Comments of Vote Solar on the Draft NARUC Manual on Distributed Energy Resources Compensation

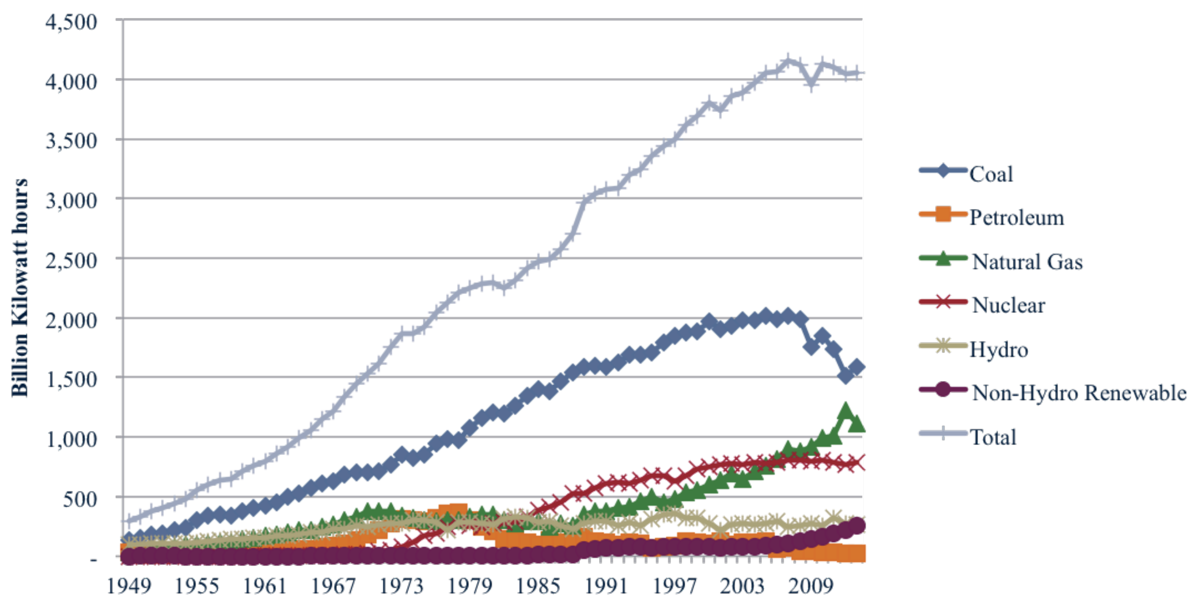
Vote Solar appreciates the opportunity to provide comments and feedback on the Draft NARUC Manual on Distributed Energy Resources Compensation ("manual" or "draft manual") prepared by NARUC's Staff Subcommittee on Rate Design (Subcommittee) released July 21 of this year. Vote Solar is a non-profit grassroots organization working to fight climate change and foster economic opportunity by bringing solar energy into the mainstream. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. We have staff in California, Colorado, Maryland, Massachusetts, and Washington, D.C. Over the past 24 months, Vote Solar staff have engaged in formal proceedings related to distributed solar generation in Arizona, Arkansas, California, Colorado, District of Columbia, Florida, Georgia, Idaho, Maryland, Massachusetts, Minnesota, Mississippi, Nevada, New Mexico, New York, South Carolina, Utah, Vermont, and Wisconsin. Vote Solar is not a trade group or affiliated with the solar industry.

Executive Summary

The draft manual is an excellent start towards the development of comprehensive information and guidelines that will be useful to regulators, their staffs, utilities, and stakeholders engaged in formal and informal regulatory processes addressing Distributed Energy Resources, or DER. We agree with and support much of the information contained in the manual and here address areas we believe need emphasis, modification, or additions. Because of the rapidly changing environment in which regulators work, we urge the Subcommittee to frame the manual as a dynamic piece that should receive regular updates as technologies and other economic factors change, perhaps every three to five years.

The introduction to the draft manual describes two goals. First, to "create a practical set of tools – a manual, if you will – for regulators who are having to grapple with the complicated issues of rate design for distributed generation and for other purposes." Second, "[t]his Manual is intended to assist jurisdictions in developing policies related to DER compensation." As the manual notes, DER consists of many technologies, not just distributed solar generation. In our view DER compensation and rate design are two different matters, and each should be evaluated objectively. While rate design and DER compensation can be related to one another, it is important to understand their distinctions. As such, we have maintained and further emphasized the differences between these two areas of regulatory policy in our comments on the manual.

The technology revolution over the last 10-20 years has both increased the use of electricity for new appliances (e.g. the internet), devices and services including mobility (electric vehicles), and allowed customers to take greater control over their utility bills by first becoming more efficient in their consumption, and then by generating their own power. Increasing numbers of consumers perceive that the value of self-generated power exceeds the value of power from the incumbent utility. As a result of these trends, we are seeing less need for additional bulk power generation and in some regions the need for early retirements. There is no doubt that continued efficiency efforts and self-generated power will depress load growth in the future. A utility revenue model that is contingent upon load growth and the addition of assets to increase shareholder value is not compatible with anything but monopoly service and requires rethinking.



Source: EIA, *Total Energy,* Electricity Net Generation, 2014. http://www.eia.gov/totalenergy/data/monthly/index.cfm#electricity.

With little sales growth on the horizon, utilities must find other ways to operate profitably. Strategies of increasing revenue or reducing costs have practical limits. The DER manual is well timed to be a catalyst to a discussion of new utility business models that will lead to a transition to a more decentralized, electric system.

One of the most insightful paragraphs in the draft manual is found at the outset of Section IV. We note that this observation could be elevated to a guiding principle for regulatory processes related to DERs. The Manual should acknowledge at the beginning that there is a critical need to gather and evaluate empirical data on the advantages and disadvantages of relying more on DERs as policy is formulated.

