels should be stable in themselves, with minimal unexpected changes that are seriously averse to existing customers.
- Rates should be fair in apportioning cost of service among different consumers.

[20] Austin Energy response to SUN 1-36g.
[21] Austin Energy response to SUN 1-39.
[22] Austin Energy response to SUN 1-40.
[23] Austin Energy responses to SUN 1-34, 1-35.
[24] James C. Bonbright, *Principles of Public Utility Rates* (Columbia Univ. Press 1961), available at: https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/.
[25] This summary was derived from Jess Totten, *Tariff Development II: Rate Design for Electric Utilities,* Briefing for NARUC/INE Partnership (Feb. 1, 2008), https://pubs.naruc.org/pub.cfm?id=538EA65C-2354-D714-5107-44736A60B037 (last visited Mar. 25, 2022).

- Rate design and application should avoid undue discrimination.
- Rates should advance economic efficiency, promote the efficient use of energy, and support market growth for competing products and services.

As they have for decades in hundreds if not thousands of rate proposals across the country and around the world, the Bonbright Principles provide a useful starting point in this proceeding. In addition to themselves being simple, understandable, acceptable, free from controversy in interpretation, stable, and non-discriminatory, the principles provide the foundation for competent and substantial evidence that utilities must provide to establish that proposed customer-generator credit rates are grounded in actual revenue requirements, and an honest and comprehensive assessment of the costs to serve customer-generators and the benefits that customer-sited generation creates.

C. Adapting Bonbright's Principles to the Modern Regulatory Environment

While the core principles remain valid, some things have changed since Bonbright published his work. Today, utilities are not the only investors with skin in the electric service game; customer-generators are significant investors, too. Indeed, a wide range of distributed energy resources ("DER") are available and increasingly being adopted by customers of all kinds. The general practice in the industry is to use the terms "distributed energy resources" and "DER" to describe a wide range of technologies and services deployed in the distribution system to meet demand for energy services. These technologies and services include generation, storage, electric vehicles, energy efficiency and conservation, demand response, and demand management. Customer classes, like energy technologies, are becoming more diverse, not less so. As a result, the tools and metrics of economic efficiency require attention to far more factors than the price revealed solely by a century-old approach to cost of service accounting—though this is still a sound starting point. There is important work to do in ensuring that public utility rates impacting distributed generators—like the VOST—serve and support the public interest, including public policy objectives. In order to advance economic efficiency, these policy objectives should be internalized into the rate design process, not externalized as social adders. There are several modern adaptations of Bonbright's principles that Austin Energy and the Austin City Council should rely upon in reviewing the underlying methods and foundation for Austin Energy's proposed VOS tariffs, and to ensure that equitable cost-of-service based rates are in place for customer-generators.[26] These additional considerations are:

- Full comprehension and reflection of the resource value of customer-sited generation in rates.
- Accounting for the relative market positions of the various market actors, and especially for the information asymmetries among customers, utilities, and other parties.
- Grounding rates in a careful assessment of the practical economic impacts of DER rates, including customer-sited generation rates, on all market participants.
- Ensuring that customer-sited generation rates, like utility rates in general, support capital attraction for beneficial investments.
- Accounting for the incentive effects of DER and customer-sited generation rates.
- Ensuring that rates for customer-sited generation and other DERs are based on accurate accounting for utility costs and careful differentiation between cost causation and the potential for cost shifting.

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[26] Exhibit KRR-4, K. Rábago & R. Valova, *Revisiting Bonbright's Principles of Public Utility Rates in a DER World,* The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018), available at: https://peccpubs.pace.edu/getFileContents.php?resourceid=43bdf87a9063c34.

Before reviewing Austin Energy's VOST proposals against traditional and updated rate making principles, it is important to review the context for evaluation of those proposals. Cost of service studies are backward-looking, even when future test years are used; the data is based on sunk or embedded costs. Rate making, on the other hand, is forward-looking. There is no widely recognized economic principle nor any demonstrated economic efficiency nor any recognized rate making principle that says rate design should mimic historical cost structure. A just and reasonable approach to rate design for customer-sited generation should account for what price signals are most efficient to communicate to potential customer-generators in order to secure optimal sizing, siting, design, technology integration, and operation.

Austin Energy's VOST proposals do not account for future investment in and operation of distributed generation—they are intentionally designed to do the opposite. Austin Energy's VOST proposals do not examine the potential impacts on customer investments, sizing, siting, or operation of distributed generators. They do not account for investment in complementary services and technologies such as energy storage, energy efficiency, energy management, demand response, or green building practices. Austin Energy's proposals are not grounded in a Value of Solar study, a benefit-cost assessment, or even a study of customer elasticity and potential market impacts. They do not account for the ways in which advanced metering infrastructure, distribution management systems, or other technology can inform economic and operational optimization of distributed generation operations could create benefits for the community and Austin Energy.

D. Austin Energy's VOST Proposals Fail to Align with Traditional Rate Making Principles.

The Austin Energy VOST proposal fails to align with traditional rate making principles in several regards. These deficiencies include:

- The proposed VOST rate structure will be tied to highly volatile and unpredictable wholesale market rates. Such market information is the stuff of professional energy traders and marketers, some of whom profit wildly and many of whom frequently get burned. But it is not a simple, understandable, acceptable, and easily applied and interpreted way for potential customer generators to evaluate and commit to the significant investments that are associated with customer-sited generation facilities.
- There is no way to tell from the Austin Energy's proposal whether the proposed VOST rates are effective in yielding total revenue requirements. Neither Austin Energy or its consultant, NewGen, have conducted a cost of service study or benefit-costs analysis specific to customer generators.
- Likewise, the basing of VOST credit rates on short-term *ex post* market price artifact data does not reflect the manner in which customer-generator operations impact revenue and cash flow over the decades they operate. Austin Energy's proposed crediting approach will also impair cash flow and payback stability for customer-generators.
- Rather than trying to create VOST stability, Austin Energy proposes to maximize credit instability and shift all market price risk to customer-generators who are often in the worst position to manage those risks.
- The lack of any benefit-cost analysis or cost of service analysis specific to customer generators means there is also no way to determine whether Austin Energy's VOST proposal advances inter- and intra-class rate equity.

- As explained further in this report, Austin Energy's proposals are unjustly discriminatory against non-utility customer-generators. Austin Energy has not even studied the impact of customer-sited generation on distribution system costs.
- Austin Energy's VOST proposals are not calibrated to advance economic efficiency, may have the effect of retarding investment in customer-sited generation, may frustrate AE 2030 Plan goals achievement, and suppress rather than support market growth for non-utility products and services. Austin Energy's explicit proposals to externalize so-called social and policy credits from core utility costs, and to implement changes through piece-meal rate making are also inefficient and uneconomic.

E. Austin Energy's VOST Proposals Would Result in Uneconomic Rates and Customer-Generators Being Forced to Subsidize Other Customers.

Austin Energy proposes to implement a new method of calculating the value of saved energy based on the previous year's day-ahead prices for ERCOT delivered energy, to calculate saved transmission costs value based on the previous year's ERCOT postage stamp rate, and to calculate saved ancillary services charges based on the previous year's ERCOT prices for four ancillary services products. Austin Energy and NewGen refer to these as avoided costs even though these are not all the costs avoided by customer-sited generation over the useful life of these facilities. Austin Energy proposes to recover revenues associated with credits provided to customer-generators through the Power Supply Adjustment,[27] after an adjustment for average annual, but not marginal, line losses, despite the fact that line losses increase with increased demand.[28]

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[27] Austin Energy RFP Ch. 9.
[28] Austin Energy response to SUN 1-30.

Whenever the production credit for customer-sited solar generation is artificially suppressed in a VOS credit that does not reflect the full range of avoided costs and benefits, an uneconomic subsidy is created in which customer-generators are required to subsidize other non-solar customers (especially large users of electricity) and the utility. Whenever customer-generators are forced to subsidize other customers, they will be less likely to invest in solar generation, frustrating policy and economic goals for the community. It does not matter that some benefits are labeled as societal or policy-based, because Austin Energy is a publicly-owned utility and the citizens of Austin and surrounding served communities are the customers that pay for the utility and its customers pay the costs created by the production, provision, and use of energy by Austin Energy. Rather, Austin Energy takes the position that "societal benefits do not reflect actual reductions in operating costs for Austin Energy,"[29] and therefore, the "VoS [sic] credit is greater than the economic savings enjoyed by Austin Energy and its customers."[30] As a result, Austin Energy is "unaware of any actual avoided costs to the City of Austin" that flow from the societal benefits created by customer-sited generation.[31] From Austin Energy's mistaken perspective , crediting customer-generators for the societal benefits provided by distributed generation is somehow a subsidy to those customer-generators.[32]

There are, in fact, subsidies inherent in Austin Energy's current and proposed VOST rates, but they flow in exactly the opposite direction asserted by Austin Energy and is consultant, NewGen. Austin Energy's proposal ignores avoided costs associated with system capacity, reserve generation, and distribution capacity that customer-sited solar defrays. Excluding VOS

[29] Austin Energy response to SUN 1-23a.
[30] *Id.*
[31] Austin Energy response to SUN 1-23b.
[32] Austin Energy response to SUN 1-27.

credit for these values, as well as additional environmental benefits provided by customer-sited generation, means that solar customers are providing significant subsidies to Austin Energy and other customers. In fact, solar customers are allowing Austin Energy to avoid costs that it would otherwise have to charge customers for.

This report recommends specific adjustments to mitigate the cross subsidy that Austin Energy wants solar customers to pay. These recommended adjustments would be fair to all ratepayers, and stimulate solar deployment that will help Austin meet its local renewable energy goals.

Summary.

Austin Energy's proposals, and the NewGen memoranda upon which they appear to rely do not rest on a comprehensive resource valuation of customer-sited generation. They seem to presume that customer-generators have the resources and experience to operate like ERCOT market traders and the investment resources to rely on compensation credits based solely on one-year historical data emerging from the volatile and scarcity-driven ERCOT energy-only market. Notably, as Austin Energy moves to ignore and not internalize the resource value of customer-sited generation, the Federal Energy Regulatory Commission, the Public Utility Commission of Texas, and ERCOT are embarked on efforts to figure out how to use DERs to cost-effectively and reliably provide grid services.[33] Austin Energy and NewGen provided no information relating to an assessment of the impacts of the proposed VOST changes on current or potential customer-generators, including assessment of impacts on the rate of rooftop solar adoption. Because Austin Energy proposes to abandon VOST crediting based on future avoided costs and other benefits, it has not evaluated the practical economic impacts of changes in deployment

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[33]Exhibit KRR-5, R. Walton, *Texas Regulators Look to Distributed Resources, Additional Coal Reserves, to Boost Reliability,* Utility Dive (Apr. 22, 2022), available at: https://bit.ly/3Hr0rhk.

rates or other aspects of customer-sited generation.[34] In sum, neither Austin Energy nor NewGen has conducted an assessment of the cost-effectiveness of its proposed VOST changes.[35]

Later in this report, I show that existing and proposed VOS credit rates result in significant cross subsidies by solar generation customers in favor of Austin Energy and other customers. To mitigate these cross subsidies, the VOS credits should be significantly higher. Under the current VOST, the credit rate should be increased from $0.0970 per kilowatt-hour to $0.1363 per kilowatt-hour. Under the proposed VOST, the credit rate should be increased from $0.0991 per kilowatt-hour to $0.1686 per kilowatt-hour.

F. Austin Energy's VOST Proposals and the NewGen Memoranda.

Austin Energy's proposed VOST changes are detailed in the Rate Filing Package ("Austin Energy RFP").[36] Austin Energy appears to have relied upon reports from its consultant, NewGen, though the RFP does not include any explicit crosswalk between the analysis and recommendations from NewGen and the recommendations in the RFP.

NewGen's documented input to Austin Energy is contained in two parts. On February 8th, 2022, NewGen submitted a memorandum titled "Review of Austin Energy's Value of Solar." On April 5th, 2022, NewGen submitted to Austin Energy another memorandum, this one titled "Avoided Cost Based Component of the Value of Solar Credit."

The premise of the NewGen VOS Review is that forward-looking valuation of the costs and benefits of customer-sited solar results in a subsidy from non-solar to solar customers if it results in a VOS credit larger than "direct economic savings" to Austin Energy.[37] Further, NewGen opines that utility-scale solar may cost less than customer-sited solar. NewGen's VOS

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[34] *See supra* notes 11-20 and accompanying text.
[35] Austin Energy responses to SUN 1-34, 1-35.
[36] Austin Energy RFP at pp. 138-50.
[37] NewGen VOS Review at p. M-1.

Review, therefore, is aimed at "reducing the subsidy" by reducing the VOS credit even if that impairs achievement of customer-sited PV goals for Austin contained in the AE 2030 Plan.[38] NewGen characterizes this proposed balancing of its narrow approach to utility economics against the City of Austin's policy directives as a "Policy Consideration."[39]

As previously discussed, a core aim of the Value of Solar construct was to treat customer-sited generation as and on the same terms as utility resources. The NewGen/Austin Energy proposal ends this approach in favor of treating solar generators as as-available suppliers of wholesale energy, rather than the reliable, highly-available, zero-marginal cost generators of energy at or near the point of consumption that they are. Treating customer-generators as competition or characterizing these customer investors as dependent on subsidies without a comprehensive evaluation of the impacts of customer-sited generation is discriminatory, conclusory, and inconsistent with principles underlying just and reasonable rates.

NewGen proposed that Austin Energy adopt a single VOS credit rate for all customer-sited solar smaller than 1 MW-ac; Austin Energy adopted this proposal with no detailed justification.

A detailed evaluation of the impacts of distributed generation would reveal whether the relative size and grid placement of these generators impacts their value. While it is possible that the relative differences related to facility size and customer type would have no material impact on the value of these resources to the grid, this seem doubtful at best. The only way to determine if the rate schedules for different types of customers should be compressed in order to pursue administrative savings is by ensuring that the differences are not materially related to the cost of

[38] NewGen VOS Review at p. M-1, M-6.
[39] *Id*.

serving those different customer types. Since neither NewGen or Austin Energy have conducted cost of service studies specific to customer-generators of any type, the proposal to compress the VOST rates is unsupported.

NewGen takes the position that commercial customers on a demand rate that successfully reduce their peak demand with solar generation are receiving a double benefit by earning a VOS credit that reflects avoided transmission and distribution costs while also reducing their consumption charges. NewGen assumes this unquantified benefit is unintended and unfair, but offers no data based on the cost of serving such customers to support the assertion.

NewGen's assertion of unintended benefit accruing to demand rate customers that reduce their peak usage cannot stand in the absence of the kind of cost of service and other data necessary to verify that total compensation outweighs Austin Energy's long-run marginal avoided costs.

NewGen proposed that Austin Energy replace its Effective Peak Capacity calculation and replace it with an annual value calculated based on solar production for a number of generators that "appeared" to be smaller than 1 MW-ac during the ERCOT four coincident peaks. Austin Energy adopted this proposal. This set of data appears to indicate a difference between estimated data based on PV-Watts and actual data for the selected generators, but there is no analysis of the overall impact of switching to estimated versus annual metered data.[40] NewGen's analysis was based on data for 645[41] of the more than 10,000 customer-generators on Austin Energy's system,[42] but provides no statistical or analytical evidence that the sample was representative and that the conclusions based on this analysis are reliable.

[40] NewGen VOS Review at p. M-6-7.
[41] NewGen VOS Review at p. M-7.
[42] Austin Energy response to SUN 1-36a, Att.

The data on which NewGen and Austin Energy rely to justify elimination of the Effective Peak Capacity calculation should be evaluated in an open and transparent process, and against reasonable estimates of the contribution to peak capacity that distributed solar generators are reasonably expected to make over their useful lives. Recently observed problems with ERCOT's energy-only, scarcity-based market exemplify the importance of valuing future capacity value in an objective manner. That evaluation remains to be done.

NewGen proposes, and Austin Energy adopts, an end to estimating the avoided energy value from customer-sited generation over the life of the generator in favor of a backward look at prices in a single year and adjusted to eliminate the kinds of extreme costs caused by climate change, fuel supply problems, and market price volatility.[43] NewGen asserts that its approach "allows for increased transparency"[44] and supports the *ad hoc* adjustment for extreme weather and market effects without any proposal for analysis of how existing PV has mitigated such effects in the past.[45]

Historically-based evaluations of grid conditions, stripped of the evidence of increasingly frequent and extreme conditions driven by weather and markets, are not a credible basis for valuing the future stream of benefits and avoided costs that customer-sited generation can bring to all customers. Doubtless Austin Energy would make arguments for contracts for utility-scale generation based on a future stream of costs and benefits; to refuse to do so for customer-sited generation is unreasonably discriminatory and likely to produce uneconomic outcomes.

[43] NewGen VOS Review at p. M-8-9.

[44] Presumably, this transparency is available if customer-generators routinely log into the ERCOT website, locate nodal pricing data for nodes serving Austin, and calculate annual averages that correspond with whatever annual calculation dates Austin Energy choses. This is an unreasonable burden for customer-generators and discredits any claim of transparency benefit.

[45] *Id*.

NewGen proposed to Austin Energy that it eliminate the generation capacity value credit that is now included in the VOST and replace it with "an approach that includes capacity pricing either in a manner similar to the Demand VOS energy value component under a forward-looking approach" or through a historical market pricing approach.[46] Austin Energy proposes to eliminate the generation capacity value credit and not replace it with anything, ignoring generation capacity value in its proposed VOST.

Austin Energy has not produced substantial evidence that customer-generators should be denied credit for the generation capacity value their systems bring to Austin Energy all its customers. The VOST was designed to recognize and provide just and reasonable compensation to customer-generators for capacity value; the fact that the ERCOT market does not provide a historical or forward-looking capacity market price does not change the fact of the capacity value of customer-sited generation. Austin Energy's failure to explain its position and demonstrate that it is just and reasonable is discriminatory.

NewGen proposed, and Austin Energy supports, elimination of a credit for avoided generation O&M costs as part of its general proposal to only provide credit for avoided and not avoidable costs.[47]

The proposal to eliminate credit for avoided O&M costs for generation as well as other infrastructure is unreasonable. O&M costs lead to capital replacement costs; savings on O&M can defer or avoid capital replacement costs. To the extent that customer-generators create these added benefits by avoiding these costs, treating their facilities as a resource compels a forward-looking valuation.

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[46] NewGen VOS Review at p. M-9-10.
[47] NewGen VOS Review at p. M-10-11.

NewGen proposes that Austin Energy provide no credit for avoided distribution costs. Austin Energy does not propose any credit for distribution value, but offers no explanation for why it takes this approach. NewGen states that "the presence of PV installations on the system can result in avoided distribution costs or increased distribution costs," but because Austin Energy "does not dictate or encourage installation of PV based on the needs of its distribution system," it is difficult to determine if incremental costs or benefits exist. Further, because "Austin Energy's distribution planning staff does not consider the presence or absence of PV when sizing distribution facilities," it agrees with Austin Energy's approach to assign no value for distribution impacts.[48] Moreover, NewGen observes that Austin Energy, despite having a VOST in place for ten years, has yet to investigate whether and to what extent distributed solar generation impacts transmission and distribution costs.[49]

Austin Energy's failure to assess the impact of distributed generation on distribution system costs is on its face unreasonable. Moreover, Austin Energy's failure to understand its distribution costs and the impacts of distributed generation on those costs suggests that Austin Energy is incurring unnecessary costs and adversely impacting electricity affordability.

NewGen observes that Austin Energy has used the VOST credit for environmental value to represent avoided emissions costs related with Austin's environmental/renewable energy policy goals, but nonetheless takes the position that even though customer-generators provide this value to all customers, any credit for such value represents a subsidy.

NewGen concludes it VOS Review with an abbreviated discussion of California net metering regulatory activity, and an even more abbreviated discussion of recent net metering

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[48] NewGen VOS Review at p. M-11.
[49] NewGen VOS Review at p. M-13.

activity at Pedernales Electric Cooperative and the City of Georgetown, under the unreasonably broad categorical label of "The State of the Industry for Solar Policy." NewGen provides no explanation of the purported relevance of the information; Austin Energy does not address the information in its RFP.

IV. RECOMMENDED COURSE OF ACTION: BENEFIT-COST ANALYSIS AS A FOUNDATION FOR CUSTOMER-GENERATOR RATES

The best place for Austin Energy to start to remedy the many deficiencies in its VOST proposals is conducting a transparent and comprehensive assessment of the costs and benefits of customer generation, and not rely on vague and untested assertions from a consultant's report. A growing number of jurisdictions have used true Value of Solar analysis to inform and support net metering and related customer generation rate decisions,[50] including Austin Energy, though it proposes to end that practice now. Best practices across jurisdictions countenance the undertaking of value analysis under a common analytical framework that can also incorporate utility-specific facts and circumstances. The development of a framework and the investigation of the costs and benefits of customer-sited generation should be conducted with experienced, independent expert support as appropriate.

A. Benefits of a Common Framework Approach for Benefit Cost Analysis (BCA)

Austin Energy should adopt a common framework approach to BCA, including an updated Value of Solar analysis to support customer-generator rates. Using a common

[50] Many states have conducted Value of Solar studies of one form or another. States that have existing studies include: Arizona (2016 and 2013); Arkansas (2017); California (2016, 2013, 2012, 2011, 2010, 2005); Colorado (2013); Florida (2005); Hawaii (2014); Iowa (2016); Louisiana (2015); Massachusetts (2015); Maine (2015); Mississippi (2013); North Carolina (2013); Nevada (2017, 2014); New Jersey and Pennsylvania (2012); New York (2012 and 2008); South Carolina (2015); Texas (2014), including for the cities of San Antonio (2013) and Austin (2006); Utah (2014); Vermont (2014); Virginia (2014); and Wisconsin (2016). Other states have conducted dockets and processes for establishing a Value of Solar methodology or framework, such as: Minnesota (2014); Rhode Island (2015); and New York (2016). Solar Energy Industries Association, *Solar Cost-Benefit Studies.* Available at: https://www.seia.org/initiatives/solar-cost-benefit-studies.

framework for BCAs aligns with tenets of sound rate making, including ease of understandability and application, and provides greater confidence that rates will track cost causation and fairly apportion costs. And importantly, a common framework approach to evaluating costs and benefits will support efficient and rational market development for DG and other DERs.

B. Austin Energy's Burden

As previously explained, the burden for proving that a proposed rate is just and reasonable is on the public utility. Austin Energy bears the responsibility of submitting sufficient and competent evidence to support the proposed tariffs and to demonstrate that the tariffs will result in rates that are just and reasonable. Any proposal for a new VOS tariff methodology and rates must be based on cost of service data for customer generators—and not merely the summing of limited and averaged data for a select subset of customer-generators. Austin Energy has conducted Value of Solar analysis in the past; it should start doing so again.

C. A Common Analytical Framework for BCA is Best Practice

The concept of standardized BCA frameworks goes back nearly 40 years in the U.S., when the California Standard Practice Manual was published in 1983.[51] Indeed, the common use of standardized frameworks to evaluate energy efficiency programs has improved the stock and performance of such programs to the extent that it is now common knowledge that efficiency is the least expensive energy resource everywhere. Over the past 40 years, state regulatory commissions have developed, shared, and adopted common methods and evaluation frameworks for calculating wholesale avoided cost rates. While each state has adapted these methods to address specific local conditions and policy priorities, a strong non-utility wholesale generation

[51] *See, generally,* California PUC, *California Standard Practice Manual,* Regulatory Assistance Project (Oct. 1, 2001), available at: https://www.raponline.org/knowledge-center/california-standard-practice-manual.

sector has emerged in many states, saving all customers significant amounts of money. Development and application of BCA frameworks for DER markets have now been launched in several other states and jurisdictions.

D. The Relationship between BCAs and Value of Solar Studies

The Value of Solar study is at heart a Benefit-Cost Analysis, specialized to distributed solar production. As early as 2013, the methods and metrics of best practices for Value of Solar studies were already identifiable and documented in "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar."[52] That reference lists the key categories of impacts that should be assessed and describes methods to quantify those impacts. Transparent and comprehensive evaluations of the value of solar and of DER have tracked the guidance in the Regulator's Guidebook to describe and quantify costs and benefits resulting from the production of energy by DG facilities over the useful life of facilities. It is important to note that the most useful reports employ a fairly standardized analysis framework and transparently document the methods chosen for calculating costs and benefits. The "gold standard" for such analysis remains the work done in Minnesota, by Clean Power Research, published in 2014.[53] That report was the product of a transparent multi-stakeholder process and the report fully documents the methods and results. The study was reviewed multiple times by the Minnesota Public Service Commission, and the methodology was adopted for informing compensation rates for community solar projects. Unlike Austin Energy's proposal in this proceeding, it was not the product of a closed process of report generation. Today, the Minnesota Community Solar

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[52] Exhibit KRR-6, J. Keyes & K. Rábago, *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar,* Interstate Renewable Energy Council-IREC (Oct. 2013), available at: http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.
[53] Clean Power Research, *Minnesota Value of Solar: Methodology,* Minnesota Department of Commerce (Mar. 2014), available at: https://www.cleanpower.com/research/economic-valuation-research.

program, which bases community solar credits on regularly and publicly updated value analysis, leads the nation in DER.[54] For examples of BCA success stories across the nation, see Exhibit 3. While the examples are illustrative and not exhaustive, they reveal the benefits of using a BCA Framework approach to address many of the most important issues facing electric utility regulators and electric utilities today.

E. The Benefits that Austin Energy Can Realize from Adopting a BCA Framework

A BCA Framework can lead to clarity in understanding and communication between Austin Energy and stakeholders about benefit and cost impacts particular to Austin. A BCA Framework is essential to establishing fair, just, and reasonable rates for DER services and technologies. A BCA Framework can provide a platform for evaluating and prioritizing grid modernization and other investment decisions, and for moving toward the customer-sited solar goals established by the AE 2030 Plan. A BCA Framework can provide a mechanism for examining interactive, portfolio, and competitive effects between programs and rate structures. And, over the long-term, a BCA Framework can provide essential analytical rigor to agendas as big as utility sector transformation. These benefits provide all the justification necessary for Austin Energy to develop and propose a BCA Framework by which fair, just and reasonable rates for DER services can be determined. A consistent and well-structured BCA Framework can be applied to program evaluation, investment decision making, and rate design. More directly, efforts in other jurisdictions reveal just how far Austin Energy's approach in this proceeding is from best industry practices.

[54] *See* J. Farrell, *Why Minnesota's Community Solar Program is the Best,* Institute for Local Self-Reliance (5 Feb. 2021—updated monthly), available at: https://ilsr.org/minnesotas-community-solar-program.

V. BCA FRAMEWORK RECOMMENDATION – ADOPT ESTABLISHED NATIONAL BEST PRACTICES

Fortunately, the decades of work invested in sound BCA processes yielded a consensus among leading practitioners as to the elements of best-practices BCAs. That consensus is documented in the NSPM—the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources, published in August of 2020.[55] Austin Energy and its consultant did not rely upon the Manual or follow the Manual's best practices guidance in formulating their VOST proposals.[56]

The NSPM is a comprehensive document that includes guiding principles, recommended process steps, impact category lists, definitions, and specific guidance on a wide range of issues associated with developing a BCA Framework and conducting cost effectiveness analysis. It would be wise for Austin Energy to take advantage of the comprehensive and integrated nature of its recommendations. The entire NSPM guidance document is 300 pages in length, including several appendices. For an overview of specific guidance including guiding principles, the standard five-step process, and impacts to be considered, including utility system, customer, and societal impacts, please see the NSPM Summary published by the National Energy Screening Project.[57]

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[55] T. Woolf, et al, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources,* National Energy Screening Project (Aug. 2020). Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/. While the NSPM-DER was published recently, it reflects best practices articulated in a prior NSPM for efficiency resources and generally recognized in the industry. Mr. Rábago was a co-author of the manual.

[56] Austin Energy responses to SUN 1-33, 1-34, 1-35.

[57] National Energy Screening Project, National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources—Summary (Aug. 2020), available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-Summary_08-24-2020.pdf.

Austin Energy's proposals in this proceeding fail to align with the best practices guidance from the NSPM-DER in several important ways. In regard to core NSPM BCA principles, Austin Energy's proposals are deficient in several regards:

Principle 1 - Treat DERs as a Utility System Resource: Austin Energy proposes not to assess the broad range of resource benefits that DG deployment and operation can provide to the utility system.

Principle 2 - Align with Policy Goals: Austin Energy proposes not to account for alignment of its proposals with the AE 2030 Plan, nor in light of any assessment of impacts on market activity that could result from the implementation of proposed base and VOST changes. Austin Energy proposes to leave to a future, unspecified date, the development of incentives for customer-generators to support the AE 2030 Plan.

Principle 3 - Ensure Symmetry: Austin Energy's proposal does not treat customer-sited generation on a level playing field with monopoly-owned resources, ignores many beneficial impacts, and prioritizes utility concerns over a competitive market for DG. Again, there is no documentation of a transparent and comprehensive analysis of the full life-cycle benefits of customer-sited generation.

Principle 4 - Account for All Relevant, Material Impacts: There is no accounting for the full range of utility impacts that the NSPM-DER identifies as resulting from DG. As this report addresses, Austin Energy used a commissioned report from a consultant as a foundation for its proposals, and only shared the work publicly after the proposals were finalized. The core of the Austin Energy VOST proposal is to account only for a narrow set of impacts, relying on a single year's worth of historical data at a time.

Principle 5 - Conduct Forward-Looking, Long-term, Incremental Analyses: Austin Energy's proposal is limited in temporal scope, and does not align with the 25+ years of benefits that customer-sited generation can produce, especially in reducing and deferring costs of Austin Energy's business-as-usual approaches.

Principle 6 - Avoid Double-Counting Impacts: While Austin Energy's consultant, NewGen, spoke to a potential double counting of benefits in its VOS Review, there appears to be no substantive analysis of that concern, nor any proposal by Austin Energy to address the potential issue.

VI. RECOMMENDED ADJUSTMENTS TO VOST CREDIT RATES

Austin Energy must do a great deal of work to restore consistency in its VOST with the principles and purposes upon which the VOST was based. The result will be economically efficient rates that support achievement of the AE 2030 Plan objective for customer-sited solar, a stronger local market for clean energy generation, and reduced costs for Austin Energy and the Austin community. While this work is ongoing, customer-generators should not be deprived of fair compensation for measurable benefits that they create for Austin Energy and the community. For this reason, and to address significant shortcomings in the VOST that exist and that will be worsened should Austin Energy's VOST proposals be approved to any extent, I recommend interim adjustments in the VOST credit rate for avoided costs relating to generation capacity, reserve capacity, distribution capacity, and to additional environmental benefits.

Austin Energy Should Adjust its Avoided Capacity Costs.

If the City Council allows Austin Energy to adopt its backward-looking calculation methods for avoided energy, transmission, and ancillary services costs—which it should not—

the City should require Austin Energy to adjust the credit for avoided generational capacity costs, avoided reserve capacity costs, and avoided distribution capacity costs.[58]

A just and reasonable VOS credit would be based on data specific to Austin Energy and the Texas market. However, because Austin Energy has not assessed all of these benefits, this report proposes the inclusion of proxy costs pending the investigation that Austin Energy should conduct. The use of proxy costs is also reasonable because Austin Energy controls the relevant data and has not used it to generate a VOS study. Recently published work in the form of a meta-analysis offers reasonable proxy values for avoided generation capacity, reserve capacity, and distribution capacity.[59] This report recommends proxy values based on the mid-range of costs reported in the Hayibo VOS study.[60] This report recommends use of the following capacity-related avoided costs:

- Avoided Generation Capacity Costs of $0.0302 per kilowatt-hour
- Avoided Reserve Capacity Costs of $0.0079 per kilowatt-hour
- Avoided Distribution Capacity Costs of $0.0175 per kilowatt-hour

The Hayibo VOS Study also assessed VOS study results relating to avoided health liability costs that are significant. This report does not recommend use of a proxy value for these avoided health liability costs at this time, but does recommend that these avoided costs be addressed in a comprehensive VOS study.

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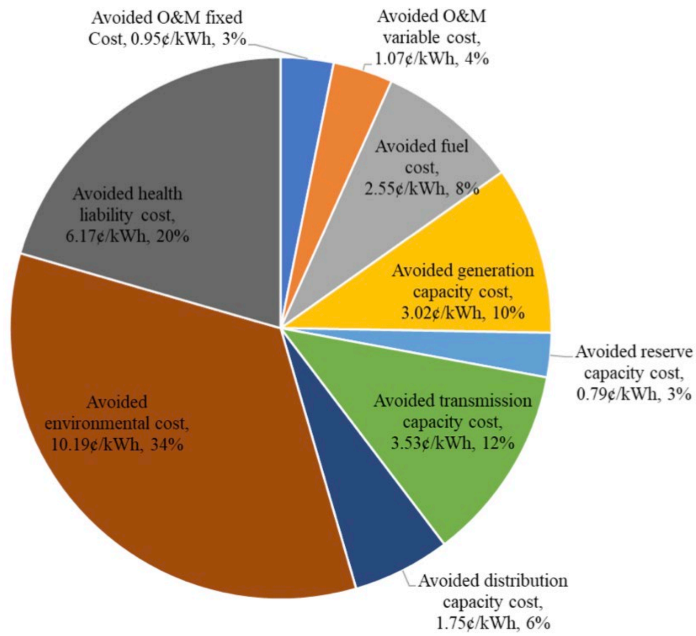
[58] The existing VOST includes a value for avoided generation capacity costs. *See* Austin Energy response to SUN 1-14, Att. 1-14A at p. 10.
[59] Exhibit KRR-7, K.S. Hayibo & J. Pearce, *A Review of the Value of Solar Methodology with a Case Study of the U.S. VOS,* Renewable and Sustainable Energy Reviews 137 (2021), https://doi.org/10.1016/j.rser.2020.110599. ("Hayibo VOS Study")
[60] *Id.* at p.25.

Figure KRR-1: Mid-Costs of Avoided Costs for VOS



Avoided Social Costs of Environmental Emissions.

Austin Energy proposes to recover credits paid for the environmental performance of customer-sited generation as a societal benefit to be recovered through the CBC. Austin Energy is proposing to base avoided emissions benefits of customer-sited generation on Texas statewide carbon dioxide emissions rates reported by the U.S. Energy Information Administration ("EIA") in 2020 and an annually adjusted federal social cost of carbon value.[61] The most recent EIA data is from the year 2020, even though the social cost data is provided for future years.

While Austin Energy's proposed shift to statewide emissions rates as the baseline for evaluating emissions benefits is an improvement, Austin Energy's proposal includes several elements that artificially reduce the environmental credit. Austin Energy relies on EIA data for carbon emissions, but ignores EIA data for other emissions that are avoided by customer-sited generation. In addition, the Environmental Protection Agency's ("EPA") continuous emissions

[61] Austin Energy RFP § 9.4.

monitoring system ("CEMS") reports total carbon emissions almost 1.7 times higher for Texas than the EIA data. CEMS data is also available annually. Austin Energy has not reconciled this large difference that could significantly undervalue the avoided carbon benefits of customer-sited solar generation. Austin Energy's approach ignores avoided costs, beyond compliance costs, associated with avoided methane, nitrous oxide, and sulfur dioxide emissions, even though the social cost of methane and nitrous oxide are available from the same federal social cost of carbon reference and emissions rates are available from the same EIA data used by the utility. In addition, Austin Energy does not monetize the benefits of avoided water use and water pollution associated with local distributed generation. Nor does it account for the environmental benefits of other avoided pollutants, such as nitrogen oxides, mercury, selenium. Consistent with its proposal to limit benefits quantification to a single years' worth of impact, Austin Energy also ignores the fact that these environmental benefits will continue for the entire useful life of the customer generation facility. All these shortcomings further undervalue the benefits of customer-sited solar significantly. The value of avoided environmental emissions of carbon dioxide, methane, nitrous oxide, and sulfur dioxide is almost double Austin Energy's proposed 2.3 cents rate if the median of 25 years of avoided costs is assessed and EIA emissions rates are used. Even for a single year, using 2023 costs and 2020 emissions rates, the credit should be 60% higher, or 3.65 cents per kilowatt-hour. If EPA CEMS emissions rates are used with 2023 costs, the single year credit rate should be more than twice what Austin Energy proposes, at 5.25 cents per kilowatt-hour. The table below shows how Austin Energy undercounts environmental benefits significantly as to air emissions. This report uses the conservative one-year value of $0.0365 per kilowatt-hour for additional social costs of avoided emissions pending a more thorough analysis of such avoided costs.

Table KRR-1: Social Cost of Avoided Emissions

	Austin Energy Proposal	25-year (2020-2044) Average Using Federal SCC (3% Discount Rate)	1-year (2023) Value, Using 2020 Emissions Rates	1-year (2023) Value, Using EPA CEMS 2020 Emissions Rates	Source of Social Cost Value	Source of Texas 2020 Emissions Rate
CO2	$ 0.0230	$ 0.0274	$ 0.0230	$ 0.0390	Table A-1, Tech Spt Doc	EIA Texas Profile 2020
CH4	$ -	$ 0.0014	$ 0.0011	$ 0.0011	Table A-2, Tech Spt Doc	EPA Inventory of GHG Emissions & Sinks 1990-2020
N2O	$ -	$ 0.0076	$ 0.0064	$ 0.0064	Table A-3, Tech Spt Doc	EIA Texas Profile 2020
SO2	$ -	$ 0.0071	$ 0.0060	$ 0.0060	Estimated social cost from D. Shindell, The Social Cost of Atmospheric Release (2015).	EIA Texas Profile 2020
Total Environmental Credit	**$ 0.0230**	**$ 0.0435**	**$ 0.0365**	**$ 0.0525**		
	Difference	$ 0.0205	**$ 0.0135**	$ 0.0295		
			$ / kWh			

<u>*Summary and Proposed VOST Credit Rates*</u>

When the mid-cost values from the Hayibo VOS Study and the avoided social costs of emissions are added to the existing and proposed VOST rates, the result show that the existing and proposed VOS credit rates result in significant cross subsidies by solar generation customers in favor of Austin Energy and other customers. To mitigate these cross subsidies, the VOS credits should be significantly higher. Under the current VOST, the credit rate should be increased from $0.0970 per kilowatt-hour to $0.1363 per kilowatt-hour. Under the proposed VOST, the credit rate should be increased from $0.0991 per kilowatt-hour to $0.1686 per kilowatt-hour.

Table KRR-2: Adjusted VOS Credit ($/kWh), to reduce solar customer subsidies to other customers

	As proposed by Austin Energy	$	(0.0991)
plus	Avoided Generation Capacity	$	(0.0302)
plus	Avoided Reserve Capacity	$	(0.0079)
plus	Avoided Distribution Capacity	$	(0.0179)
plus	Avoided CH4, N2O, SO2	$	(0.0135)
	Total VOS Credit	$	(0.1686)
	Difference	$	(0.0695)
	Percent		70%

	Current VOS Credit	$	(0.0970)
	Avoided Generation Capacity	$	-
plus	Avoided Reserve Capacity	$	(0.0079)
plus	Avoided Distribution Capacity	$	(0.0179)
plus	Avoided CH4, N2O, SO2	$	(0.0135)
	Total VOS Credit	$	(0.1363)
	Difference	$	(0.0393)
	Percent		41%

VII. ACTION PLAN TO MEET AE 2030 PLAN GOAL FOR CUSTOMER-SITED LOCAL SOLAR

Austin Energy offers, in the RFP, an initial and incomplete proposal do develop performance-based incentives for customer generators.[62] These incentives are tied to Austin Energy's obligations under the AE 2030 Plan.[63] Austin Energy recognizes that stakeholder engagement is necessary to inform effective incentives,[64] but the overall VOST proposal reflects a backwards and piece-meal approach to designing a comprehensive approach to achieving the goal set for the utility in the AE 2030 Plan and by the City Council. Austin Energy should have started its VOST proposal development process with its overarching 2030 Plan goal, and not reserve it for an afterthought in the RFP.