> "Often, discussions on DER are made more difficult due to the regulatory framework and utility incentives that have been in place for decades, or in some respects a century, are being challenged by these new technologies. Traditional means of regulation, rate design, and planning largely assume the utility will meet all demand with generation; with the increase in DER, and the recent lack of load growth, the current regulatory and utility models are a constraint to effectively addressing the

growth of DER and its impacts on utility and regulatory frameworks. This is made more difficult by parties in regulatory proceedings often only addressing one aspect of the interaction; either cost recovery for utilities or customer compensation on the part of the advocates. This separates the conversation and makes it harder to reach an agreement that is beneficial for the public interest. Though these specific challenges will lessen with time as knowledge and experience are accumulated, currently one of the biggest issues, if not currently the biggest, is the dearth of empirical data available on the impacts and specific pros and cons of the different ways regulators can address DER and rate design. Identifying and understanding these challenges will assist the regulator in determining an appropriate rate design for its utilities." (page 28)

Vote Solar strongly supports these sentiments, and many of our comments address the need for data and analysis, as well as for a more comprehensive view of DER, customer classes, the utility system, and the utility business and regulatory model. Our review of the draft manual found a number of consistent themes in our comments that apply to many areas. We list these here as a way of setting the stage for the more detailed comments to follow.

1. Regulators should evaluate long-term impacts when considering policies that affect DER deployment.
2. Rate design guidelines and principles should be treated separately from DER compensation methods and proposals.
3. DER evaluation should be comprehensive across all customer classes.
4. More focus should be given to developing and applying good process principles related to the collection and analysis of data, the formulation of pilot projects, and stakeholder collaboration.
5. DER policies should be periodically re-evaluated at predetermined DER penetration threshold levels. Caution should be observed regarding setting policy today based on the impacts of levels that are likely to occur many years in the future.
6. Methods, proposals, and recommendations that create barriers to the deployment of DERs should be avoided.
7. The manual should provide unbiased guidelines and recommendations to regulators. The anti-solar bias in Sections IV and V should be eliminated.

We have organized the body of our comments to address DER technologies first (including Sections III.A-D and VI of the draft manual), followed by rate design (addressing draft manual Sections II, III.E-G, and IV), and finally DER compensation (Section V). As noted previously we believe it is important to segregate the discussion of rate design from that of DER compensation. While rate design certainly can affect the economics of DER, the purpose and goals of rate design are considerably more far reaching than those of DER compensation.

Following on to the themes, we have brought all of the recommendations made in these comments into the following summary. Discussion of individual sections and rationale for the comments and recommendations can be found by turning to the appropriate section of these comments.

Table of Contents

Executive Summary	1
Summary of Detailed Recommendations	5
DER Technologies	11
Rate Design	17
DER Compensation	43

Attachments

Good process letter	A
Bonbright Criteria for a Sound Rate Structure	B
Summary of inherent cross-subsidies	C

Summary of Detailed Recommendations:

Recommendations related to DER Technologies Sections III.A-D and VI

General recommendations for the manual:

- Recognize the capabilities of DER, including the provision of ancillary services in assessing the value of DER by regulators.
- Provide guidance for establishing threshold penetration levels at which point regulators should "take a closer look" at the effects of distributed solar generation (DSG) penetration.
- Emphasize the effects of integrating DER technologies and propose strategies for regulators to do so.
- Reflect the attributes of regulatory processes that could be more effective in achieving consensus results as alternatives to formal litigation.
- Acquire and utilize accurate, reliable, and robust data for evaluations;
- Analyze opportunities for integrating the rich variety of DER technologies in ways that increase grid efficiency and reduce the need for utility grid investments.
- Avoid erecting barriers to DER technology adoption;
- Establish regulatory processes to examine changing technology, and to promote integration of those that benefit customers and the grid.
- The manual should make clear that the utility asset investment incentive in the current regulatory model requires caution on the part of regulators when reviewing fixed asset investment proposals from utilities.

Specific recommendations regarding the definition of DER (page 17):

- Include technologies that can shift load or supply from one period to another.
- Include advanced inverters.

Recommendations related to Rate Design Sections II, III.E-G, and IV

Recommendations for Rate Design Section II.B.1:

- General: Identify the degree of actionable price signal in each of the rate designs addressed.

Flat rates:

- Note that flat rates do not require any special type of meter.

Block rates:

- Note here too that inclining block rates do not require any special type of meter.

- Strike any discussion of declining block rates as we believe these are not in the public interest, and discouraged by PURPA.

Time variant rates:

- Note here that time-variant rates (including PTR, CPP, and RTP) do require an electric meter capable of measuring the timing of customer consumption.
- Specify time varying rates better reflect cost causality, provide an actionable price signal, and cost reductions related to customer response.

Three part rate/Demand charges:

- The link between individual small customer peak demands and cost incurrence is limited and weak;
- For small customers with limited technological capability, demand charges do not provide an actionable price signal and effectively act as a fixed charge.
- Demand charges require an electric meter capable of measuring the timing of maximum customer consumption.

Fixed charges and minimum bills:

- Striking a balance between price signals and cost recovery requires consideration of multiple perspectives.
- There is no requirement or even economic theory supporting fixed charges for the recovery of costs that are fixed in the short term.

Revenue Decoupling (Section II.C.2):

- Regulators should carefully consider the structure and implementation of decoupling to avoid unintended consequences;
- Regulators should consider changes in the utility risk profile resulting from the implementation of decoupling.

Recommendations for additions to the rate reform subsections III.E.1 through 3:

- Rate setting is a snapshot of relationships among assets, expenses, and customer class characteristics, and does not set required individual customer revenue contributions. These relationships will begin to change immediately following a rate case based on economic conditions, fuel prices, uptake of DER, and personal behavioral changes. This narrow issue can be addressed through mechanisms like decoupling.
- The revenue/cost relationship must be viewed over the long term.
- Charges for revenue shortfalls should be complemented with credits for revenue windfalls.
- Significant deployment of DER technologies can result in revenue erosion <u>or enhancement</u> in the short term.
- Thresholds for review should be established.

Recommendations for additions to the Technology and physical issues subsections III.E.4:

- At current levels of penetration of customer-sited generation, no deleterious effects have been documented;
- The current strategies of proper use of interconnection standards and increased visibility into the distribution system mitigate these concerns;
- As penetration levels of customer-sited generation grow, strategic deployment of other DER technologies including advanced inverters that can mitigate the impacts of concern;
- Establish reasonable penetration thresholds for review.

Recommendations for additions to the Benefits subsection III.F:

- The benefits of DSG have been well studied and there is a growing consensus on positive benefits;
- The least biased studies are those sponsored by agencies without a financial self-interest;
- Cost-benefit studies should be performed for all rate classes in which customers have deployed DSG, and can inform rate design choices;
- Commissions should be clear that DSG integrated with other forms of DER can provide greater benefits and should be studied; and
- Rate design changes, if any, should not be confined to the residential and small commercial classes.

Recommendations for additions to the Ownership and control subsection III.G:

- Establish reasonable penetration thresholds for review.
- Consider integration of the full suite of DER, and the benefits of such integration to the utility grid.

Rate Design Considerations (Section IV): Overall recommendation

- Data and analysis forms the basis of good decision-making.

Recommendations for additions to the Different customer classes subsection IV.A.1.b:

- Integrate the following factors into subsection IV.A.1.b.
  - Do DER customers have a unique service, usage, or cost characteristics that would be tracked by a separate rate class;
  - Are there now or are there expected to be a sufficient number of customers to justify a new rate class; and,

- Does the utility provider have sufficient capability/technology (such as metering/billing) to separate the customers and bill differently.

- Proposals for separate rate classes for a subgroup of small customers (e.g. residential DSG customers) should always be supported with data and analysis, and compared to other subgroups with equally different characteristics from the core group of customers.
- Separate rate classes should be analyzed in a manner similar to other rate classes and allocated costs based on the services provided to them by the utility.

Recommendations for Long-term vs. short-term costs/benefits/outlooks Section IV.A.3:

- Note that interconnection related costs are typically recovered from the interconnecting customer, and other distribution costs are speculative and require supportive data and analysis.
- Current rates are based on broad class averages and do not reflect the costs to serve individual customers within the class;
- No costs (not paid by the DER customer) have been demonstrated to exist as a result of connecting DER to the grid;
- Shortfalls in the recovery of short-term fixed costs are largely a myth, and current utility investments that provide long-term benefits but increase current rates have been a part of utility planning and ratemaking for decades. The manual should emphasize the long-term view.

Recommended framework for evaluation of Impacts on other customers subsection IV.B:

- Evaluation should be based on actual data and analysis;
- Time frames for analysis: long-term, short-term, or both, and why;
- Comprehensiveness: the scope of customer classes to be reviewed and analyzed;
- DER technologies being scrutinized, and the degree of integration considered.

Recommendations for changes to the subsections under Impacts on other customers Section IV.B:

- Combine like impacts, i.e. numbers 2 and 5.
- Impact number 6, Lifespan of utility assets do not match lifespan of DER, identifies no impact, and should be stricken.
- Eliminate biases in each remaining impact.
- Compare DER impacts with those of existing inherent rate subsidies that have long been found reasonable.
- Avoid speculation on future impacts not well grounded in facts.
- Evaluate impacts with a long-term view.

Recommendations for changes to the subsections under Impacts on utility Section IV.C and Cross subsidies, including cross-class Section IV.D:

- Avoid regulatory changes that would decrease access to DER technologies for low-income customer (reference bottom of page 34).
- The entire subsection IV.D presumes outcomes to evaluation processes that have not been conducted, and without data, evidence, or analysis must be stricken due to extreme anti-DER bias.

Recommendations for changes to the Grandfathering Section IV.E:

- Strike the following three paragraphs: the last full paragraph on page 37, the paragraph that flows from page 37 over to page 38, and the first full paragraph on page 38.
- Scrub unrealistic customer choices such as "whether or not to maintain the DER system."
- Include that regulators should consider the impacts on a spectrum of customers, not just the average or typical customer.
- Create a new subsection that addresses the implementation of grandfathering policy under which points 3, 4, and 5 belong.
- Include that regulators should not use the DER systems installed under one pricing regime as a proxy for new systems after that regime changes significantly.
- No grandfathering for customers should be accompanied by no opportunity for related utility stranded cost recovery.

Recommendations to DER Compensation Section:

Overall recommendations to the DER Compensation Section:

- Strike subsection V.C, demand charges, as it is addressed in the manual's subsection on rate design.
- Move subsection V.D, fixed charges and minimum bills, to section II.B.1 as these are rate design issues.
- Eliminate bias in the descriptions of DER compensation policies.
- Evaluate DER compensation alternatives with full consideration given to the following framework elements:
    - Appropriate time frame: short term, long term, or both;
    - Comprehensive review of all customer classes with DER
    - Full complement of stand alone and integrated DER technologies

Recommended framework for evaluation of Net Energy Metering Section V.A:

- Customers have the right to reduce consumption through use of DER;

- Full consideration must be given to the compensation received by the utility from the actual consumer of excess solar energy generation.
- Clarify that excess energy is not physically "banked."
- It's important for the manual to note that the situation of "a small fraction of households" remains applicable today in many states and supports the concept of establishing threshold penetration levels for NEM review.
- The *complications of NEM* described on pages 42 (near bottom) through the end of the NEM subsection on page 44 of the manual are largely biased and not supported by facts. The manual should provide topical guidance for regulators for evaluation of NEM, but should not reflect assumptions and effects that are not supported by facts and analysis relevant to the regulators state, practices, and policies.

Recommendations for changes to the Valuation methodology Section V.B:

- The manual should note that the BA/SA framework results in a separate sale of energy, effectively at wholesale, from customer to utility and may have unintended consequences.
- The manual should note the utility has monopsony power over the customer as the only purchaser in the market.
- The manual should recommend regulators allow DER customers the option of switching to a BA/SA framework from a net metering regime, rather than imposing such a dramatic change.

Recommendations for changes and additions to the Standby and back up charges Section V.E:

- Sudden changes in cloud conditions impacting the production of more than a few systems is not supported by facts;
- Any proposal for imposition of standby or backup charges must be based upon real data and factual analysis;
- Regulators should evaluate the extent to which DER could alter system operations and requirements, based upon facts and data from actual experience;
- Consideration should be given to integrated DER technologies, and the geographic diversity of DER systems.

Recommendations for two additional recommendations to regulators in Interconnection fees and metering charges Section V.F.

- The interconnection standards utilized by the State should be updated to reflect the most current FERC Small Generator Interconnection Procedures set forth in Order No. 792.
- Individual customers should not be required to pay for production meters on their DER systems for research or information gathering purposes, particularly

given the asset-deploying incentives built in to the regulatory model. We do not dispute the need or customer cost responsibility for production meters to determine generation for the purposes of tallying renewable energy credits.