[62] Austin Energy RFP § 9.5.
[63] Austin Energy RFP § 9.5.1.
[64] *Id.*

The remedy for these problems is for Austin Energy to approach the customer-generator market opportunity holistically, through a concrete and actionable plan that starts with the current 2030 goal of 200 MW of customer-sited local solar capacity. A comprehensive benefit-cost analysis and research, including through stakeholder engagement, can then identify whether market failures exist that justify the creation and guide the design of additional or different incentives until markets are rationalized.

My final recommendation is that the City Council require Austin Energy to establish and follow such a plan for achieving the AE 2030 Plan goal for customer-sited generation.

VIII. SUMMARY OF COMMENTS AND RECOMMENDATIONS

Austin Energy seeks to alter the fundamental structure of the VOST by suppressing the production credit for customer-sited solar generation. In so doing, it would artificially suppress the VOST credit so that it does not reflect the full range of avoided costs and benefits created by that generation, and create an uneconomic subsidy under which customer-generators are required to subsidize non-solar customers (especially large users of electricity) and the utility. Whenever customer-generators are forced to subsidize other customers, they will be less likely to invest in solar generation, frustrating policy and economic goals for the community. The remedy for this uneconomic approach is to calibrate the production credit against a comprehensive and transparent VOS study in the form of a BCA.

A BCA framework developed in accordance with best practices guidance, such as that contained in the NSPM, is essential to provide a substantial and competent evidentiary foundation for the design of fair, just, and reasonable rates for customer generators. An open and transparent process of investigating the benefits and costs of customer-sited generation can provide all stakeholders with meaningful opportunity for engagement. In addition to providing cost-based analytical support for customer-generator compensation, such a framework can also provide broad and future benefits in supporting the development of other tariffs relating to DERs, evaluation of grid modernization investments including those relating to advanced metering infrastructure, and transmission, distribution, and generation planning.

Austin Energy should withdraw and suspend proposals for modifications to the VOST. As previously noted, Austin Energy's recognition that environmental benefits assessment should be measured against emissions rates for ERCOT or all of Texas is sound, as is increased reliance on actual performance data for customer-sited generation. The proposed tariff revisions have not been demonstrated to be fair, just, and reasonable and in the public interest. Austin Energy should leave the existing VOST in effect until it develops and proposes a tariff that will result in fair, just, and reasonable rates, based on the development and application of a BCA Framework. Austin Energy should report on assumptions, methods, and results in a transparent and comprehensive manner to the interested public and provide a meaningful opportunity for stakeholder comments and suggestions. Austin Energy should make the BCA Framework and tool it develops available to the public and interested stakeholders. And any subsequent proposal for new rates relating to DERs should be grounded in the methods and evaluation of impacts established in the BCA Framework. Finally, Austin Energy should adopt a schedule for updating the impacts quantification in the BCA Framework on a regular interval—such as once every one or two years—in order to take advantage of evolving experience and best practices in the industry in general. The BCA Framework itself need be comprehensively reviewed less often, as necessary in order to capture new or modified quantification methods for impacts.

<u>**Rábago Exhibit 1**</u>

Karl R. Rábago
Rábago Energy LLC
2025 E. 24th Avenue, Denver, CO 80205
c/SMS: +1.512.968.7543 | e: karl@rabagoenergy.com

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a regulatory expert, utility executive, research and development manager, sustainability leader, senior government official, educator, and advocate. Successful track record of working with U.S. Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. Nationally recognized speaker on energy, environment, and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing business sustainability, expert witness, and regulatory advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 30 states and 100 electricity and gas regulatory proceedings. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board.
- Director, Solar United Neighbors (2018-present).
- Director, Texas Solar Energy Society
- Advisor, Commission Shift

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—September 2020. Part-time advisor and staff member. Provide expert witness, project management, and business development support on electric and gas regulatory and policy issues and activities.

Executive Director: May 2014—August 2019. Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secured funding for and managed execution of regulatory intervention, research, market development support, and advisory services. Taught Energy Law. Provided learning and development opportunities for law students. Additional activities:

- Former Director, Alliance for Clean Energy – New York (2018-2019).
- Former Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Former Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Director, Global Regulatory Affairs, provided regulatory support and group management to AES's international electric utility operations on five continents. Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Government and regulatory affairs manager for AES Wind Generation. Managed a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provide natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications; the Gulf Coast Combined Heat and Power Application Center; and the High-Performance Green Buildings Practice. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector.

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, led and managed successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative as an umbrella structure for a number of biofuels related projects.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking bio-based polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives.

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.

- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Managed, coordinated, and developed international agreements. Supervised development and deployment support activities at national laboratories. Developed, advocated, and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019. Non-tenured member of faculty. Taught Energy Law. Supervised a student intern practice.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Publications

"Climate Change Law: An Introduction," contributing author (chapter on energy), Edward Elgar Publishing (2021).

"Distributed Generation Law," contributing author, American Bar Association Environment, Energy, and Resources Section (August 2020)

"National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources," contributing author, National Energy Screening Project (August 2020)

"Achieving 100% Renewables: Supply-Shaping through Curtailment," with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019).

"A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed," with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019).

"Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition," with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019).

"Northeast Solar Energy Market Coalition (NESEMC)," United States (Mar. 28, 2018)

"Revisiting Bonbright's Principles of Public Utility Rates in a DER World," with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018).

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

"The Net Metering Riddle," Electricity Policy.com, April 2016.

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"Maine Distributed Solar Valuation Study," Maine Public Utilities Commission (Apr. 14, 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

“The ‘Value of Solar’ Rate: Designing an Improved Residential Solar Tariff,” Solar Industry, Vol. 6, No. 1 (Feb. 2013)

“Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development,” lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

“A Review of Barriers to Biofuels Market Development in the United States,” 2 Environmental & Energy Law & Policy Journal 179 (2008)

“A Strategy for Developing Stationary Biodiesel Generation,” Cumberland Law Review, Vol. 36, p.461 (2006)

“Evaluating Fuel Cell Performance through Industry Collaboration,” co-author, Fuel Cell Magazine (2005)

“Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production,” co-author, Polymer Degradation and Stability 80, 403-19 (2003)

“An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options,” contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

“Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size,” co-author, Rocky Mountain Institute (2002)

“Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado,” with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

“Study of Electric Utility Restructuring in Alaska,” with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

“New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers,” EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

“Building a Better Future: Why Public Support for Renewable Energy Makes Sense,” Spectrum: The Journal of State Government (Spring 1998)

“The Green-e Program: An Opportunity for Customers,” with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

“Being Virtual: Beyond Restructuring and How We Get There,” Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

“Information Technology,” Public Utilities Fortnightly (March 15, 1996)

“Better Decisions with Better Information: The Promise of GIS,” with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

“The Regulatory Environment for Utility Energy Efficiency Programs,” Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

<u>Rábago Exhibit 2</u>

KARL RÁBAGO'S SPECIFIC EXPERIENCE RELATING TO SOLAR ENERGY

Mr. Rábago has extensive experience working in the field of distributed energy resources, a category of energy resources that includes distributed solar generation, energy efficiency, energy management, energy storage, and other technologies and related services. That experience includes regulation of electric utilities in Texas, including review and approval of rates, tariffs, plans, and programs proposed by electric utilities. While managing director at the Rocky Mountain Institute, Mr. Rábago co-authored the seminal treatise on distributed energy resource value, entitled "Small Is Profitable"[65] and has published several articles and essays relating to the topic.

As a vice president for Distributed Energy Services for Austin Energy, Mr. Rábago had responsibility for all of the utility's customer-facing programs relating to distributed solar generation, energy efficiency, demand management, low-income weatherization, energy storage, electric transportation, building energy ratings and codes, and the utility's electric vehicle initiatives. While with Austin Energy, he led development and implementation of the nation's first distributed solar tariff based on objective and comprehensive valuation of solar generation and avoided system energy costs, often referred to as the "Value of Solar Tariff."

While at the U.S. Department of Energy, Mr. Rábago was the federal executive responsible for the nation's research, development, and deployment programs relating to renewable energy, energy efficiency, energy storage, and other advanced energy technologies in the Department's Office of Utility Technologies.

[65] Amory B. Lovins, et al., "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size,"* Rocky Mountain Institute (2003).

As executive director for the Pace Energy and Climate Center, based at the Pace University Elisabeth Haub School of Law in White Plains, New York, Mr. Rábago led a team actively engaged as a public interest intervenor in the ground-breaking "Reforming the Energy Vision" process administered by the New York Public Service Commission.

Mr. Rábago works with the Local Solar for All coalition, on behalf of the Coalition for Community Solar Access, a trade association for providers and developers of community solar services and facilities across the U.S. Local Solar for All has members from solar businesses and advocacy organizations.[66] Most notably, Local Solar for All published the "Local Solar Roadmap" in December of 2020.[67] The Roadmap study relied upon a modern, high-resolution analysis of the electric grid in the continental United States, and has been followed by several additional studies. The Local Solar Roadmap study, conducted by Vibrant Clean Energy using its powerful WIS:dom-P® model, found that by coordinating and optimizing DERs in production cost and capacity expansion analysis, the added deployment of 273 GW of local solar and storage could yield nearly $500 billion in savings and create more than two million incremental jobs over the kind of business-as-usual approaches typically favored by monopoly utilities, all while eliminating 95% of carbon emissions from the grid by 2050.

Mr. Rábago is a frequent speaker, author, and commentator on issues relating to electric utility regulation, distributed energy resource markets and technologies, and electricity sector market reform.

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[66] Local Solar for All. More information at https://www.localsolarforall.org.
[67] Local Solar for All, Local Solar Roadmap (Dec. 2020), available at: https://www.localsolarforall.org/roadmap.

Rábago Exhibit 3

BENEFIT-COST ANALYSIS SUCCESS STORIES

Over the past fifteen years, utilities have invested billions of dollars through smart grid, grid modernization, and/or power sector transformation initiatives. Standardized BCA frameworks have been central to the leading efforts in this regard. Three such processes merit attention.

1. Perhaps one of the most comprehensive transformation initiatives was that initiated by New York, styled New York REV (for "Reforming the Energy Vision"). This proceeding resulted in the institution of a Value of DER proceeding and comprehensive distribution system planning processes that included a BCA Framework.[68] In the words of the NY Commission's order, the BCA Framework was premised on a number of foundational principles:

BCA analysis should:

- Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
- Avoid combining or conflating different benefits and costs.
- Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
- Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
- Compare benefits and costs to traditional alternatives instead of valuing them in isolation.[69]

2. The Hearing Examiner's attention is also directed to the Rhode Island Public Utilities Commission (RI PUC), Docket 4600 proceeding from 2016 to 2017.[70] The RI PUC initiated that

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[68] *See* NY PSC, *Order Establishing the Benefit Cost Analysis Framework,* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Jan. 21, 2016), available at: https://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E.
[69] *Id.* at 2.
[70] RI PUC, *In Re: Investigation into the Changing Distribution System and the Modernization of Rates in Light of the Changing Distribution System,* Docket No. 4600. Documents available at: http://www.ripuc.ri.gov/eventsactions/docket/4600page.html.

proceeding, informed by a multi-party stakeholder working group's work, to determine what attributes are possible to measure on the electric system and why should they be measured. This overarching question was further broken down into three broad questions:

- What are the costs and benefits that can be applied across any and/or all programs, identifying each and whether each is aligned with state policy;
- At what level should these costs and benefits be quantified—where physically on the system and where in cost-allocation and rates; and
- How can we best measure these costs and benefits at these levels–what level of visibility is required on the system and how is that visibility accomplished?[71]

In 2017, the RI Docket 4600 working group delivered to the RI PUC a final report that addressed: (1) how to better evaluate the benefits and costs of a wide range of technologies, programs, and investments; and (2) how rate design should evolve in Rhode Island over time.[72] The RI Docket 4600 Stakeholder Working Group, which included utility, developer, consumer, regulatory, and economic development stakeholders, delivered a report that established a Rhode Island Benefit-Cost Framework and several rate design recommendations.[73] The RI PUC accepted the report and issued directives for further work in July 2017.[74] The process and RI PUC orders set the stage for power sector transformation work that was a priority for that state.

3. The Hearing Examiner's attention is also directed to recent decisions of the Kentucky Public Service Commission ("KYPSC") in Case Numbers 2020-00174 (Kentucky Power Co.),[75]

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[71] RI PUC Docket No. 4600, *Notice of Commencement of Docket and Invitation for Stakeholders Participation,* RI PUC (Mar. 18. 2016), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600page.html.
[72] Raab Associates, et al., *Docket 4600: Stakeholder Working Group Process Report to the Rhode Island Public Utilities Commission,* RI PUC Docket No. 4600 (Apr. 5, 2017), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600-WGReport_4-5-17.pdf.
[73] *Id.*
[74] RI PUC, *PUC Report and Order No. 22851 Accepting Stakeholder Report,* RI PUC Docket No. 4600 (Jul. 31, 2017), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf.
[75] KYPSC, Electronic Application of Kentucky Power Company, KYPSC Case No. 2020-00174, Order dtd. May 14, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00174.

2020-00349 (Kentucky Utilities Co.),[76] and 2020-00350 (Louisville Gas & Electric Co.).[77] In those proceedings, the KYPSC was charged with reviewing and implementing net metering rates for investor-owned utilities in the state of Kentucky. After extensive proceedings, the KYPSC developed guiding principles for compensating eligible customer-generators based on best practices developed in other states. In establishing these principles, the KYPSC relied extensively on the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM"), published by the National Energy Screening Project.[78] With these principles in mind, the KYPSC adopted net metering rates that included compensation credits for avoided energy costs, avoided generation capacity costs, avoided distribution capacity costs, avoided ancillary services costs, avoided carbon emissions costs, avoided environmental compliance costs, and job benefits.

[76] KYPSC, Electronic Application of Kentucky Utilities Company, KYPSC Case No. 2020-00349, Order dtd. Nov. 4, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00349.

[77] KYPSC, Electronic Application of Louisville Gas & Electric Company, KYPSC Case No. 2020-00350, Order dtd. Nov. 4, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00350.

[78] T. Woolf, et al, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources,* National Energy Screening Project (Aug. 2020). Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/. While the NSPM-DER was published recently, it reflects best practices articulated in a prior NSPM for efficiency resources and generally recognized in the industry.

<u>Rábago Exhibit 1</u>

Karl R. Rábago

Rábago Energy LLC

2025 E. 24th Avenue, Denver, CO 80205

c/SMS: +1.512.968.7543 | e: karl@rabagoenergy.com

Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a regulatory expert, utility executive, research and development manager, sustainability leader, senior government official, educator, and advocate. Successful track record of working with U.S. Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. Nationally recognized speaker on energy, environment, and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing business sustainability, expert witness, and regulatory advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 30 states and 100 electricity and gas regulatory proceedings. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board.
- Director, Solar United Neighbors (2018-present).
- Director, Texas Solar Energy Society
- Advisor, Commission Shift

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—September 2020. Part-time advisor and staff member. Provide expert witness, project management, and business development support on electric and gas regulatory and policy issues and activities.

Executive Director: May 2014—August 2019. Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secured funding for and managed execution of regulatory intervention, research, market development support, and advisory services. Taught Energy Law. Provided learning and development opportunities for law students. Additional activities:

- Former Director, Alliance for Clean Energy – New York (2018-2019).
- Former Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Former Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

Vice President, Distributed Energy Services: April 2009—June 2012. Executive in 8th largest public power electric utility serving more than one million people in central Texas. Responsible for management and oversight of energy efficiency, demand response, and conservation programs; low-income weatherization; distributed solar and other renewable energy technologies; green buildings program; key accounts relationships; electric vehicle infrastructure; and market research and product development. Executive sponsor of Austin Energy's participation in an innovative federally-funded smart grid demonstration project led by the Pecan Street Project. Led teams that successfully secured over $39 million in federal stimulus funds for energy efficiency, smart grid, and advanced electric transportation initiatives. Additional activities included:

- Director, Renewable Energy Markets Association. REMA is a trade association dedicated to maintaining and strengthening renewable energy markets in the United States.
- Membership on Pedernales Electric Cooperative Member Advisory Board. Invited by the Board of Directors to sit on first-ever board to provide formal input and guidance on energy efficiency and renewable energy issues for the nation's largest electric cooperative.

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Director, Global Regulatory Affairs, provided regulatory support and group management to AES's international electric utility operations on five continents. Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Government and regulatory affairs manager for AES Wind Generation. Managed a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provide natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications; the Gulf Coast Combined Heat and Power Application Center; and the High-Performance Green Buildings Practice. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector.

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, led and managed successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative as an umbrella structure for a number of biofuels related projects.
- Member, Committee to Study the Environmental Impacts of Windpower, National Academies of Science National Research Council. The Committee was chartered by Congress and the Council on Environmental Quality to assess the impacts of wind power on the environment.
- Advisory Board Member, Environmental & Energy Law & Policy Journal, University of Houston Law Center.

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking bio-based polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives.

- Successfully completed Minnesota Management Institute at University of Minnesota Carlson School of Management, an alternative to an executive MBA program that surveyed fundamentals and new developments in finance, accounting, operations management, strategic planning, and human resource management.

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles.

- President of the Board, Texas Ratepayers Organization to Save Energy. Texas R.O.S.E. is a non-profit organization advocating low-income consumer issues and energy efficiency programs.

- Co-Founder and Chair of the Advisory Board, Renewable Energy Policy Project-Center for Renewable Energy and Sustainable Technology. REPP-CREST was a national non-profit research and internet services organization.

CH2M HILL

Vice President, Energy, Environment and Systems Group: July 1998–August 1999. Responsible for providing consulting services to a wide range of energy-related businesses and organizations, and for creating new business opportunities in the energy industry for an established engineering and consulting firm. Completed comprehensive electric utility restructuring studies for the states of Colorado and Alaska.

PLANERGY

Vice President, New Energy Markets: January 1998–July 1998. Responsible for developing and managing new business opportunities for the energy services market. Provided consulting and advisory services to utility and energy service companies.

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Managed, coordinated, and developed international agreements. Supervised development and deployment support activities at national laboratories. Developed, advocated, and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019. Non-tenured member of faculty. Taught Energy Law. Supervised a student intern practice.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate.

NON-LEGAL MILITARY SERVICE

Armored Cavalry Officer, 2d Squadron 9th Armored Cavalry, Fort Stewart, Georgia, May 1978–August 1981. Served as Logistics Staff Officer (S-4). Managed budget, supplies, fuel, ammunition, and other support for an Armored Cavalry Squadron. Served as Support Platoon Leader for the Squadron (logistical support), and as line Platoon Leader in an Armored Cavalry Troop. Graduate of Airborne and Ranger Schools. Special training in Air Mobilization Planning and Nuclear, Biological and Chemical Warfare.

Formal Education

LL.M., Environmental Law, Pace University School of Law, 1990: Curriculum designed to provide breadth and depth in study of theoretical and practical aspects of environmental law. Courses included: International and Comparative Environmental Law, Conservation Law, Land Use Law, Seminar in Electric Utility Regulation, Scientific and Technical Issues Affecting Environmental Law, Environmental Regulation of Real Estate, Hazardous Wastes Law. Individual research with Hudson Riverkeeper Fund, Garrison, New York.

LL.M., Military Law, U.S. Army Judge Advocate General's School, 1988: Curriculum designed to prepare Judge Advocates for senior level staff service. Courses included: Administrative Law, Defensive Federal Litigation, Government Information Practices, Advanced Federal Litigation, Federal Tort Claims Act Seminar, Legal Writing and Communications, Comparative International Law.

J.D. with Honors, University of Texas School of Law, 1984: Attended law school under the U.S. Army Funded Legal Education Program, a fully funded scholarship awarded to 25 or fewer officers each year. Served as Editor-in-Chief (1983–84); Articles Editor (1982–83); Member (1982) of the Review of Litigation. Moot Court, Mock Trial, Board of Advocates. Summer internship at Staff Judge Advocate's offices. Prosecuted first cases prior to entering law school.

B.B.A., Business Management, Texas A&M University, 1977: ROTC Scholarship (3–yr). Member: Corps of Cadets, Parson's Mounted Cavalry, Wings & Sabers Scholarship Society, Rudder's Rangers, Town Hall Society, Freshman Honor Society, Alpha Phi Omega service fraternity.

Publications

"Climate Change Law: An Introduction," contributing author (chapter on energy), Edward Elgar Publishing (2021).

"Distributed Generation Law," contributing author, American Bar Association Environment, Energy, and Resources Section (August 2020)

"National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources," contributing author, National Energy Screening Project (August 2020)

"Achieving 100% Renewables: Supply-Shaping through Curtailment," with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019).

"A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed," with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019).

"Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition," with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019).

"Northeast Solar Energy Market Coalition (NESEMC)," United States (Mar. 28, 2018)

"Revisiting Bonbright's Principles of Public Utility Rates in a DER World," with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018).

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

"The Net Metering Riddle," Electricity Policy.com, April 2016.

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"Maine Distributed Solar Valuation Study," Maine Public Utilities Commission (Apr. 14, 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

"The 'Value of Solar' Rate: Designing an Improved Residential Solar Tariff," Solar Industry, Vol. 6, No. 1 (Feb. 2013)

"Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development," lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

"A Review of Barriers to Biofuels Market Development in the United States," 2 Environmental & Energy Law & Policy Journal 179 (2008)

"A Strategy for Developing Stationary Biodiesel Generation," Cumberland Law Review, Vol. 36, p.461 (2006)

"Evaluating Fuel Cell Performance through Industry Collaboration," co-author, Fuel Cell Magazine (2005)

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

"An Energy Resource Investment Strategy for the City of San Francisco: Scenario Analysis of Alternative Electric Resource Options," contributing author, Prepared for the San Francisco Public Utilities Commission, Rocky Mountain Institute (2002)

"Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size," co-author, Rocky Mountain Institute (2002)

"Socio-Economic and Legal Issues Related to an Evaluation of the Regulatory Structure of the Retail Electric Industry in the State of Colorado," with Thomas E. Feiler, Colorado Public Utilities Commission and Colorado Electricity Advisory Panel (April 1, 1999)

"Study of Electric Utility Restructuring in Alaska," with Thomas E. Feiler, Legislative Joint Committee on electric Restructuring and the Alaska Public Utilities Commission (April 1, 1999)

"New Markets and New Opportunities: Competition in the Electric Industry Opens the Way for Renewables and Empowers Customers," EEBA Excellence (Journal of the Energy Efficient Building Association) (Summer 1998)

"Building a Better Future: Why Public Support for Renewable Energy Makes Sense," Spectrum: The Journal of State Government (Spring 1998)

"The Green-e Program: An Opportunity for Customers," with Ryan Wiser and Jan Hamrin, Electricity Journal, Vol. 11, No. 1 (January/February 1998)

"Being Virtual: Beyond Restructuring and How We Get There," Proceedings of the First Symposium on the Virtual Utility, Klewer Press (1997)

"Information Technology," Public Utilities Fortnightly (March 15, 1996)

"Better Decisions with Better Information: The Promise of GIS," with James P. Spiers, Public Utilities Fortnightly (November 1, 1993)

"The Regulatory Environment for Utility Energy Efficiency Programs," Proceedings of the Meeting on the Efficient Use of Electric Energy, Inter-American Development Bank (May 1993)

"An Alternative Framework for Low-Income Electric Ratepayer Services," with Danielle Jaussaud and Stephen Benenson, Proceedings of the Fourth National Conference on Integrated Resource Planning, National Association of Regulatory Utility Commissioners (September 1992)

"What Comes Out Must Go In: The Federal Non-Regulation of Cooling Water Intakes Under Section 316 of the Clean Water Act," Harvard Environmental Law Review, Vol. 16, p. 429 (1992)

"Least Cost Electricity for Texas," State Bar of Texas Environmental Law Journal, Vol. 22, p. 93 (1992)

"Environmental Costs of Electricity," Pace University School of Law, Contributor–Impingement and Entrainment Impacts, Oceana Publications, Inc. (1990)

<u>Rábago Exhibit 2</u>

KARL RÁBAGO'S SPECIFIC EXPERIENCE RELATING TO SOLAR ENERGY

Mr. Rábago has extensive experience working in the field of distributed energy resources, a category of energy resources that includes distributed solar generation, energy efficiency, energy management, energy storage, and other technologies and related services. That experience includes regulation of electric utilities in Texas, including review and approval of rates, tariffs, plans, and programs proposed by electric utilities. While managing director at the Rocky Mountain Institute, Mr. Rábago co-authored the seminal treatise on distributed energy resource value, entitled "Small Is Profitable"[65] and has published several articles and essays relating to the topic.

As a vice president for Distributed Energy Services for Austin Energy, Mr. Rábago had responsibility for all of the utility's customer-facing programs relating to distributed solar generation, energy efficiency, demand management, low-income weatherization, energy storage, electric transportation, building energy ratings and codes, and the utility's electric vehicle initiatives. While with Austin Energy, he led development and implementation of the nation's first distributed solar tariff based on objective and comprehensive valuation of solar generation and avoided system energy costs, often referred to as the "Value of Solar Tariff."

While at the U.S. Department of Energy, Mr. Rábago was the federal executive responsible for the nation's research, development, and deployment programs relating to renewable energy, energy efficiency, energy storage, and other advanced energy technologies in the Department's Office of Utility Technologies.

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[65] Amory B. Lovins, et al., "*Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size,"* Rocky Mountain Institute (2003).

As executive director for the Pace Energy and Climate Center, based at the Pace University Elisabeth Haub School of Law in White Plains, New York, Mr. Rábago led a team actively engaged as a public interest intervenor in the ground-breaking "Reforming the Energy Vision" process administered by the New York Public Service Commission.

Mr. Rábago works with the Local Solar for All coalition, on behalf of the Coalition for Community Solar Access, a trade association for providers and developers of community solar services and facilities across the U.S. Local Solar for All has members from solar businesses and advocacy organizations.[66] Most notably, Local Solar for All published the "Local Solar Roadmap" in December of 2020.[67] The Roadmap study relied upon a modern, high-resolution analysis of the electric grid in the continental United States, and has been followed by several additional studies. The Local Solar Roadmap study, conducted by Vibrant Clean Energy using its powerful WIS:dom-P® model, found that by coordinating and optimizing DERs in production cost and capacity expansion analysis, the added deployment of 273 GW of local solar and storage could yield nearly $500 billion in savings and create more than two million incremental jobs over the kind of business-as-usual approaches typically favored by monopoly utilities, all while eliminating 95% of carbon emissions from the grid by 2050.

Mr. Rábago is a frequent speaker, author, and commentator on issues relating to electric utility regulation, distributed energy resource markets and technologies, and electricity sector market reform.

[66] Local Solar for All. More information at https://www.localsolarforall.org.
[67] Local Solar for All, Local Solar Roadmap (Dec. 2020), available at: https://www.localsolarforall.org/roadmap.

<u>Rábago Exhibit 3</u>

BENEFIT-COST ANALYSIS SUCCESS STORIES

Over the past fifteen years, utilities have invested billions of dollars through smart grid, grid modernization, and/or power sector transformation initiatives. Standardized BCA frameworks have been central to the leading efforts in this regard. Three such processes merit attention.

1. Perhaps one of the most comprehensive transformation initiatives was that initiated by New York, styled New York REV (for "Reforming the Energy Vision"). This proceeding resulted in the institution of a Value of DER proceeding and comprehensive distribution system planning processes that included a BCA Framework.[68] In the words of the NY Commission's order, the BCA Framework was premised on a number of foundational principles:

BCA analysis should:

- Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
- Avoid combining or conflating different benefits and costs.
- Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
- Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
- Compare benefits and costs to traditional alternatives instead of valuing them in isolation.[69]

2. The Hearing Examiner's attention is also directed to the Rhode Island Public Utilities Commission (RI PUC), Docket 4600 proceeding from 2016 to 2017.[70] The RI PUC initiated that

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[68] *See* NY PSC, *Order Establishing the Benefit Cost Analysis Framework,* Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (Jan. 21, 2016), available at: https://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E.
[69] *Id.* at 2.
[70] RI PUC, *In Re: Investigation into the Changing Distribution System and the Modernization of Rates in Light of the Changing Distribution System,* Docket No. 4600. Documents available at: http://www.ripuc.ri.gov/eventsactions/docket/4600page.html.

proceeding, informed by a multi-party stakeholder working group's work, to determine what attributes are possible to measure on the electric system and why should they be measured. This overarching question was further broken down into three broad questions:

- What are the costs and benefits that can be applied across any and/or all programs, identifying each and whether each is aligned with state policy;
- At what level should these costs and benefits be quantified—where physically on the system and where in cost-allocation and rates; and
- How can we best measure these costs and benefits at these levels–what level of visibility is required on the system and how is that visibility accomplished?[71]

In 2017, the RI Docket 4600 working group delivered to the RI PUC a final report that addressed: (1) how to better evaluate the benefits and costs of a wide range of technologies, programs, and investments; and (2) how rate design should evolve in Rhode Island over time.[72] The RI Docket 4600 Stakeholder Working Group, which included utility, developer, consumer, regulatory, and economic development stakeholders, delivered a report that established a Rhode Island Benefit-Cost Framework and several rate design recommendations.[73] The RI PUC accepted the report and issued directives for further work in July 2017.[74] The process and RI PUC orders set the stage for power sector transformation work that was a priority for that state.

3. The Hearing Examiner's attention is also directed to recent decisions of the Kentucky Public Service Commission ("KYPSC") in Case Numbers 2020-00174 (Kentucky Power Co.),[75]

[71] RI PUC Docket No. 4600, *Notice of Commencement of Docket and Invitation for Stakeholders Participation,* RI PUC (Mar. 18. 2016), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600page.html.
[72] Raab Associates, et al., *Docket 4600: Stakeholder Working Group Process Report to the Rhode Island Public Utilities Commission,* RI PUC Docket No. 4600 (Apr. 5, 2017), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600-WGReport_4-5-17.pdf.
[73] *Id.*
[74] RI PUC, *PUC Report and Order No. 22851 Accepting Stakeholder Report,* RI PUC Docket No. 4600 (Jul. 31, 2017), available at: http://www.ripuc.ri.gov/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf.
[75] KYPSC, Electronic Application of Kentucky Power Company, KYPSC Case No. 2020-00174, Order dtd. May 14, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00174.

2020-00349 (Kentucky Utilities Co.),[76] and 2020-00350 (Louisville Gas & Electric Co.).[77] In those proceedings, the KYPSC was charged with reviewing and implementing net metering rates for investor-owned utilities in the state of Kentucky. After extensive proceedings, the KYPSC developed guiding principles for compensating eligible customer-generators based on best practices developed in other states. In establishing these principles, the KYPSC relied extensively on the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM"), published by the National Energy Screening Project.[78] With these principles in mind, the KYPSC adopted net metering rates that included compensation credits for avoided energy costs, avoided generation capacity costs, avoided distribution capacity costs, avoided ancillary services costs, avoided carbon emissions costs, avoided environmental compliance costs, and job benefits.

[76] KYPSC, Electronic Application of Kentucky Utilities Company, KYPSC Case No. 2020-00349, Order dtd. Nov. 4, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00349.
[77] KYPSC, Electronic Application of Louisville Gas & Electric Company, KYPSC Case No. 2020-00350, Order dtd. Nov. 4, 2021, available at: https://psc.ky.gov/Case/ViewCaseFilings/2020-00350.
[78] T. Woolf, et al, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources,* National Energy Screening Project (Aug. 2020). Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/. While the NSPM-DER was published recently, it reflects best practices articulated in a prior NSPM for efficiency resources and generally recognized in the industry.

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Revisiting Bonbright's principles of public utility rates in a DER world

Karl R. Rábago*, Radina Valova

Pace Energy and Climate Center, Pace University Elisabeth Haub School of Law, White Plains, NY, United States

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ABSTRACT

Professor James Bonbright's *Principles of Public Utility Rates*, first published in 1961, was built around a model of vertically integrated electricity monopolies and approached ratemaking largely as an exercise in balancing the interests of capital attraction with those of ratepayers, all within a 'public interest' framework. This article seeds a new conversation about changes to the venerable Bonbright principles and introduces new principles of public utility rates for an era of electric utility transformation.

1. Introduction

When James Bonbright's "Principles of Public Utility Rates"[1] was published in 1961, electric utilities and the environment in which they operated were vastly different. The central station utility model was dominant, and economies of plant scale appeared inexhaustible. In fact, the 1960s marked the zenith of the trend toward large power plants,[2] and since that decade, we have seen a wide range of fundamental changes in the electricity system. These changes include widespread competition in the generation sector, retail competition, the emergence of renewable energy generation, and, most significantly, a revolution in scale that has ushered in an era of distributed energy resources (DER).[3] Bonbright's text did not account for these changes; now, nearly 60 years since the publication of the Bonbright's treatise, it is time for a rewrite.[4]

Rewriting such a profoundly influential treatise is beyond the scope of this article. Indeed, such a project would be worthy of an extended sabbatical and a genius grant's worth of funding. With all due respect for the enormity of that effort, and with keen appreciation of the authors' limited resources, we can nevertheless briefly introduce some of the important revisions and additions to Bonbright's principles that today's utility sector conditions compel.

2. Drivers of change

In 2002, Rocky Mountain Institute published *Small Is Profitable,* presaging today's rapidly expanding markets for DER technologies and services.[5] More importantly, *Small Is Profitable* also foresaw the potential sector impacts:

> *These "distributed resources" could displace new bulk power generation, bulk power trade, and even much transmission as new technologies, market forces, institutional structures, analytic methods, and societal preferences propel a rapid shift to "distributed utilities," operating on a scale more comparable to that of individual customers and their end-use needs.*[6]

Small Is Profitable identified 12 key drivers of change, still powerful

* Corresponding author.
E-mail address: krabago@law.pace.edu (K.R. Rábago).

[1] Bonbright (1961), "*Principles of Public Utility Rates*," Columbia University Press (1st ed., 1961), available at http://www.raponline.org/ document/download/id/813.

[2] In fact, the economics of large central station generation were waning already with Bonbright's book was published. *See* A. Lovins (2002) *"Small Is Profitable,"* Rocky Mountain Institute (2002), available at https://www.rmi.org/insights/knowledge-center/small-is-profitable/.

[3] This article uses the broadest definition of "distributed energy resources," to include generation, efficiency, energy management, storage, electric vehicles, and other technologies and services interconnected and operated as resources at the distribution edge of the electric system.

[4] A second edition was published in 1988, three years after Bonbright's death, and was authored by Albert L. Danielsen and David R. Kamerschen. This article references only the original first edition.

[5] *Small Is Profitable,* at § 1.2.1.

[6] *Id.* The full list of drivers included: more efficient end use; small-scale fueled cogeneration; cheap kilowatt-scale fuel cells; new fuels; cheap, easy-to-use renewable sources; distributed electric storage; grid improvements; distributed information; distributed benefits; competition; shifts in electricity providers' mission, structure, and culture; and unbundled service attributes.

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and defining today. These included energy efficiency and distributed generation, distributed storage and cogeneration, business model changes and competition, and data. New technologies and evolving consumer attitudes continue to drive transformation of the traditional utility business model into a new, more transactive, competitive, and customer-responsive marketplace. As customers increasingly seek to generate their own electricity through on-site generation, reduce their load through energy efficiency, and otherwise take more control over their energy usage and bills, utilities are facing challenges unimagined or at least not fully appreciated when Bonbright articulated principles for public utility ratemaking.

In response to low or negative sales growth, many utilities have increasingly pushed for rate designs that feature higher non-bypassable customer charges to increase the certainty of revenue recovery (and weaken the incentive for efficiency and self-generation), demand charges intended to generate the revenue to pay for infrastructure and grid modernization investments, access charges and reduced compensation rates for customer-generators to address alleged cost shifts and lost revenues,[7] and standby fees that increase charges for self-generators who interact with the grid less frequently than customer-generators.

Other shifts are also contributing to the changing electric utility landscape, including changing priorities in the broad concept of the "public interest." These shifts include the growth of third-party markets for products and services that in Bonbright's day would have traditionally rested with the utility as a monopoly provider; the increased recognition of and commitment to address the opportunities and challenges associated with ensuring that low- and moderate-income customers have equitable access to sustainable energy; state renewables and climate change goals; and a now decades-old efforts to value and incorporate into prices and costs the economic externalities of the electricity sector associated with generation, transfer, and use.

In a few jurisdictions, regulators are working with utilities and market participants to develop rates and pricing strategies designed to better align with public policy objectives. Often these efforts are seen as progenitors to a transition to performance-based revenue models and a new platform-provider role for electric distribution utilities.

Public utility rates are hardly the only tool at the disposal of regulators and policymakers for securing the benefits of access to reliable, affordable, and clean electric service. Indeed, they are not even the best tool in all circumstances. But electric rates are a vital tool, and if poorly designed and implemented, they can be a significant and pernicious obstacle to meeting public policy objectives. The purpose of this article is to continue and advance a decades-old discussion and exploration of how to design and implement electric utility rates so as to protect and serve the public interest inherent in those rates.

3. New principles for the DER era

Bonbright's Principles of Public Utility Rates are often summarized as three: (1) revenue requirement, (2) fair apportionment of costs among customers, and (3) optimal efficiency. These principles have generally been read as focusing on the *utility's* revenue requirement, fair apportionment of costs among customer *classes*, and optimal efficiency in consumption of electricity as a *commodity*. In addition, Bonbright instructed that rates must be simple, understandable, acceptable, free from controversy in interpretation, stable, and non-discriminatory. Today, utilities are not the only investors with skin in the electric service game; customers classes are becoming more diverse, not less so; and the tools and metrics of economic efficiency require attention to far more factors than the price revealed by a century-old approach to cost-of-service accounting. There is important work to do in ensuring that public utility rates serve and support the public interest.

Responsibility for addressing these issues rests with regulators. As one commentator succinctly summed up the raison d'être for regulation of utilities and their rates, "[r]eal competition disciplines performance so that sellers' self-interest is aligned with customers' needs. Monopolists don't face competition, so the missing discipline is provided by regulation."[8] Where there are no plans to increase the operation of market forces in the electricity sector, the primary responsibility of regulators is to ensure that the utilities do not use rate design as a vehicle for abusing their monopoly power and extracting monopoly rents. Where the state policy favors the introduction of competitive market forces into the utility landscape, the regulator must also ensure that utilities do not use their relative market power to discriminate against competitors—today that especially means DER services and technologies. That is because DER services and products increasingly offer superior value in serving customers' needs and advancing the public interest.

DERs have changed the electricity landscape, and should change the regulatory approach to setting rates. A walk through Bonbright's principles in this new era illustrates the need for change. Customers, in their own right and through non-utility parties, are making their own investments in electric service provision—they have their own "revenue requirements." Services are no longer only provided by the electric utility, so the scope of inquiry regarding economic efficiency must countenance a much broader review of costs and benefits, over both the short and long run.

Utilities still largely enjoy state action antitrust immunity, but the underlying comprehensive regulation of utilities by state regulators has, in many places, given way to competitive market structures, raising the very real fairness concern that rate design can be used as an anti-competitive tool against emergent competitors and customer-generators. So, regulatory review of rates should include scrutiny of anti-competitive effects. Similarly, just as PURPA[9] forbids discrimination against small power producers, rate design should not be used to advance undue discrimination. This principle should relate not just to class rates, but also to rates impacting subsets of traditional customer classes—customer-generators, and owners, operators, and providers of other DER.