DER Technologies[1]

Definition

Given the focus of the manual on DER technologies, we support the Subcommittee's emphasis on defining the types of resources encompassed in section III. We believe this section should be the first substantive section of the manual to set the stage for the information that follows. The manual includes a series of definitions (DOE, LBNL, EPRI, and several states) of DER on pages 15-17, ultimately establishing its own definition as follows:

> A DER is a resource sited close to customers that can provide all or some of their immediate power needs and can also be used by the system to either reduce demand (such as energy efficiency) or increase supply to satisfy the energy or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include photovoltaic solar, wind, and combined heat and power (CHP), energy storage, demand response, electric vehicles, microgrids, and energy efficiency.

We believe the Subcomittee's definition works fine for the purposes of the manual, but suggest one addition. While it may be intuitively obvious to a reader, we recommend specifying that some DER has the capability to move load or generation from one period to another, i.e. load or supply shifting.

- ➢ We recommend adding technologies that can shift load or supply from one period to another into the manual's DER definition (page 17).

We also want to emphasize the importance of a definition that will allow for the incorporation of new technologies and integration of such technologies into the grid. We are in a period of rapid technological change, and regulators should be prepared to deal with advanced technologies that provide services to customers or the grid which we may not even envision currently.

For example, the manual notes "[o]ther services and applications as envisioned by vendors and suppliers, such as microgrids, Volt/VAR, frequency ride-through, and locational ramping, also do not clearly fit inside current definitions of resources. These types of services, while clearly valuable and potentially worthy of compensation, are not as universally accepted as DER primarily due to lack of use across the industry, lack of sufficient technology installed which can assist in measuring, and scheduling such resources with greater certainty and confidence." (page 20) Indeed several of these

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[1] Addresses Sections III.A-D and VI of the draft manual.

services can be provided by DER technologies that do clearly fall within the Subcommittee's definition. For example, distributed solar (with advanced inverters) and storage can both supply many of the ancillary services noted, which can improve the efficiency of the grid without the need for the utility to invest in new distribution equipment, thus reducing costs for all customers.

- We recommend the capabilities of DER, including the provision of ancillary services, be recognized in assessing the value of DER by regulators.

Thresholds

The Subcommittee makes a very good point in the opening paragraph of section III: "[O]nce DER adoption passes certain levels, DERs can begin to cause significant issues for traditional rate making, utility models, and delivery of electricity." "[A]fter empirically establishing at what adoption level they will affect the grid, regulators should explore and implement rates and compensation methodologies that will lead to greater benefits for the public, customers, and utilities alike." (page 15) Similar comments regarding penetration levels are found throughout the manual.

We want to provide extra emphasis for this point about thresholds from two perspectives. First, the definition of DER is comprehensive, yet a good portion of the manual focuses on distributed solar generation or "DSG." There has been much attention on DSG around the country and relatively little on other forms of DER, including electric vehicles or "EVs." We understand the concerns of EEI, utilities and some other stakeholders we've heard in our work around the country about the effects in some states around the rapid growth of DSG, but clearly the issues faced in Hawaii where the DSG capacity penetration exceeds 35% on some islands, are very different than those faced in Alabama (and many other states) where DSG capacity deployment is less than one half of one percent.

Moreover, the Subcommittee acknowledges the usefulness of reliable data collected through the deployment of DER can help regulators understand appropriate thresholds:

> "Knowing power flows, voltage fluctuations, and available capacity for feeders across the distribution system can greatly assist in helping locate DER in locations most beneficial to the grid. Having this information can also assist in developing appropriate DER compensation methodologies, as without this level of knowledge about the grid, DERs will be located with little input from the utilities. Similarly, recognizing how to use this information to understand adoption levels of technology will assist the regulator in determining when a change is needed." (page 63)

We urge the Subcommittee to note the broad spectrum of penetration rates and suggest some guideline threshold penetration levels for Commissions to "take a closer look" at the effects of DSG penetration. The penetration in CA, for example, exceeds 5% and there have been no demonstrable impacts, thus we would recommend an initial *closer look* threshold of between 5 and 10% penetration on an energy basis.

Second, as part of this process, we urge the Subcommittee to include consideration of the effects of integrating other DER technologies and strategies as a means of mitigating anticipated effects of high DSG penetration. Customers will likely be better off if a portion of load can be served safely and reliably through customer-owned integrated DER technologies, rather than utility investment in assets and equipment that provide the same service but are idle or underused for much of the year.

Again, we believe the concept of identifying thresholds for review is critically important to assure wise use of the resources of the Commissions. The Subcommittee's summary at the end of Section III.D. is very well put, and we highlight it here:

> "Thus, in any evaluation, the utility's specific characteristics and their most likely reaction to any rate design changes must be clearly and thoroughly determined before questions and challenges from DER are addressed through rate making changes. The level of transparency and detail on the operations and physical characteristics of a utility's distribution system may be significantly more than may have been employed in the past." (page 22)

In summary, we make the following recommendations for Section III.D:

- The manual should provide guidance for establishing threshold penetration levels at which point regulators should "take a closer look" at the effects of DSG penetration.
- The manual should emphasize the effects of integrating DER technologies and propose strategies for regulators to do so.

Transparency

We also agree with the Subcommittee's view that "each utility territory is unique with its own set of circumstances which may render the ideal regulatory treatment from one territory unworkable or not advisable in another." (page 22) However, in many of the proceedings in which we've been engaged, there have been dramatic claims made about the effects of DSG (and often similar between states), but precious little data to support the claims. In some cases, the reason has been simply that the data doesn't exist while in others it has been deemed confidential. Regulatory commissions cannot make well-informed decisions without the necessary data to support those decisions.

Moreover, this need for transparency extends to the grid itself – pulling back the curtain on optimizing the location of all forms of DER. The importance of this transparency is well described in the last section at the end of the manual in the "Hosting Capacity" subsection VI.C.4. However, the description therein could be misinterpreted as applying only to DSG. We urge the Subcommittee to clearly indicate that the transparent hosting capacity should be made available for not only DSG but in such a fashion that informs developers of the specific needs for integrated DER technologies across the distribution grid.