As policy continues to advance the use of market forces in the electricity services sector, revenue stability for traditional utility and emerging platform functions must be balanced with increased utility exposure to markets and performance standards. Customers are increasingly presented with the opportunity to take service under more dynamic and innovative rates, raising important concerns about the necessary prerequisites for exposing customers to such rates, including comprehensive assessment of the relative costs and benefits of utility service and non-utility options, and in terms of rate design, data access, opt-out provisions, tools to understand and manage use of services, safe harbors, grandfathering, and other features. Finally, the concept of discouraging wasteful use of electricity has heightened importance in a world facing huge environmental challenges, such as global climate change. Full assessment of costs and benefits and of the costs avoided through use of or reliance on DER for the provision of electric service is absolutely essential.

Revisiting Bonbright's principles necessitates both revisiting the manner in which still-relevant principles must be updated for today's realities, as well as the articulation of new principles. A start to the effort means addressing the most important issues that DERs and increasing sector competition bring to the industry. Candidate new

[7] Rábago (2016), *"The Net Metering Riddle,"* ElectricityPolicy.com (Apr. 2016), available at: http://peccpublication.pace.edu/publications/net-metering-riddle.

[8] Hempling (2018), *Regulatory Candor: Do We Own Up?*," (Jul. 18, 2018), available at: http://www.scotthemplinglaw.com/essays/regulatory-candor-do-we-own-up.

[9] 18 C.F.R § 292.304 (2018).

principles appear in the following discussion.

3.1. Regulators should fully comprehend and reflect resource value in rates

John Dos Passos once said that "[a]pathy is one of the characteristic responses of any living organism when it is subjected to stimuli too intense or too complicated to cope with. The cure for apathy is comprehension."[10] Regulation is complex, even more so in an era of DER and increasingly competitive markets. Rates are often based on historical costs, but have their most profound impact on future behaviors and costs. The growing menu of cost-effective DER-based services and increasing customer choice compels an analysis and explicit reflection of costs, avoided costs, and benefits in basic service and optional rates because of their impact on DER utilization. Regulators can easily recognize that there are significant and challenging gaps between costs, prices, and value in the electricity sector. The cure for reconciling these differences is not regulatory apathy but conscious engagement with objective, data-driven valuation processes.

3.2. Rate making must account for the relative market positions of various market actors, and for the information asymmetries among different customers, utilities, and market participants

The communication of price signals is often touted as the primary, and often only, justification for rate designs that increase fixed customer charges, impose charges on self-generators, or impose demand charges on small customers. Too often, sending price signals to customers about utility cost structure is the only criteria applied to such rate changes. The notion is that utilities have always been high-fixed-cost businesses, but are even more so today. And so, the argument applies a distorted version of the principle that "rate design should reflect cost causation."

The twisted and increasingly common version of the original principle is that "increasing fixed costs should be reflected in increasing fixed charges," with the implication that this will improve economic efficiency.[11] The formulation has the appeal of syntactical alliteration, but this hardly qualifies the proposition as a principle of economics. Indeed, the authors can find no principled economic basis or practical market evidence to support the proposition that fixed costs dictate fixed charges.[12] Moreover, the concept of communicating the utility's cost structure as a price signal ignores the very real price signals that these approaches send to the utility, to the relative information position and choice options of diverse customer types, and to markets for DER. Immunizing a utility's fixed cost investments from the consequences of customer behavior is a recipe for gold-plating, and for the extraction of monopoly rents from customers without the tools and resources to cost-effectively respond to the new rate design.

3.3. Sound rate design must be grounded in a careful assessment of practical economic impacts on all market participants, especially customers

Well-designed and well-understood rates can be an effective tool in encouraging changes in customer behavior and investments over both the short and the long term. But customer charges and access charges for distributed generation, for example, can establish a monthly minimum bill that customers cannot save their way out of, no matter how efficient their use or how much they invest their private capital in generation for self-consumption. Increased customer charges can weaken the economic signal supporting two market segments that are recognized as priorities in many states—efficient use and local generation.

Rate design is often a zero-sum game once revenue requirements are determined and costs are functionalized, classified, and allocated. Fixing or imposing effectively non-bypassable charges therefore reduces volumetric charges and weakens the incentive and value of efficiency and self-generation. Imposing demand-based charges, whether directly through demand charges or indirectly through time-variant charges, on customers who have no practical, meaningful opportunity to respond to those charges turns the theory of "price signals" into the regulatory equivalent of telling customers that if they can't afford electricity during peak periods, they can just "eat cake."

This bundle of issues, related to the recent explosion of rate design innovations proposed across the country, merits another new rate-making principle: No new rate design should be imposed on customers in the absence of that customer enjoying a meaningful opportunity to respond to the rate through modification of behavior or affordable investment in technologies or services. (Caveat: Going without electric service—privation—is seldom a meaningful option). Call it the principle of economic symmetry in rates, perhaps, but it is vital in an era of rate design experimentation and the growth of DER markets and services. Customers must have the education, experience, resources, and options to respond to new rates. Else, the rate is just a tool for the extraction of monopoly rents.[13]

3.4. Rates must support capital attraction for all resources that provide energy services, regardless of whether the affected investor is the utility, the customer, or a third-party provider

Buying or leasing a rooftop solar system, replacing a roof or an HVAC system, weatherizing a home, or just changing a lightbulb all reflect investments by the customer, the landlord, or the DER service provider. Mobilizing capital investments by non-utility parties reduces the cost of service for utility customers, supports market innovation, and diversifies the capital risk associated with the provision of electric services of all kinds. Successful growth in DER markets can reduce the overall societal costs of obtaining reliable electric service. For these reasons, regulators must increasingly account for the impact that electric rates have on capital attraction and project financeability for non-utility DER service and technology providers, and for customers who make direct investments themselves.

[10] Dos Passos (1950) "The Prospect Before Us,". Thanks to Scott Hempling for the reminder of this great quote.

[11] The assertion that it is more efficient to recover fixed costs through fixed charges has been used as a justification for minimum-system approaches to cost classification, recovering demand-related costs through customer charges or increases to customer charges, residential demand charges, and reductions in volumetric energy charges, usually justified only with incantation of some version of the phrase: "Fixed costs should be reflected in fixed charges."

[12] The logical extension of this proposition would be cover charges at coffee shops, cable TV pricing for electric service, and monthly charges for hotels, airlines, railroads, and toll roads, regardless of use. One particularly dogmatic economist once asserted to author Rábago that the proposition that high fixed charges advance economic efficiency is supported by the approach known as Ramsey-Boiteux pricing, a second-best approach in which costs are allocated to customers in inverse proportion to the demand elasticity demonstrated by the customer class. Aside from the fact that regulators largely rejected the broad application of the method because of the fairness and policy impacts when it was originally used to argue for allocating the burdens of expensive power plant investments to residential customers, the concept of Ramsey-Boiteux pricing has no place in a world where regulation seeks to increase competitive choice in all market segments. The idea now belongs squarely on the dust heap of regulation.

[13] A simple thought experiment makes the case: Imagine a customer of modest income, living in a rental apartment and holding down two jobs, one that ends at 5:00 pm, and a second that starts at 7:00 pm. If the system peaks at 5:00 pm, a coincident-peak demand charge or time-of-use rate will hit that customer just as they come home to do the dishes and the laundry, bathe the children, and cook the dinner. What are the practical, affordable options for reducing demand or on-peak use for such a customer?

3.5. Rates must be designed to account for the incentives they create for utilities, customers, and non-utility market participants

Just as "all regulation is incentive regulation,"[14] all rate design is incentive rate design. Regulators must resist indifference to the reality of changing electricity service markets and their influence on the relative positions of utilities, customers, and third-party service providers. As explained above, high customer charges reduce the incentive to pursue energy efficiency or distributed generation and the attendant paybacks for customers, and weaken the financeability of products offered by non-utility service and technology providers. High fixed charges and straight fixed variable rates also reduce the incentive for utilities to find or support third-party alternatives to utility self-build investment options.

3.6. Just and reasonable rates require accurate accounting for utility costs

Ratemaking is the transformation of costs into charges. Unfortunately, cost-of-service studies often rely upon outdated and inaccurate rules of thumb in classifying costs. These classified costs are often directly translated into rate design. For example, under FERC's Uniform System of Accounts, Account 370, entitled "Meters," is used to "include the cost of installed meters or devices and appurtenances thereto, for use in measuring the electricity delivered to its users."[15] In Bonbright's era, all that a meter could do was measure electricity use, and one was required for each customer. It is not surprising, then, that utility cost-of-service studies routinely classify all Account 370 costs as "customer costs," and that these costs are routinely allocated to the fixed monthly customer charge. Putting meter costs in the customer charge is the end result of straight fixed variable rates, the basic customer method, and minimum system methods. But today's meters are not Bonbright's meters. New advanced meter functionality (AMF) meters not only measure consumption like yesterday's spinning-disk analog meters, but they are also a key component of integrating distributed generation, logging demand response, and generating data to support dynamic rates and other services. These meters house data logs and telemetry functions, and are an element of increasingly complex networks of monitoring, signaling, and control systems embedded in the distribution system. With all this change in what used to be the simple task of measuring consumption, it seems plain error to treat all meter-related costs as a customer cost, much less recover these costs through customer charges.

The economically efficient integration of DER services and technologies on an increasingly widespread basis opens the door for many ratemaking innovations, especially for regulators seeking to maximize the benefits and reduce the costs associated with increased market penetration of DERs, whether the hardware and customer interface is owned by the utility, its customers, or non-utility market players.[16] New cost categories are appropriate for energy efficiency-related cost, demand response functionality, and integration costs associated with distributed generation, distributed storage, and electric vehicles. Regulators should work with utilities and other market stakeholders in developing more granular functionalization regimes for electric service costs, in order to support the development of more precise cost accounting structures, and ultimately, more accurate and effective rates.

[14] Lazar (2016), *"Electricity Regulation in the U.S.,"* Regulatory Assistance Project (Jun. 2016), available at: https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/.

[15] 18 C.F.R. Part 101 (2013).

[16] *See, e.g.,* Hawaii Revised Stat. § 269-6(d)(4), requiring the Hawaii PUC to consider a shared cost savings incentive, a renewable energy curtailment mitigation mechanism, a stranded cost recovery mechanism, and the establishment of differentiated authorized rates of return on common equity to encourage particular kinds of utility investments.

3.7. Rate design and cost allocation are separate functions, driven by distinct policy objectives

As previously discussed, the common practice of recovering customer costs through customer charges has alliterative appeal, but does not honor economic policy or necessarily best serve the public interest. Once costs are labeled, however they are labeled, the process of designing rates should not be dictated by mere accounting convention. Treating accounting labels as determinants of rate design serves to encourage the pernicious practice of contorting customer cost definitions in an effort to increase customer charges. The minimum system method stands as an example of the kind of poor policy that remains today, in spite of Bonbright's specific rejection of the approach.[17]

4. Conclusion

Much of Bonbright's classic treatise on the principles of public utility rates has stood the test of time, and still provides a basis for useful reflection on principles of regulation and rate development. Today, a massive sea change is sweeping through the electric utility industry, finally inviting the realization of a service model, performance-based rate making, and the emergence of exciting non-utility markets. And so, some new interpretations of Bonbright's principles and even some new principles are in order. Bonbright's book was published 63 years after Samuel Insull delivered his call for public regulation of electric utilities,[18] and as history now shows, it was published at the point that might be called "peak central station" for the industry. Now that we are nearly 60 years into the new era of distributed energy resources, a new take on those valuable precepts is most timely.

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Karl R. Rábago is Executive Director of the Pace Energy and Climate Center, at the Pace Law School in White Plains, New York, where he leads the Center's team in engagement in regulatory and policy proceedings, in development and training of law student interns, and ensuring that the Center is engaged in the critical clean energy and regulatory issues of our day. The Center uses law, economics, and technology and policy analysis to secure clean energy for communities in New York, the Northeast, across the U.S., and around the world. Mr. Rábago has more than 27 years of experience in energy and climate policy development, regulation, markets, and business. In his career, he has been a military officer, a utility regulator, a utility executive, a renewable energy developer, a law professor, and a clean energy advocate. Those past positions have included Commissioner, Texas Public Utility Commission; Deputy Assistant Secretary at the US Department of Energy; Vice President of Distributed Energy Services at Austin Energy; Director of Regulatory Affairs for the AES Corporation and AES Wind; and Managing Director & Principal of the Rocky Mountain Institute. The author also serves as Chair of the Board of the Center for Resource Solutions, a San Francisco-based non-governmental organization that works to advance voluntary clean energy markets. He also sits on the Board of the

[17] Bonbright, at pp. 347-49.

[18] Insull (1898), *"Public Control and Private Operation,"* speech before the National Electric Light Assoc. (now Edison Electric Institute), Chicago (Jun. 7, 1898), available at: https://www.masterresource.org/edison-electric-institute/the-insull-speech-of-1898/.

Interstate Renewable Energy Council (IREC) and the Alliance for Clean Energy-New York. Mr. Rábago holds a Bachelor of Business Administration degree in Business Management from Texas A&M University, a J.D. with Honors from the University of Texas Law School, and post-doctorate LL.M. degrees in environmental law from the Pace University School of Law and in military law from the U.S. Army Judge Advocate General's School.

Radina Valova is Senior Staff Attorney with the Pace Energy and Climate Center. Ms. Valova manages the Center's regulatory and litigation dockets in New York and other jurisdictions, drafts public comments in regulatory proceedings, and oversees the Center's rate case engagement, including coordinating the team's expert witness testimony and participation in hearings and settlements. She also co-leads the Clean Energy Organizations Collaborative (CEOC) with the Center's partners at the Alliance for Clean Energy-New York. CEOC is a coalition of more than 30 clean energy and consumer advocacy non-profit organizations and ACE-NY members, who work together to speak as a unified voice in New York's Reforming the Energy Vision proceeding. Ms. Valova holds a B.A. in Psychology from the University of California, Los Angeles, and earned her J.D., with Certificates in Environmental and International Law, and her LL.M., with a concentration in Land Use and Sustainable Development, from Pace Law School. Prior to joining the Pace Energy and Climate Center, Ms. Valova worked in commercial litigation at Peska & Associates, and before embarking on the legal path, she managed a sustainable living program for community college students at Sustainable Works, a non-profit organization located in Santa Monica, California.

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DIVE BRIEF

Texas regulators look to distributed resources, additional coal reserves, to boost reliability

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Robert Walton
Reporter

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Dive Brief:

- The Public Utilities Commission of Texas is requesting information on how distributed energy resources can boost reliability, and what grid upgrades would be required to facilitate their integration. Initial responses to the inquiry are due June 15, in advance of a formal rulemaking.
- DERs are a "holy grail issue" for the electric grid, Commissioner Will McAdams said at the PUCT's open meeting on Thursday. The questions involved may be considered alongside efforts to standardize the distribution system interconnection process, he said.
- Commissioners also discussed development of a new Firm Fuel Supply Service (FFSS) that would incentivize gas generation units with on-site storage to be available in the 2022-23 winter. Looking further ahead, commissioners said they will also consider encouraging generators to purchase more coal for on-site storage.

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Dive Insight:

The PUCT on Thursday continued its work to overhaul the state's wholesale markets in the wake of Winter Storm Uri and widespread blackouts last year. Commissioners are rushing to hammer out details that will inform an Aug. 1 FFSS request for proposals to be issued by the state's grid operator.

An April 20 memo by Commissioner Lori Cobos sketched out what resources could be eligible in the Electric Reliability Council of Texas' first FFSS procurement. Commissioners suggested those would be limited to dual-fuel capable generation units with on-site alternative fuel storage, and generators that own and control the pipeline to a storage facility.

That limits the first tranche of FFSS resources to certain gas units, but commissioners discussed expanding the product for the 2023-24 winter and beyond.

"Coal piles provide firm fuel," Commissioner Jimmy Glotfelty said. "I would be interested in looking, in perhaps a second phase, if additional coal stocks beyond what is normally contracted for during winter months, or times of need, would be considered."

Coal is "very firm," Chairman Peter Lake agreed. "I think it's worthwhile to include consideration of coal for phase two."

More gas units could be eligible for an expanded FFSS product, as well. Commissioners discussed allowing units with fuel supply arrangements consisting of off-site storage with firm transportation contracts to participate in future years.

Cobos did raise some concerns regarding additional coal purchases.

"I've been reading that coal prices are going up. I've also been reading that the [U.S. Environmental Protection Agency] is coming out with regulations that impact coal," she said, referring to cross-state air rules. "What are we ultimately going to have to pay for, a pile of coal? Or are we going to be asked to pay for a scrubber?"

PUCT wants help with DER integration

Commission discussion of how distributed resources can boost Texas reliability was based around an April 20 memo filed by McAdams. There are nearly 3 GW of distributed generation resources on the ERCOT grid, and about a quarter of that was added in 2021, according to the memo.

"This is a dynamic and evolving area of the energy industry," McAdams said. "It is growing leaps and bounds by the day and it's only accelerated after Winter Storm Uri because everybody is looking at trying to have some type of backup power source on their house."

PUCT staff is developing a formal filing, based on the memo, to request one round of industry comments. Questions revolve around issues of distribution planning and control, costs, grid upgrades and the need for more data on distributed resources.

Questions include:

- What level of remote, granular controllability is possible?
- Presently, how are existing DERs utilized on distribution networks?
- What equipment, processes, and standards need to be implemented to allow for further DER participation?

As more Texans install backup generation following blackouts last winter, the request for comments on how to muster that resource is "a cry for help," McAdams said.

"If we can ever crack the code on [DERs], then the grid has unlimited potential in terms of resiliency capabilities and resource adequacy," McAdams said. "All the other grids are tackling this, and [the Federal Energy Regulatory Commission] is keenly interested in it."

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October 13

A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation

Interstate Renewable Energy Council, Inc.

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About the Authors

Interstate Renewable Energy Council
Jason B. Keyes, Partner, Keyes, Fox & Wiedman, LLP. Mr. Keyes has represented the Interstate Renewable Energy Council in state utility commission rulemakings regarding net energy metering for the past six years. Prior to becoming an attorney, he managed government contracts for a solar energy R&D company and developed load forecasts and related portions of integrated resource plans at a large electric utility. Mr. Keyes can be reached at jkeyes@kfwlaw.com.

Rábago Energy LLC.
Karl R. Rábago, Principal. Mr. Rábago is an attorney with more than 20 years experience in utility regulation and clean energy, including as a former utility executive with Austin Energy and the AES Corporation, Commissioner for the Texas Public Utility Commission, and Deputy Assistant Secretary for the U.S. Department of Energy. Mr. Rábago can be reached at karl@rabagoenergy.com.

Executive Summary

As distributed solar generation ("DSG") system prices continue to fall and this energy resource becomes more accessible thanks to financing options and regulatory programs, regulators, utilities and other stakeholders are increasingly interested in investigating DSG benefits and costs. Understandably, regulators seek to understand whether policies, such as net energy metering ("NEM"), put in place to encourage adoption of DSG are appropriate and cost-effective. This paper first offers lessons learned from the 16 regional and utility-specific DSG studies summarized in a recent review by the Rocky Mountain Institute ("RMI"),[1] and then proposes a standardized valuation methodology for public utility commissions to consider implementing in future studies.

As RMI's meta-study shows, recent DSG studies have varied widely due to differences in study assumptions, key parameters, and methodologies. A stark example came to light in early 2013 in Arizona, where two DSG benefit and cost studies were released in consecutive order by that State's largest utility and then by the solar industry. The utility-funded study showed a net solar value of less than four cents per kilowatt-hour ("kWh"), while the industry-funded study found a value in excess of 21 cents per kWh. A standard methodology would be helpful as legislators, regulators and the public attempt to determine whether to curtail or expand DSG policies.

Valuations vary by utility, but the authors contend that valuation methodologies should not. The authors suggest standardized approaches for the various benefits and costs, and explain how to calculate them regardless of the structure of the program or rate in which this valuation is used. Whether considering net NEM, value of solar tariffs, fixed-rate feed-in tariffs, or incentive programs, parties will always want to determine the value provided by DSG. The authors seek to fill that need, without endorsing any particular DSG policy in this paper.

Major Conclusions

Three conclusions stand out based on their potential to impact valuations:

- DSG primarily offsets combined-cycle natural gas facilities, which should be reflected in avoided energy costs.
- DSG installations are predictable and should be included in utility forecasts of capacity needs, so DSG should be credited with a capacity value upon interconnection.
- The societal benefits of DSG policies, such as job growth, health benefits and environmental benefits, should be included in valuations, as these were typically among the reasons for policy enactment in the first place.

[1] *A Review of Solar PV Benefit & Cost Studies* (RMI), July 2013 ("RMI 2013 Study"), *available at* http://www.rmi.org/elab_empower.

I. Introduction

There is an acute need for a standardized approach to distributed solar generation ("DSG") benefit and cost studies. In the first half of 2013, a steady flow of reports, news stories, workshops and conference panels have discussed whether to reform or repeal net energy metering ("NEM"), which is the bill credit arrangement that allows solar customers to receive full credit on their energy bills for any power they deliver to the grid. [2] The calls for change are founded on the claim that NEM customers who "zero out" their utility bill must not be paying their fair share for the utility infrastructure that they are using, and that those costs must have shifted to other, non-solar customers. Only a thorough benefit and cost analysis can provide regulators with an answer to whether this claim is valid in a given utility service area. As the simplicity and certainty of NEM have made it the vehicle for nearly all of the 400,000+ customer-sited solar arrays installed in the United States,[3] changes to such a successful policy should only be made based on careful analysis. This is especially so in light of a body of studies finding that solar customers may actually be subsidizing utilities and other customers.

The topic of NEM impacts on utility economics and on rates for non-solar customers seems to have risen to the top of utility priorities with the publication of an industry trade group report in January 2013 calling NEM "the largest near-term threat to the utility model."[4] Extrapolating from the current NEM penetration of just over 0.1% of U.S. energy generation to very high market penetration assumptions (e.g., if "everyone goes solar"), some have speculated that unchecked NEM growth will lead to a "utility death spiral." One Wall Street rating agency questioned the value of utility stocks in light of the continued success of NEM programs, claiming that it was "a scheme similar to net metering that led to the destabilization of the power markets in Spain in late 2008."[5]

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[2] NEM allows utility customers with renewable energy generators to offset part or all of their electric load, both at the time of generation and through kWh credits for any excess generation. This enables customers with solar arrays to take credit at night for excess energy generated during the day, for instance. Forty-three states have implemented NEM (*see* www.freeingthegrid.org for details on state NEM policies).
[3] Larry Sherwood, *U.S. Solar Market Trends 2012* (Interstate Renewable Energy Council), at p. 5 (316,000 photovoltaic installations connected to the grid at year-end 2012, with 95,000 in 2012 alone), July 2013, *available at* http://www.irecusa.org/wp-content/uploads/2013/07/Solar-Report-Final-July-2013-1.pdf. Forecasts for 2013 installations surpass 2012. *See, e.g., U.S. Solar Market Insight Report Q1 2013*, Greentech Media, Executive Summary, at p. 14, June 2013, *available at* http://www.greentechmedia.com/research/ussmi.
[4] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business* (Edison Electric Institute), at p. 4, Jan. 2013.
[5] *Solar Panels Cast Shadow on U.S. Utility Rate Design* (FitchRatings), July 17, 2013, *available at* http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776. The piece was wrong on its facts. The Spanish model used a feed-in tariff ("FIT") based on solar energy costs and set at over US $0.60/kWh, leading to a massive build-out in a single year when solar prices dipped below the FIT rates. See *Spain's Solar Market Crash Offers a Cautionary Tale About Feed-In Tariffs*, N.Y. Times, Aug. 18, 2009, *available at* http://www.nytimes.com/gwire/2009/08/18/18greenwire-spains-solar-market-crash-offers-a-cautionary-88308.html?pagewanted=all (for up to 44 eurocent incentives, and using 0.711 average euro to U.S. dollar exchange rate in 2008, per IRS tables).

Numerous trade and industry publications have joined the chorus, with little indication that the rhetoric will abate anytime soon.[6]

DSG benefit and cost studies are important beyond the context of NEM. To address concerns about the cost-effectiveness of NEM, Austin Energy implemented the first Value of Solar Tariff ("VOST") in 2012, which is now under consideration in other jurisdictions. Under the Austin Energy approach, all of the customer's energy needs are provided by the utility, just as they would be if the customer did not have DSG, and the utility credits the residential solar customer for the value of all of the energy produced by the customer's solar array.[7] Though intended to offer a new approach to address the valuation issue, Austin Energy's VOST did little to quell the larger debate; indeed, this new policy highlights the fact that valuation is the key issue for any solar policy—NEM, VOST or otherwise.

Austin Energy's VOST rate, as initially calculated, was about three cents higher than retail rates, giving customers an even greater return than the NEM policy that the VOST replaced. However, as with NEM, discussions about "value of solar" rates have now turned to how to calculate the benefits of customer-generated energy. Claiming the use of their own VOST approach, City Public Service, the municipal utility serving San Antonio, Texas (just 80 miles from Austin) used an undisclosed, annualized value approach to conclude that the value of customer-sited energy from solar arrays was roughly half of the retail rate. A competing study for San Antonio, sponsored by Solar San Antonio and using publicly available data, showed twice that value.[8] As with NEM, the VOST approach is still subject to significant variation in valuation methodologies.

In early 2013, competing studies looking at DSG values for Arizona Public Service ("APS") kept the debate over valuation raging. APS funded a study that concluded DSG value was only 3.56 cents per kilowatt-hour ("kWh"), based on the present value of a kWh from DSG in the year 2025. Subsequently, APS filed an application to either change the rate schedule available to NEM customers or switch to a Feed-In Tariff ("FiT"), with both approaches relying on valuation in the range of 4 to 5.5 cents per kWh. At the same time, a solar industry-sponsored study found a 21 to 24 cent range for the value of each kWh of DSG, far exceeding costs, which it found to be in the range of 14 to 16 cents per kWh.[9] The lack of a consistent study approach drives the disparity in results.

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[6] *See* David Roberts, *Solar panels could destroy U.S. utilities, according to U.S. utilities*, Grist, April 2013, *available at* http://grist.org/climate-energy/solar-panels-could-destroy-u-s-utilities-according-to-u-s-utilities/; Herman Trabish, *Solar's Net Metering Under Attack*, GreenTech Media, May 2012, *available at* http://www.greentechmedia.com/articles/read/solars-net-metering-under-attack.

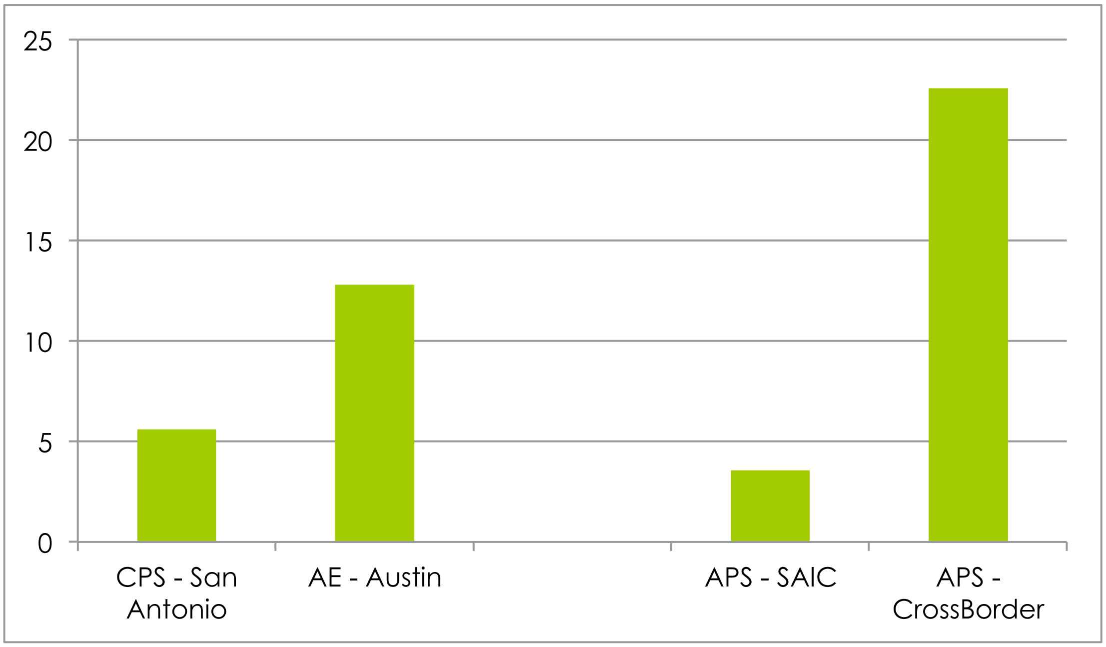
[7] *See* Austin Energy's Residential Solar Tariff, *available at* www.austinenergy.com/About%20Us/Rates/pdfs/Residential/ResidentialSolar.pdf (last accessed September 9, 2013).

[8] *See* N. Jones and B. Norris, *The Value of Distributed Solar Electric Generation to San Antonio*, March 2013 ("San Antonio Study"), *available at* www.solarsanantonio.org/wp-content/uploads/2013/04/Value-of-Solar-at-San-Antonio-03-13-2013.pdf.

[9] Arizona Corporation Commission Docket No. E-01345A-13-0248 regarding NEM valuation opened with APS's application in July, 2013, and is available at http://edocket.azcc.gov/. The May 2013 APS study prepared by SAIC is available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf. The May 2013 solar industry-sponsored study prepared by Crossborder Energy is available at http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

Figure 1 displays the 150% difference between the Austin Energy and San Antonio City Public Service DSG valuations, alongside the 6X difference in values found in the two APS studies.

Figure 1: Disparate DSG Valuations in Texas Studies (cents/kWh).



The figure above shows that Austin Energy's latest valuation of 12.8 cents per kWh is 150% greater the 5.1 cent valuation by City Public Service in San Antonio, just 80 miles away. Even more dramatic is the difference in DSG values for APS, with 3.56 cents by the utility consultant and a range of 21.5 to 23.7 cents by the solar industry consultant.

Overview of a proposed standardized approach. This paper explains how to calculate the benefits and costs of DSG, regardless of the structure of the program or rate in which this valuation is used. Whether considering NEM, VOST, FiTs or incentive programs, parties will always want to understand DSG value. Indeed, accuracy in resource and energy valuation is the cornerstone of sound utility ratemaking and a critical element of economic efficiency. Fortunately, at least 16 studies of individual utilities or regions have been performed over the past several years, providing a backdrop for the types of benefits and costs to consider. While the variation in the purposes, assumptions and approaches in these studies has been wide, the body of published work is sufficient to draw some conclusions about best practices via a meta-analysis.

Rocky Mountain Institute ("RMI"), a Colorado-based not-for-profit research organization, looked at these 16 studies and summarized the range of valuations for each benefit and cost category in *A Review of Solar PV Benefit and Cost Studies* ("RMI 2013 Study"), providing a very useful tool for regulators determining whether a new study has considered all of the relevant benefits and costs. As well, an IREC-led report in early 2012 summarized these key benefits and costs and provided a generalized, high-level approach for their inclusion in any study ("Solar ABCs Report").[10] Together, the Solar ABCs Report and the RMI 2013 Study provide a detailed summation of efforts to date to assess the net benefits and costs of DSG.

This paper discusses various studies, but does not attempt to replicate RMI's thorough meta-analysis. Rather, this paper proposes *how* each benefit should be calculated and *why*. To assist state utility commissions and other regulators as they consider DSG valuation studies and the fate of NEM, VOST, or other programs or rate designs, we offer a set of recommended best practices regulators can use to ensure that a DSG benefit and cost study accurately measures the net impact of DSG.[11]

This paper synthesizes the prevalent and preferred methods of quantifying the categories of benefits and costs of DSG. One point of agreement is that DSG-related energy benefits are well accepted and are typically employed in cost-effectiveness testing, as well as in avoided cost calculations. Additional benefits and costs, related to capacity, transmission and distribution ("T&D") costs, line losses, ancillary services, fuel price impacts, market price impacts, environmental compliance costs, and administrative expenses are less uniformly treated in regulation and in the literature, and are addressed here in an effort to establish more commonality in approach. The quantification of societal benefits (beyond utility compliance costs) is also addressed. While typically not quantified in cost-effectiveness tests, these benefits—especially as related to evaluation of the risk associated with alternate resources—also merit more uniform treatment.

Organizationally, this paper covers the types of studies undertaken in relation to DSG valuation and overarching issues in DSG valuation studies, followed by the benefits and costs considered in various studies, the rationale for them, and the authors' recommendations on how to approach them.

> *The premise of this paper is that while calculated values will differ from one utility to the next, the approach used to calculate the benefits and costs of distributed solar generation should be uniform.*

II. DSG Benefit and Cost Studies

A history of DSG benefit and cost studies. There have been an increasing number of studies conducted and published over the past 10-15 years addressing the value of DSG and other distributed energy resources. The first comprehensive effort to

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[10] J. Keyes and J. Wiedman, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering* (Solar America Board of Codes and Standards), January 2012 ("SolarABCs Report"), *available at* www.solarabcs.org/about/publications/reports/rateimpact.

[11] In addition, the Interstate Renewable Energy Council. Inc. ("IREC") is proactively working with state utility commissions to ask these questions before studies are undertaken, with the expectation that having clarified the assumptions, commissioners will be more confident in the results.

characterize the value of distributed energy resources was *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, published by RMI in 2002. Drawing from hundreds of sources, pilot project reports, and studies, *Small Is Profitable* set the stage for more specific technology-based studies, including the NEM cost-benefit studies and solar valuation studies that followed. Studies specific to DSG systems have appeared with increasing frequency since the Vote Solar Initiative published Ed Smeloff's *Quantifying the Benefits of Solar Power for California* in 2005 and Clean Power Research ("CPR") published its evaluation of *The Value of Solar to Austin Energy and the City of Austin* in 2006.

The reasons behind the appearance of these studies are several. DSG represents an increasingly affordable, interconnected form of distributed generation, creating the potential for significant penetration of small-scale generation into grids generally built around a central station model. In addition, economic and policy pressure on rebates and other mechanisms to foster DSG penetration has increased interest in improving understanding of the DSG value proposition. Utilities, policymakers, regulators, advocates, and service and hardware providers share a common interest in understanding what benefits and costs might be associated with such increased deployment of DSG, and whether net benefits outweigh net costs under a variety of deployment and analysis scenarios.

Many recent DSG valuation studies have been cost-effectiveness analyses of NEM policies for a given utility or group of utilities. NEM has proven to be one of the major drivers of distributed generation in the United States; 43 states and the District of Columbia feature some form of NEM.[12] The success of NEM as a policy to drive distributed generation market growth has caused several states to examine the impact that the policy has on other non-participating ratepayers. Efforts are currently underway in California, Arizona, Hawaii, Colorado, Nevada, North Carolina and Georgia to quantify the benefits and costs of the policy in order to inform the appropriate level of support for distributed energy generation, particularly rooftop solar photovoltaic ("PV") generation. Other states may follow soon, even those with relatively few DSG installations; for example, the Louisiana Public Service Commission indicated that it would launch a cost-benefit analysis for net-metered systems.

Another major use for DSG value analysis is in resource planning and other regulatory proceedings. In December 2012, Lawrence Berkeley National Laboratory ("LBNL") published a review of how several utilities account for solar resources in *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes.*[13] At this writing, Integrated Resource Plan ("IRP"), avoided cost, or renewable plan dockets are, or soon will be, underway at several utilities[14] where the value of DSG is directly at issue. In addition, the state of Minnesota has recently adopted legislation that establishes a

[12] *See* Database of State Incentives for Renewables and Energy Efficiency ("DSIRE"): Summary Maps – Net Metering Policies, *available at* www.dsireusa.org (last accessed Aug. 18. 2013).
[13] Andrew Mills & Ryan Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, December 2012 ("LBNL Utility Solar Study 2012"), *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.
[14] *See, e.g.,* Georgia Public Service Commission Docket No. 36989 (Georgia Power Rate Case); North Carolina Utilities Commission Docket No. E-100, Sub 136 (Biennial Avoided Cost); Colorado Public Utilities Commission Docket No. 13A-0836E (Public Service Company Compliance Plan).

Value of Solar rate for DSG.[15] The authors anticipate that additional valuation studies will result from one or more of these proceedings.

As of this writing, relatively few jurisdictions have conducted full cost-effectiveness studies for DSG and fewer still provide sufficient detail to guide development of a common methodology. CPR's Austin Energy study, updated in 2012, established an approach that has been applied in other regions, including a recent study on the value of DSG in Pennsylvania and New Jersey.[16] The California Public Utilities Commission ("CPUC") and APS commissioned comprehensive studies in 2009; both commissioned revised studies in 2013.[17] In January 2013, Vermont's Public Service Department[18] completed a cost-benefit analysis of NEM policy.

While not identical in structure, these works typify the recent reports and illustrate some commonalities in approaching the valuation of distributed energy. NEM-specific studies include the 2009 California Energy and Environmental Economics ("E3") Study, Crossborder Energy's 2013 updated look at that E3 study,[19] Crossborder Energy's 2013 analysis of DSG cost-effectiveness in Arizona,[20] and the Public Service Department's own analysis for Vermont.

As noted earlier, this paper complements IREC's recent publication, *A Generalized Approach to Assessing the Rate Impacts of Net Energy Metering*.[21] That paper reviews the DSG valuation studies that had been published to date and provides general approaches to calculating the widely recognized categories of benefits and costs that are relevant to the consideration of the cost-effectiveness of VOST, NEM, and other policy mechanisms impacting DSG. The intent of this examination is to dive deeper, find more common ground for discussion and foster greater consistency in how these values are determined across jurisdictions.

Also as noted earlier, this paper benefits from analysis recently published by RMI, entitled *A Review of Solar PV Benefit and cost Studies*.[22] That report reviews 16 studies in a meta-analysis that examines methodologies and assumptions in great detail. Figure 2 is from that study, and characterizes the differences and similarities in the studies. As

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[15] Minn. Stat. § 216B.164, subd. 10 (2013): Chapter 85--H.F. No. 729, Article 9, Distributed Generation, Section 10.

[16] Richard Perez, Thomas Hoff, and Benjamin Norris, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania,* 2012 ("CPR 2012 MSEIA Study"), *available at* http://communitypowernetwork.com/sites/default/files/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

[17] APS studies: *Distributed Renewable Energy Operating Impacts and Valuation Study*, RW Beck, Jan. 2009, available at http://www.solarfuturearizona.com/SolarDEStudy.pdf; *2013 Updated Solar PV Value Report*, SAIC, May 2013, available at http://www.solarfuturearizona.com/2013SolarValueStudy.pdf.
CPUC studies conducted by Energy and Environment Economics ("E3"): http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm.

[18] *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012,* January 15, 2013 ("Vermont Study"), *available at* www.leg.state.vt.us/reports/2013ExternalReports/285580.pdf.

[19] Thomas Beach and Patrick McGuire, *Evaluating the Benefits and Costs of Net Energy Metering in California* (Vote Solar Initiative), 2013 ("Crossborder 2013 California Study"), *available at* http://www.seia.org/research-resources/evaluating-benefits-costs-net-energy-metering-california.