<u>Process</u>

On June 23, 2016, a group of 32 consumer, low-income, environmental and technology-specific advocacy organizations including Vote Solar sent a letter (included as Attachment A) to President Kavulla addressing a regulatory process that would improve the likelihood of success and manage risk associated with the changing landscape. In a nutshell, we offered specific recommendations for a good regulatory process for evaluating rate design changes summarized as follows:

- Assessment and analysis of state conditions and sound data when determining the need and pace for rate-design change;
- Collaborative, upfront, open, docketed processes that explore the range of rate-design options in advance of or in lieu of rate cases;
- Data-driven rate-design inquiries;
- Pilots and testing for novel or untested rate designs prior to wide-scale adoption;
- Consideration and accommodation for low-income and vulnerable customers in rate design; and
- Sufficient opportunity to educate customers on new/shifting rate designs well in advance of their implementation and the development of tools to do so.

We believe these are important procedural principles and should be incorporated into the manual, especially in these times of rapid technological change, as an alternative to repeated litigation. In our view, transparency and flexibility are key attributes of future regulatory paradigms addressing DER.

> ➢ Reflect in the manual the attributes of regulatory processes that could be more effective in achieving consensus results as alternatives to formal litigation.

The threshold of review, data needs, and DER integration issues we find critical to the future efficient delivery of electricity services are well summarized in Section VI:

> "Advanced technologies can not only support operations of a grid, they can support regulators in making decisions about rate design. Communication abilities are being coupled with advanced technologies, providing data to the utility, and potentially to the regulator as well, which can be used to make informed decisions about compensation. The resulting data can help the utility measure the impacts of DER, more accurately measure consumption and generation, and analyze the need for DER at a specified level (meter, bus, feeder, circuit). With this information the regulator can also make more accurate cost and benefit analysis of DER, can evaluate the current rate design methodology, and continuously reevaluate the proper methodology as levels of penetration change, new technologies and services are developed, and other objectives or public policy goals need to be met. Additionally, using this information, a regulator

can better identify adoption levels across a jurisdiction. Being aware of the continual pace of change and adoption rates of technologies by customers, a regulator can identify appropriate strategies for addressing these changes in a more proactive manner." (page 60)

In addition to reiterating the importance of target and threshold review DER penetration levels, this summary and the paragraph that follows (Subsection VI.A, first paragraph) suggest several DER evaluation guidelines we recommend be highlighted in the manual:

- Acquire and utilize accurate, reliable, and robust data for evaluations;
- Avoid erecting barriers to DER technology adoption;
- Establish regulatory processes to examine changing technology, and to promote integration of those that benefit customers and the grid.

The admonition for ignoring the manual's guidelines by the Subcommittee at the close of subsection A on page 62 is well taken and should be highlighted:

> Reforms that are rushed and not well thought out could set policies and implement rate design mechanisms that have unintended consequences such as potentially discouraging customers from investing in DER resources, or making inefficient investments in DER.

Data – the critical starting point for compensation and rate design evaluation

We support the *eye to the future* approach in Subsection VI.B addressing the need for data, and its use in "helping locate DER in locations most beneficial to the grid. Having this information can also assist in developing appropriate DER compensation methodologies, as without this level of knowledge about the grid, DERs will be located with little input from the utilities." (page 63). The manual notes "[u]se of data generated by advanced meters can assist regulators to identify potential DER compensation methodologies, and have the data available to support the viability of the methodology as well as use it for settlement and compensation." (page 64) Vote Solar also points out that advanced inverters, the devices in a PV installation that converts DC electricity to AC, have many untapped capabilities that could include data collection. Advanced inverters are discussed on page 65, but don't seem to be part of the concept of integrating advanced technologies for maximum efficiency. We recommend:

- Data collected be used to analyze opportunities for integrating the rich variety of DER technologies in ways that increase grid efficiency and reduce the need for utility grid investments.
- Inclusion of advanced inverters within the definition of DER technologies.

The manual also discusses the potential for utility investment in additional infrastructure and technology including Advanced Distribution Management System (ADMS) or a Distribution Energy Management System (DERMS) to help meet customer demands while maintaining reliability, resilience, and flexibility. (page 64) We applaud moves towards more robust distribution infrastructure but with the regulatory return on asset incentive model currently in use also urge caution with respect to allowing utilities the opportunity to invest in more fixed cost assets that may not be the lowest cost solution or may become obsolete over time. We recommend:

- The manual make clear that the utility asset investment incentive in the current regulatory model requires caution on the part of regulators when reviewing fixed asset investment proposals from utilities.

Summary of Recommendations related to DER Technologies Sections

General recommendations for the manual:

- Recognize the capabilities of DER, including the provision of ancillary services in assessing the value of DER by regulators.
- Provide guidance for establishing threshold penetration levels at which point regulators should "take a closer look" at the effects of DSG penetration.
- Emphasize the effects of integrating DER technologies and propose strategies for regulators to do so.
- Reflect the attributes of regulatory processes that could be more effective in achieving consensus results as alternatives to formal litigation.
- Acquire and utilize accurate, reliable, and robust data for evaluations;
- Analyze opportunities for integrating the rich variety of DER technologies in ways that increase grid efficiency and reduce the need for utility grid investments.
- Avoid erecting barriers to DER technology adoption;
- Establish regulatory processes to examine changing technology, and to promote integration of those that benefit customers and the grid.
- The manual make clear that the utility asset investment incentive in the current regulatory model requires caution on the part of regulators when reviewing fixed asset investment proposals from utilities.

Specific recommendations regarding the definition of DER (page 17):

- Include technologies that can shift load or supply from one period to another.
- Include advanced inverters.

Rate Design[2]

Overview and Framework

In Section II, the manual sets forth several points important for regulators to keep in mind when considering the historical framework for regulation and rate design. First, "it is recognized that most existing rate designs are not explicitly designed to reflect accurate costs to serve each customer. Electricity costs vary throughout the year, month, week, day, and hour; rate design balances this reality to allow for the utility to recover its total costs of service (*i.e.*, revenue requirement), over the course of time, be it monthly, yearly, or across rate case proceedings." (page 6) In other words, current rate designs are based on very broad averages or summations of customer characteristics within a class and do not reflect the characteristics of individual customers. This distinction was highlighted in a recent report unpacking and evaluating demand charges.[3]

Second, the manual notes that "DER may impose new costs onto the utility" (page 6) but does not address here the associated savings and benefits to the utility from DSG, and especially when DER technologies such as Demand Response, storage, and other non-generating DER are integrated. Moreover, outside of Hawaii, there has been virtually no evidence of costs imposed on a utility through the connection of DER to the grid, including DSG. Most, if not all, interconnection standards require the interconnecting DSG customer to pay for any incremental cost additions to the grid as a result of the interconnection, and also charge a fee to recover administrative costs. Thus, we urge the Subcommittee to note that such costs are speculative at best, and that there are many benefits of deploying DER.[4]

Finally, the manual also correctly points out that "[i]n the short-term, many of the costs of a utility are fixed. In the long-term, many of the costs of a utility are variable. The question, then, is how much of a utility's costs should be considered fixed for the purposes of setting rates." (page 7) This question is at the core of rate setting, resource planning and the controversies surrounding DER, and is discussed below.