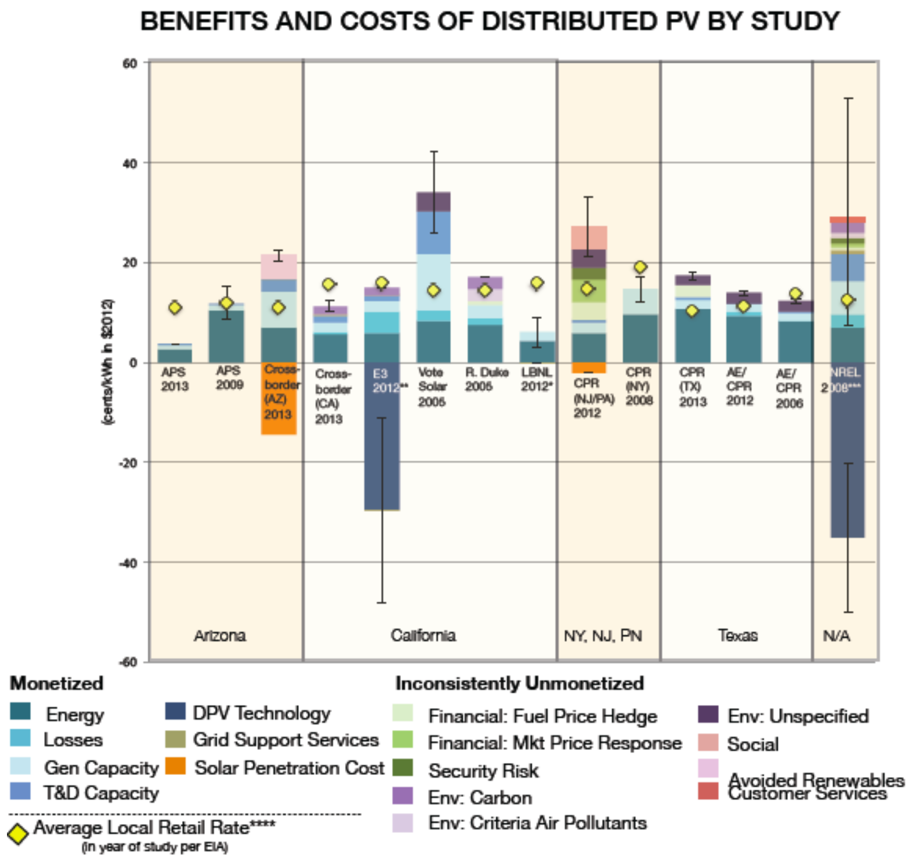
[20] Thomas Beach and Patrick McGuire, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service* (Vote Solar Initiative), at p.12, 2013 ("Crossborder 2013 Arizona Study"), *available at* http://www.solarfuturearizona.com/TheBenefitsandCostsofSolarDistributedGenerationforAPS.pdf.

[21] *See* SolarABCs Report, *supra*, footnote 10.

[22] *See* RMI 2013 Study, *supra*, footnote 1.

well as considering benefits and costs the RMI 2013 Study points out that the various studies differ significantly in the amount of DSG penetration considered, which can drastically impact values. Another important differentiator is whether the studies are based on high-level, often secondary, review of benefits and costs, or whether they rely on more granular and detailed modeling of impacts.[23]

Figure 2: Rocky Mountain Institute Summary of DSG Benefits and Costs



The RMI 2013 Study figure is reprinted here to make three important points. First and foremost, the calculated benefits often exceed residential retail rates, shown in the figure with diamonds, implying that NEM would not entail a subsidy flowing from non-solar to solar customers. Second, commercial customers almost always have unbundled rates and NEM has minimal impact on their demand charges because they still have demand after the sun sets. That means that DSG benefits compared to commercial customer energy rates would be strongly positive based on almost all of these studies. And third, costs are accounted for in varying ways: three studies show costs including lost retail rate payments, with large bars below the zero line indicating total costs, one shows costs other than retail rate payments (CPR NJ/PA), and the rest include costs as a deduction within the benefits calculation. As an overarching point,

[23] *Id.* at p. 21.

the RMI 2013 Study figure confirms that there is no single standard DSG valuation methodology today.

Types of Studies. Distributed solar valuation requires quantitative analysis of a wide range of data in an organized way. Fortunately, there are abundant existing approaches that can contribute to estimation of DSG value. This section briefly introduces the two major types of studies that underlie DSG valuation. The first category of studies is input and production cost models. These have general application in the utility industry in the comparison of resource alternatives. The second category, DSG-specific studies, includes three sub-types, depending on the purpose for which the study was conducted. In practice, most DSG-specific studies rely on inputs from input and production cost models.

A. Input and Production Cost Models

Utility planners and industry experts rely on a wide range of models and analytical tools for calculating costs associated with generation and systems. Power flow, dispatch, and planning models all provide input to the financial models used to evaluate DSG cost effectiveness and value. While detailed treatment of the utility models providing input to the DSG models is beyond the scope of this paper, they impact the DSG models and need to be understood. Often, these utility models are deemed proprietary, creating "black box" solutions regarding what generation is needed and when. Among the most critical decisions made at this juncture is whether the generation that will be offset by DSG is a relatively efficient natural gas combined-cycle combustion turbine ("CCGT")or a less efficient single cycle "peaker" plant running on natural gas, or some combination of the two.

As most of the gas-fired energy delivered by utilities comes from CCGTs, and peakers will still be needed to handle changes in load, models should reflect that DSG is primarily offsetting CCGTs. However, the APS 2013 study is an example in which the input model results are confounding, and there is no way to review the black box solution. Oddly, APS found that baseload coal would be displaced for part of the year. We believe that such an example deserves more careful study; it is a nearly universal truth that coal plants are run as much as possible. While many coal plants have been shut down in the past decade, those that remain are typically only curtailed for maintenance. Regulators should consider whether input assumptions such as coal or nuclear displacement are reasonable, particularly if the results are based on proprietary, opaque modeling.

Capacity needs in planning models are typically forecasted several years in the future and, because of the legacy of the central station utility plant paradigm, in large increments of capacity. These so-called "lumpy" capacity investments generally overshoot capacity requirements in order to ensure resource adequacy in the face of multi-year development lead times. As a result, the opportunity for DSG to provide useful capacity is generally seen as too little and too early. For example, a typical utility resource plan might state that capacity is adequate until the year 2018, at which time the company forecasts a need for an additional 200 megawatts ("MW") of generation capacity. In such a situation, traditional resource planning and avoided cost estimates assign no capacity value to DSG installed on customer roofs before 2018, and none in

2018 unless the systems provide the equivalent to 200 MW of capacity. This ignores the benefit of DSG's modularity—the utility does not need 200 MW in 2018, at that point it only starts to need more than it already has available. DSG can provide for that capacity through incremental installations starting in 2018. Likewise, if the utility has projects under development prior to 2018, it could have deferred or avoided some of that need if it had accurately predicted and valued DSG installations.

Today, many input and production cost planning models include the opportunity to adjust assumptions about customer adoption of DSG (and energy efficiency), which assume that those resources are going to play a role in the utility's near term capacity requirements. With these adjustments, the in-service requirement date can possibly be deferred, generating both energy and capacity savings attributable to the distributed resources. Accordingly, models that do not address DSG installations are inadequate and could lead to costly overbuilding and, given planning and construction lead times associated with large plants, premature expenditure of development costs.

B. DSG-Specific Studies

DSG-specific studies often start with inputs from the models just described. These studies are themselves usually of three types:

Studies of studies. Like this white paper, these studies start with work conducted by one or more experts and organize the information and data in a form that addresses questions of interest. In some cases, the authors report the results and the source conditions for the data. In others, study authors attempt to adjust the results for different local conditions. The RMI 2013 Study on solar PV reports the results of 16 different studies spanning some eight years. These studies provide useful introductions to the emerging discipline and demonstrate the ways in which differences in assumptions, methodologies, and underlying data can impact outcomes. In addition, when adjusting for outlier conditions, the studies can demonstrate where there exists relatively strong coherence in approach and results.

Cost-Benefit Analysis studies. Cost-benefit studies focus on using avoided cost methodologies and cost-benefit test approaches to review large-scale DSG initiatives and programs. They seek to answer the question of whether total costs or total benefits are greater over a specified period of time. For these studies, forward-looking cost estimates for DSG interconnection, lost revenues, avoided RPS costs, and incentive programs are important inputs. The best-known examples of this study approach were conducted by E3, reviewing the California Solar Initiative and NEM programs, and those by Crossborder Energy, reviewing the E3 reports. Most of the studies reviewed by the RMI 2013 Study are of this sort. There are several cost-benefit analysis varietals, as described in the California Standard Practice Manual and summarized in the box below.

Value of Solar studies. Smeloff and CPR pioneered the "value of solar" genre of study. As the name implies, this study approach focuses on using avoided cost and financial analysis methods in discerning the future investment value of distributed solar to the utility, ratepayers, and society. Generally, these evaluations ignore utility lost revenues, instead focusing on valuation that can be used in designing and setting incentive levels, program limits, and other features of utility DSG programs. The studies stop short of rate or tariff design features, and as a result, do not typically address lost revenue issues. Perhaps best known is the Austin Energy Value of Solar study conducted by CPR in 2006 and updated in 2012.[24]

With reference to the California Standard Practice Manual study descriptions summarized in the prior box, the type of test that the authors suggest in this paper is a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") approaches. The RIM test addresses the impact on non-participating ratepayers in terms of how benefits and costs impact the utility and are passed along to those ratepayers. That necessarily does not account for the participating ratepayers' outlay for DSG systems, nor should it. The SCT approach looks at whether it is a good idea for society as a whole to pursue a policy, and includes participating ratepayers' investment in DSG systems. The authors contend that the participants' investment is outside of the scope of the appropriate investigation. The goal should be to determine whether non-participants have a net benefit from the installation of DSG systems. As the job creation, health and environmental benefits accrue to non-participants just as much as they accrue to participants, there is no apparent reason why societal benefits should not be included. In its consideration of benefits, this approach aligns with the VOST methodology which aims to include all benefits that can reasonably be quantified and assigned to utility operations.

Utilities often object, stating that valuing societal benefits conflates customers with citizens, and note that utility rates must be based on costs directly impacting utilities. By this line of reasoning, job creation and health benefits may be the basis of legislative policies supportive of DSG, but should not be considered when developing DSG tariffs. We are reluctant to accept an artificial division between citizens and utility customers; the overlap is complete for most benefits and costs. Moreover, a major reason for establishing NEM, VOST or other DSG programs is primarily related to the same broad societal benefits that drive utility regulatory systems—economic efficiency, and rates and services in the public interest—so those benefits should be considered in any programmatic or policy analysis.

Recommendation: Use a blend of the Ratepayer Impact Measure ("RIM") and Societal Cost Test ("SCT") Cost-Benefit Tests

[24] Author K. Rábago, while at Austin Energy, helped establish the nations' first VOST. *See* K. Rábago, *The Value of Solar Rate: Designing an Improved Residential Solar Tariff*, Solar Industry, at p. 20, Feb. 2013, *available at* http://solarindustrymag.com/digitaleditions/Main.php?MagID=3&MagNo=59.

Cost-Benefit Tests

The California Standard Practice Manual is used for economic analysis of demand-side management ("DSM") programs in California. The cost-benefit tests in the Standard Practice Manual have also been used to evaluate DSG value, most notably in California, where the tests have been applied to a review of the cost effectiveness of the California Solar Initiative. The various tests differ in the perspective from which cost effectiveness is assessed.

- ***Participant Cost Test* ("PCT").** Measures benefits and costs to program participants.
- ***Ratepayer Impact Measure ("RIM") Test.*** Measures changes in electric service rates due to changes in utility revenues and costs resulting from the assessed program.
- ***Program Administrator Cost Test ("PACT").*** Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. This test differs from the RIM test in that it considers only the revenue requirement, ignoring changes in revenue collection, typically called "lost revenues."
- ***Total Resources Cost Test ("TRC").*** Measures the total net economic effects of the program, including both participants' and program administrator's benefits and costs, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall economic welfare over the entire utility service territory.
- ***Societal Cost Test ("SCT").*** The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, such as induced economic development effects, which are not considered in the TRC.

III. Key Structural Issues for DSG Benefit and Cost Studies

***Underlying study assumptions and major study components*.** The evaluation of the cost-effectiveness of a given DSG policy, particularly NEM, is a complex undertaking with many potential moving parts. Before delving into the specific benefits and costs, it is important to recognize that the ultimate outcome of the analysis is highly dependent on the base financial and framework assumptions that go into the effort. Much of the work involves forecasting—estimating the future benefits and costs, performance, and cumulative impacts associated with increasing penetration of distributed generation into the electric grid. It is important to develop a common set of base assumptions that reflect the resource being studied and to be as transparent as possible about these assumptions when reporting the results of the analysis. At the outset of a study, it is important to define these structural parameters. Below we present key questions for regulators to explore at the onset of a study:

Q1: WHAT DISCOUNT RATE WILL BE USED?

The discount rate should reflect how society evaluates costs over time. Utilities use a discount rate based on the time value of money, using the rate of return available for investments with similarly low risk, now in the 6% to 9% range. However, society may prefer the use of a lower discount rate, closer to the rate of inflation. The difference is important. High discount rates improve the evaluation of resources with continuously escalating or high end-of-life costs. For instance, an 8% discount rate may favor a natural gas generator because much of the cost (the fuel, operation and maintenance) to run the generator is incurred over the life of the generator, while the cost of DSG is almost entirely at the front end. A low discount rate improves the valuation of resources with high initial costs and low or zero end-of-life costs. The same analysis based on a 3% inflation rate may favor DSG resources, as there are no fuel costs over time and the operations and maintenance ("O&M") costs are low because there are fewer or no moving parts. While the utility's discount rate is appropriate when considering utility procurement because those funds could be invested elsewhere at competitive rates, the utility is not procuring the DSG resources in the case of NEM, VOST or FiT arrangements. It is worth questioning whether the future benefits of DSG resources should be heavily discounted, based on the utility's cost of capital, when the customer (or a third party owning a system at the customer's site) is making the investment. As utility valuation techniques improve, is it reasonable to discount future benefits and costs by the inflation rate rather than the utility's cost of capital.

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Under NEM, utility customers can take advantage of a federal law[25] allowing for on-site generation to offset consumption, with the opportunity to sell excess generation to the utility at the utility's avoided cost. Because the customer has a right to avoid any and all consumption from the utility, studies of NEM cost-effectiveness will often look only at the utility cost associated with exports to the grid. The assumption under NEM is effectively that at or below the total consumption level, the value of offset consumption is the retail rate. This valuation is supported by the concept behind cost-of-service rate regulation—that the retail rate is the accumulation of costs to generate and deliver energy for the customer.[26] Note that to the extent that NEM benefits are calculated to

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[25] *See* Public Utility Regulatory Policies Act ("PURPA"), 16 U.S.C. *et seq.*

[26] VOST studies, on the other hand, presume a difference between the value of generation at or near the point of consumption and the level of the rate. That is, the customer with DSG may well be generating electricity of greater value than that being provided by the utility.

outweigh costs, consideration of all generation amplifies the calculated net benefit. However, if NEM costs outweigh benefits, the opposite is true.

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Utility planners routinely consider the lifecycle benefits and costs of traditional utility generators, typically over a period in excess of 30 years. Solar arrays have no moving parts and are generally expected to last for at least 30 years, with much less maintenance than fossil-fired generation. Solar module warranties are typically for 25 years, and many of the earliest modules from the 1960s and 1970s are still operational, indicating that modules in production today should last for at least 30 years. This useful life assumption creates some data challenges, as utilities often plan over shorter time horizons (10-20 years) in terms of estimating load growth and the resources necessary to meet that load. As described below, methods can be used to estimate the value in future years that interpolate between current market prices or knowledge, and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Recommendation: We suggest that the most appropriate timeframe for evaluating DSG and related policy is 30 years, as that matches the currently anticipated life span of the technology.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Key to determining the value of DSG is a reasonable expectation of what customer loads will look like in the future, as much of the value of distributed resources derives from the utility's ability to plan around customer-owned generation. Other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, as customer facilities contribute to the available capacity of utility resources as small contracted generators.

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, we recommend that the assigned capacity value of the distributed systems reflect the fact that the utility can plan for lower loads than it otherwise would have.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Many benefits and costs are sensitive to how much customer-owned generation capacity is on the grid. Most studies assume current, low penetration rates. Several of the studies consider higher penetration levels, as well, typically out to 15% or 20% of peak load, with some outlier studies looking at 30% and 40% penetration levels. In a high-penetration scenario, the utility may face higher integration expenses that might undermine the specific infrastructure benefits of distributed generation. Studies that address the issue often find that marginal capacity benefits decline with high penetration.

On the other hand, some studies such as those by APS, conclude that capacity benefits are dependent on having enough DSG to offset the next natural gas generator, and therefore that there are no capacity benefits in low-penetration scenarios. Market penetration estimates should also be reasonable in light of current supply chain capacity and local market conditions. Generally, the most important penetration level to consider for policy purposes is the next increment. If a utility currently has 0.1% of its needs met by DSG and a study shows that growth to 5% is cost-effective, but growth to 40% is not, then it would be economically efficient to allow the program to grow to 5% and then be reevaluated.

Recommendation: We recommend the establishment of an expected level of DSG penetration, and the development of low and high sensitivities to consider the full range of future impacts.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?

Analysts have used a wide variety of tools to calculate the benefits and costs of DSG. There is almost no commonality at the model level, even though many of the analyses address similar or identical issues. Several studies use some version of investment and dispatch models in order to determine which resources are displaced by solar and the resulting impacts. As noted earlier, utility DSG studies have often relied on proprietary models for these inputs. The fact that CPR and Professor Richard Perez[27] have published a number of studies creates some commonality among those studies, but over time, even the CPR approaches have evolved as tools have been improved.

Recommendation: We suggest that transparent input models accessible to all stakeholders are the proper foundation for confidence and utility of DSG studies. If necessary, non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?

Value of solar analysis is heavily influenced by local resource and market conditions. Most published studies are geographically scoped at the state, service territory, or interconnected region level. Given its leadership in solar deployment, California also leads as the subject of studies and as a data source. Some studies relating to economic development and environmental impacts use a national and regional scope.

Recommendation: We suggest that it is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

The majority of studies consider benefits and costs in the generation, transmission, and distribution portions of the system. Of the studies that consider environmental impacts,

[27] Richard Perez is a Research Professor at the University at Albany-SUNY.

most only look at avoided utility environmental compliance costs at the generation level.

Recommendation: We recommend considering impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [28]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Nearly all the studies consider impacts from the perspective of the utility and ratepayers. Several also consider customer and societal benefit and costs. Cost-benefit studies apply California Standard Practice Manual tests for Demand Side Management, discussed earlier.

Recommendation: We suggest that rate impacts and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

When a DSG system is installed, it is like commissioning a 30-year power plant that will, if properly maintained, produce energy and other benefits during that entire period. Several studies look at snapshots of benefits and costs in a given year, which fails to answer the basic question of whether DSG is cost-effective over its lifetime. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options. As such, levelization of the entire stream of benefits and costs is appropriate.

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the entire DSG life of 30 years.

Q11: WHAT DATA AND DATA SOURCES ARE USED?

As the number of solar valuation studies has increased, so has the frequency with which newer studies cite data provided in prior studies. There are two reasons behind this trend, cost and availability of data, which we discuss in detail below.

As with any modeling exercise, models are only as good as the data fed into them. The ability to precisely calculate the benefits of DSG often rests on the availability and granularity of utility operational and cost data. More granular data yields more reliable analysis about the impacts of DSG deployment and operation.

Calculating many of the benefit and cost categories requires that analysts address utility-specific or regional conditions that can vary significantly from utility to utility, even within the same state. In addition, the availability of the type of granular data needed

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[28] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012, *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

to accurately project location and time-specific benefits varies from one utility to the next. Much of the data needed to quantify the benefits of DSG resides with utilities.

Fortunately, additional data, such as energy market prices, is often publicly available, or can be released by the utility without proprietary concerns. In some limited cases, the utility may have proprietary, competitive, or other concerns with plant- or contract-specific information. And in some cases, the form and format of utility data may require adjustments.

These problems are not insurmountable. Utility general rate cases and regulatory filings with the Federal Energy Regulatory Commission ("FERC") are good sources for data relevant to utility peak demand and for the components of cost of service, including transmission costs, line loss factors, O&M costs, and costs of specific distribution upgrades or investments, among other cost categories. Additionally, the federal Energy Information Administration ("EIA") and various state agencies compile utility cost data that can be used as a reference to determine heat rates, the costs of O&M associated with various plants, and the overall capital cost of new construction of generating capacity.[29]

Recommendation: Require that utilities provide the following data sets, both current information and projected data for 30 years[30]:

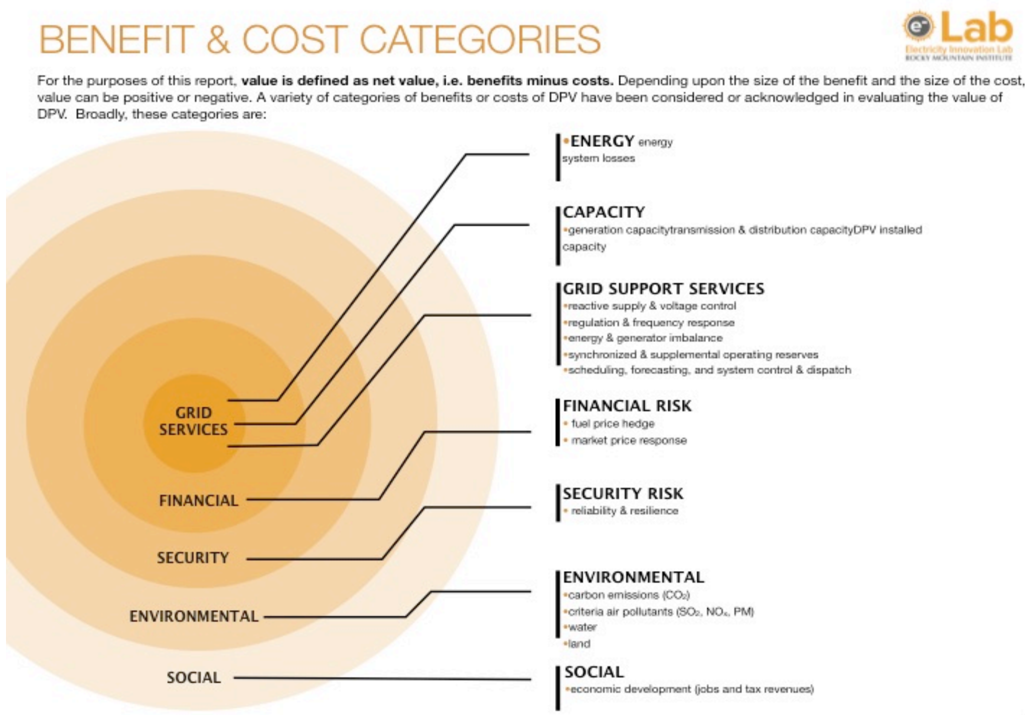
1) The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG.
2) Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy.
3) Hourly production profiles for NEM generators. The use of time-correlated solar data is important to correctly assess the match of solar output with system loads. In the case of solar PV, this could vary according to the orientation of the system. For example, while south-facing systems may have greater overall output, west or southwest facing systems may produce more overall value with fewer kWh because of peak production occurring later in the day than a south-facing system.
4) Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated.
5) Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
6) Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
7) Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades.

[29] *See Updated Capital Cost Estimates for Electricity Generation Plants* (EIA), November 2012, *available at* http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (providing estimate of capital cost, fixed O&M, and variable O&M for generation plants with various technical characteristics).
[30] Note: Where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

IV. Recommendations for Calculating the Benefits of DSG

Benefits of DSG get categorized and ordered in various ways from study to study, typically based on the relative magnitude of the benefits. The RMI 2013 Study is structured around a list of "services," encompassing flows of benefits and costs to and from solar PV. That list is replicated here in an effort to coordinate with that study.[31] The RMI services categories are depicted in the graphic below.

Figure 3: Rocky Mountain Institute Summary of DSG Benefits



While replicating the RMI services categories, we have subdivided them in recognition that the divide between utility avoided costs and other societal benefits is not clear from the list above. For instance, utilities can avoid certain environmental compliance costs, which are direct utility avoided costs, while other environmental benefits inure to society more generally. As another example, reliability or resiliency is only a utility avoided cost to the extent that the utility was going to take some other measures to achieve the levels enabled by DSG. If DSG enables higher reliability than would have otherwise been achieved, that is undoubtedly a benefit, though it is most notably realized by utility customers when a storm event does not cause a major service interruption, which may occur once in a decade. As a further example, market price

[31] *See* RMI 2013 Study.

response benefits can be felt by the utility itself but will also extend to citizens who are customers of nearby utilities.

To track utility avoided costs and societal benefits separately, separate subsections are provided below, with the final three RMI environmental and social benefit categories covered after utility avoided costs. We note where some categories listed under utility avoided costs have societal benefits as well, and we separately create an environment category under utility avoided costs to capture utility avoided environmental compliance costs.

Calculating Utility Avoided Costs

1. *Avoided energy benefits*

To determine the value of avoided generation costs, the first step is to identify the marginal generation displaced. In most instances, the next marginal generator will be a natural gas-fired simple-cycle combustion turbine ("CT") or a more efficient CCGT. Avoiding the operation of that marginal generating facility to produce the next increment of electricity means that the solar generator allows the utility to avoid both variable O&M activities (i.e., those activities and expenses that vary with the volume of output of the CT or CCGT plant) and the fuel that would be consumed to produce that next unit at the time that the customer-generator allows the utility to avoid that operation.

To calculate the avoided generation cost over the life of the DSG system—assumed throughout this paper to be 30 years—the calculation must estimate the market price of energy throughout that time span. Given the limitations on the availability of data, including the future price of a historically volatile commodity like natural gas, many studies have used interpolation and extrapolation to estimate gas prices in the 30 year horizon by taking the readily attainable current market price for natural gas and referencing it against the most forward natural gas price available.

Additionally, the calculation of avoided generation costs over time must account for degradation in the marginal generation plant and adjust expected heat rates (i.e., the measure of efficiency by which a unit creates electricity by burning fuel for heat to power a turbine). Over time, the marginal generation plant will become less efficient and require incrementally more fuel to reach the same production levels. Production cost modeling enables the utility to cumulate value of avoided costs throughout the useful life of the solar generating system. However, due to built in constraints or other issues, such modeling can produce results that are illogical, as has been seen in Arizona (baseload coal generation displaced by DSG) and Colorado (high cost of frequent unit startups reducing energy benefits).

A standard approach to determining the value of avoided generation over the life of a DSG system is to develop: (1) an hourly market price shape for each month and (2) a forecast of annual average market prices into the future.[32] One way to forecast the annual market prices, with less reliance on forward market prices, is to project the rolled-in costs of the marginal generation unit, accounting for variable O&M and

[32] E3 Study, Appendix A at pp.10-11.

Comparison with PURPA Avoided Cost Calculations

Value of solar analysis literature is complemented by other studies and reports related to the issue. These include studies relating to avoided cost methodologies under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and those addressing utility resource planning evaluation of distributed resources.

Because both the cost-benefit and value-of-solar approaches start with avoided cost calculations, publications and processes used in conducting such calculations are informative in establishing the costs and benefits of DSG. State utility commissions and public utility regulators have approached PURPA valuation of avoided costs quite differently, and FERC has rarely constrained the approach selected. Rather than attempt to discern a consensus approach, a more fruitful approach is to consider what PURPA allows.

IREC recently published a paper to do this, cataloguing the kinds of DSG-related avoided cost calculations that could improve understanding of DSG value, and citing most of the utility avoided costs discussed in this paper.

See the full report:
http://www.irecusa.org/wp-content/uploads/2013/05/Unlocking-DG-Value.pdf

degradation of heat rate efficiency in future years. This method still relies on forecasts of natural gas prices in future years, but provides more certainty for variable O&M costs.[33]

In the Vermont study, the Public Service Department assumed that the New England Independent System Operator ("ISO-NE") wholesale market would provide the marginal generation price for energy displaced by solar generation. To account for the high correlation of solar PV with system peak, and therefore the offset of higher value generation, the Department created a hypothetical avoided cost for 2011 using real output data that was matched with actual hourly market data from the ISO-NE market.[34] This adjusted hourly market price was then scaled to future years by utilizing an energy price forecast, based on the forward market energy prices for the first five years and for the forward natural gas prices for years five to ten.[35] Prices for years after year ten were based on an extrapolation of the market prices for electricity and natural gas for years one through ten.

As CPR observes, there are inherent shortcomings in relying on future market prices for marginal generation decades into the future.[36] A more straightforward method would be to "explicitly specify the marginal generator and then to calculate the cost of the generation from this unit."[37] In this way the avoided fuel and O&M cost savings are roughly equivalent to capturing the future wholesale price. Of course, this approach still relies on forward projections in the natural gas market.

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[33] CPR 2012 MSEIA Study at pp. 28-29.
[34] Vermont Study at p. 16.
[35] *Id.*
[36] CPR 2012 MSEIA Study at pp. 28-29.
[37] *Id.* at p. 29.

2. *Calculating system losses*

DSG sited at or near load avoids the inefficiencies associated with delivering power over great distances to the end-use customer due to electric resistance and conversion losses. When a DSG customer does not consume all output as it is being produced, the excess is exported to the grid and consumed by neighboring customers on the same circuit, with minimal losses in comparison to electricity generated by and delivered from a utility's centralized but distant plant. Without DSG and its local load reduction impact, utilities are forced to generate additional electricity to compensate for line losses, decreasing the economic efficiency of each unit of electricity that is delivered.

Including avoided line losses as a benefit is relatively straightforward and should be non-controversial. For instance, FERC's regulations implementing PURPA recognize that distributed generation can account for avoided line losses.[38] This benefit exists for all types of DG technologies and, to some extent, in all locations. Typically, average line losses are in the range of 7%, and higher during heavier load periods, which can correlate with high irradiance periods for many utilities.[39] Additional losses termed "lost and unaccounted for energy" are also likely associated with T&D functions and, with further research, may also be avoided by DSG.[40]

Average line loss is often used as the primary approach to adjusting energy and capacity-related benefits. However, because line losses are not uniform across the year or day, the use of average losses ignores significant value because it fails to quantify the "true reduction in losses on a marginal basis."[41] Considering losses on a marginal basis is more accurate and should be standard practice as it reflects the likely correlation of solar PV to heavy loading periods where congestion and transformer thermal conditions tend to exacerbate losses. In its Austin Energy study, CPR evaluated marginal T&D losses at times of seasonable peak demand using load flow analysis. CPR decided to average the marginal energy losses on the distribution system, for purposes of the study, and added marginal transmission losses in order to report hourly marginal loss savings due to solar generation. According to one APS study, the degree of line losses may decrease as penetration increases.[42]

As with the effect of reducing market prices by reducing load at times of peak demand, and therefore reducing marginal wholesale prices (see below), DSG-induced reduction of losses at times of peak load has a spillover effect. The ability of customers to serve on-site load without use of the distribution system reduces transformer

[38] *See* FERC Order No. 69, 45 Fed. Reg. 12214 at 12227.("If the load served by the [QF] is closer to the [QF] than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.").

[39] For example, the E3 study assumes an average loss factor of 1.073, which indicates that 7.3% more energy is supplied to the grid than is ultimately delivered and metered by the end-use customers. In contrast, Vermont's study noted that the Department's energy efficiency screening tool concluded that typical marginal line losses are about 9%. Vermont Study at p.17.

[40] *See*, *e.g.*, A. Lovins *et al.*, Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size, Rocky Mountain Institute, at p. 212, August 2002; U.S. Energy Information Administration's Annual Energy Review, *available at* http://www.eia.gov/totalenergy/data/annual/diagram5.cfm.

[41] CPR 2012 MSEIA Study at p. 27.

[42] *Distributed Renewable Energy Operating Impacts and Valuation Study, R. W. Beck for Arizona Public Service, Jan. 2009, at p. 4-7 and Table 4-3. (Finding that a "law of diminishing returns" applies to solar distributed energy installations.) Available at: http://www.solarfuturearizona.com/SolarDEStudy.pdf.*

overheating, a major driver of transformer wear and tear, and in turn allows customers to receive power from utility generators at lower marginal loss rates. Without on- or near-peak DSG, all customers would face higher marginal loss rates with the contribution to thermal transformer conditions caused by all customers seeking grid delivered power for all on-site needs at times of peak load.

With consideration of the line losses avoided in relation to both the energy that did not have to be delivered due to DSG, and the marginal improvement in line losses to deliver power for the rest of utility's customers' needs, the appropriate methodology developed by CPR is to look at total line losses without DSG and total line losses with DSG. In practice this can equal 15-20% of the energy value.

Separately, line losses figure into capacity value as well, as a peak demand reduction of 100 MW means in turn that a generation capacity of more than 100 MW is avoided. This aspect of avoided line losses should be included with generation and T&D capacity benefits, discussed below.

3. Calculating generation capacity

Determining the capacity benefits of intermittent, renewable generation is a more complex undertaking than analyzing energy value, but there is a demonstrated capacity value for DSG systems. Capacity value of generation exists where a utility can count on generation to meet its peak demand and thereby avoid purchasing additional capacity to generate and deliver electricity to meet that peak demand.

While individual DSG systems (without energy storage) provide little firm capacity value to a utility given the potential for cloud cover, there is compelling research supporting the consideration of the aggregate value of DSG systems in determining capacity value. A recent study by LBNL demonstrates that geographic diversity tends to smooth the variability of solar generation output, making it more dependable as a capacity resource.[43] As well, FERC considered the fact that distributed solar and wind should produce some capacity value when considered in the aggregate when it was developing its avoided cost pricing regulations.[44] Capacity value for DSG systems should look to the characteristics of all DSG generators in the aggregate, including the smoothing benefits of geographic diversity.

Solving for Intermittency. CPR developed the most prominent and widely used method to address the intermittency of DSG technologies. This method recognizes a capacity value for intermittent, non-dispatchable resources, and is referred to the as the "effective load carrying capability" ("ELCC"). ELCC is a statistical measure of capacity that is "effectively" available to a utility to meet load. "The ELCC of a generating unit in a utility grid is defined as the load increase (MW) that the system can carry while

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[43] *See* Andrew Mills and Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power* (Lawrence Berkeley National Laboratory), LBNL-3884E, September 2010.
[44] FERC Order No. 69, 45 Fed. Reg. 12214 at 12227 ("In some instances, the small amounts of capacity provided from [QFs] taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual [QF] may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.").

maintaining the designated reliability criteria (e.g., constant loss of load probability)."[45] In this way, ELCC provides a reliable statistical method to project the capacity value of intermittent resources.

On the other hand, the ELCC method can be data intensive and complex to some stakeholders. Simpler methods may also yield reasonable results. For example, an alternate method, based on the utility's load duration curve, looks at the solar capacity available for the highest load hours, usually the top 50 hours.

Implemented in a rate, a capacity credit for DSG denominated in kWh represents the best approach. This ensures that DSG only receives capacity credit for actual generation.

Valuing Small, Distributed Capacity Additions. An often controversial issue in determining avoided capacity value is the fact that distributed generation provides small, incremental additions and utility resource planning typically adds capacity in large, or "lumpy," blocks of capacity additions. For example, if a utility has ample capacity to meet its reserve margin and its next capacity addition will be a 500 MW CCGT, a utility might argue that incremental additions of 1 MW or 20 MW do not allow them to avoid capacity costs. FERC's regulations recognize that distributed generation provides a more flexible manner to meet growing capacity needs and can allow a utility to defer or avoid the "lumpy" capacity additions.[46] Therefore, it is inappropriate to hold that there is no capacity benefit for deployment of distributed generation in years that come before the time where the "lumpy" capacity investment is required. Distributed generation resources, like other demand-side resources that are continuously pursued to address load growth and to reduce peak demand, provide immediate benefit and a hedge against unexpected outages that could lead to a shortage in capacity. There is, therefore, no good reason to value DSG capacity for its long-term value only in years where it physically displaces the next marginal generating unit.

One solution around the valuation of incremental capacity additions versus lumpy additions that would follow more traditional utility planning is laid out in Crossborder Energy's 2013 update to the 2009 E3 Net Metering Cost-effectiveness study for California. In the E3 study, a mix of short-run and long-run avoided capacity costs are applied to renewable generators based on the fact that additional capacity would not be required until a certain year, called the "Resource Balance Year" in the E3 study. Crossborder's update recognizes the incremental value of small capacity additions for the years leading up to the Resource Balance Year and uses a long-run capacity value methodology for the life of the distributed generation system.[47] In other words, utilities are responsible for predicting load growth and planning accordingly, so the full penetration of DSG installations should already be built into their plans, reflecting the incremental capacity benefits these systems provide.

Adding It All Together: Determining the capacity credit for DSG systems. There are two basic approaches taken to determine capacity credit: (1) determine the market value

[45] CPR 2012 MSEIA Study at pp. 32-33.
[46] 18 C.F.R. 292.304(e)(2)(vii) (providing that avoided cost may value "the smaller increments and shorter lead times available with additions of capacity from qualifying facilities").
[47] Crossborder 2012 California Study, Appendix B.1.

of avoided capacity; or (2) estimate the marginal costs of operating the marginal generator, typically a CCGT.[48] For the same reasons that it is less than ideal to rely solely on the future projected market price for energy, it is also unreliable to credit DSG based on the projected future capacity market. The preferred approach is to determine the capacity credit by looking at the capital and O&M costs of the marginal generator.[49]

The resulting value is often termed a capacity credit—a credit for the utility capacity avoided by DSG. It is important to recognize that this credit is different from the "capacity value" of DSG. Capacity value is a term for the percentage of energy delivered as a fraction of what would be delivered if the DSG unit was always working at its rated capacity, that is, as if the sun were directly overhead with no clouds and the temperature was a constant 72 degrees at all times. Capacity value is typically in the range of 15-25% in the United States, depending on location. Because DSG generates electricity during daylight hours, often with high coincidence with peak demand periods, it earns a capacity credit based on the higher value of its generation during the hours in which it operates—a higher amount than simple capacity value. Alternatively, for a utility with an early evening peak or a winter peak, the capacity credit may be based on a lower percentage of its rated capacity than the capacity value.

Once the ELCC is determined for DSG resources for a given utility, the calculation of generation capacity is straightforward. The capacity credit for a DSG system is "the capital cost ($/MW) of the displaced unit times the effective capacity provided by PV."[50] Inherent in the ELCC calculation are the line losses associated with capacity, as discussed earlier.

4. *Calculating transmission and distribution capacity*

Distributed solar generation, by its nature, is usually located in close proximity to load on the distribution system, which may help reduce congestion and wear and tear on T&D resources. These benefits can reduce, defer, or avoid operating expenses and capital investments. Tactical and strategic targeting of distributed solar resources could increase this value.

The ability of DSG systems to yield T&D benefits is location-specific and also depends on the extent to which system output correlates to cost-causing local load conditions, especially before and during peak load periods. Utilities undertake system resource planning (i.e., planning for upgrades or additions to T&D capacity) to meet peak load conditions, so the correlation of DSG output to peak load conditions is important to understand. On the distribution system, unlike the bulk transmission system, this is a more difficult undertaking because local cost-causing load conditions (i.e., the timing, duration, and ramping rates associated with peak load on a given circuit) will vary according to a number of factors. These factors include customer mix, weather conditions, system age and condition, and others. As a simple example, a circuit that carries predominantly single-family residential load is likely to rise relatively smoothly to a peak in early evening, when solar PV output is waning. A circuit primarily serving

[48] CPR 2012 MSEIA Study at p. 32.
[49] *Id.* at pp. 32-33.
[50] *Id.*

commercial customers in a downtown setting will typically peak in the early afternoon. All other things being equal, DSG systems on circuits primarily serving commercial customers are more likely to avoid distribution capacity costs.

It is also important to consider system-wide T&D impacts. Transmission lines, and to an extent, substations, serve enough of a cross-section of the customer base to peak at approximately the same time as the utility as a whole. DSG coincidence with system peak means that DSG, even located on residential circuits, contributes to reduced demand at the substation level and above. Based on interconnection procedures, DSG systems in the aggregate on a circuit do not produce enough to export power off of the circuit; they simply reduce the need for service to the circuit. The avoided need for transmission infrastructure creates an avoided cost value to a utility and should be reflected as a benefit for DSG systems. Combining any granular distribution value with avoided, peak-related transmission costs, all DSG may demonstrate significant T&D value in allowing the utility to defer upgrades or avoid capital investments.

Estimating T&D Capacity Value. To determine the ability of DSG systems to defer T&D upgrades or capacity additions, it is critical to have current information on the system planning activities of utilities, and to periodically update that information. Often, the cost information is obtainable through rate case proceedings, where the utility ultimately seeks to include the upgrade or capital project in rate base. To make use of any cost data, however, it is important to have a sufficient amount of hourly data on both load and solar resource profiles. Much of the relevant information is also contained in utility maintenance cost data, grid upgrade and replacement plans, and capital investment plans. Beyond the planning horizon, expense and investment trends must be extrapolated to match the expected useful generating life of DSG.

With the data in hand, T&D capacity savings potential can be determined in a two-step process.[51] As described by CPR, "The first step is to perform an economic screening of all areas to determine the expansion plan costs and load growth rates for each planning area. The second step is to perform a technical load-matching analysis for the most promising locations."

For solar PV profiles, output can be estimated at particular places using irradiance data and various methods of estimating the output profile.[52] By looking at the load profile for a year, it is possible to isolate peak days at the circuit or substation level and calculate a capacity credit by measuring the net load with solar PV production. By reducing absolute peak load, DSG systems may allow a utility to avoid overloading transformers, substations or other distribution system components and, thereby, to defer expensive capital upgrades.

To determine deferral value, it is necessary to monetize the length of time that DSG allows a utility to defer a capital upgrade. Deferring an upgrade allows a utility to avoid the carrying cost or the cost of ownership of an asset and defers substantial expenditures that may be, at least to some extent, debt financed. Generally, the

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[51] *Id.* at p. 33 (citing T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Energy Journal: 17(4), 1996).
[52] M. Ralph, A. Ellis, D. Borneo, G. Corey, and S. Baldwin, *Transmission and Distribution Deferment Using PV and Energy Storage*, published in Photovoltaic Specialists Conference (PVSC), 2011 37th IEEE, June 2011, *available at* http://energy.sandia.gov/wp/wp-content/gallery/uploads/TransandDistDeferment.pdf.

avoided capital is multiplied by the utility's weighted average cost of capital or authorized rate of return to determine the value of deferring that investment.[53] However, as noted earlier, a lower discount rate could be used. For instance, the avoidance of a million dollar transmission upgrade five years from now—for a utility with a 7% discount rate—is arguably worth that amount divided by (1.07)^5, or approximately $713,000. From the ratepayers' perspective, avoiding the million dollar upgrade in five years might be worth more; based on an estimated inflation rate of 3%, the value would be $862,000.

System-Wide Marginal Transmission and Distribution Costs. When conducting a statewide or utility-wide analysis, it may be difficult to hone in on specific locations to determine the ability of DSG systems to enable deferment or avoidance of system upgrade activity. In some cases, distribution deferral value manifests in changes in distribution load projection profiles and should be calculated as the difference in what would have happened without the DSG. E3's approach to valuing avoided T&D takes a broader look at the ability to avoid costs and estimates T&D avoided costs in a similar manner to other demand-side programs, such as energy efficiency. E3's avoided cost methodology develops "allocators" to assign capacity value to specific hours in the year and then allocates estimates of marginal T&D costs to hours. E3 acknowledges that it lacks sufficient data to base its allocators on local loads and that, ideally, "T&D allocators would be based upon local loads, and T&D costs would be allocated to the hours with the highest loads."[54]

E3 determined that temperature data, which is available in a more granular form for specific locations in the many climate zones of California's major utilities, would be a suitable proxy method for allocating T&D costs. After determining these allocators and assigning them to specific hours, E3 determined the marginal distribution costs by climate zone, using a load-weighted average. Since marginal transmission costs are specific to each utility, those are added to the marginal distribution costs to arrive at the overall marginal T&D for a specific climate zone. This approach lacks the potential for capturing high-value, location-specific deferral potential, but it does approximate some value without requiring extensive project planning cost and load data for specific feeders, circuits, and substations. E3's methodology may be suitable in circumstances where there is limited local load data to develop what E3 described as an "ideal" methodology, but it does come with drawbacks. For example, allocating costs to certain hours by temperature may not correlate to peak conditions in certain locations.

Alternative Approaches to T&D Valuation. Clean Power Research also approached T&D value broadly in its study of Pennsylvania and New Jersey, taking utility-wide average loads in a conservative approach to valuation. CPR's Pennsylvania and New Jersey report notes that T&D value may vary widely from one feeder to another and that "it would be advisable to . . . systematically identify the highest value areas."[55]

Where information on specific upgrade projects is known, and there is sufficiently detailed local load data, a more detailed analysis of deferral potential should yield far more accurate results that better reflect the T&D value of DSG. For example, CPR was

[53] *Id.*
[54] E3 Study, Appendix A at p. 16.
[55] CPR 2012 MSEIA Study at p. 20.

ablle to take a more granular and area-specific look at T&D deferral values of DSG in its Austin Energy study, where it had specific distribution system costs for discrete sections of the city's distribution system.[56]

In Vermont, the Public Service Department took a reliability-focused approach. Noting that T&D upgrades are driven by reliability concerns, the Department determined that the "critical value is how much generation the grid can rely on seeing at peak times." To capture this benefit, the Department calculated a "reliability" peak coincidence value by calculating the average generator performance of illustrative generators for June, July and August afternoons.[57] The resulting number reflects the percentage of a system's nameplate capacity that is assumed to be available coincident with peak, as if it is "always running or perfectly dispatchable."[58] Accordingly, the generation system receives the same treatment as firm capacity in terms of value for providing T&D upgrade deferrals at that coincident level of output.

The risk of the Vermont approach is that it may overstate the ability of certain generators to provide actual deferral of T&D upgrades, since system planners often require absolute assurance that they could meet load in the event that a particular distributed generation unit went down. Another apparent weakness of this approach is the inability to target or identify location-specific values in the dynamic, granular nature of the distribution system.

T&D Capacity Value Summary. Distributed solar systems provide energy at or near the point of energy consumption. When they are generating, the loads they serve are therefore are less dependent on T&D services than other loads. In addition, because DSG provides energy in coincidence with a key driver of consumption—solar insolation—these resources can reduce wear and tear. Calculating the T&D benefits of DSG requires data that allows estimation of marginal T&D energy and capacity related costs. Ideally, utilities will collect location-specific data that can support individualized assessment of DSG system value. In the absence of such data, system-wide estimations of T&D offset and deferral value can be used with reasonable confidence.

5. Calculating grid support (ancillary) services

Grid support services, also referred to as ancillary services in many studies, include VAR support, and voltage ride-through. Existing studies often include estimates of ancillary services benefits as well as costs associated with DSG, as reported in the RMI 2013 Study. Costs, also called grid integration costs, are discussed below.

Currently, DSG systems utilize inverters to change direct current to alternating current with output at a set voltage and without VAR output, and with the presumed functionality of disconnecting in the event of circuit voltage above or below set limits. This disconnection feature has become a concern, as a voltage dip with the loss of a major utility generator could lead to thousands of inverters disconnecting DSG systems, reducing voltage inputs and exacerbating the problem. In practice, inverters could be

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[57] Vermont Study at p. 19 (The Department looked at ten two-axis tracking solar PV systems, four fixed solar PV systems, and two small wind generators.).
[58] *Id.* at p. 19.

much more functional or "smart"; indeed Germany is in the process of changing out hundreds of thousands of inverters to achieve added functionality.

Because U.S. electrical codes generally preclude inverters that provide ancillary services, many valuation studies have concluded that no ancillary service value should be calculated. While that approach had some merit in the past, when more versatile inverters where generally unavailable and regulatory change seemed far off, the present circumstances warrant a near-term recognition of ancillary services value. With proof of the viability of advanced inverters, it is highly likely that advanced inverters will be standard in the next few years, and ancillary services will be provided by DSG.

A group of Western utilities and transmission planners recently issued a joint letter on the issue of advanced inverters, calling for the deployment as soon as feasible to avoid the sort of cascading problem described above, which could lead to system-wide blackouts.[59] With the utilities themselves calling for advanced inverter deployment, and costs expected to be only $150 more than current inverters, there will be good reason to collect the data and develop the techniques to quantify ancillary services benefits of DSG. Modeling these ancillary services is important to inform policy decisions such as whether to require such technology as a condition of interconnection, and under what circumstances.

6. *Calculating financial services: fuel price hedge*[60]

DSG provides a fuel cost price hedge benefit by reducing reliance on fuel sources that are susceptible to shortages and market price volatility. In addition DSG provides a hedge against uncertainty regarding future regulation of greenhouse gas and other emissions, which also impact fuel prices. DSG customer exports help hedge against these price increases by reducing the volatility risk associated with base fuel prices—effectively blending price stability into the total utility portfolio.

The ideal method to capture the risk premium of natural gas uncertainty is to consider the difference between an investment with "substantial fuel price uncertainty" and one where the uncertainty or risk has been removed, such as through a hypothetical 30-year fixed price gas contract. As CPR explains, a utility could quantitatively set aside the entire fuel cost obligation up front, investing the dollars into a risk free instrument while entering into natural gas futures contracts for future gas needs.[61] Performing this calculation for each year that DSG operates isolates the risk premium and provides the value of the price hedge of avoiding purchases involving that risk premium.

Interestingly, utilities often used to hedge against fuel price volatility, but do less such hedging now. That leads some utilities to conclude that since the fuel price hedge benefit is not avoiding a utility cost, it should not be included. In practice, the risk of fuel price volatility is falling on customers even if the utility is not mitigating the risk. Reducing that risk has value to utility customers, even if the utility would not otherwise protect against it.

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[59] *See* L. Vestal, *Utility Brass Call for Smart-Inverter Requirement on Solar Installations*, California Energy Markets No. 1244, at p. 10, August 11, 2013.
[60] Clean Power Research now uses the term "Fuel Price Guarantee" in order to distinguish this benefit from traditional utility fuel price hedging actions.
[61] CPR 2012 MSEIA Study at p. 31.

7. *Calculating financial services: market price response*

Another portfolio benefit of DSG is measured in reductions to market prices for energy and capacity. By reducing demand during peak hours, when the price of electricity is at its highest, DSG reduces the overall load on utility systems and reduces the amount of energy and capacity purchased on the market. In this way, DSG reduces the cost of wholesale energy and capacity to all ratepayers.[62] This benefit is not captured by E3's methodology; it is reflected in CPR's most recent Pennsylvania and New Jersey study, where it is illustrated and explained in much greater detail.[63]

The premise of this benefit is that total expenditures on energy and capacity are less with DSG generation than without. The total expenditure, as CPR explains, is the current price of power times the current load at any given point in time. Because the amount of load affects the price of power, a reduced load condition, such as occurs as a result of DSG generation, reduces the market price of all other power purchases at those times.[64] While this change in market price is incrementally small, it represents a potentially significant system-wide benefit. This means that all customers, including non-solar customers, enjoy the benefit of lower prices during these reduced load conditions. As CPR notes, however, the reduction in price cannot be directly measured, as it is based on a hypothetical of what the price would have been without the load reduction, and must be modeled. The total value of market price reductions is the total cost savings calculated by summing the savings over all time periods during which DSG operates.[65] A similar analysis for capacity market prices can be conducted as well.

8. *Calculating security services: reliability and resiliency*

Particularly with the extended blackouts from Hurricane Sandy in 2012, a value is being attributed to added reliability and resiliency due to DSG, at both the grid and the individual customer levels. For grid benefits, this value in particular is difficult to quantify; it depends on the assumed risk of extended blackouts, the assumed cost to strengthen the grid to avoid that risk, and the assumed ability of DSG to strengthen the grid. With utility generation and T&D out of service, DSG can only do so much, and storm conditions often occur during periods of limited sunshine, so it is particularly hard to determine what DSG can do in this regard.

The ancillary services benefit discussed earlier is closely related to this benefit when considering the potential for the grid as a whole to continue operation. Even at the level of a circuit outage, the ancillary services benefit is capturing the value of providing VAR support and voltage ride-through. Arguably, the ancillary services benefit captures this level of grid support.

On the other hand, CPR noted in its first Austin Energy study that reliability and resiliency are very real DSG benefits at the individual customer level. The hospital with traditional backup generation powers up during an outage, and can be supported during a prolonged outage by the addition of DSG. Instead of relying entirely on the traditional generation and a substantial fuel supply, it can get by with less fuel. Likewise the

[62] *Id.* at 15.
[63] *Id.* at pp. 33-43.
[64] CPR 2012 MSEIA Study at p. 34.
[65] *Id.* at p. 36.

residential customer with a medical condition requiring certainty can rely on DSG plus battery storage rather than a generator.

To the extent that utilities have an obligation to provided heightened reliability to vulnerable customers, DSG can be counted as avoiding those utility costs. On a larger scale, to the extent that customers enjoy greater reliability than the utility would otherwise provide, that is a benefit to participating customers that can be included.

9. _Calculating environmental services_

A. Utility avoided compliance costs. The cost of complying with regulatory and statutory environmental requirements is a real operating expense of a generating plant and should be included in the avoided cost of generation. This avoided cost typically is included in the studies as a direct utility cost. In the CPUC's 2010 CSI Impact Evaluation report, conducted by Itron, the CSI general market program and the Self-Generation Incentive Program ("SGIP") were estimated to be responsible for reducing over 400,000 tons of CO_2 emissions in 2010. Additionally, the report estimated that the CSI general market program and the SGIP provided over 52,000 pounds of PM_{10} and over 92,000 pounds of NOx emissions reductions in 2010.[66] These reductions can be quantified and calculated against the market price for the relative compliance instrument. To the extent these values are fully reflected in the cost of the avoided energy, they should not be counted again in a DSG valuation analysis. It is important to account for only residual environmental compliance costs in estimating the benefit of DSG.

While certain emissions credit markets will be geographically tied to a small area with no established compliance market, the markets for NOx, SOx, and CO_2 are more readily identified and quantified with publicly available sources. Accordingly, any study of DSG should include the value of avoided compliance costs reflected in air emissions, land use, and any consumption and discharge costs associated with water.

Likewise, utilities in states with Renewable Portfolio Standards ("RPS") avoid RPS compliance costs due to DSG. For example, if a utility must comply with a 20% RPS and has a billion megawatt hours ("MWh") of annual load, it has to secure 200 million MWh of renewable generation. If instead, 100 million MWh is generated by DSG facilities, the utility's annual load is reduced by that amount and its RPS compliance obligation is reduced by 20 million MWh. The utility's cost of procuring those 20 million MWh should be considered, to the extent that the procurement is greater than the utility's avoided natural gas energy and capacity costs already attributed to those 20 million MWh.

Quantification of societal benefits is particularly difficult and controversial. Regarding environmental benefits, avoided utility compliance costs capture what society has decided are the proper tradeoffs of electricity generation for pollution, but society recognizes additional value related to not generating electricity from fossil generation in the first place. If DSG within a given utility service territory avoids a 100 million MWh of gas-fired generation, the utility avoids paying for the required clean up the emissions

[66] *California Solar Initiative 2010 Impact Evaluation* (California Public Utilities Commission), prepared by Itron, at p. ES-2, 2011, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

that never occurred. However, had the utility generated those 100 million MWh, millions of pounds of pollutants would have gotten past the required emissions controls, and not emitting all of those pollutants is a significant benefit to the society.

While most utility avoided costs benefit the utility's ratepayers directly, societal benefits tend to be spread beyond the utility's customers. Job creation can be expected to center in the utility's service territory, but will also lead to jobs in adjoining service territories. Emissions benefits are even more dispersed. The benefits are regional or global, with utility generation often far removed from utility customers. This is the traditional "tragedy of the commons[67]" problem, but on a global scale. As with the problem of colonial farmers not having an incentive to care for the commons on which their cows grazed, utilities use the environment but have no incentive to care for it beyond what is legally required. By recognizing the value of not emitting pollutants in a DSG valuation study, analysts capture this value that utilities would otherwise ignore. To say that this benefit is realized by society, but somehow not by utility customers, is to ignore the reality that society is made up of utility customers.

Again, we use the benefits categories outlined in the RMI 2013 Study, of which the last three address societal benefits and are listed here.

B. Carbon. The RMI 2013 Study breaks out carbon as a separate avoided cost, based on the significant uncertainty of carbon regulation. On the one hand, carbon markets and restrictions on carbon emissions have been frequently discussed, and tied to climate change. On the other hand, almost no carbon restrictions are currently in place, despite all of the discussion. Studies now five years old that presumed carbon costs by 2013 have been proven wrong. However, with the establishment of a carbon market in California, and the continuation of carbon markets in Europe, the likelihood of carbon costs throughout the U.S. is well beyond zero.

Even in the absence of a carbon market or carbon restrictions, the benefits of not emitting carbon are considered to be real by many people. While some have touted the benefits of carbon for plant life, the widespread view appears to be that emitting more carbon has a negative impact. One way to approach this is to consider what customers are willing to pay for reduced emissions of both carbon and other matter. For instance, Austin Energy uses the premium value for their GreenChoice® green power product in the absence of compliance cost information in its Value of Solar rate.

Another carbon valuation option is to use the added utility cost to comply with RPS targets. The argument for this approach is that if society has determined that a 20% RPS is appropriate, and renewable energy costs an extra $10 per MWH to procure, then it would presumably value additional avoided emissions (both carbon and other matter) at the same rate. However, RPS systems are compliance systems that integrate price impact controls, credit trading schemes, and other features that impact compliance certificate prices without direct relationship to the value of associated emissions reductions. Caution should be used in applying a regulatory system designed to minimize the cost of compliance with an effort to accurately value benefits net of costs.

[67] G. Hardin, "The Tragedy of the Commons," Science 13 December 1968: 1243-1248. Available at: http://www.sciencemag.org/content/162/3859/1243.full?sid=f031fb58-2f56-4c25-ac0e-d802771c92ef

Where a state has a RPS mandate for its utilities, DSG provides a dual benefit. First, it lowers the number of retail sales that comprise the compliance baseline. Second, it results in the export of 100% renewable generation to the grid to offset some mix of renewable and fossil-fuel generation being produced to meet customer load.[68] The first benefit was discussed above, under avoided utility compliance costs. The second benefit accounts for the fact that energy exports from DSG are 100% renewable generation and arguably should be valued at 100% of the RPS value for purposes of a cost-benefit study.[69]

Another way to look at this is to say that all exports from a DSG system should receive the value of a market-priced renewable energy certificate, even where such a generator cannot easily create a tradable certificate.[70] This is justified because DSG exports help meet other customers' load on the utility's grid with 100% renewable energy and displace grid delivered electricity, which is only partially renewable. If a state has an RPS of 33% renewables, as does California, then DSG exports give rise to at least a 67% improvement in the renewable component of electricity.[71]

C. Airborne Emissions Other than Carbon and Health Benefits. Exceeding utility compliance with air regulations can be taken into account in a manner akin to that described for valuation of avoided carbon emissions. The public health impacts of fossil fuel generation have been well documented, though not well reflected in electricity pricing. In particular, air pollution can increase the severity of asthma attacks and other respiratory illnesses in vulnerable populations living in close proximity to fossil fuel-fired plants. Impacts on crops and forest lands have also been documented.

DSG reduces fossil fuel generation, especially from less efficient peaker plants and potentially from thermal plants that emit higher levels of pollution during startup operations. We are not aware of a dominant methodology, but note that public health literature will continue to grow in the area of recognizing and quantifying the public health impacts of electric generation, including health impacts related to climate change. Valuing emissions of carbon and other matter based on green energy pricing programs or RPS compliance costs, as described earlier, is an effective way to capture this benefit. Even outside of states with such programs, the value of reduced emissions is not zero; the value ascribed by nearby states with programs could serve as a proxy.

D. Avoided Water Pollution and Conservation Benefits. The utility industry uses and consumes a substantial portion of the nation's freshwater supplies for thermoelectric generation.[72] The benefit of not using the water for fossil-fuel generation should be

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[68] A third benefit associated with reducing overall market costs for renewable energy certificates may also manifest with increased DSG penetration.
[69] Crossborder 2013 California Study at pp.18-21.
[70] For example, owners of California NEM systems rarely bother to establish RECs related to their output given required documentation, and the treatment of RECs from NEM systems in a lower value "bucket" than RECs from systems with in-state wholesale sales to utilities.
[71] Crossborder 2013 California Study at p. 18.
[72] *How It Works: Water for Energy* (Union of Concerned Scientists), July 2013, *available at* http://www.ucsusa.org/clean_energy/our-energy-choices/energy-and-water-use/water-energy-electricity-overview.html.

based on the value of the water to society, that is, the value of conserving water for other beneficial uses.

Valuing water is intrinsically difficult. The tangle of water rights laws among the states complicate the determination of water value. To the extent that utilities have specific contracts for delivery or withdrawal of water to serve particular plants, it is likely that those expenses are already captured as an operating expense of the plant, but those are often at historic, ultra-low rates. Where a plant uses potable water, the value should be based on what society is willing to pay for that water. Likewise, where a plant is using non-potable, reclaimed water for cooling purposes, the appropriate value might be the price that someone would pay for an alternate use, such as irrigation.

The value to society of conserving water, which is of growing importance in water constrained regions of the country, is not adequately captured by the contract price for water or in the retail price that one would pay for an alternate use. We are not aware of a dominant methodology for measuring the conservation value of water, but this value should be considered as utilities consume a tremendous amount of water each year and will be increasingly competing for finite water resources. Avoiding the increased risk associated with maintaining secure, reliable, and affordable supplies of water is a benefit that DSG, with its 30-year expected operating life, delivers to all customers of the utility system.

10. <u>Calculating social services: economic development</u>

Installation and construction associated with onsite generation facilities is inherently local in nature, as contractors or installers must be within reasonably close geographic proximity to economically install a system and be present for building inspections. Accordingly, the solar industry creates local jobs and generates revenue locally. Economic activity associated with the growing rooftop solar industry creates additional tax revenue at the state and local levels as installers purchase supplies, goods and other related services subject to state and local sales tax, and pay payroll taxes. Locally spent dollars displace those frequently sent out of state for fuel and other supplies.

Taking a conservative approach, CPR's Pennsylvania and New Jersey study focused solely on tax enhancement value, which derives from the jobs created by the PV industry in those states. CPR used representative job creation numbers from previous studies in Ontario and Germany that quantify the number of jobs created by installing a unit of solar PV. CPR used assumptions that construction of solar PV involves a higher concentration of locally traceable jobs than construction of a centralized CCGT plant and determined the net local benefit of a solar project on the economy.

There remains a legitimate regulatory policy question of whether economic development benefits should be considered in calculating the value of DSG for use in setting electricity rates, or avoided cost calculations, even though there is a long history of economic development factors influencing commercial rates and line-extension fees. In any event, the economic development and tax base benefits of DSG deployment and operation should be consider when evaluating the societal cost-effectiveness of the technology and policies to support it.

Checklist of Key Requirements for a Thorough Evaluation of DSG Benefits

- ☑ **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
- ☑ **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
- ☑ **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
- ☑ **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
- ☑ **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for their use; ancillary services will almost certainly be available in the near future. Modeling the costs and benefits of ancillary services can also inform policy decisions like those related to interconnection technology requirements. and provides a hedging benefit.
- ☑ **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.
- ☑ **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase for less, saving money.
- ☑ **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.
- ☑ **The utility's avoided environmental compliance costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture those pollutants.
- ☑ **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, and should not be ignored or not quantified.

V. Recommendations for Calculating the Costs of DSG

Distributed solar generation comes with a variety of costs. These include the costs for the purchase and installation of the DSG equipment, the costs associated with interconnecting DSG to the electric grid, the costs of incentives, the cost associated with administration and billing, and indirect costs associated with lost revenues and other system-wide impacts. As with cost of service regulation in general, the important principles of cost causation and cost allocation are critical in dealing with DSG costs as well.

DSG cost estimation depends on the perspective from which one seeks to examine policies. Some costs, depending on perspective, should not be treated as costs in a DSG valuation study at all. For example, the cost of a DSG system net of incentives and compensation that the individual solar customer ultimately bears—the net investment cost, does not impact other customers. Whether a customer pays $100,000 or $20,000 for a five kilowatt ("kW") DSG system, the avoided utility costs and the societal benefits are unchanged.

In general, solar valuation studies address costs in varying degrees according to the aim of the individual study. A convenient way to characterize solar costs is according to who bears them. Costs relevant to determining value or cost effectiveness can generally be grouped into three categories:

1. Customer Costs—Customer costs are costs incurred by or accruing to the customers who use DSG. These include purchase and installation costs, insurance costs, maintenance costs, and inverter replacement, all net of incentives or payments received.
2. Utility and Ratepayer Costs—Utility and ratepayer costs are costs incurred by the utility and ratepayers due to the operation of DSG systems in the utility grid. These include integration and ancillary services costs, billing and metering costs, administration costs, and rebate and incentive expenses. In NEM valuation studies, utility lost revenues are potentially a significant utility cost, under the assumption that there are no other mechanisms to adjust for these losses.[73]
3. Decline in Value for Incremental Solar Additions at High Market Penetration—A number of studies also identify modeled impacts associated with significant penetration of solar on the utility system. Most studies characterize low penetration as less than 5% of peak demand or total energy met by solar generation, and characterize high penetration as 10%-15% or more. These

[73] Lost revenues arise when market penetration of consumption-reducing measures like energy efficiency and distributed generation have sales impacts that exceed those forecasted in the last rate-setting procedure, and only last until the next rate-setting, when a true-up can occur. Between rate cases, trackers or other mechanisms to mitigate impacts of regulatory lag can also be installed. Valuation studies themselves do not dictate whether lost revenues occur or are recovered. This is a function of tariff design. In some jurisdictions, for example, stand-by charges are used to adjust for revenue losses under NEM. In others, Buy All-Sell All arrangements or Net Billing models are used.

impacts can be accounted for as a cost or as an adjustment to value credit for solar energy when long-term impacts are considered.

When evaluating the cost-effectiveness of NEM, most utilities have access to cost-of-service data that can measure energy-related impacts. As noted earlier, the most direct and obvious source of potential cost or benefit of NEM policy is the mechanism that sets NEM customers apart from general ratepayers—the ability to use electricity not consumed instantaneously (i.e., exported energy) against future purchases of electricity in the form of a kWh or monetary bill credit. The value that customers derive from these bill credits is solely assignable to NEM as a policy, as distinguished from changes in behind-the-meter consumption that could occur under PURPA, in the absence of NEM policy. Accordingly, it is only appropriate to examine the net value of exports, and not behind the meter consumption, as a cost to non-participating ratepayers. It is also appropriate to note that NEM export costs are likely different depending on the class of customer generating excess solar energy. The good news is that the easy starting point for calculating NEM export energy costs is the monthly sum of the bill credits appearing on the customer bill, already adjusted by customer class. These credit costs can then be netted against the value of avoided produced or purchased energy.

1. Recommendations for calculating customer costs

Most value of solar studies focus on utility, ratepayer, and society costs, but not private costs. Therefore, these studies do not address customer investments or expenses in DSG. On the other hand, these costs are part of the total cost effectiveness of solar and have been addressed in broader societal perspective studies or in evaluating cost effectiveness for a solar incentive program. NEM and VOST programs are not intended to be incentive programs, but rather to fairly compensate customers for DSG.

When customer costs are included for a broader societal test, a major challenge in evaluating forward-looking solar customer costs associated with a long-term policy relates to accurately predicting the market prices for solar systems and installation as well as maintenance costs.

Regarding customer O&M costs, NREL has estimated costs between 0.05 and 0.15 cents per kWh.[74] E3 estimates customer O&M costs at $20 per kW with an escalator of .02% per year, factors inverter replacement at $25 per kW, once every 10 years, and estimates insurance expenses at $20 per kW, escalating at .02% per year.[75] Together, these O&M costs are fractions of a cent when converted to kWh, in line with the NREL estimate.

As noted, customer costs are rarely relevant to DSG policy valuation studies. The relevant question when evaluating DSG programs is what the net effect is on other utility customers.

2. Recommendations for calculating utility costs

[74] *Photovoltaics Value Analysis* (National Renewable Energy Laboratory), February 2008, *available at* http://www.nrel.gov/analysis/pdfs/42303.pdf.

[75] *Technical Potential for Local Distributed Photovoltaics in California: Preliminary Assessment* (Energy & Environmental Economics, Inc.), March 2012 ("E3 Technical Potential Study 2012"), *available at* http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf.

The most significant utility cost for NEM program valuation purposes is avoided revenue. A customer who used to pay $1000 per year to her utility and then installed a NEM system and cut her bills to only $200 per year is seen as costing the utility $800 of lost revenue. Again, to the extent that the customer could install the same system under PURPA and reduce her bill to $300 per year, the net cost of the NEM program would only be $100, representing the extra savings that she realized due to the NEM program. For a VOST program, the intent is to determine the value of the benefits and credit that amount to customers for all generation. In effect, the cost of the program is automatically equated to the benefits of the program, net of charges for consumption or network services.

The second largest utility or societal cost of DSG programs is the cost of incentives, though this cost is declining rapidly. Incentive costs are direct costs when the utility provides the funding from ratepayers, but are indirect when considering taxpayer-funded incentives. While incentive costs are real, they are primarily justified on market-stimulation bases, and scheduled to expire in a matter of years. Given that independent rationale for incentives, incentive costs are generally not included in DSG valuations. As the installed cost of DSG has declined, the need for incentives and rebates has diminished, with the California market reaching the end of its state incentive program almost entirely, and federal incentives slated to end in 2016.

Integration costs are the third most important utility cost for NEM programs, and the leading factor for value of solar studies addressing utility costs. Integration costs include the direct costs associated with administration of utility functions associated with distributed solar systems, rebates and incentives, and other administrative tasks. Direct costs can be addressed as a cost or as a decrement to the benefits of DSG, since these costs enable the benefits.

Reports of utility costs vary most significantly with the assumed solar penetration rate used in the study. Integration costs are variously labeled as "integration costs," "grid support expenses," or "benefits overhead." Estimates of these costs range from 0.1 to 1 cent per kWh in studies that attempt to account for increased variability in the overall generation mix and resulting increases in ancillary services costs starting from very low solar penetration rates. Solar integration costs for a 15% market penetration level were estimated at 2.2 to 2.3 cents per kWh by Perez and Hoff, based on an analysis that focuses on the need and cost of storage to complement solar intermittency in order to provide firm capacity.[76] Navigant and Sandia performed an assessment of high penetration of utility scale solar in 2011 and estimated integration costs associated with increasing production to account for solar variability at between 0.31 cents for low penetration and 0.82 cents for higher penetration of roughly one gigawatt of installed solar.[77]

In states like California, where utilities are prohibited from charging solar customers for interconnection costs or upgrades, interconnection costs may be a substantial source of costs directly assignable to a DSG program. Where this is the case, it is necessary to have real, disaggregated data that tracks the exact interconnection costs of DSG. In

[76] CPR 2012 MSEIA Study at p. 47.
[77] *Large Scale PV Integration Study* (Navigant), July 2011, *available at* http://www.navigant.com/insights/library/energy/2011/large-scale-pv-integration-study/.

the E3 study, for example, utilities did not have sufficient detail on interconnection costs in 2009 to provide a clear or transparent picture on the extent of those costs, or whether the costs incurred were reasonable and not blended in with other upgrades that would have occurred without the solar generator's interconnection. Interconnection costs should, in theory, be clearly identifiable through utility-provided data. In analyzing the value of distributed solar, these costs should also be amortized against the useful life of the measures.

In states where customers are responsible for interconnection costs and upgrades, however, this would not be a cost assignable to DSG policy. As with other customer costs, this is not a cost borne by the utility and should not be factored into an evaluation of the impact of a DSG policy on other customers.

Experience and more sophisticated modeling will be required to understand the shape and ultimate level of the integration cost curve. While integration costs are likely low at low market penetration levels, they are also likely to increase with market penetration. But these increases may decline as solar systems become more widely dispersed and as utilities begin targeting deployment to high-value locations within the grid. In addition, increased deployment of other distributed technologies, such as electric vehicles, distributed storage, load control, and smart grid technologies will impact the costs associated with larger scale DSG deployment.

The billing and administration costs associated with DSG encompass the one-time setup expenses of processing and verifying applications and the ongoing expense of administering unique features of solar customer bills. In states with modest numbers of solar customers, it is not uncommon to manually adjust solar customer bills, with associated incremental costs. Depending on the utility's accounting practices and billing capabilities, solar-specific billings cost should be relatively easily segregated and allocated. In states with automated processes, the ongoing incremental costs of administering solar customer accounts should be, as was determined in the Vermont study, nearly zero.[78]

In some cases, utilities will incur costs directly associated with DSG that are not fairly assignable to DSG policy. For example, in Texas, renewable energy generators under one MW are classed as "microgenerators," subject to registration and reporting requirements under the state's renewable energy portfolio standard law.[79] To the extent that the utility acts as a program manager and aggregator of renewable energy certificates assigned by solar generators, these costs are not fairly assigned to NEM or other solar promotional program unless also offset by the value of the assigned certificates.

3. Recommendations for calculating decline in value for incremental solar additions at high market penetration

The incremental positive value of additional solar deployment within a particular utility service territory is anticipated to decline as solar penetration levels increase. There are two major drivers of these impacts, which are not technically costs, but actually

[78] Vermont Study at p. 15.
[79] *See* 16 Tex. Admin. Code 15, *available at* http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.173/25.173.pdf.

decrement adjustments that impact value of solar in the context of expanding markets and higher solar penetration.

These impacts address the value of additional deployments and not past installations, and not replacement installations. The two major drivers are the expected reduction in capacity credit for solar and reduced peak energy value as market penetration increases. Capacity credits for solar are typically higher than capacity factor due to good solar coincidence with peak demand periods. However, as more solar is added to a system, the difference between peak and non-peak demand dissipates. Without storage, solar has a limited ability to reduce a system peak that is essentially shifted forward into evening hours. As a result, the incremental capacity benefit of solar is reduced for incremental additions as penetration increases. This impact could reduce capacity credit by 20-40% as penetration rates approach 15%.[80]

To the extent that solar energy is generated at periods of high utility cost, it provides great value. As the penetration rate of solar increases, peak market prices are likely suppressed, reducing the value of incremental solar energy. E3 estimated the reduced energy value at 15% over ten years in a study for California.[81]

Much work is needed in measuring and modeling the impact of high penetrations of DSG to address exactly how much DSG creates high penetration impacts, and inserting this clarity in valuation and cost effectiveness studies. Most states receive less than 0.5% of peak energy from distributed solar generation, while most studies looking at high penetration model levels at 10-15%. As noted earlier, the most relevant costs to consider are those that will occur at more modest penetrations. For example, if capacity benefits decline significantly at higher penetrations, that does not justify finding low capacity benefits at early stages.

Other important issues to be addressed include the impacts of different assumptions regarding geographic region, system size, and long-term changes in energy demand. It is important to note that both the capacity credit and energy value deterioration could be mitigated through consideration of energy sales from areas of high solar penetration to areas of lower penetration. For example, utilities facing near term surplus capacity situations could incur short-term lost revenues that could be mitigated over the period that solar systems operate, creating the potential for net benefits over that longer term.

[80] *See* LBNL Utility Solar Study 2012, *supra*, footnote 13.
[81] *See* E3 Technical Potential Study 2012, *supra*, footnote 74.

Checklist of Key Requirements for a Thorough Evaluation of DSG Costs

- ☑ **Is lost revenue or utility costs the basis of the study?** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
- ☑ **Assumptions about administrative costs must reflect an industrywide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
- ☑ **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
- ☑ **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

VI. Conclusion

Valuations vary by utility, but valuation methodologies should not. In this report IREC and Rabago Consulting LCC suggests a standardized approach for calculating DSG benefits and costs that we hope proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Please see the mini-guide at the end of this report for a quick reference guide to the recommendations in this report.

REGULATOR'S MINI-GUIDEBOOK

Calculating the Benefits and Costs of Distributed Solar Generation

Valuations vary by utility, but valuation methodologies should not. IREC and Rábago Energy LLC suggest a standardized approach for calculating DSG benefits and costs in the white paper "A REGULATOR'S GUIDEBOOK: Calculating the Benefits and Costs of Distributed Solar Generation." We hope that this paper proves helpful to regulators as they embark on commissioning or reviewing valuation studies. Below is a high-level summary of the recommendations in the white paper. Please see the full report for more detail per section.

A. KEY QUESTIONS TO ASK AT THE ONSET OF A STUDY

Q1: WHAT DISCOUNT RATE WILL BE USED?

Recommendation: We recommend using a lower discount rate for DSG than a typical utility discount rate to account for differences in DSG economics.

Q2: WHAT IS BEING CONSIDERED – ALL GENERATION OR EXPORTS ONLY?

Recommendation: We recommend assessing only DSG exports to the grid.

Q3: OVER WHAT TIMEFRAME WILL THE STUDY EXAMINE THE BENEFITS AND COSTS OF DSG?

Recommendation: Expect DSG to last for thirty years, as that matches the life span of the technology given historical performance and product warranties. Interpolate between current market prices (or knowledge) and the most forward market price available or data that can accurately be estimated, just as planners do for fossil-fired generators that are expected to last for decades.

Q4: WHAT DOES UTILITY LOAD LOOK LIKE IN THE FUTURE?

Recommendation: Given that NEM resources are interconnected behind customer meters, and result in lower utility loads, the utility can plan for lower loads than it otherwise would have. In contrast, other DSG rate or program options involving sale of all output to the utility do not reduce utility loads, but rather the customer facilities contribute to the available capacity of utility resources.

Q5: WHAT LEVEL OF MARKET PENETRATION FOR DSG IS ASSUMED IN THE FUTURE?

Recommendation: The most important penetration level to consider for policy purposes is the next increment: what is likely to happen in the next three to five years. If a utility currently has 0.1% of its needs met by DSG, consideration of whether growth to 1% or even 5% is cost-effective is relevant, but consideration of whether higher penetrations are cost-effective can be considered at a future date.

Q6: WHAT MODELS ARE USED TO PROVIDE ANALYTICAL INPUTS?
Recommendation: Transparent input models that all stakeholders can access will establish a foundation for greater confidence in the results of the DSG studies. When needed, the use of non-disclosure agreements can be used to overcome data sharing sensitivities.

Q7: WHAT GEOGRAPHIC BOUNDARIES ARE ASSUMED IN THE ANALYSIS?
Recommendation: It is important to account for the range in local values that characterize the broader geographical area selected for the study. In some cases, quantification according to similar geographical sub-regions may be appropriate.

Q8: WHAT SYSTEM BOUNDARIES ARE ASSUMED?

Recommendation: It may also be appropriate to consider impacts associated with adjacent utility systems, especially at higher (above 10%) penetration levels of DSG. [82]

Q9: FROM WHOSE PERSPECTIVE ARE BENEFITS AND COSTS MEASURED?

Recommendation: We recommend that ratepayer and societal benefits and costs should be assessed.

Q10: ARE BENEFITS AND COSTS ESTIMATED ON AN ANNUALIZED OR LEVELIZED BASIS?