Introduction to rate design (subsection II.B, pages 8-10)

> Our initial recommendation is for the Subcommittee to propose some basic rate structure guidelines for regulators to use when evaluating and comparing alternative rate structures, such as the criteria set forth in Professor James Bonbright's 1961

[2] Addressing draft manual Sections II, III.E-G, and IV
[3] See "Charge without a Cause" in the Electricity Journal, August, 2016: https://electricitypolicy.com/Articles/charge-without-a-cause-assessing-electric-utility-demand-charges-on-small-consumers
[4] Relevant benefit studies are discussed below in these comments.

Principles of Public Utility Rates.[5] Below we comment on the individual structures listed.

a) *Flat rate*: The characteristics of this rate structure meet some of the objectives identified by a state, such as affordability, according to the manual. In addition, flat rates meet the key Bonbright criteria of simplicity, understandability, public acceptability and feasibility of application. We generally agree with the manual's description, including the lack of a time-differentiated price signal. However, this is the trade-off for simplicity.

   - We recommend noting that flat rates do not require any special type of meter.

b) *Inclining block rate*: Here too, we generally agree with the manual's description, including the lack of a time-differentiated price signal. While slightly more complicated than flat rates, we believe IBRs still meet the Bonbright criteria. The defining feature however of higher prices for greater usage, is an important conservation signal. IBR's also don't recognize the timing of costs.

   - We recommend noting here too that inclining block rates do not require any special type of meter.
   - We recommend striking any discussion of declining block rates as we believe these are not in the public interest, and discouraged by PURPA.

c) *Time-variant rates*: the manual fairly describes the attributes of time-based rates: recognizing the timing of utility cost differences, providing flexibility to the regulator for a wide variety of goals, and so on. The footnote discussing peak time rebates (PTR) is helpful (page 9), and we highlight that the PTR alternative can be implemented in conjunction with flat volumetric rates, inclining block rates, or time varying rates, but also note that the nature of PTR requires metering capable of measuring consumption over specific, sometimes variable hours during a billing cycle. Similarly, critical peak pricing (CPP) is the other side of the same PTR coin, but rather than providing a rebate to customers for load reductions during certain times (the carrot), CPP imposes much higher prices during those times (the stick), but both effectively have the same goal.

   An important and defining feature of time varying rates is the specificity of tying costs incurred to rates and time periods. Because the peak, shoulder and off-peak hours and prices are explicit and known by customers, they provide an actionable price signal. PTR and CPP can also provide such a signal, although the advance notice is often much shorter, e.g. 24 hours. Finally, the use of real time pricing (RTP) is a mixed bag. Residential and small customers may have difficulty responding immediately to market prices without technologies and appliances that can be pre-

[5] Criteria for a Sound Rate Structure, Principles of Public Utility Rates, 1961, Attachment B.

programmed to be price-sensitive. Day ahead RTP begins to move away from direct market signals, but may be more reflective of market conditions.

- We recommend noting here that time-variant rates (including PTR, CPP, and RTP) do require an electric meter capable of measuring the timing of customer consumption.
- We recommend specifying time varying rates better reflect cost causality, provide an actionable price signal, and cost reductions related to customer response.

d) *Three part rate/demand charges*:[6] The complexity of demand rates is considerably higher than any of the rates previously discussed from the customer's perspective. We recommend the recent "Charge Without A Cause?" paper which unpacks the attributes of and evaluates demand charges, as helpfully on point for the manual. We highlight here, and comment on, several important statements in the manual's demand charges description.

> "In an effort to identify costs associated with peak, a "demand charge" is one way for a utility to send a peak pricing signal over a certain time period, such as monthly. Peak coincident demand charges can be useful in sending a price signal to the customer regarding when the system peaks, and consumption during that period is charged accordingly; however, non-coincident peak demand charges merely charge a customer for its peak consumption, regardless of the time it occurred." (page 10, bottom) Our comments are as follows:

It's important to note also that the timing of peak coincident demands is not known in advance by the customer. The utility system will experience a highest demand each day, but there is no way of knowing whether that peak will be supplanted by a peak on a later day during the billing period. Thus, peak coincident demand charges do not provide an actionable price signal.

The paragraph notes properly that non-coincident peak (NCP) demand charges do not reflect cost causation, a significant shortcoming of a rate that is supposed to be more closely tying rates to costs. These NCP charges are marginally actionable and extensive customer training is required, along with load management technologies, for customers to be able to respond.

The bottom line in either case is that the demand charge effectively acts like a fixed charge for small customers.

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[6] We note that there is a demand charge section included in the manual's Section V on compensation methodologies. Because demand charges are a rate design and not a compensation methodology for DER, we recommend striking the later inclusion and describing it here along with the other rate designs.

> "There is some disagreement over how appropriate it is to apply a demand charge to smaller customers. Some argue that the diversity of customers in a large class is such that any given customer's on-peak demand is not a good indicator of the costs associated with that customer. Given that these rates are calculated based on averages and generally applied to a number that is resistant to downward pressure, such a concern is somewhat mitigated. There is also disagreement on the amount of costs that are actually related to demand, or a particular measurement of demand." (page 11)

The important key phrase is the demand charge is "applied to a number that is resistant to downward pressure" – in other words, customers can't or don't respond. Without customer response, even if the charge was related to costs, there would be no resulting benefit from imposing demand charges.

Finally, we also wish to highlight the last subsection under demand charges in Section V. Compensation:

> "At the time of writing this Manual empirical data for demand-based rate designs that are being implemented on a mandatory basis for large investor-owned utilities is limited. Thus, regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself." (page 53)

Indeed, this is an understatement. Regulators have been wary, and none has approved mandatory demand charges for residential customers to date.