Recommendation: We recommend use of a levelized approach to estimating benefits and costs over the full assumed DSG life of 30 years. Levelization involves calculating the stream of benefits and costs over an extended period and discounting to a single present value. Such levelized estimates are routinely used by utilities in evaluating alternative and competing resource options.

B. DATA SETS NEEDED FROM UTILITIES

- ☑ The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the DSG
- ☑ Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of NEM policy
- ☑ Hourly production profiles for NEM generators, including south-facing and west-facing arrays
- ☑ Line losses based on hourly load data, so that marginal avoided line losses due to DSG can be calculated
- ☑ Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit

[82] Mills and Wiser point out that consideration of inter-system sales of capacity or renewable energy credits could mitigate reductions in incremental solar value that could accompany high penetration rates. *See* A. Mills & R. Wiser, *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (Lawrence Berkeley National Laboratory), LBNL-5933E, at p. 23, December 2012 (nt Processes energy credits could *available at* http://emp.lbl.gov/publications/evaluation-solar-valuation-methods-used-utility-planning-and-procurement-processes.

- ☑ Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth
- ☑ Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of DSG, in order to capture the potential for avoiding or deferring circuit upgrades

Note: where a utility or jurisdiction does not regularly collect some portion of this data, there may be methods to estimate a reasonable value to assign to DSG.

C. RECOMMENDATIONS FOR ASSESSING BENEFITS

1. **The following benefits should be assessed:**
    1. Energy
    2. System Losses
    3. Generation Capacity
    4. Transmission and Distribution Capacity
    5. Grid Support Services
    6. Financial: Fuel Price Hedge
    7. Financial: Market Price Response
    8. Security: Reliability and Resiliency
    9. Environment: Carbon& Other Factors
    10. Social: Economic Development
2. **Energy benefits should be based on the utility not running a CT or a CCGT.** It is highly unlikely that DSG will offset coal or nuclear generation. Some combination of intermediate and peaking natural gas generation, with widely accepted natural gas price forecasts, should establish the energy value.
3. **Line losses should be based on marginal losses.** Losses are related to load and DSG lowers circuit loads, which in turn lowers losses for utility service to other customers. Average line losses do not capture all of the loss savings; any study needs to capture both the losses related to the energy not delivered to the customer and the reduced losses to serve customers who do not have DSG.
4. **Generation capacity benefits should be evaluated from day one.** DSG should be credited for capacity based on its Effective Load Carrying Capacity ("ELCC") from the day it is installed. If the utility has adequate capacity already, it may not have taken into account DSG penetration in its planning and overbuilt other generation; the DSG units that are actually operating during utility peaks should be credited with capacity value rather than a plant that is never deployed.
5. **T&D capacity benefits should be assessed.** If the utility has any transmission plans, then DSG is helping to defer a major expense and should be included. On distribution circuits, watch for a focus on circuits serving residential customers, which tend to peak in the early evening when solar energy is minimal. Circuits serving commercial customers tend to peak during the early afternoon on sunny days, and a capacity value should be recognized for them in the form of avoided or deferred investment costs.
6. **Ancillary services should be evaluated.** Inverters that can provide grid support are being mass-produced, and utility CEOs in the United States are calling for

their use; ancillary services will almost certainly be available in the near future. Modeling the benefits and costs of ancillary services can also inform policy decisions like those related to interconnection technology requirements.

7. **A fuel price hedge value should be included.** In the past, utilities regularly bought natural gas futures contracts or secured long-term contracts to avoid price volatility. The fact that this is rarely done now and that the customer is bearing the price volatility risk does not diminish the fact that adding solar generation reduces the reliance on fuels and provides a hedging benefit.
8. **A market price response should be included.** DSG reduces the utility's demand for energy and capacity from the marketplace, and reducing demand lowers market prices. That means that the utility can purchase these services for less, saving money.
9. **Grid reliability and resiliency benefits should be assessed.** Blackouts cause widespread economic losses that can be reduced or avoided in some situations with DSG. As well, customers who need more reliable service than average can be served with a combination of DSG, storage and generation that is less expensive than the otherwise necessary standby generator.
10. **The utility's avoided environmental compliance and residual environmental costs should be evaluated.** DSG leads to less utility generation, and lower emissions of NOx, SOx and particulates, lowering the utilities costs to capture or control those pollutants.
11. **Societal benefits should be assessed.** DSG policies were implemented on the basis of environmental, health and economic benefits, which should not be ignored and should be quantified.

D. RECOMMENDATIONS FOR ASSESSING COSTS

1. **Determine whether lost revenue or utility costs are the basis of the study.** For NEM studies, lost revenue is the standard (what the DSG customer would have otherwise paid the utility). For other studies and even some NEM studies, the cost to serve the DSG customer is addressed instead, which should lead to an inquiry in particular regarding allocation of capacity costs.
2. **Assumptions about administrative costs should reflect an industry-wide move towards automation.** With higher penetration, costs per DSG customer tend to decline, so administrative costs should assume automation of processes.
3. **Interconnection costs should not be included.** If the DSG customer pays for the interconnection, this should not be included as a cost to the utility. As well, the utility's interconnection costs should be compared to national averages to determine whether they are reasonable.
4. **Integration costs should not be based on unrealistic future penetration levels.** Studies tend to find minimal grid upgrade requirements at DSG penetrations below a few percent. Looking ahead to what the grid might need to accommodate 50% penetration unnecessarily adds costs that are not actually being incurred.

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A Review of the Value of Solar Methodology with a Case Study of the U.S. VOS

Koami Soulemane Hayibo[1], Joshua M. Pearce[2,3,*]

1. Department of Electrical & Computer Engineering, Michigan Technological University, Houghton, MI, USA
2. Department of Materials Science & Engineering, Michigan Technological University, Houghton, MI, USA
3. Visiting Professor of Photovoltaics and Nanoengineering, School of Electrical Engineering, Aalto University, Finland
* pearce@mtu.edu
khayibo@mtu.edu

Abstract

Distributed generation with solar photovoltaic (PV) technology is economically competitive if net metered in the U.S. Yet there is evidence that net metering is misrepresenting the true value of distributed solar generation so that the value of solar (VOS) is becoming the preferred method for evaluating economics of grid-tied PV. VOS calculations are challenging and there is widespread disagreement in the literature on the methods and data needed. To overcome these limitations, this study reviews past VOS studies to develop a generalized model that considers realistic future avoided costs and liabilities. The approach used here is bottom-up modeling where the final VOS for a utility system is calculated. The avoided costs considered are: plant O&M fixed and variable; fuel; generation capacity, reserve capacity, transmission capacity, distribution capacity, and environmental and health liability. The VOS represents the sum of these avoided costs. Each sub-component of the VOS has a sensitivity analysis run on the core variables and these sensitivities are applied for the total VOS. The results show that grid-tied utility customers are being grossly under-compensated in most of the U.S. as the value of solar eclipses the net metering rate as well as two-tiered rates. It can be concluded that substantial future work is needed for regulatory reform to ensure that grid-tied solar PV owners are not unjustly subsidizing U.S. electric utilities.

Highlights

- Distributed generation solar photovoltaic (PV) economically competitive if net metered in U.S.
- Value of solar (VOS) is becoming preferred method for evaluating economics of grid-tied PV.
- Here review VOS calculations, inputs and sensitivity analysis on all core variables
- Results: VOS eclipses the net metering rate as well as two-tiered rates in US
- Regulatory reform needed: solar PV owners are unjustly subsidizing electric utilities

Keywords: utility policy; photovoltaic; distributed generation; value of solar; net metering; economics

Nomenclature:

B	Burner tip fuel price [$/MMBtu]
C_D	Distribution capacity [MW]
C_G	Utility generation capacity [p.u.]
C_H	Health cost of natural gas [$/kWh]
C_{PV}	PV capacity for year 'n' [kW]

C_T	Transmission capacity [p.u.]
D	Utility Discount rate
D_E	Environmental discount rate
D_H	Heat rate degradation rate
D_{PV}	Degradation rate of PV
E	Environmental cost [$/MMBtu]
F	Utility discount factor
F_E	Environmental discount factor
h	Number of hours in the analysis period
H_C	Heat rate of combined cycle gas turbine [Btu/kWh]
H_{CT}	Heat rate of peaker combustion turbine [Btu/kWh]
H_n	Heat rate for year n [Btu/kWh]
H_P	Heat rate of the plant [Btu/kWh]
H_S	Solar heat rate [Btu/kWh]
i	Number of years in analysis period
I_C	Installation cost of combined cycle gas turbine [$/kW]
I_D	Investment on distribution capacity per year without PV [$]
I_{DP}	Investment on distribution capacity per year with PV [$]
I_P	Installation cost of peaker combustion turbine [$/kW]
K	Growth rate
M	Reserve capacity margin
n	n^{th} year of analysis period
O	Output of the PV [kWh]
$PL1$	1^{st} year load capacity [kW]
$PL10$	10^{th} year load capacity [kW]
Q	Distribution cost [$/kW]
S	PV fleet shape [kW]
S_C	Solar capacity cost [$/kW]
U_C	Utility cost [$]
U_F	Utility fixed operation and maintenance cost [$/kW]
U_P	Utility price [$/kWh]
U_T	Utility transmission capacity cost [$/kW]
U_V	Utility variables operation and maintenance cost [$/kWh]
VOS	Value of solar [$/kWh]
V_x	V_1: Avoided operation and maintenance fixed cost [$] V_2: Avoided operation and maintenance variable cost [$] V_3: Avoided fuel cost [$] V_4: Avoided generation capacity cost [$] V_5: Avoided reserve Capacity cost [$] V_6: Avoided transmission capacity cost [$] V_7: Avoided distribution cost [$] V_8: Avoided environmental cost [$] V_9: Avoided health liability [$]

1. Introduction

Solar photovoltaic (PV) technologies have had a rapid industrial learning curve [1-4], which has resulted in continuous cost reductions and improved economics [5,6]. This constant cost reduction pressure has resulted in a spot price of polysilicon Chinese-manufactured PV modules of only US$0.18/W as of April 2020 [7]. There are several technical improvements, which are both already available and slated to drive the costs further down such as black silicon [8-10]. The International Renewable Energy Agency (IRENA) can thus confidently predict that PV prices will fall by another 60% in the next decade [11]. However, even at current prices, any scale of PV provides a levelized cost of electricity (LCOE) [12] lower than the net metered cost of grid electricity [13] and this will only improve with storage costs declining [14-18]. Specifically, PV already provides a lower levelized cost of electricity [12,19,20] than coal-fired electricity [13,21,22]. In addition, PV technology can be inherently distributed (e.g. each electricity consumer produces some or all of their electricity on site thus becoming ‘prosumers’). Distributed generation with PV has several technical advantages, including improved reliability, reduced transmission losses [23,24], enhanced voltage profile, reduced transmission and distribution losses [25], transmission and distribution infrastructures deferment, and enhanced power quality [26]. As PV prices decline, prices of conventional fossil fuel-based electricity production are increasing due to aging infrastructure [27-29], increased regulations (in some jurisdictions) [30-33], fossil fuel scarcity [34-36], and pollution costs [37-41]. Thus, PV represents a threat to conventional utility business models [42] and there is evidence that some utilities are manipulating rates to discourage distributed generation with solar [43], while others are embracing it such as Austin Texas or the state of Minnesota [44]. Rates structures vary widely throughout the U.S. [45-48] and there has been significant effort to determine the actual value of solar (VOS) electricity.

This shift towards VOS is fueled by criticisms of its predecessor [49], net metering, that is misrepresenting the true value of distributed solar generation [50-52]. VOS is more representative of the electricity cost because under a Value of Solar Tariff (VOST) scheme, the utility purchases part of, or the whole net solar photovoltaic electricity generation from its customers, therefore dissociating the VOST from the electricity retail price [51,53]. Performing a complete VOS calculation, however, is challenging. One of the main challenges is data availability and accuracy [54,55]. Three data challenges have been identified by [55] that are: 1) the time granularity of the solar irradiation data, 2) the origin of the data, modeled versus measured, and 3) the data measurement accuracy. Other challenges faced by utilities while assessing the VOS are which components to include in the calculations, and what calculations method to assess the value of each components [56]. The possible components across the literature that are suggested to be included in a VOS as avoided costs and solar benefits are: **energy production costs** (operation and maintenance) [45-47,57-63], **electricity generation capacity costs** [45-47,50,57-63], **transmission capacity costs** [45-47,50,57-61,63], **distribution capacity costs** [45-47,50,57-63], **fuel costs** [45-47,50,57,60-63], **environmental costs** [45,47,57,58,60-63], **ancillary including voltage control benefits** [47,57-59,63], **solar integration costs** [47], **market price reduction benefits** [47,60], **economic development value or job creation** [46,47,57,60,61], **health liability costs** [57,60,64]**,** and **value of increased security** [47,57]. A guidebook has been developed by the United States’ Interstate Renewable Energy Council (IREC) for the calculation of several of the VOS components [57]. These methods have been further developed by the U.S. National Renewable Energy Laboratory (NREL) [58]. NREL has provided more detailed calculation methods than the guidebook from the IREC with a different level of accuracy. The methods with a higher level of accuracy are more complicated to implement and require a higher level of data granularity. A qualitative study on VOS performed in 2014 suggested the inclusion of all relevant components in a VOS studies [64]. The calculation of the VOS can be done annually, as in the case of Austin Energy [50,53], or can be fixed for a selected period, as per the case of Minnesota state’s VOS (25 years) [45,53]. There are recently an increasing number of studies looking into externality-based components of VOS especially environmental costs and health liability costs [65-67]. This is because a country with high solar PV penetration rate provides a healthy population according to a German study [68]. An estimated average of 1,424 lives could be saved each summer in the Eastern United States, and $13.1 billion in terms of health savings if the total electricity generation capacity in the Eastern United States included 17% of solar PV [69]. For the entire U.S. if coal-fired electricity were replaced with solar generation, roughly 52,000 premature American deaths would be prevented from reduced air pollution alone [70]. Not surprisingly, the latest report from North Carolina Clean Energy Technology Center found out that there are policy changes on VOS across the United States with 46 states, in addition of DC considering making significant changes in their solar policies and might be transitioning to a VOS model in coming years [63].

This indicates VOS is the way of the future for grid integrated PV, but how exactly should solar be valued on the modern grid? In this study the VOS literature is reviewed, and a generalized model is developed taking realistic future avoided costs and liabilities into account from the literature. The approach used here is a bottom-up modeling where the final value of solar to a utility system is calculated. This model factors in the existing parameters, that have been identified in VOS studies in different U.S. jurisdictions. The approach starts from the existing formula to calculate the levelized cost of electricity from solar PV technology [12] and updates the formula by adding the avoided and opportunity costs and the effect of different externalities. The costs considered in the study are: avoided plant operation and maintenance (O&M) fixed cost; avoided O&M variable cost; avoided fuel cost; avoided generation capacity cost, avoided reserve capacity cost, avoided transmission capacity cost, avoided distribution capacity cost, avoided environmental cost, and the avoided health liability cost. The value of solar represents the sum of these costs. Each sub-component of the VOS has a sensitivity analysis run on the core variables and these sensitivities are applied for the total VOS. These sensitivities are limited by the best available data on the variables in the literature and future work is needed to quantify the secondary costs that would lead to an even higher VOS. The conservative results developed here are presented and discussed in the context of aligning policy and regulations with appropriate compensation for PV-asset owners and electric utility customers.

2. Methods/Theory

2.1. Avoided Plant O&M – Fixed Cost (V_1):

The use of solar energy results in a displacement of energy production from conventional energy sources. The avoided cost of plant operation and maintenance (V_1) [$] depends on the energy saved by using solar PV for electricity generation instead of conventional energy generation processes. Equation (1) describes the calculation of the capacity of solar PV (C_{PV}) [kW] throughout the lifetime of the solar PV system. During the first year of operation, the installed solar PV system is considered to not have suffered any degradation. Therefore, the capacity has a value of one. The degradation of the installed solar PV system is expressed by the degradation rate of PV (D_{PV}) and for a marginal year (n), the marginal capacity of the installed PV system for that year would be:

$$C_{PV} = (1 - D_{PV})^n \qquad (1)$$

The fixed O&M cost is directly linked to the need for new conventional electricity generation plants. If the construction of new conventional generators in the location of interest can be avoided, there is no need to include the fixed O&M in the valuation of solar for this location. To calculate the value of the fixed O&M (V_1), the value of the utility cost (U_C) [$] needs to be known first. The utility cost depends on four parameters, the capacity of solar PV (C_{PV}) mentioned above, the utility capacity (C_G) [p.u.], the utility fixed O&M cost (U_F) [$/kW], and the utility discount factor (F). To calculate this utility cost, first the ratio of the capacity of solar to the utility capacity is calculated. This ratio is then multiplied by the utility fixed O&M cost. A discount is applied to the result by multiplying it by the utility discount factor [71]. The discount factor (F) depends on the year and can be calculated by using the discount rate (D). The discount factor for year (n) is [45]:

$$F = \frac{1}{(1+D)^n} \quad (2)$$

The discount rate used in the formula describes the uncertainty and the fluctuation of the value of money in time. The value of the discount rate differs when considered from a utility point of view or a societal point of view and can highly impact the utility cost. While considering the economics of solar PV systems, [57] has suggested the use of a discount rate lower than the value used by the utility.

$$U_C = U_F * \frac{C_{PV}}{C_G} * F \quad (2)$$

The avoided plant O&M fixed cost (V_1) is then calculated by summing the utility cost for all the years included in the analysis period.

$$V_1 = \sum_0^i U_C \quad (3)$$

2.2. Avoided Plant O&M – Variable Cost (V_2):

The utility cost for the avoided variable O&M cost (V_2) [$] is calculated by multiplying the utility variable O&M cost (U_V) [$/kWh] by the energy saved by using solar PV systems or the output of the solar PV system (O) [kWh], and the result is discounted by the discount factor (F).

$$U_C = U_V * O * F \quad (4)$$

The avoided variable O&M (V_2) cost is the sum of the utility cost over the analysis period:

$$V_2 = \sum_0^i U_C \quad (5)$$

2.3. Avoided Fuel Cost (V_3)

Additionally, the calculation of the utility price (U_P) [$/kWh] require the knowledge of the equivalent heat rate of a marginal solar. According to [72], the heat rate [Btu/kWh] describes how much fuel-energy, on average, a generator uses in order to produce 1kWh of electricity. It is typically used in the energy calculation of thermal-based plants and is therefore misleading for the calculation of solar energy production. Since the method evaluates the avoided cost from thermal-based plants, however, it is applied to solar PV generation. The heat rate (H_S) [Btu/kWh] of solar PV or displaced fuel heat rate during the first marginal year is calculated as:

$$H_S = \frac{\sum_0^h (H_p * S)}{\sum_0^h S} \quad (6)$$

In the equation above, the heat rate (H_p) [Btu/kWh] represent the real value of the utility plant's heat rate during the operation hours of the solar PV systems over the analysis period and the parameter (S) [kW] describes the PV fleet shape that is the hourly PV fleet shape production over the hours (h) in the analysis period.

After the heat rate for the first year has been calculated, the heat rate for the succeeding years in the analysis period can be calculated by the following equation [45]:

$$H_n = H_S * (1 - D_H)^n \quad (7)$$

The primary use of heat rates is the assessment of the thermal conversion efficiency of fuel into electricity by conventional power plants. As a result, it is natural to deduce that the rate at which the heat rate (D_H) decreases corresponds to the efficiency lost rate of the power plant [73].

The utility price (U_P) depends on the heat rates and can be calculated once the heat rate is known as:

$$U_P = \frac{B * H_n}{10^6} \quad (8)$$

Another parameter to account for is the burner tip price (B)[$/MMBtu]. The burner tip price describes the cost of burning fuel to create heat in any fuel-burning equipment [74].

The avoided fuel cost (V_3) [$] is calculated in a similar way as the value of the fixed O&M. First, the utility cost is calculated by multiplying the value of the per unit PV output (O) by the utility price (U_P). The result is then discounted by the discount factor. The discount factor used in the case of the avoided fuel cost depends on the treasury yield [45]. The avoided fuel cost is obtained by summing up the utility cost over the analysis period.

$$U_C = U_P * O * F \quad (9)$$

$$V_3 = \sum_0^i U_C \quad (10)$$

2.4. Avoided Generation Capacity Cost (V_4):

The installation of solar systems reduces the generation of electricity from new plants. This is represented by the avoided capacity cost. To calculate the avoided generation capacity cost, the solar capacity cost (S_C) [$/kW] needs to be known. Two variables are essential to evaluate the solar capacity cost, the cost of peaker combustion turbine (I_P) [$/kW] and the installed capital cost (I_C) [$/kW]. The cost of peaker combustion turbine (I_P) is the cost associated with the operation of a turbine that function only when the electricity demand is at its highest. The installed capital cost (I_C) describes the cost of combined cycle gas turbine updated by the cost based on the heat rate. The solar capacity can be calculated as follows [75]:

$$S_C = I_C + (H_S - H_C) * \frac{I_P - I_C}{H_{CT} - H_C} \quad (11)$$

H_{CT} [Btu/kWh] and H_C [Btu/kWh] are respectively the heat rate of the peaker combustion turbine, and the combined cycle gas turbine. After the calculation of the solar capacity cost (S_C), the utility cost can be obtained by first, multiplying the ratio of solar PV capacity (C_{PV}) and utility generation capacity (C_G) by the value of solar capacity cost (S_C). Then, the result is discounted by the discount factor (F) to obtain the final value of the utility cost. And as in the previous cases the value of avoided generation capacity is the sum of the utility cost overs the analysis period.

$$U_C = S_C * \frac{C_{PV}}{C_G} * F \quad (12)$$

$$V_4 = \sum_0^i U_C \quad (13)$$

2.5. Avoided Reserve Capacity Cost (V_5):

The calculation of the avoided reserve capacity cost (V_4) [$] follows the same pattern as the avoided cost of generation capacity. But in this case, the effective solar capacity, that is the ratio of the solar PV capacity (C_{PV}) and utility generation capacity (C_G) is multiply by the solar capacity cost, then the result is multiplied by the reserve capacity margin (M) to obtain the utility costs. After that, the utility cost is discounted as previously described by the discount factor (F). Then, the avoided reserve capacity is calculated by adding up the utility cost over the analysis period [58].

$$U_C = S_C * \frac{C_{PV}}{C_G} * M * F \qquad (14)$$

$$V_5 = \sum_0^i U_C \qquad (15)$$

2.6. Avoided Transmission Capacity Cost (V_6):

The avoided transmission capacity cost (V_6) [$] calculation is also performed similarly to the avoided generation capacity cost. This cost describes the losses that are avoided when electricity does not have to be transported on long distance because of installed solar systems. It is calculated by first multiplying the utility transmission capacity cost (U_T) [$/kW] by the solar PV capacity (C_{PV}). The result is then divided by the transmission capacity (C_T) [p.u.] and the discount factor (F) is applied to obtain the utility cost for a marginal year. The avoided transmission cost is calculated by the sum, over the years in the analysis period, of the corresponding utility costs [76].

$$U_C = U_T * \frac{C_{PV}}{C_T} * F \qquad (16)$$

$$V_6 = \sum_0^i U_C \qquad (17)$$

2.7. Avoided Distribution Capacity Cost (V_7):

The two major variables that influence the avoided distribution capacity cost (V_7) [$] are the peak growth rate (K) and the system wide costs. The system wide costs account for several financial aspects of a distribution plant, among which, overhead lines and devices, underground cables, line transformers, leased property, streetlights, poles, towers etc. [77].

All the deferrable system wide costs throughout a year have been summed up and the result divided by the yearly peak load increase in kW over a total period of a decade to obtain the distribution cost per growth of demand.

The ratio of the 10^{th} year peak load (PL_{10}) [kW] and the 1^{st} year peak load (PL1) [kW] are used in the calculation of the growth rate (K) of demand. The expression of the growth rate (K) is as follows [45,78]:

$$K = ¿ \qquad (18)$$

The distribution capital cost (Q) [$/kW] is utility owned data and depends on the utility, and the growth rate (K) that can be obtained by using the previous formula. An escalation factor is necessary to evaluate the distribution cost for deferral consecutive years [79].

After obtaining the distribution cost (Q) from the utility and growth rate (K) calculated, the distribution capacity (C_D) [kW] can be calculated from the growth rate. The result is then multiplied by the distribution cost and discounted by the discount factor (F) to get the discounted cost for a particular year. The discounted cost for the analysis period can in turn be used to calculate the investment during each year (I_D) [$] of the analysis period [45].

$$I_D = C_D * Q * F \quad (19)$$

When there is no other generation system than solar PV that comprised the installed capacity, the investment per year (I_{DP}) [$] in terms of deferred distribution can be calculated from the investment deferred [45].

$$I_{DP} = C_D * Q * DF \text{ (in terms of deferred distribution)} \quad (20)$$

After obtaining the yearly investment without PV (I_D) and the yearly investment in terms of deferred distribution (I_{DP}), the utility cost can be obtained by dividing the difference between the yearly investment without PV and the yearly investment with PV by the distribution capacity (C_D). This utility cost can be called the deferred cost per kW of solar. This deferred cost per kW of solar is discounted by the discount factor (F), multiplied by the solar PV capacity, and summed up over the analysis period to obtain the avoided distribution capacity cost.

$$U_C = \frac{I_D - I_{DP}}{C_D} * F * C_{PV} \quad (21)$$

$$V_7 = \sum_0^i U_C \quad (22)$$

2.8. Avoided Environmental Cost (V_8):

The three major pollutants that are considered in the calculation of the avoided environmental cost (V8) [$] are: greenhouse gases (GHGs), pollutants sulfur dioxide, nitrogen oxide, and hazardous particulates [80].

The two parameters that influences the cost linked to CO_2 and other greenhouse gasses' emission are the social cost of CO_2 and the gas emission factor [81]. With these two variables, the cost of avoided CO_2 can be calculated in dollars and then the real value linked to this cost is obtained by converting the previously calculated value in current value of dollars. This is done by multiplying the externality cost of CO_2 by the consumer price index (CPI) [82]. The obtained result is then multiplied by the general escalation rate for the following years [80]. The cost of CO_2 for every year is obtained by multiplying the previous value by pounds of CO_2 per kWh. The same logic is applied to the other pollutants to calculate the related costs and the cost related to all three categories of pollutant are added up to get the environmental cost (E) [$/MMBtu].

By multiplying the environmental cost by the solar heat rate (H_S), the utility cost (U_C) is obtained. An environmental discount factor (F_E) is applied to the utility factor. The environmental discount factor (F_E) is defined as follows [83]:

$$F_E = \frac{1}{(1 + D_E)^n} \quad (23)$$

Here, D_E is the environmental discount rate taken from the Social Cost of Carbon report [81].

$$U_C = E * H_S * F_E * O \quad (24)$$

$$V_8 = \sum_0^i U_C \quad (25)$$

2.9. Avoided health liability cost (V_9):

The use of solar PV systems prevents part of the emissions of pollutants from getting into the air. This can in turn result in great health benefits. The harmful pollutants that greatly impact human health are NO_x and SO_2. These two chemicals react with other compounds when they are released in the air to form a heavy and harmful product that is called particulate matter $PM_{2.5,}$ [84-86]. Particulate matter $PM_{2.5,}$ can cause diseases such as lung cancer and cardiopulmonary diseases [87]. It is difficult to evaluate the cost related to the avoided health liabilities and the saved lives. Several works have investigated the calculation of the cost of human health related to electricity production through fossil fuels [88-91]. Nevertheless, the most relevant approach is the work of [91] because the methods accounts for changes of the cost at a regional and plant level. This has been made possible because of data collected by EPA on the emission level of facilities through the Clean Air Markets Program. The result obtained by [91] is conservative as it does not include environmental impacts over the long term (e.g. climate change) [66,68,69,92]. The calculation of the cost of health liability by [91] depends on the quantity of pollutants emitted [tons/year] during a year, the cost of a unit mass of emission for each pollutant in [$/tons], and the annual gross load [kWh/year].

The health cost of energy produced by fossil fuel sources (C_H) [$/kWh] obtained by [91] are used to calculate the utility cost. The utility cost (U_C) is the product of the health cost by the PV systems output (O), that is discounted by the environmental discount factor (F_E).

$$U_C = C_H * O * F_E \qquad (26)$$

The avoided health liability cost (V_9) [$] is then calculated by:

$$V_9 = \sum_0^i U_C \qquad (27)$$

2.10. Value of solar (VOS)

There are three different ways to represent the value of solar. It can be expressed either as the annual cost [$] over the analysis period or the lifetime of the installed solar photovoltaic system, or as the cost per unit of solar PV power installed [$/kW], or finally as the cost of generated electricity by the solar system [$/kWh] [58]. The most commonly used metric to express the VOS is the cost of electricity generated by the solar system [$/kWh] because it is user friendly and is the same metric used by utilities on electricity bills [58]. To calculate the levelized value of VOS per kilowatt-hour of electricity produced, the sum of the value of all the avoided cost is calculated and then divided by the total amount of energy produced (O) during the analysis period discounted by the discount factor (F).

$$VOS = \frac{V_1 + V_2 + V_3 + V_4 + V_5 + V_6 + V_7 + V_8 + V_9}{\sum_0^i (O * F)} \qquad (28)$$

Where:
V_1: Avoided O&M fixed cost
V_2: Avoided O&M variable cost
V_2: Avoided fuel cost
V_4: Avoided generation capacity cost
V_5: Avoided reserve capacity cost
V_6: Avoided transmission capacity cost
V_7: Avoided distribution cost
V_8: Avoided environmental cost
V_9: Avoided health liability cost
O: Output of the solar PV system

F: Utility discount factor

3. Sensitivity

The calculation of VOS requires several parameters that come from different sources. Some parameters are location dependent, while other parameters are state dependent, and there are parameters that are utility dependent. Many of these parameters can also change from one year to another. As a result, there are wide differences in the calculation of VOS across the literature [56]. The utility-related parameters that can change from one VOS calculation to another are the number of years in the analysis period (i), the utility discount rate (D), the utility degradation rate, the utility O&M fixed, and variable costs, the O&M cost escalation rate, the hourly heat rate (H_P), the heat rate degradation rate (D_H), the reserve capacity margin (M), the transmission capacity cost (U_T), the peak load of year 1 (PL_1) and year 10 (PL_{10}), the distribution cost (Q), the distribution cost escalation factor (G_D), and the distribution capacity (C_D). Parameters such as the cost of peaker combustion turbine (I_P), the cost of combine cycle gas turbine (I_C), the heat rate of peaker combustion turbine (H_{CT}), and the heat rate of combine cycle gas turbine (H_C) can be either obtained from the utility or from the U.S. Energy Information Agency. The solar PV fleet (S) can also be obtained from the utility or by simulation using the open source Solar Advisory Model (SAM) (https://github.com/NREL/SAM) [45]. Other variables that can affect the VOS but are not controlled by the utility are the PV degradation rate (D_{PV}), the environmental discount factor (F_E), the environmental cost of conventional energy, the health cost of conventional energy, and the cost of natural gas on the energy market. Table 1 summarizes high and low estimates of the values for the variables that are required to perform a VOS calculation and the VOS component they are used to calculate.

Table 1. Assumptions used for required variables for a VOS calculation

Variable	High estimate	Source	Low estimate	Source	VOS components
Degradation rate of PV (D_{PV}) [%]	1	[93]	0.5	[57,93, 94]	All components
Distribution capacity (C_D) [kW]	429000	[95]	237000	[95]	Avoided distribution cost (V_7)
Distribution cost (Q) [$/kW]	1104	[95]	678	[95]	Avoided distribution cost (V_7)
Environment discount rate (D_E) [%]	2.5	[81]	5	[81]	Avoided environmental cost (V_8)
Environmental Cost (E) [$/metric tons of CO_2]	[62-89]	[81]	[12-23]	[81]	Avoided environmental cost (V_8)
Health cost of natural gas (C_H)[$/kWh]	0.025	[91]	0.025	[91]	Avoided health liability cost (V_9)
Heat rate degradation rate (D_H) [%]	0.2	[96]	0.05	[96]	• Avoided fuel cost (V_3) • Avoided environmental cost (V_8)
Heat rate of combined cycle gas (H_C) [Btu/kWh]	7627	[97]			• Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5)
Heat rate of peaker combustion turbine (H_{CT}) [Btu/kWh]	11138	[97]			• Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5)

Installation capital cost of combined cycle gas turbine (I_C) [$/kW]	896	[98]			• Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5)
Installation cost of peaker combustion turbine (I_P) [$/kW]	1496	[98]			• Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5)
Load Growth Rate (K) [%]	1.17	[99]	-0.94	[99]	Avoided distribution capacity cost (V_7)
Number of years in analysis period	30	[57]	25	PV industry warranties	All components
Reserve capacity margin (M) [%]	36	[100]	13	[100]	Avoided reserve capacity (V_5)
Solar Heat Rate (H_S) [Btu/kWh]	8000	[53]			• Avoided fuel cost (V_3) • Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5) • Avoided environmental cost (V_8)
Transmission capacity cost (U_T) [$/kW]	130.535	[101]	17.895	[101]	Avoided transmission capacity (V_6)
Utility Discount rate (D) [%]	9	[57]	2.18	[57]	• Avoided plants O&M fixed cost (V_1) • Avoided plants O&M variable (V_2) • Avoided generation capacity cost (V_4) • Avoided reserve capacity cost (V_5) • Avoided transmission capacity cost (V_6) • Avoided distribution capacity cost (V_7)
Utility fixed O&M cost (U_F) [$/kW]	18.86	[95]	7.44	[95]	Avoided O&M fixed cost (V_1)
Utility variable O&M cost (U_V) [$/kWh]	0.01153	[95]	0.00216	[95]	Avoided O&M variable cost (V_2)

3.1. Number of years in analysis period

The number of years in the analysis period varies and can be as low as 20 years, and as high as 30 years or more [12,57]. The typical warranty provided by solar panels manufacturer is 25 years. As a result, it is reasonable to set the lowest value of the analysis period to 25 years. Also, solar modules have proved to continue to reliably deliver energy 30 years after the installation of the system [57], therefore, 30 years has been set as the higher value of the analysis period in this study. Keyes et al. have pointed out that utility planning is often over shorter time periods (e.g. 10-20 years) [57]. However, economic decisions should be made over the entire life of the physical project not an arbitrary cutoff date [102] and there are existing methods to estimate the load growth on the utility side as it is usually done for conventional energy generators [53].

3.2. PV system degradation rate

The degradation rate of PV panels overtime depends on the location of operation as well as climate conditions (temperature, wind speed, dust, etc.). A statistical study conducted by the National Renewable Energy Laboratory [93] has found the value of the PV system degradation rate to be comprised between 0.5% and 1%. These two values are the boundaries that will be used as low and high values for the sensitivity analysis on the PV system degradation rate.

3.3. Utility discount rate

The discount rate is used to assess the change in money value overtime. This value can change depending not only on the location, but also, on the utility. A discount rate value as high as 9% can be used or a value as low as the inflation rate might be used. The discount rate used by utilities are usually in the high values, but the social discount rate is closer to the inflation rate [57]. As a result, 9% will be considered as the high-end value of the discount rate while the current inflation rate of 2.18% will be considered for the lowest value. It is important to note that the value of the inflation rate changes with time and if this value is chosen as the discount rate it should be updated regularly for new calculations of the VOS. Also, the value of the inflation rate can be subjected to ongoing events. The value of the inflation rate of 2.18% was chosen at a date before the coronavirus outbreak in the United States that is ongoing. The outbreak has brought the inflation rate to as low as 0.25%. This value will not be used to run a sensitivity analysis because of the special conditions in which it occurred.

3.4. Environmental cost

The environmental cost associated with electricity production through conventional energy sources depends on the cost associated with the pollution from carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxide (NO_x), and hazardous particulates (PM). The environmental cost of carbon dioxide dominates the cost of the other components. Different estimates of the CO_2 cost are given by the EPA [81]. The cost of CO, NO_x, and PM depends on state laws. The lowest value and highest value used for the cost of CO, NO_x, and PM were chosen from the state of Minnesota [103]. It has been hypothesized that if conventional energy sources are being used to produce electricity in the future, the effects on environment are going to worsen (e.g. lower quality fuel, higher embodied energies, etc.), therefore the environmental cost will be expected to increase. This will be investigated by raising the environmental cost while analyzing the sensitivity of VOS to the environmental cost. This will show the trend of the impact of the environmental cost on the VOS and in the future, the values will need to be updated because the environmental cost is likely to exceed the maximum used value in this study.

3.5. Health liability cost

The health liability cost is a new calculated VOS component introduced by this study. This component has been mentioned by several studies but was not incorporated in the calculation due to lack of data for the evaluation [57,66,67,104]. The health and mortality impacts of coal in particular are so severe an ethical case can be made for the industries elimination [105]. For example, Burney estimated that 26,610 American lives were saved between 2005 and 2016 by a conversion of coal-fired units to natural gas in the U.S. [106]. More lives as well as non-lethal health impacts would be avoided with a greater transition from coal to solar [70]. The values used here were obtained from the study of [91] that found the value of health impact cost of natural gas to be $0.025/kWh. As previously hypothesized, the use of fossil fuel energy sources in the future will increase the emissions, and the cost of health care has been escalating faster than inflation [106] thus increasing the cost of derived health liability.

Several increase rates will be investigated. Although it should be pointed out the approach taken here was extremely conservative as the potential for climate/greenhouse gas emission liability [107,108] was left for future work as discussed below.

3.6. Other parameters

The other parameters are utility related and in case of absence of utility data, generic values from the U.S. government agencies is used as indicated in Table 1 and run through realistic percent increases or decreases to determine their effect on the VOS components.

3.7. Sensitivity Analysis

A sensitivity analysis has been run on each of the nine VOS components as well as on the VOS. For each component, the sensitivity has been analyzed for some of its parameters wherever data was available. The evaluation of the variability of the VOS components has been performed for each parameter. The sensitivity of a component to one of its parameters is determined by maintaining an average value of the other parameters and varying the studied parameter from its lowest value to its highest value. The different values that are obtained for the VOS component are then plotted to show its variation according to the parameter studied. A correlation study between the different parameters has not been conducted because there was no evident relationship between these parameters. Most of the parameters are set by the utilities and is often not disclosed openly. An interaction study between the parameters and how their interaction affects the VOS components would be interesting for future studies where utility data are available.

A similar process has been used for the sensitivity analysis of the main VOS. The main VOS's variability has been studied according to the nine VOS components. For each component for which the sensitivity of the VOS is analyzed, average values of the other components are maintained while the studied component's value is varied from its lowest value to its highest value.

4. Results and Discussion

The simulation results are plotted first for each VOS components. For each component, sensitivities on the different input variables have been investigated. Then the sensitivity of the overall VOS to each of the VOS components has been analyzed.

4.1. Avoided O&M fixed cost (V_1)

Figure 1 shows the results for the avoided O&M fixed cost (V_1). The sensitivity has been plotted for five parameters: the utility O&M fixed cost, the utility O&M cost escalation, the PV degradation rate, the utility discount rate, and the utility degradation rate. According to the results, the avoided O&M cost is highly sensitive to the utility O&M fixed cost and O&M cost escalation. When the utility O&M fixed cost increases, the avoided O&M cost increases accordingly and an increase in the O&M escalation rate obviously increases the avoided O&M cost because it increases the utility fixed O&M cost over the analysis period. V_1 is also sensitive to the utility discount rate and decreases when the discount rate increases. This means that using a discount rate close to the social discount rate while conducting a VOS study will increase the avoided O&M cost while using a higher discount rate will lower the cost. this is in accordance with the recommendation of [57] that is the use of a discount rate lower than that of the utility in a distributed solar generation economic calculation. Also, the avoided O&M fixed cost is not very sensitive to the utility degradation rate or the PV degradation rate. Nevertheless, its value is slightly reduced when the PV degradation rate increases.

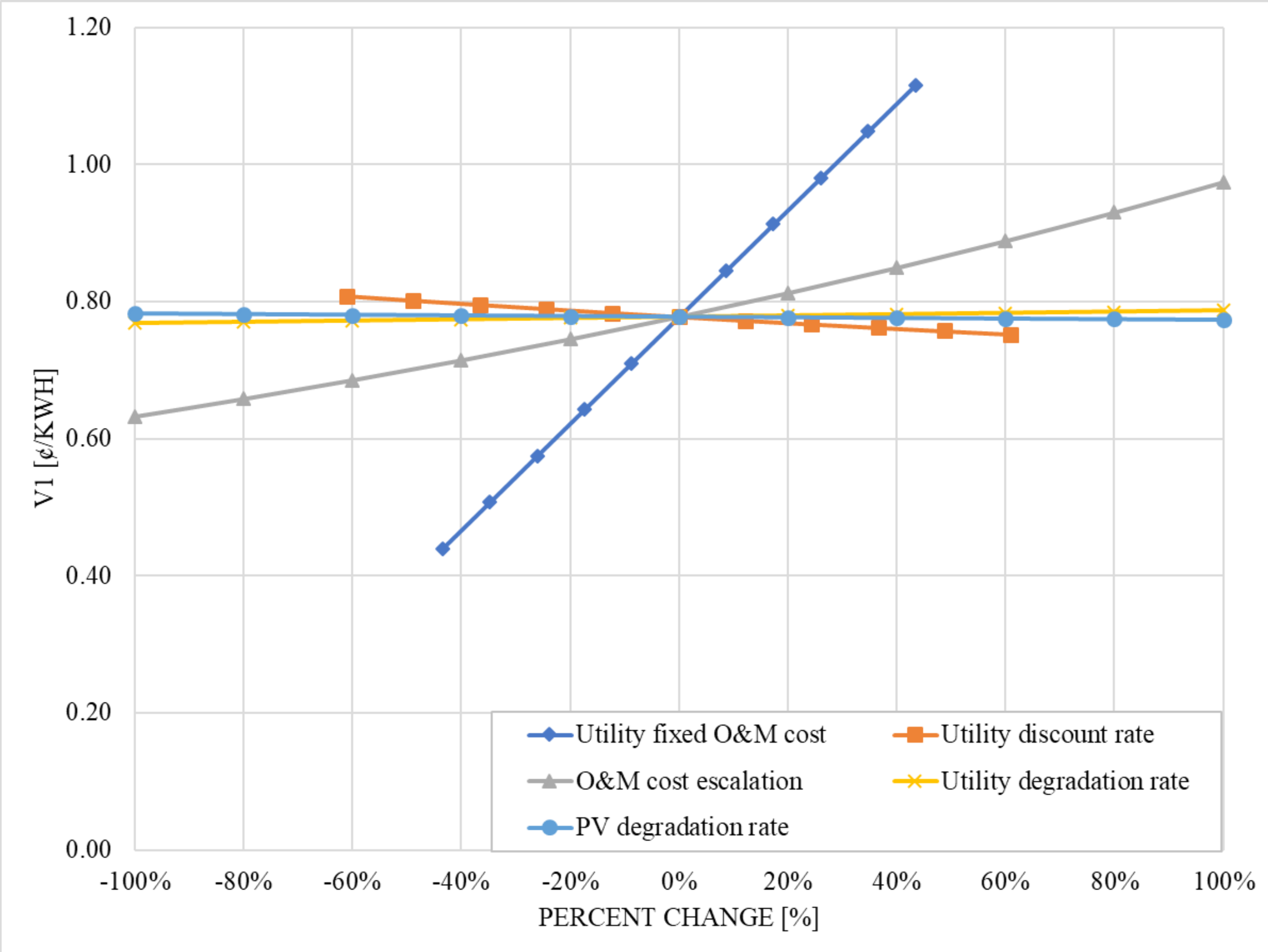

Figure 1. Sensitivity of avoided O&M fixed cost (V_1) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.2. Avoided O&M variable cost (V_2)

The parameters for which the avoided O&M variable cost's (V_2) sensitivity has been studied are: the utility O&M variable cost, the utility O&M cost escalation, the PV degradation rate, and the utility discount rate. The sensitivity of the avoided O&M to its parameters are plotted in Figure 2. Figure 2 shows a similar variation trend of V_2 as compared to the case of the avoided fixed O&M cost. It is highly sensitive to the utility variable O&M cost, and the O&M cost escalation. The avoided variable O&M cost increases when the variable O&M, or the O&M cost escalation rate is increased but decreases with the increase of the discount rate, and the PV degradation rate.

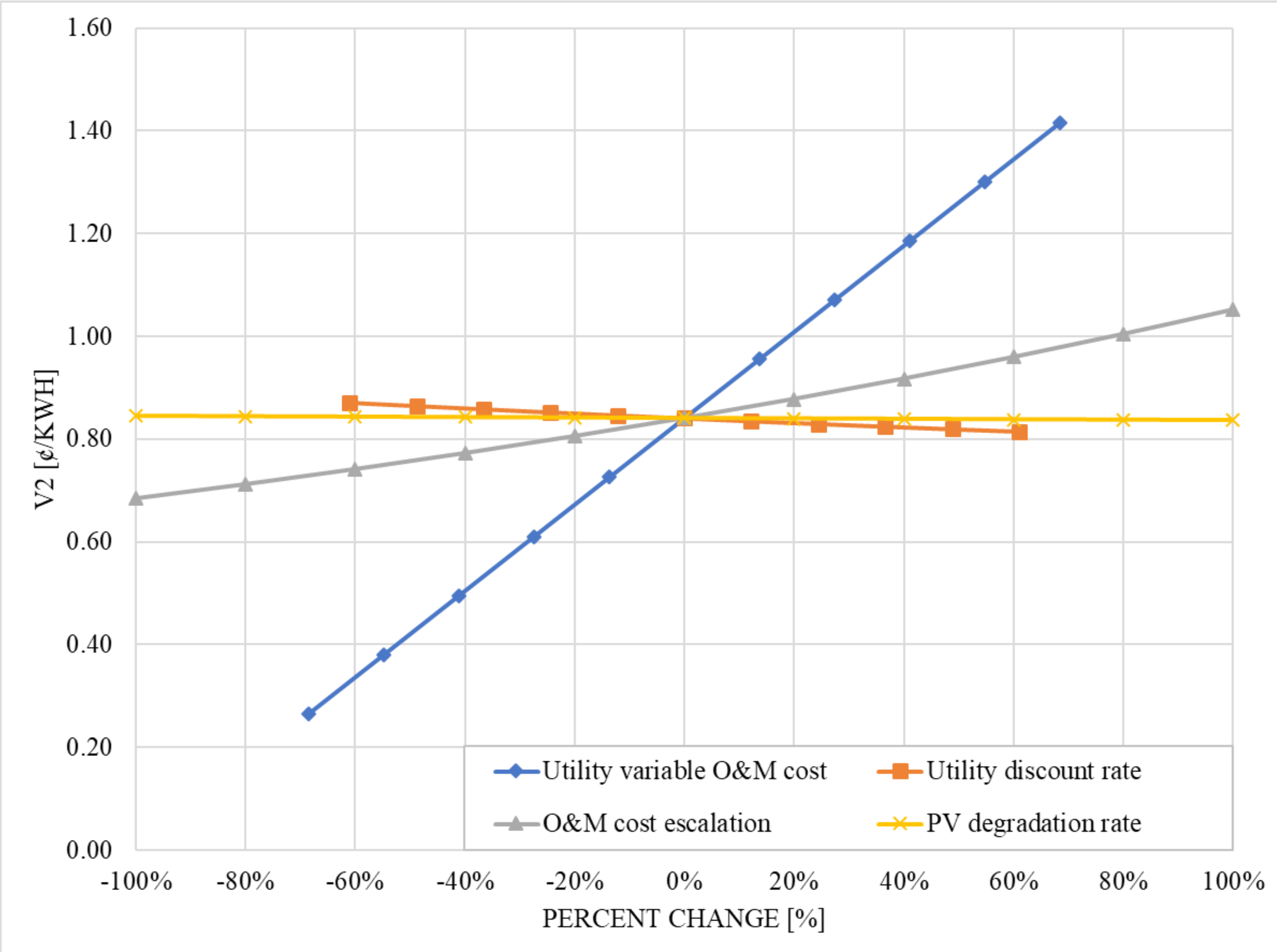

Figure 2. Sensitivity of avoided O&M variable cost (V_2) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.3. Avoided fuel cost (V_3)

In the case of the avoided fuel cost (V_3), the variable considered for the sensitivity analysis are the heat rate degradation rate, the natural gas price fluctuation rate and the PV degradation rate. While the avoided fuel cost has shown to be not very dependent on the heat rate degradation rate or the PV degradation rate, this value changes very quickly with a change in the natural gas price as in Figure 3. This is an important factor that should be carefully considered while conducting a VOS study because the price of natural gas is not fixed and varies according to several parameters that are not controlled by the utility such as, the economy, the weather, market supply and demand [109,110]. The equivalent heat rate degradation rate expresses the degradation of the utility plant's efficiency over the analysis period and when the efficiency decreases, there is a slight decrease in the avoided fuel cost. Another value for which the avoided fuel's sensitivity could have been studied is the equivalent heat rate for solar, which was not analyzed in detail here because of the lack of utility data. This is left for future work.

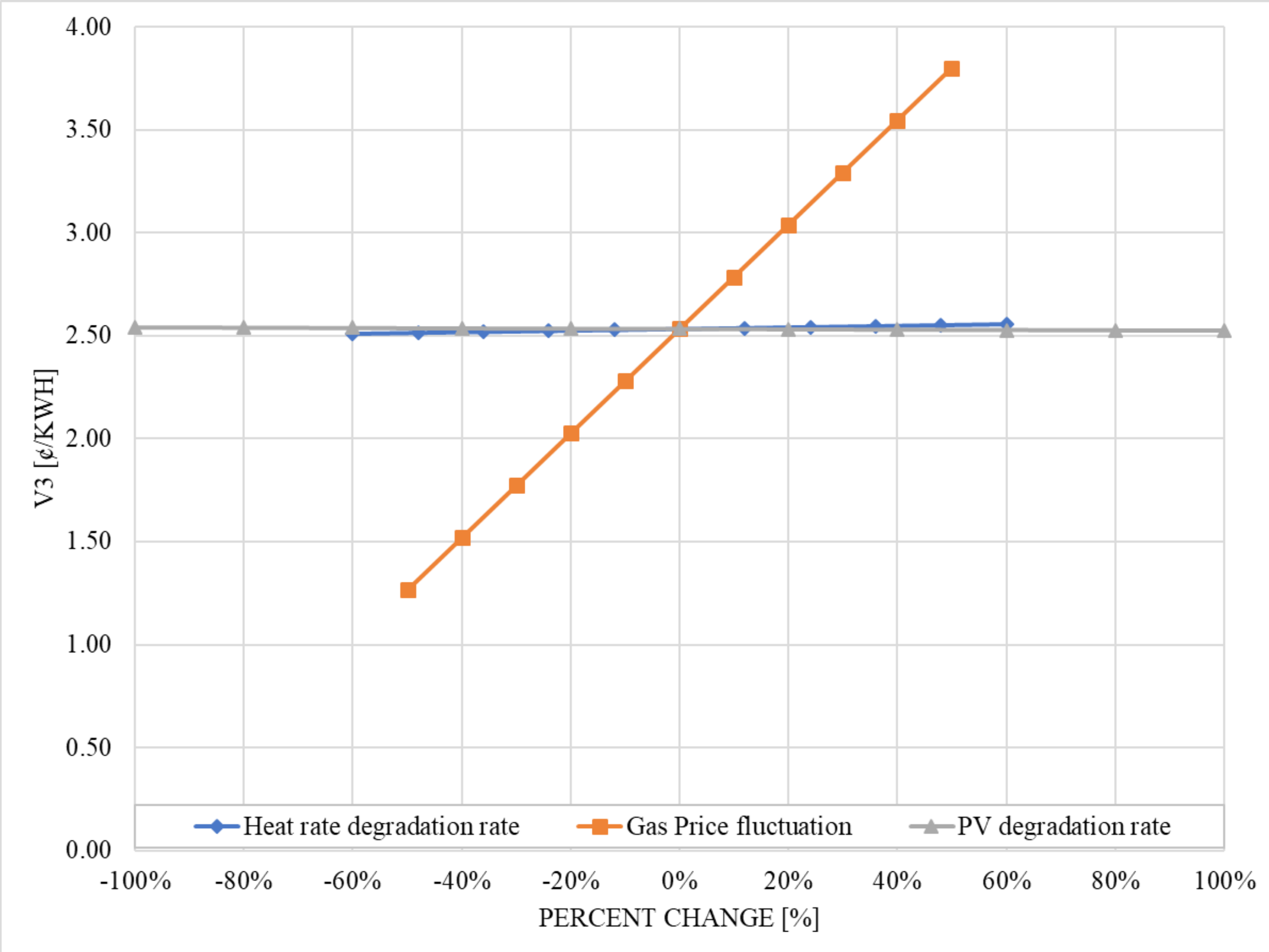

Figure 3. Sensitivity of avoided fuel cost (V_3) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.4. Avoided generation capacity cost (V_4)

The sensitivity of the avoided generation capacity cost (V_4) has been plotted in Figure 4 for the discount rate, the utility degradation, and the PV degradation rate. The V_4 VOS component does not have a high variability to the PV degradation rate even though it shows a decreasing trend with the increase of PV degradation. But it reacts sharply to the utility degradation rate. This is because the generation capacity of the utility is highly impacted by the utility degradation. Also, as previously observed, when the discount rate grows far from the social discount rate, the avoided generation capacity cost decreases.

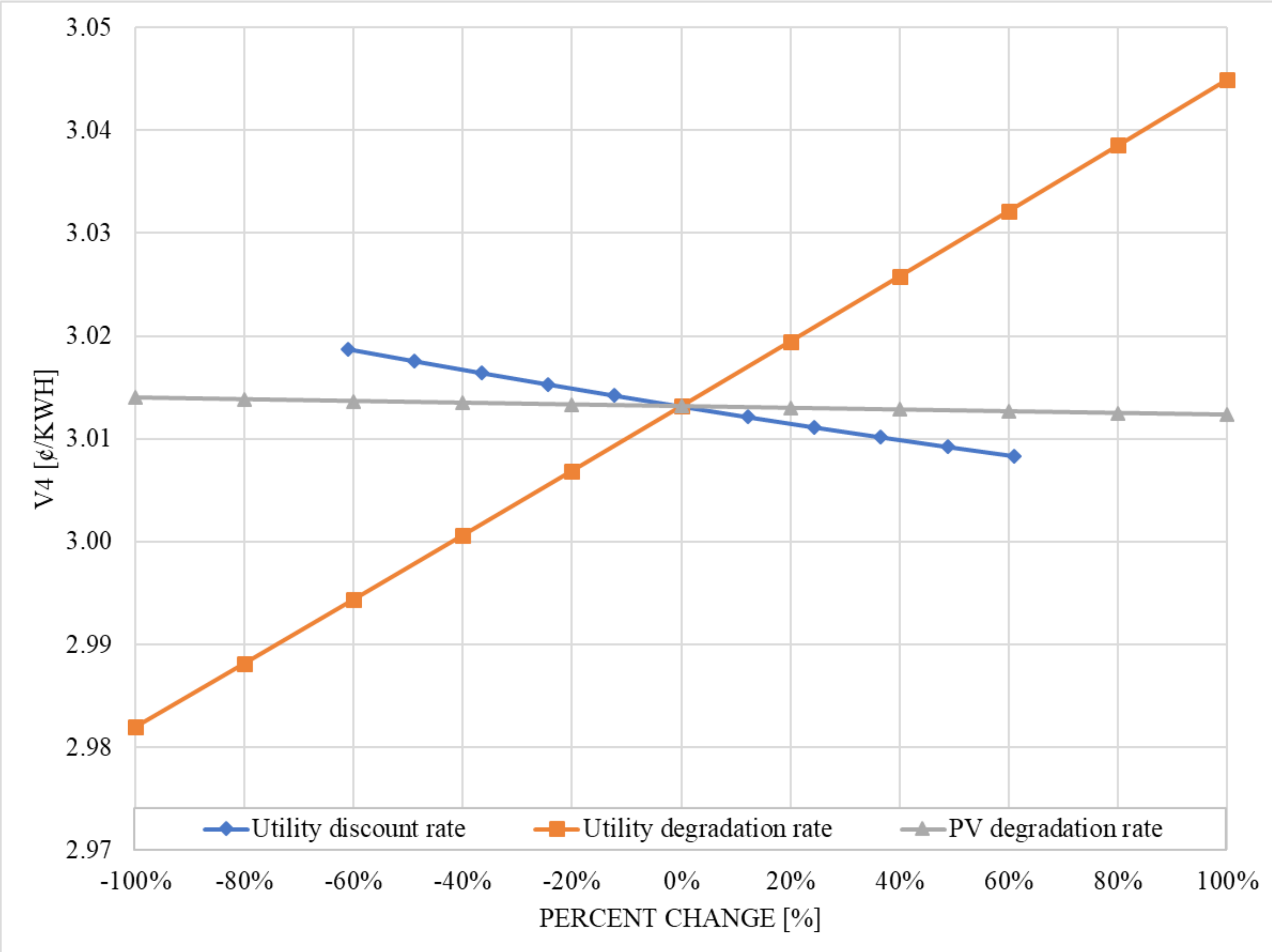

Figure 4. Sensitivity of avoided generation capacity cost (V_4) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.5. Avoided reserve capacity cost (V_5)

The avoided reserve capacity cost (V_5) expresses the reserve component of the generation capacity; therefore, it can have a value of zero when there is no reserve capacity planned by the utility as shown in Figure 5. V_5 is highly sensitive to the reserve margin and the result shows that the more generation capacity is reserved, the more the avoided generation capacity cost increases. On the other hand, the avoided reserve capacity cost is not very sensitive to the discount rate compared to its sensitivity to the other parameters. V_5's value goes up when the utility degradation rate increases and goes down when the PV degradation rate increases.

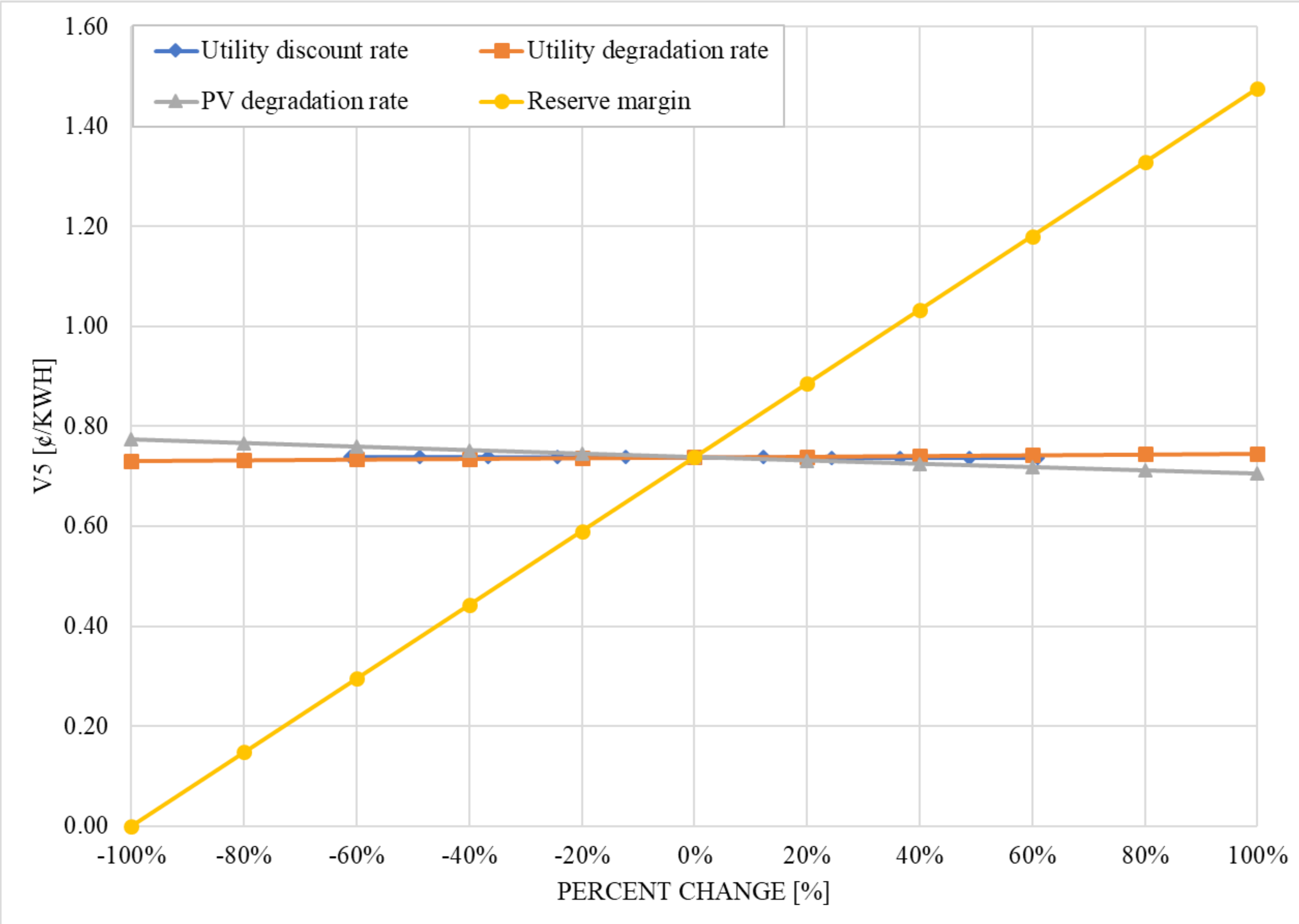

Figure 5. Sensitivity of avoided reserve capacity cost (V_5) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.6. Avoided transmission capacity cost (V_6)

Three parameters have been analyzed in the sensitivity study of V_6: the discount rate, the transmission capacity cost, and the PV degradation rate. The parameter it is the most sensitive to is the transmission capacity cost. Obviously, when the transmission is low cost in a location, the avoided cost associated will be low. The results shown in Figure 6 make it clear that the avoided transmission capacity cost does not change with the PV degradation rate or the discount rate. This is because the utility transmission capacity has been assumed to be constant over the analysis period, and the transmission capacity degradation rate has not been considered because utility data on this parameter was not available.

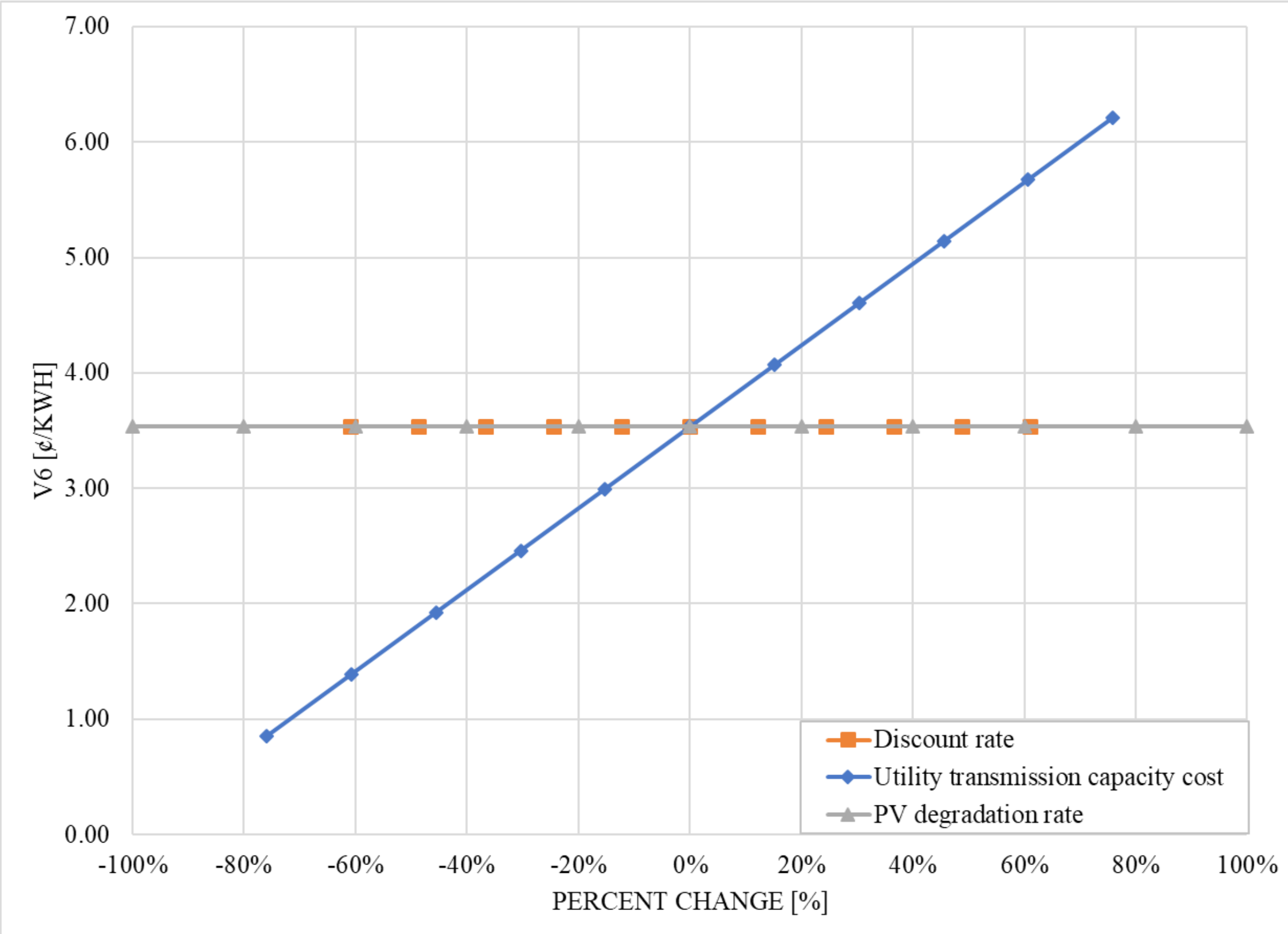

Figure 6. Sensitivity of avoided transmission capacity cost (V_6) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.7. Avoided distribution capacity cost (V_7)

The avoided distribution capacity cost (V_7) is one of the most complicated VOS components to evaluate. As shown in Figure 7, its sensitivity has been studied for six variables: the load growth rate, the distribution capacity, the distribution capacity cost, the utility discount rate, the distribution cost escalation, and the PV degradation rate. But it depends on more than six parameters. The growth rate, for example is calculated from utility data, mainly, the load for the past ten years of operation [45,111]. Here, the sensitivity has been analyzed on the growth rate directly to be as widely applicable as possible. Another parameter is the number of deferred years that is also a utility owned data.

The avoided distribution capacity cost naturally increases with the distribution capital cost. Figure 7 shows that the avoided distribution capacity cost does not fluctuate with the distribution capacity at all, but it is highly sensitive to the discount rate, the distribution cost, and the distribution cost escalation rate. It can even shift to a negative value when the discount rate is too low. This shows that choosing the discount during a VOS study must be a trade-off between the social discount rate and the utility discount rate. It is interesting to note that the avoided distribution capacity cost goes down when the distribution cost escalation in increasing. A possible explanation for this observation is that when a utility has enough distribution capacity, it will purchase less power from solar PV systems owners, therefore the price goes down. The same reasoning can be used to explain the decreases of the cost when the load growth goes up. Finally, V_7 shows a slight decrease with the increase of the PV degradation rate.

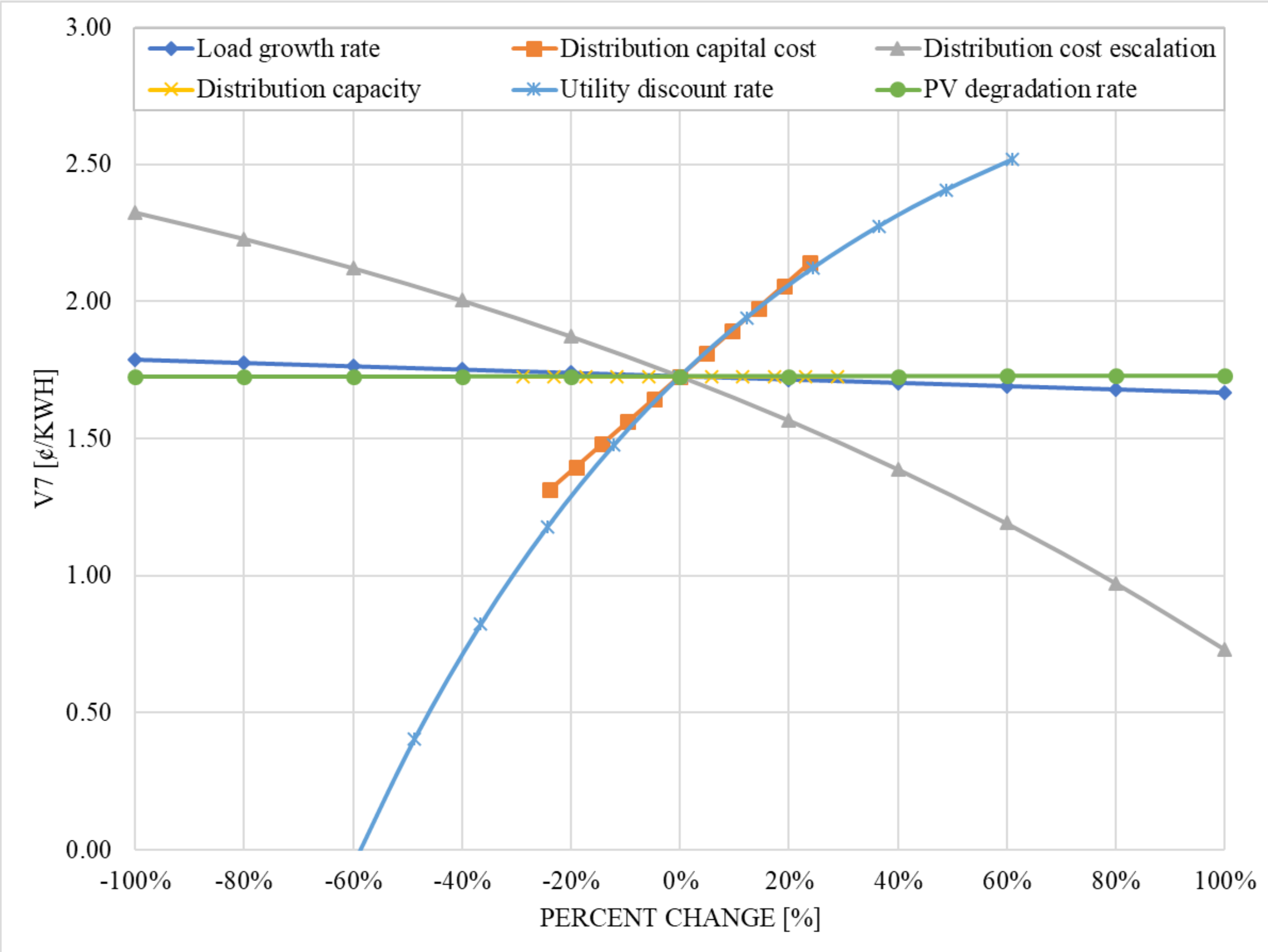

Figure 7. Sensitivity of avoided distribution capacity cost (V_7) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.8. Avoided environmental cost (V_8)

The second most complicated component of the VOS calculation is the avoided environmental cost (V_8). The sensitivity has been analyzed for the three environmental discount rate scenarios provided by the EPA [81]. For each scenario, a sensitivity analysis has been conducted on the environmental cost increase rate. V_8 will increase when the chosen environmental discount rate is low but overall, each of the three EPA scenarios show an increase when the environmental cost increase rate goes up as seen in Figure 8. This is useful to see how the avoided environmental costs might change in the future. Environmental externalities are volatile and changing quickly [66]. If it is assumed that in the future, the environmental impact of conventional energy production technologies will increase, then the costs of the environmental externalities will increase as well [104]. On the other hand, an increase in distributed renewable energy generation could lead to a decrease or stabilization of the avoided environmental cost.

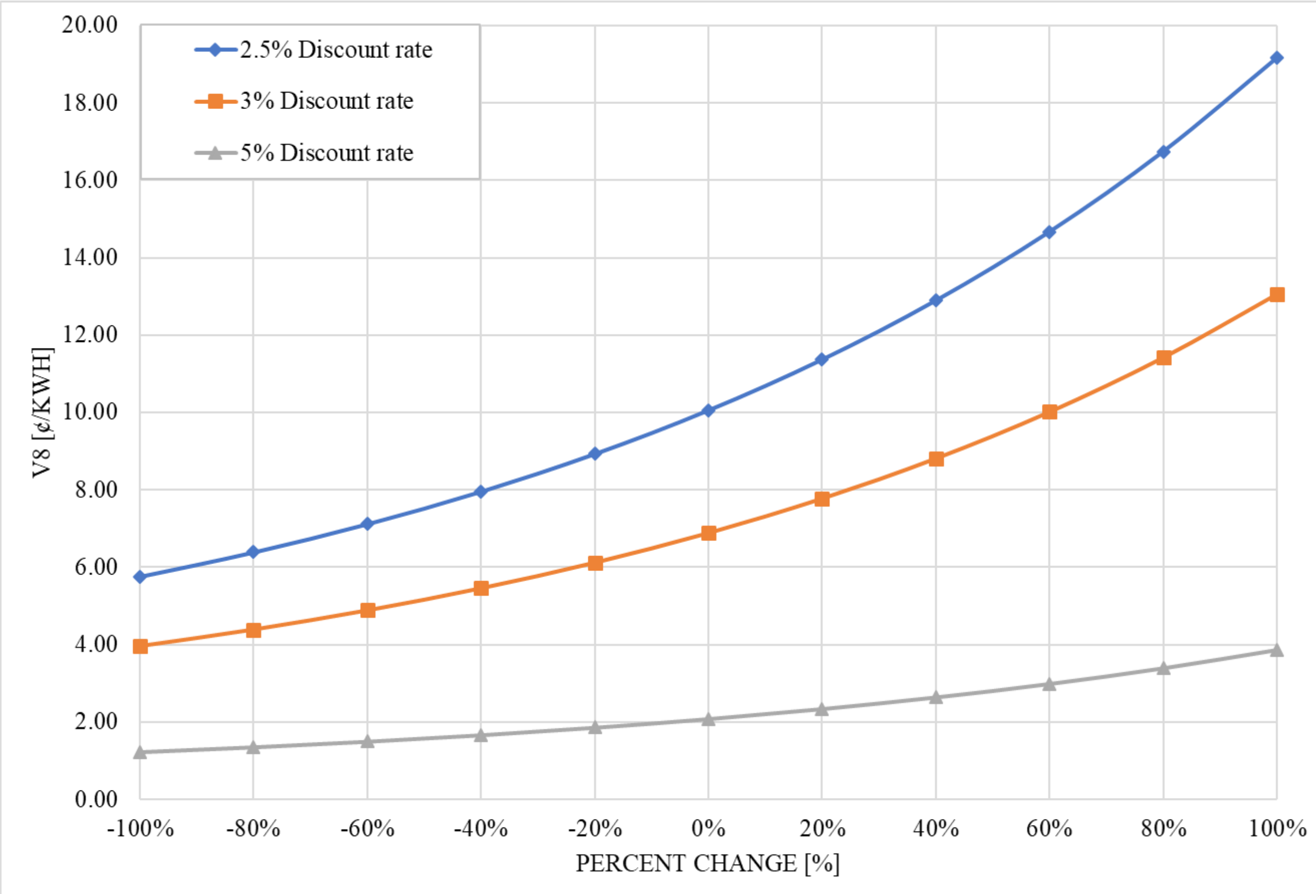

Figure 8. Sensitivity of avoided environmental cost (V_8) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.9. Avoided health liability cost (V_9)

The avoided health liability cost, V_9, depends on three values, the health cost increase rate, the environmental discount rate, and the PV degradation. This cost does not fluctuate with the PV degradation rate but is very sensitive to the other two parameters. The environmental discount rate used here is the same as the environmental discount rate used in the evaluation of the avoided environmental cost's sensitivity study. As a result, the avoided health liability cost decreases when the environmental discount rate goes up as is the case for the avoided environmental cost.

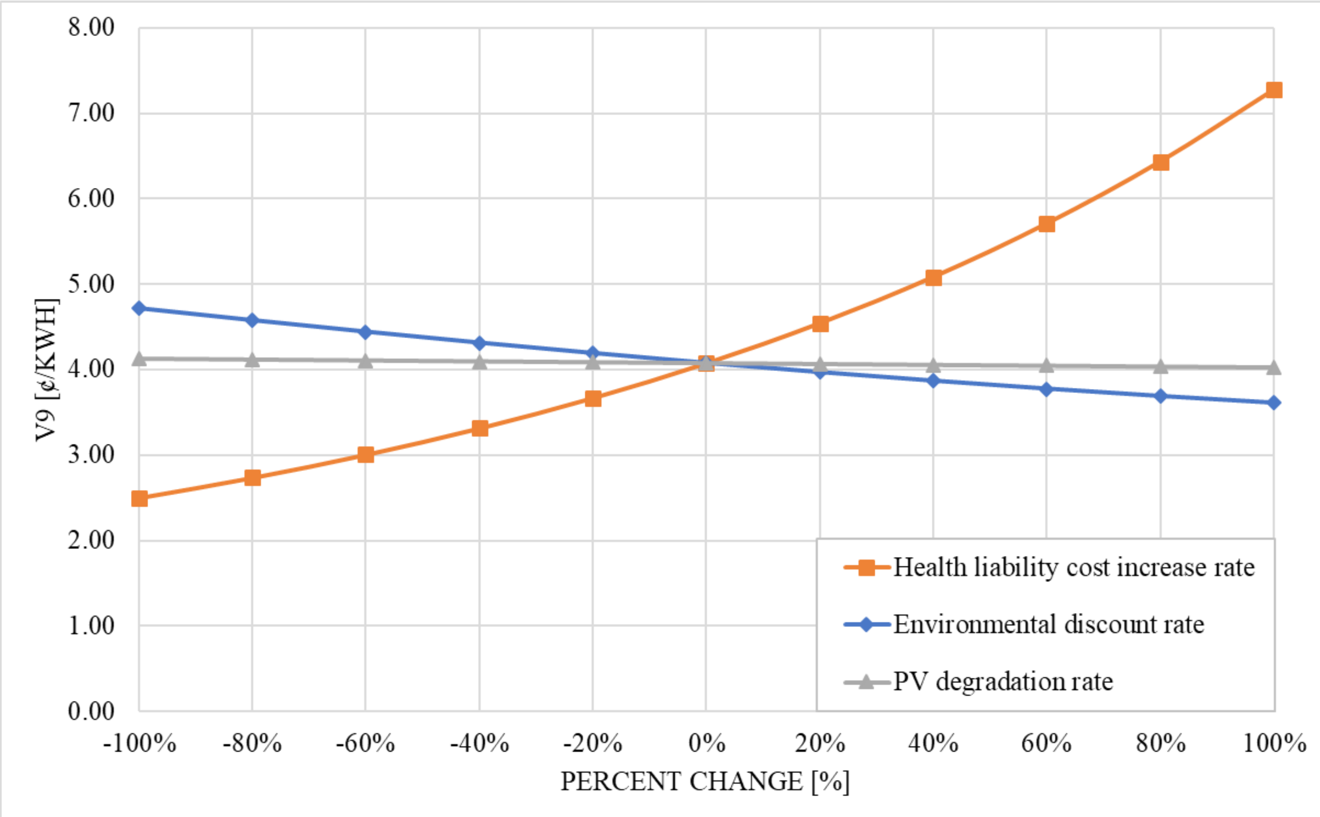

Figure 9. Sensitivity of avoided health liability cost (V_9) in terms of LCOE (¢/kWh) to its parameters in percent change.