We recommend the following additions to this demand charge subsection of the manual:

- The link between individual small customer peak demands and cost incurrence is limited and weak;
- For small customers with limited technological capability, demand charges do not provide an actionable price signal and effectively act as a fixed charge.
- Demand charges require an electric meter capable of measuring the timing of maximum customer consumption.

e) *Fixed Charges and Minimum Bills:* Similar to the demand charge section above, this subsection is related to rate design but is found in Section V as a compensation methodology. We recommend removing it from Section V and including it as part of the discussion of different rate design options.

We believe that the description is generally fair and highlight the following: "This potentiality [for increased uneconomic investment] also highlights the disconnect between costs and their causation that a higher fixed charge may have. If higher usage leads to increased investment, then it may be appropriate for the volumetric rate to reflect the costs that will be necessary to serve it, which would point towards the appropriateness of a lower fixed charge. In other words, it may be more reasonable to lower the fixed costs and increase the volumetric rate, which would send a more efficient price signal." (page 54)

It should be noted that Consumers Union recently published a study reviewing and analyzing the plethora of dramatic fixed charge increase proposals entitled "Caught in a Fix."[7] We recommend the following additions to the fixed charge subsection:

- Striking a balance between price signals and cost recovery requires consideration of multiple perspectives.
- There is no requirement or even economic theory supporting fixed charges for the recovery of costs that are fixed in the short term.

Revenue Decoupling

We also use this opportunity to address Revenue Decoupling (II.C.2 on page 11). The manual describes both full and partial revenue decoupling fairly. We would like to point out however, that there are a variety of ways to structure and implement decoupling. For example, regulators should consider the mechanics of how the decoupling result (a credit or a charge) is reflected in customer rates. For example, utilities that have IBR could provide decoupling credits to the first block and decoupling charges to the last block. This has the effect of helping lower use, often lower income customers who may not be supportive of decoupling generally. Regulators should also consider the effects of decoupling, i.e. keeping the utility whole, on the relative riskiness of the utility, and consider adjustments to the equity return authorized. We recommend the following additions to the Revenue Decoupling subsection:

- Regulators should carefully consider the structure and implementation of decoupling to avoid unintended consequences;
- Regulators should consider changes in the utility risk profile resulting from the implementation of decoupling.

The need for rate design reform

Subsections E, F, and G of Section III address the need for reform, highlighting some of the concerns raised in proceedings around the country that are driving most of the investigations into NEM policies and searches for alternate ways to treat DER in rate making. "These concerns include revenue erosion and cost recovery issues as well as inter-class cost shifting apparent in traditional utility rate design and Net Energy Metering

[7] Caught in a Fix: The Problem with Fixed Charges for Electricity, 9-Feb, 2016.

(NEM) discussions." (page 22) We note here that the first three subsections under <u>cost</u> do not address costs imposed on the grid by DER, but rather the effects of reduced revenue collection. These are addressed here, while subsections E.4 through G are addressed below.

Taking these issues one at a time, we submit that revenue erosion is not a problem in and of itself. Anytime retail customers use less electricity, often based on programs that encourage efficiency DER, utility revenue is *eroded*. We are compelled to point out that some DER, notably electric vehicles, have the opposite effect, i.e. enhancing utility revenue. There has been little outcry about this "problem." There is no requirement that customers in a rate class, for example residential, contribute a specified amount of money to the utility, nor purchase a specific amount of electricity. Larger consumers of electricity pay more and smaller consumers pay less. Moreover, following a rate case, there is no requirement for individual customers or the class as a whole to either consume the same amount of electricity or contribute the same amount of revenue to the utility as reflected in the rate case test year. The rate case is a snapshot of relationships among assets, expenses, and customer class characteristics for a one-year period. Many factors affect these relationships subsequent to the rate case. Some DER may reduce revenue while others may increase revenue. We recommend the following additions to subsections III.E.1 through 3:

- Rate setting is a snapshot of relationships among assets, expenses, and customer class characteristics, and does not set required individual customer revenue contributions.
- These relationships will begin to change immediately following a rate case based on economic conditions, fuel prices, uptake of DER, and personal behavioral changes. This narrow issue can be addressed through mechanisms like decoupling.

Having made those points, we recognize that the changes driving most of the investigations into NEM policies and searches for alternate ways to treat DER in rate making is not simply revenue erosion (or enhancement) but reduced utility revenue <u>without a commensurate reduction in utility costs</u>. If costs are reduced along with revenue, then arguably there is no net impact on the utility or on other customers.[8] The short-term view of a rate proceeding stands in contrast to the long-term view of resource planning. DER technologies that reduce revenue in the short term but reduce costs over their life should be viewed on the same basis as other resources, e.g. efficiency technologies or large centralized power plants (as discussed below). Dissimilar treatment would be discriminatory. The benefits that DER technologies can bring to the grid go beyond simply avoiding long term assets like generating plants or transmission lines, but also providing ancillary services in the nearer term, reducing utility investments in some grid management equipment. Some utilities suggest that additional revenue should be collected from those DER technology owners

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[8] See discussion of rate design structures above.

that reduce revenue without reducing cost in the short term to make up for the shortfall. We question whether these utilities would also argue as vociferously for utility bill credits for DER technologies like EVs that increase revenue to compensate for the windfall. We certainly have not seen any such proposals to date. Our further recommendations for additions to rate reform subsections III.E.1 through 3 are as follows:

- The revenue/cost relationship must be viewed over the long term.
- Charges for revenue shortfalls should be complemented with credits for revenue windfalls.

As should be evident from the previous discussion, the issue of cost-shifting can be viewed as a complicated ratemaking scenario of changes in cost responsibility due to reduced or enhanced revenue, or might be considered a red herring. Stakeholders in the latter camp will note that short term increases or decreases in consumption have occurred within customer classes since utilities were formed nearly a century ago. The rate case process rebalances those relationships, particularly when such impacts are relatively small. The manual captures these principles by recognizing "under the traditional ratemaking model and commonly used rate design, if the utility passes its relevant threshold of DER penetration, it may face significant intra-class cost shifting and erosion of revenue in the short-run." (page 24) Our final recommendations for additions to the rate reform subsections are as follows:

- Significant deployment of DER technologies can result in revenue erosion or enhancement in the short term.
- Thresholds for review should be established.