4.10. VOS

After the sensitivity analysis of each VOS component, the main VOS value has been studied to find out how the impact of different components compare to one another and which components have more variability. Figure 10 shows that the VOS is, in decreasing order, sensitive to the avoided environmental cost (V_8), avoided health liability cost (V_9), avoided transmission capacity cost (V_6), avoided fuel cost (V_3), avoided distribution capacity cost (V_7), avoided O&M variable cost (V_2), avoided reserve capacity cost (V_5), avoided O&M fixed cost (V_1), and avoided generation capacity cost (V_4)

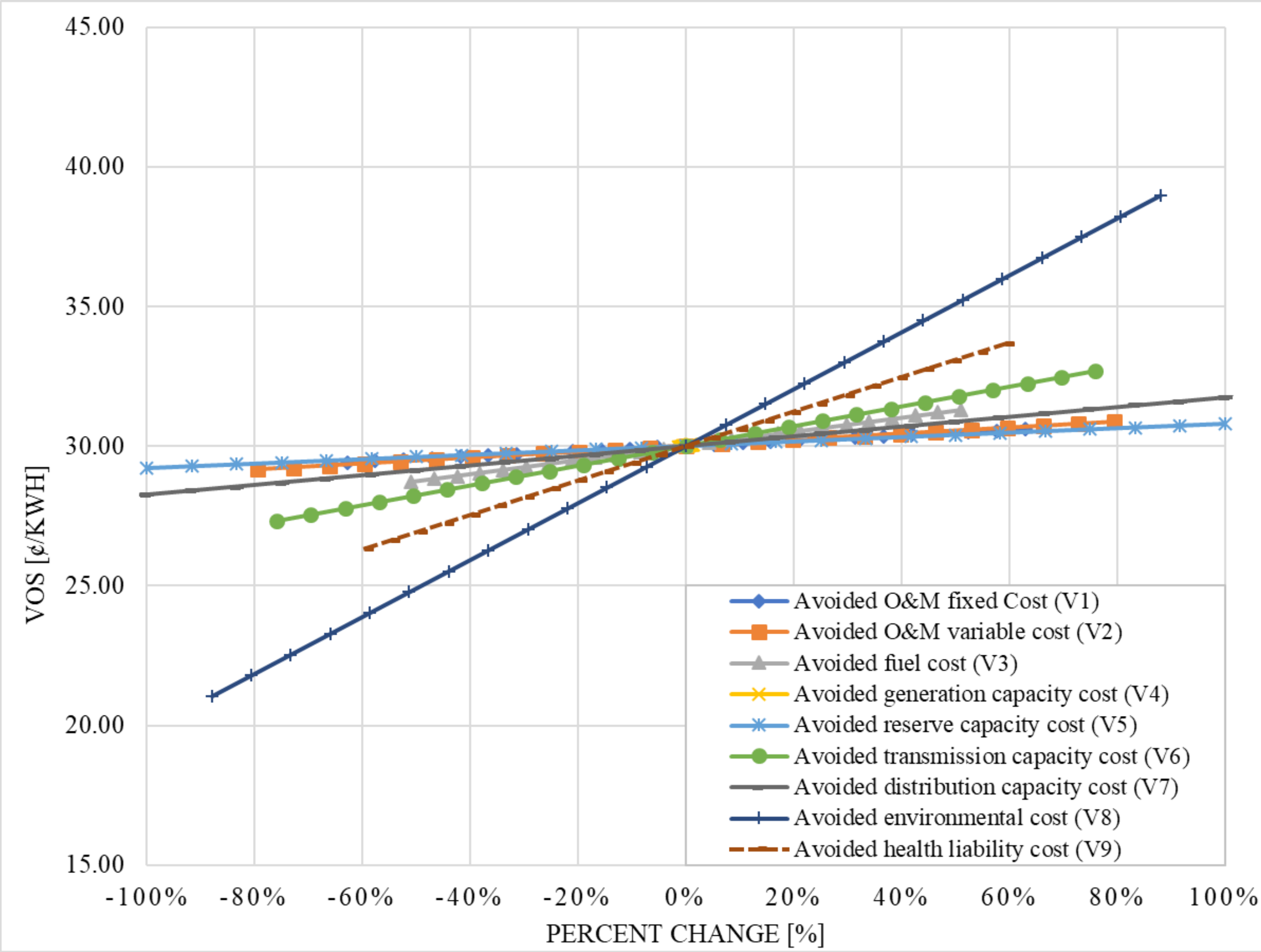

Figure 10. Sensitivity of VOS LCOE (¢/kWh) to all the components in this study, in percent change.

The contribution of each VOS component to the overall VOS depends on the case. The lowest VOS value calculated with the assumptions used in this study in term of LCOE is 9.37¢/kWh while the highest value calculated is 50.65¢/kWh. This variation observed in the VOS value comes from the fact that the parameters values considered from this study are chosen to have the lowest and the highest value of a VOS. The values of calculated VOS using utility data are highly likely to be located within this interval. It is also clear based on the values shown in Figure 10, that the VOS exceeds the net metering rates (when they are even available as shown in Table 2) in the U.S. Thus, it can be concluded that even when grid-tied solar owners are provided with a full net metered rate for electricity fed back onto the grid they are effectively subsidizing the electric utility/other customers.

For the low VOS value case shown in Figure 11, the avoided distribution cost (V_7), and the avoided reserve capacity cost (V_5) has no contribution in the VOS value. The avoided generation capacity cost (V_4) and the avoided health liability cost (V_9) represent most of the VOS value followed by the avoided environmental cost (V_8) and avoided fuel cost (V_3).

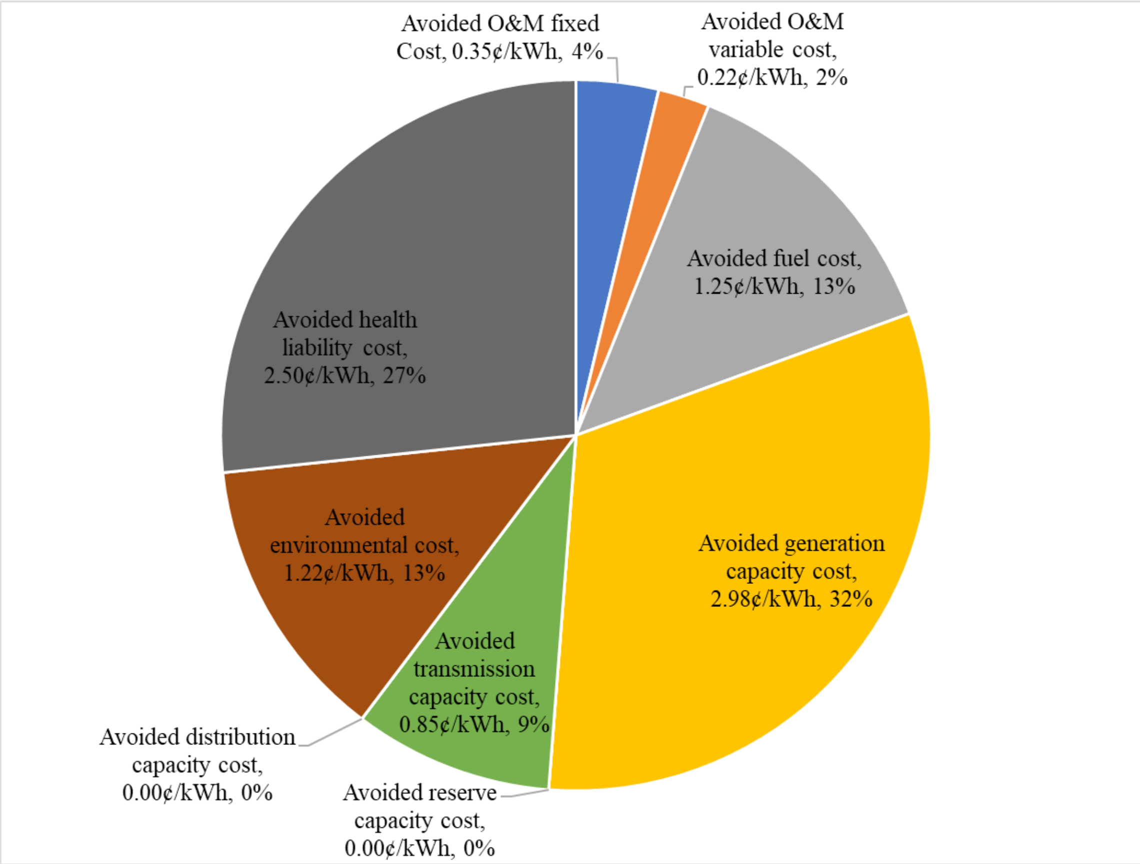

Figure 11. Contribution of each VOS component to the overall VOS LCOE – Low Cost Scenario.

The contribution of the avoided environmental (V_8) cost increases with the VOS value as it becomes the largest contributor to the overall value followed by the health liability (V_9) cost as shown in Figure 12 representing a middle VOS value. The avoided generation capacity cost's (V_4) is reduced as well as the contribution of the avoided fuel cost (V_3).

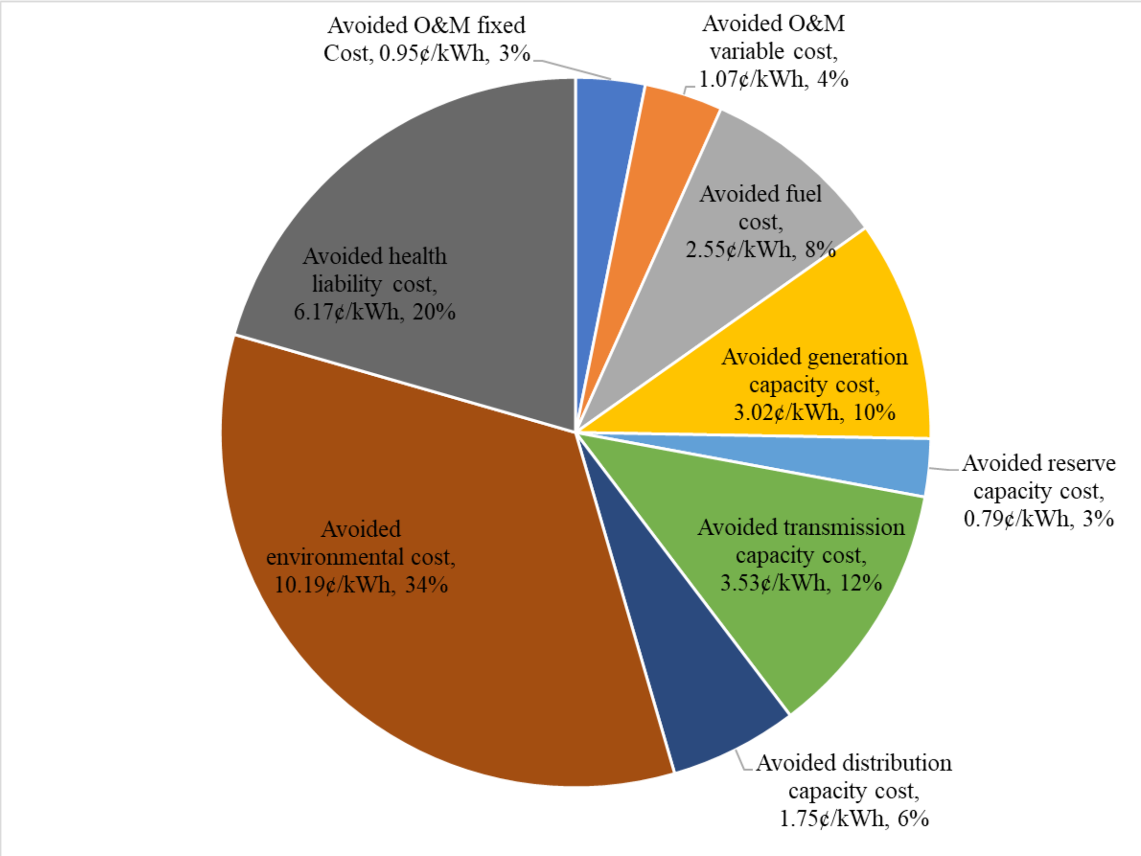

Figure 12. Contribution of each VOS component to the overall VOS LCOE – Middle Cost Scenario.

Figure 13 represents the contribution of each of the VOS components to the overall value in the case of the highest obtained value in the scope of this study. The avoided environmental cost (V_8), avoided health liability cost (V_9), and avoided transmission capacity cost (V_6) represent 69% of the total cost.

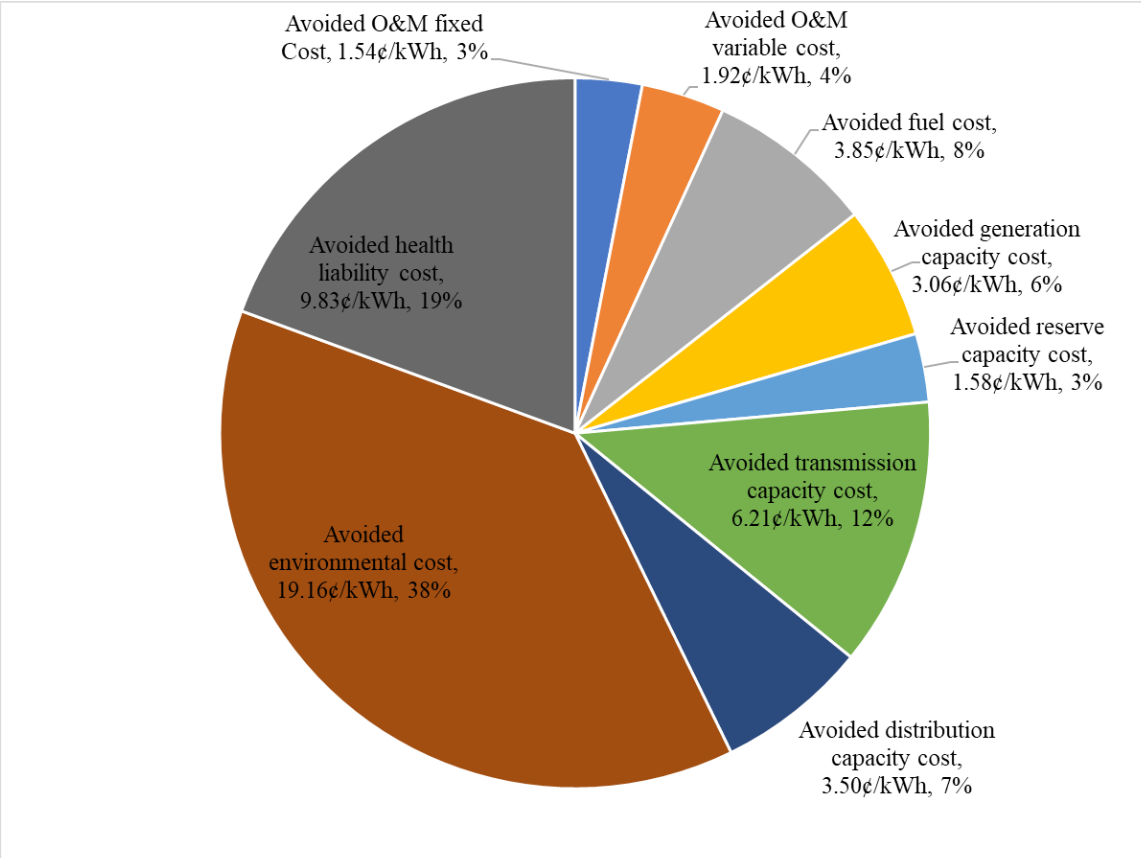

Figure 13. Contribution of each VOS component to the overall VOS LCOE – High Cost Scenario.

The evolution of the cost percentage contribution of each VOS throughout Figure 11, Figure 12, and Figure 13 shows the level of uncertainty of the VOS in respect to the corresponding component.

The lowest and highest LCOE VOS values obtained from the assumptions made in this study are respectively 9.37¢/kWh and 50.65¢/kWh. The existing VOS studies results fall into this interval. The sample calculation made by [45] for Minnesota is 13.5¢/kWh while [46] calculated a VOS of 10.7¢/kWh for Austin Energy. These values are in the lower spectrum of the result of this study because of the considerations made. They incorporate less VOS components than the present study, and this study focuses on sensitivity, therefore higher values of parameters have been considered. Other results summarized by [47] have found the VOS to be 33.7¢/kWh in Maine, between 25.6 and 31.8¢/kWh in New Jersey and Pennsylvania [48], and 19.4¢/kWh in Washington DC. In general, the VOS is much higher than the net metering costs as even the highest costs observed at the residential level pay [50,62,112]. The residential net metering rates are also the highest as compared to commercial and industrial rates so the latter two are even more unjustly compensated for installing solar. Overall, this indicates that utilities are under-compensating customers with grid-connected PV systems if they are only paying net metering rates, as displayed in Table 2. Table 2 shows a comparison between VOS rates and net metering rates in the U.S. states mentioned above, wherever data is available. As only a tiny fraction of utilities (3%) are paying full net metering rates anyway [43], there is a need for regulators to ensure that solar customers are being adequately compensated for the value of solar electricity they are sharing with the grid [42]. Substantial future work is needed to ensure that solar PV owners are not subsidizing non-solar electricity customers.

Table 2. Comparison of VOS rates and net metering rates for some U.S. States

State	VOS	Net Metering
Minnesota	13.5¢/kWh	
Austin (Texas)	10.7¢/kWh	Approximately 4 – 5¢/kWh (1.2 – 1.6$/kWh) [113]
Maine	33.7¢/kWh	12.16 – 14.66¢/kWh [114]
New Jersey	25.6 – 28¢/kWh	
Pennsylvania	28.2 – 31.8¢/kWh	Minimum value of (4¢/kWh) [115]
Washington D.C.	19.4¢/kWh	

5. Future Work

This study has covered a vast number of existing VOS components, but some components were not included in this study due to the lack of a reliable evaluation methodology. These components include the economic development cost, the avoided fuel hedge cost, and the avoided voltage regulation cost. These represent opportunities for future work once the evaluation methodologies have been developed. Also, there are some parameters sensitivities that would provide insights with multiple utility data sets. These parameters include the analysis period, the hourly solar heat rate and solar PV fleet, and the 10-years load profile. Future studies can focus on incorporating the sensitivities of these parameters into the model or can use the foundation of this model to build on new VOS studies according to a specific location and available data from utilities. Another limitation to this study is that it does not include the effect of the load match factor, and loss saving factor.

As the results show the environmental and health costs can dwarf the technical costs and thereby determine the VOS. There are also second order effects that can be used to obtain a more accurate VOS values. For example, the negative impact of pollution from conventional fossil fuel electricity generation on crop yields [106] as well as PV production could also be considered in future work to give a more accurate V_8. In addition, as greater percentages of PV are applied to the grid the avoided costs will change and there is a need for a dynamic VOS akin to dynamic carbon life-cycle analyses needed for real energy economics [116]. This complexity will be further enhanced by the introduction of PV and storage systems [117] as it will depend on size [118] and power flow management and scheduling [119,120].

Perhaps the most urgent need for future work is accurate estimations of the value of avoided GHG liability costs because the magnitude of the potential liability [107,108] could overwhelm other subcomponents of the VOS. This is because as the realities of climate change have become more established, a method gaining traction to account for the negative externalities is climate litigation [107,108,121-131]. For utility VOS analysis this is particularly complex as it is difficult to know where to draw the box around environmental costs. As some studies have concluded there is liability for past emissions as well as for harm done in other nations [122]. Liability for disastrous events is also challenging to predict [126]. Combining both other nations and disaster creates liability potential that could become enormous with prioritization given to victims that are losing their land, culture, and lives due to climate change [127]. Tort-based lawsuits are already possible from a legal point of view [126], but there are other legal methods that could be used to reduce climate change such as public nuisance laws [128]. Some authors have argued a ‘polluters pay principle’ for carbon emissions [129]. Other studies have concluded that emitters such as conventional fossil fuel power plant operators should be forced to buy long term insurance in order to cover their share of climate change costs for minimizing risks in case of insolvencies [130]. Determining what such insurance premiums should be is another area of substantial future work. Determining what the greenhouse gas liability costs are for conventional electricity generators (as well as potential avoided insurance costs) that can be avoided with PV is extremely challenging. These estimates will become easier with time as climate change impact studies become more granular thereby assigning specific costs to specific amounts of emissions. In addition, realizing these climate liability costs in courtrooms will become more likely. As Krane points out it is clear that as the negative impacts of climate change grow more pronounced, the fossil-fuel based electricity industry faces a future that will be less accepting of current practices and that will increase economic (and maybe even industry existential) risks [131]. Avoiding these risks has real value, which should be included in the VOS in the future.

6. Conclusions

This study demonstrated a detailed method for valuing the incorporation of solar PV-generated electricity into the grid and analyzed the sensitivity of each VOS component to its input parameters, and the overall sensitivity of the VOS to the each of its components. Several components have been found to be sensitive to the utility discount rate, namely the avoided O&M fixed cost; avoided O&M variable cost; avoided generation capacity cost, and the avoided distribution capacity cost. Except for the avoided distribution capacity, the other components' value decreases with the increase of the utility discount rate. The distribution capacity is more sensitive to the discount rate than the other components. It increases with the discount rate and can be negative if the discount rate is very low. This has shown the necessity of carefully choosing the discount rate for VOS studies. Most of the VOS values do not have a high variability to the solar PV degradation rate even though its increase slightly reduces the value of each component, and the overall VOS. The environmental cost and the health liability cost are sensitive to the cost increase rate that can be tied to the emissions impact of the conventional energy sources. These two costs are likely to increase in the future with the worsening of the emission of fossil fuel sources and more information about its effects, which increases potential emissions liability for utilities. Finally, specific case studies could provide additional sensitivities on the few areas of the VOS that were not evaluated in this paper to create better VOS models. Overall the results of this study indicate that grid-tied utility customers are being grossly undercompensated in most of the U.S. as the value of solar eclipses the net metering rate. The implications of this sensitivity analysis demand a reevaluation of the compensation for U.S. PV prosumers as the VOS is much higher than net metering or any lesser compensation schemes. Substantial future work is needed for regulatory reform to ensure that solar owners are not unjustly subsidizing U.S. electric utilities. In addition, future work can obtain an even more accurate (and higher) value of VOS by evaluating economic development costs, the avoided fuel hedge costs, the avoided voltage regulation costs, secondary health and environmental effects such as increased crop yields from PV-reduced pollution, and accurate estimations of the value of avoided GHG liability costs or avoided GHG emissions liability insurance.

7. Acknowledgments

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Customer Driven.
Community Focused.℠

Austin Energy Resource, Generation and Climate Protection Plan to 2030
(As Recommended for Action to Austin City Council by the EUC and RMC on March 09, 2020)

On August 12, 2019, the Electric Utility Commission (EUC) created the Resource Plan Working Group[1] (Working Group) to provide leadership and guidance to Austin Energy and the Austin City Council on technical and market issues to meet environmental, efficiency and affordability goals established by the Austin City Council.[2]

This Austin Energy Resource, Generation and Climate Protection Plan to 2030 (2030 Plan) outlines the Working Group's recommendations and strategic goals and represents an extensive effort of the Austin community working through the Working Group and Austin Energy staff. The 2030 Plan is based on analysis of the risks, costs and opportunities to meet future demand for electricity. The 2030 Plan is intended to be flexible and dynamic in order to respond to changing circumstances, including customer electric load, economic conditions, energy prices, and technological development, while strictly committing to firm carbon reductions.

The 2030 Plan updates and replaces the Generation and Climate Protection Plan to 2027.[3] To the extent the provisions of this 2030 Plan are inconsistent with prior resource plans for Austin Energy or related City Council resolutions adopting such plans, this 2030 Plan will prevail upon its adoption by the City Council. The Working Group believes this 2030 Plan is groundbreaking in its approach and can serve as a model for others in achieving immediate, large-scale environmental benefits and reducing emissions, while maintaining affordable electricity rates.

Vision Statement

This 2030 Plan commits Austin Energy to continuing to provide affordable, dependable and safe electricity service to residents and businesses while pursuing the City of Austin's climate protection and sustainability goals[4] and the directives set forth in the Austin Climate Emergency Resolution.[5] As a part of its commitment, Austin Energy will maintain an energy supply portfolio sufficient to offset customer demand while eliminating carbon and other pollutant emissions from its electric generation facilities as rapidly as feasible within the limitations set by the Austin City Council. Austin Energy commits to providing access to the benefits of this 2030 Plan for limited-income communities and communities of color.

[1] The Working Group members are listed at the end of this 2030 Plan. The Resource Plan Working Group met ten times in late 2019 and early 2020.

[2] The Working Group Charter can be found at: https://austinenergy.com/wcm/connect/2febfc53-8bad-4029-aabe-a9e5461fb516/EUCWG-Sep26-Agenda-Packet.pdf?MOD=AJPERES&CVID=mRKMujG .

[3] See: Austin City Council Resolution No. 20170817-061, https://austinenergy.com/wcm/connect/6dd1c1c7-77e4-43e4-8789-838eb9f0790d/gen-res-climate-prot-plan-2027.pdf?MOD=AJPERES&CVID=mNO-55U.

[4] Austin Community Climate Plan, https://www.austintexas.gov/sites/default/files/files/Sustainability/FINAL_-_OOS_AustinClimatePlan_061015.pdf .

[5] https://s29017.pcdn.co/wp-content/uploads/2019/08/document_A5987C4F-D3DF-27DD-3FFC54EBBB0D1B0B.pdf . In August 2019, City Council passed Resolution No. 20190808-078 declaring a Climate Emergency and directing the City Manager to examine other objectives related to greenhouse gas emissions reduction (such as those set by the Austin Energy Resource Generation and Climate Plan) and identify the feasibility of accelerating the timelines of achieving such objectives.

Affordability

Affordability of electricity service for AE customers is an overarching goal of the 2030 Plan. Developments in the wholesale energy market in recent years have demonstrated that if Austin Energy carefully manages its portfolio it can achieve its environmental goals economically, efficiently and affordably. Austin Energy will do so with a commitment to the specific affordability metrics set by the Austin City Council.[6]

Generation Resource Objectives

As of March 2020, Austin Energy generates energy on an annualized basis equal to approximately 63% of its total customer load using carbon-free resources, 40% from renewable resources and 23% from the South Texas Project nuclear facility. As explained in more detail below, under this plan Austin Energy will eliminate its existing emissions through retirement of its carbon-emitting generation plants and will purchase additional, cost-effective, renewable energy resources.

-- *No New Carbon Generating Assets*

Austin Energy will no longer purchase, contract for or build long-term generation or storage resources that emit new carbon,[7] nor any additional nuclear power generation resources.

-- *Carbon Reduction Goals*

86% of Austin Energy's electricity generation will be carbon-free by year-end 2025, 93% will be carbon-free by year-end 2030, and all generation resources will be carbon-free by 2035. Austin Energy commits to advance these goals more rapidly, if feasible given technological developments, affordability, and risks to Austin Energy customers.

-- *Additional Renewable Generation Facilities*

Austin Energy will utilize its annual RFP process to seek the best available renewable energy and electricity storage opportunities to add to Austin's generation resource portfolio as necessary to meet 2030 Plan goals and to assess market trends for future planning. With the exception of the Local Solar goals set out in this report, the 2030 Plan does not designate the components of Austin Energy's renewable energy portfolio. Austin Energy will plan for least-cost and least-risk acquisition of renewable resources and electricity storage as available in the energy market and as necessary to meet 2030 Plan goals.

[6] Minutes of Austin City Council, February 17, 2011 at http://www.austintexas.gov/edims/document.cfm?id=148844 . The affordability goal approved by City Council is composed of two metrics: a) control all-in (base, fuel, riders, etc.) rate increases to residential, commercial and industrial customer to 2% or less per year; and, b) maintain AE's current all-in competitive rates in the lower 50% of all Texas rates.

[7] This will not apply to Austin Energy provisioning of emergency back-up generation for critical facilities.

Specific Actions to Achieve Generation Resource Objectives

-- *Fayette Power Project*

Austin Energy will maintain its current target to cease operation of Austin Energy's portion of the Fayette Power Project (FPP) coal plant by year-end 2022. Austin Energy will continue to recommend to the City Council the establishment of any cash reserves necessary to provide for that schedule.

-- *Decker Creek Power Station*

Austin Energy will maintain its current target to cease operations and begin retirement of existing Decker Steam gas-fired units, assuming ERCOT approval, with Steam Unit 1 ceasing operations after summer peak of 2020 and Steam Unit 2 ceasing operations after summer peak of 2021.

-- *REACH for Carbon Free by 2035*

Upon City Council approval of this 2030 Plan, Austin Energy will adopt a new market-based approach to accelerate reduction of carbon emissions by its legacy generators in the most economic manner available. This approach, known as *Reduce Emissions Affordably for Climate Health* ("REACH"), will incorporate a cost of carbon in the generation dispatch price, allowing Austin Energy to reduce generation output during low-margin periods but keep the resources available for high-margin periods. Austin Energy will apply an annual amount of approximately 2% of the prior year's PSA to implement REACH. Austin Energy will continue to adhere to the City Council affordability metrics through active portfolio management. The REACH plan is expected to reduce the utility's carbon emissions by 30% or approximately 4 million metric tons between approval of this 2030 Plan and Austin Energy's exit from FPP. Thereafter, the REACH plan is expected to reduce carbon emissions by 8% each year, while maintaining the flexibility to protect our customers' rates in periods of high prices in the wholesale market, until achieving zero carbon emissions by 2035.[8] Austin Energy will report semi-annually to the Electric Utility Commission and the City Council the realized reduction in carbon emissions from the REACH plan's implementation.

-- *Local Solar Resources*

In addition to the large-scale energy resources discussed above, Austin Energy will:

Achieve a total of 375 MW of local solar capacity by the end of 2030, of which 200 MW will be customer-sited (when including both in-front-of-meter and behind-the-meter installations).

[8] A graphic illustration of the REACH expectations is attached hereto as Exhibit A.

Continue a shared solar pilot program for multi-family housing and upon development of an automated electronic billing system, allow for expansion of this program.

Provide moderate and limited-income customers preferential access to community solar programs.

-- *Energy Efficiency and Demand Response*

In addition to the generation resources described above, Austin Energy will sponsor energy efficiency and demand response initiatives aimed to reduce overall system load and reduce peak demand as follows:

Achieve energy efficiency savings equal to at least 1% per annum of retail sales, targeting a total of at least 1,200 MW of demand side management (energy efficiency and demand response) capacity by 2030, including a target of 225 MW of economic peak demand response capacity by 2030.

Target serving at least 25,000 residential and business customer participants per year for all CES programs (Energy Efficiency, Austin Energy Green Building, Demand Response and Solar) with at least 25% of those customers being limited-income customers.

Commit to achieving 30 MW of local thermal storage by 2027 and 40 MW of local thermal storage by 2030.

Allow near real-time access to hourly energy use data for Austin Energy customers via the automated meter infrastructure, including compatibility with Green Button products and services.

Continue to move forward on energy code and green building development, including assessing the 2021 International Energy Conservation Code, and specific solar-ready, EV-ready, electric building-ready and net-zero requirements for commercial and residential construction for possible adoption in future codes.

-- *Equitable Participation in Programs*

Austin Energy will contract with a qualified third-party service provider to design and implement, with the co-operation of the Austin Equity Office, the convening of community meetings comprised of those living in, or serving those in limited-income communities and communities of color, and others who cannot afford or access current programs. These community meetings should identify barriers and recommend approaches, goals and outcomes to achieve more equitable energy efficiency, demand response and solar programs that reach customers currently underserved by existing programs because of income limitations and/or other barriers (renting, language barriers, etc).

This process is intended to craft recommendations for programs to best meet community needs and should also consider the best methods for coordinated delivery and implementation of energy program offerings with other available programs of the City, such as home repair and affordable housing, when serving limited-income communities. It is the task of Austin Energy to translate these community recommendations into affordable, successful programs.

The meetings should focus on those not currently engaged and should aim to include nonprofit home repair program contractors (Austin Housing Repair Coalition), Climate Plan Climate Ambassadors, and direct service organizations such as Family Eldercare, Caritas, Foundation Communities, Ladies of Charity and the Austin Tenant's Council. Meetings should be held in the community, accessible, near public transportation, accommodate work schedules and provide for children who may be in attendance. The community meetings should not seek input from anyone with a vested interest in the outcome of the plan, such as issue advocates, trade groups and vendors.

A final report should be provided no later than one year after the retention of the service provider. The report should be made to EUC, RMC and City Council and those bodies should hold Austin Energy accountable for implementing programs that address the recommendations of the meetings. Thereafter the EUC will annually review Austin Energy's progress in achieving these goals.

-- *Electric Transportation*

Austin Energy will pursue the Climate Protection Plan Goals and Austin Mobility Plan and expansion of Austin Energy revenue base by:

Supporting private-public partnerships that promote, market, and provide electric vehicle support to assist in the transition to electric transportation.

Support the City of Austin Fleet Services' electrification plan.

Evaluate equitable growth of public and private charging station deployments by offering rebates, operational support, outreach, and special public charging rates that includes support for limited-income populations.

-- *Transmission Study*

Commencing in 2020, Austin Energy will conduct a transmission study to assess the costs, benefits, technical and asset requirements of upgrading transmission resources to allow for the retirement of Austin Energy's existing natural gas generators as early as 2027, 2030 or as per the schedule set forth in this 2030 Plan. Austin Energy will also consider the viability of large-scale energy storage units and local solar installations within the Austin Energy load-zone to mitigate transmission requirements and exposure to peak electric market risks. Austin Energy will report its findings to the EUC and City Council.

Recommendations for Further Study

Austin Energy will seek new opportunities by engaging in the following further research:

Study the technical and economic feasibility of investing in emerging technologies, including dispatchable renewable energy, distribution-level energy storage, transmission-level storage as a non-wire alternative to transmission facilities, aggregated demand response, and Vehicle-to -Grid.

Continue to study the costs, benefits, risks and potential rate impacts of achieving 100 -200 MW of electric storage.

Assess opportunities to accelerate Plug-In Electric Vehicle (PEV)-based demand-response capabilities, including limitation of the Electric Vehicle Supply Equipment (EVSE) rebate program to smart devices that have Wi-Fi or other acceptable communication capabilities, to encourage the deployment of equipment that enables peak shaving for PEV's.

Upon completion of its automated meter infrastructure rollout, Austin Energy will assess how to monitor the demand response achieved by smaller consumers and reward responsive consumers.

Explore how to utilize new technologies, including energy storage systems and connected appliances, to increase the amount of Demand Response that can be used to control peak demand.

Continue active participation in the development and deployment of smart-grid technologies, and continue with an active and leadership role in the Pecan Street Project and other partnerships.

Take the lead with other city departments, especially Austin Water, to maximize DSM and load shifting opportunities within City of Austin operations.

Austin Energy will continue to support utility industry organizations working to develop best practices to prevent methane and hydrocarbon leaks in natural gas fields and in pipelines.

Future Process

Austin Energy will conduct an update of this 2030 Plan in advance of its cost-of-service study in approximately five years from adoption of the 2030 Plan, or sooner if significant changes in technology or market conditions warrant. At the end of 2022 the EUC will decide whether there have been sufficient changes in circumstances that an interim update would be beneficial.

Austin Energy will provide an update every two years to the EUC, RMC and City Council reporting progress towards reaching established goals.

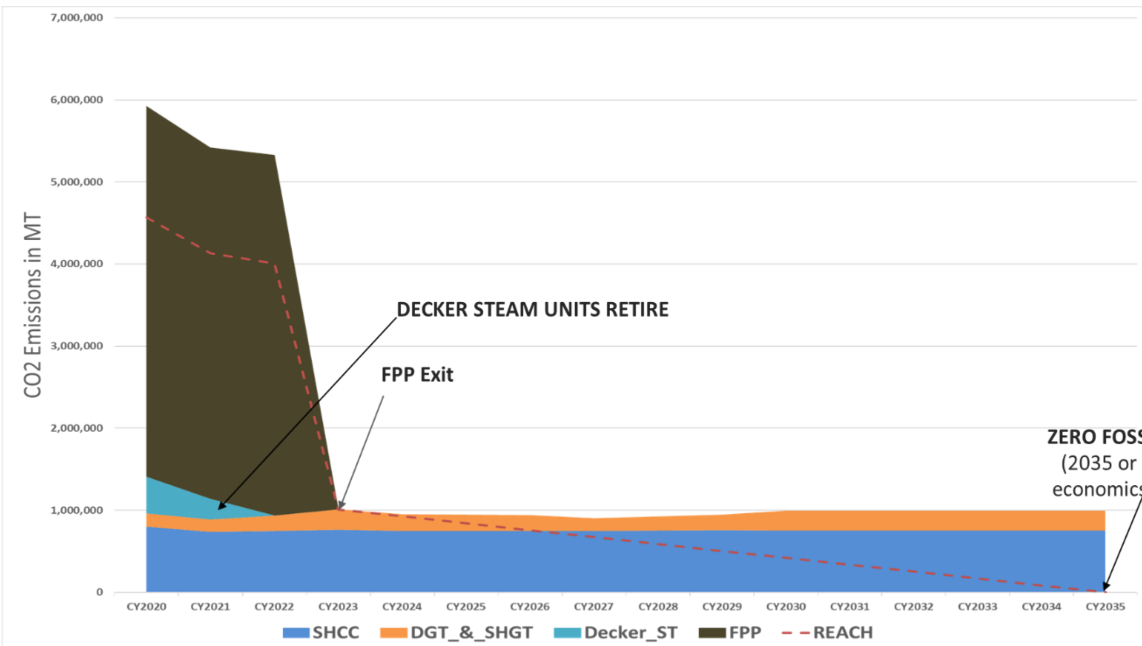
Austin Energy will work to ensure that future resource planning advisory or stakeholder groups include broad based customer representation, including representatives of residential and limited-income customer advocacy organizations and communities of color.

This 2030 Plan Was Unanimously Approved by the Members of the Austin Energy Generation Resource Working Group on March 5, 2020:

Cary Ferchill (Chair), Bob Batlan, Al Braden, Janee Briesemeister, Todd Davey, Leo Dielmann, Karen Hadden, Marty Hopkins, Ed Latson, Cyrus Reed, Ruby Roa, Luis Rodriguez, Kaiba White

Exhibit A to the 2030 Plan

Austin Energy Generation Emissions Projections*



Austin Energy Generation Emissions Projections in Metric Tonnes (MT)																
	CY2020	CY2021	CY2022	CY2023	CY2024	CY2025	CY2026	CY2027	CY2028	CY2029	CY2030	CY2031	CY2032	CY2033	CY2034	CY2035
Current Goals	5,928,016	5,419,359	5,328,741	1,011,916	952,147	945,250	940,819	905,102	923,256	946,587	994,288	994,288	994,288	994,288	994,288	994,288
REACH	4,570,050	4,133,072	4,008,219	1,011,274	927,001	842,729	758,456	674,183	589,910	505,637	421,364	337,091	252,819	168,546	84,273	0

*These are projections as of March 2020 and actual results for a given period may differ depending upon market conditions.