<u>Costs and benefits of DER</u>

Here we address subsections III.E.4 through G, i.e. those that deal directly with costs and benefits. A close reading of subsection III.E.4 finds little, if any, demonstrated cost impacts. It notes that DER, especially renewable generation, "puts pressure on the physical grid" and that "it's effects are often localized at the feeder level," and that DER "makes utility and RTO demand forecasting problematic." However, there are no cost impacts identified. The third paragraph (page 24) lays out a possible scenario (paraphrased here): (1) if DER is clustered in a specific area, and (2) and all are reacting to the same cloud moving overhead, and (3) if the utility does not have visibility into the situation on that feeder at sufficient granularity, then the voltage on that line may fall outside of acceptable parameters without the wider system being able to timely absorb the impacts and may impact local reliability conditions if unaddressed, by either the utility or the customer. The manual is quick to note however that many interconnection standards address these issues. This worst case scenario can be readily resolved by proper use of the interconnection standards and more granular visibility into the distribution system – an existing goal of many utilities and regulatory commissions today. Additionally, as discussed elsewhere, advanced inverters can be programmed to regulate voltage (and frequency and power factor) on a line and across a feeder as necessary.

The physical issue that can lead to this scenario is identified as: "the presence of clouds or sudden changes in wind velocity can mean that output can vary greatly from moment to moment, including going from 100% output to 0% almost instantaneously." (page 24) The result of such a change in output is the on-site load that was being served by the on-site generation is shifted back to the utility. In our experience, the average residential rooftop solar system is in the 5 – 7 kW range, representing the maximum load that could suddenly come back on to the system. In comparison, when plugging a Nissan Leaf in to be charged, an instantaneous 6.6 kW load is placed on the system. There have been no complaints from utilities about these loads. In addition, some refrigerated home air conditioners place an instantaneous load of up to 25 kW on the system, although such power draws are generally of sub-second duration.

There is also the warning that "some utilities have already seen output that exceeds an individual feeder's peak usage." (page 24) We have seen few if any actual cases of this situation occurring outside of Hawaii,[9] and no instances where this created a problem on the grid. Nevertheless, we support the manual's proposal for establishing thresholds for review when penetration reaches specified levels.

Finally, we note that the entire discussion in this subsection focuses on the customer-sited generation form of DER, and does not consider the integration of storage, demand response, or other DER that can mitigate the effects raised. Summarizing the cost issue in subsections III.E.4, we recommend the following additions to this subsection:

- At current levels of penetration of customer-sited generation, no deleterious effects have been documented;
- The current strategies of proper use of interconnection standards and increased visibility into the distribution system mitigate these concerns;
- As penetration levels of customer-sited generation grow, strategic deployment of other DER technologies including advanced inverters that can mitigate the impacts of concern;
- Establish reasonable penetration thresholds for review.

The manual then addresses the benefits associated with DER, again with the focus on customer-sited generation, and identifies a number of benefits to be considered in the last two paragraphs on page 25. The manual correctly notes: "A growing number of parties

[9] Some circuits on Oahu have reported aggregate DSG capacity exceeding 250% of minimum daytime loading.

involved in the DER debate acknowledge some benefits of DER, and some jurisdictions, utilities, researchers, and advocates have concluded or posited that responsible encouragement of DER adoption leads to positive cost benefit results." (page 25) While many studies of benefits have been performed, a majority of those have been sponsored by a stakeholder that has a vested interest in the outcome, i.e. utility or solar industry. Vote Solar recommends reviewing the far more limited subset of studies performed on behalf of agencies of state government. A recent paper[10] from the Brookings Institute summarized five recent studies sponsored by agencies of state government as follows:

> [b]y the end of 2015, regulators in at least 10 states had conducted studies to develop methodologies to value distributed generation and net metering, while other states conducted less formal inquiries, ranging from direct rate design or net-metering policy changes to general education of decision makers and the public. And there is a degree of consensus. What do the commission-sponsored analyses show? A growing number show that net metering benefits all utility customers:
>
> In 2013 Vermont's Public Service Department conducted a study that concluded that "net- metered systems do not impose a significant net cost to ratepayers who are not net- metering participants." The legislatively mandated analysis deemed the policy a successful component of the state's overall energy strategy that is cost effectively advancing Vermont's renewable energy goals.
>
> In 2014 a study commissioned by the Nevada Public Utility Commission itself concluded that net metering provided $36 million in benefits to all NV Energy customers, confirming that solar energy can provide cost savings for both solar and non-solar customers alike. What's more, solar installations will make fewer costly grid upgrades necessary, leading to additional savings. The study estimated a net benefit of $166 million over the lifetime of solar systems installed through 2016. Furthermore, due to changes to utility incentives and net-metering policies in Nevada starting in 2014, solar customers would not be significantly shifting costs to other ratepayers.
>
> A 2014 study commissioned by the Mississippi Public Services Commission concluded that the benefits of implementing net metering for solar PV in Mississippi outweigh the costs in all but one scenario. The study found that distributed solar can help avoid significant infrastructure investments, take pressure off the state's oil and gas generation at peak demand times, and lower rates. (However, the study also warned that increased penetrations of distributed solar could lead to lower revenues for utilities and suggested that the state investigate Value of Solar Tariffs, or VOST, and other alternative valuations to calculate the true cost of solar.)
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> In 2014 Minnesota's Public Utility Commission approved a first-ever statewide "value of

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[10] Muro, M and Saha, S, "Rooftop solar: Net metering is a net benefit," Brookings Institute, May, 2016.

solar" methodology which affirmed that distributed solar generation is worth more than its retail price and concluded that net metering undervalues rooftop solar. The "value of solar" methodology is designed to capture the societal value of PV-generated electricity. The PUC found that the value of solar was at 14.5 cents per kilowatt hour (kWh)—which was 3 to 3.5 cents more per kilowatt than Xcel's retail rates—when other metrics such as the social cost of carbon, the avoided construction of new power stations, and the displacement of more expensive power sources were factored in.

Another study commissioned by the Maine Public Utility Commission in 2015 put a value of $0.33 per kWh on energy generated by distributed solar, compared to the average retail price of $0.13 per kWh — the rate at which electricity is sold to residential customers as well as the rate at which distributed solar is compensated. The study concludes that solar power provides a substantial public benefit because it reduces electricity prices due to the displacement of more expensive power sources, reduces air and climate pollution, reduces costs for the electric grid system, reduces the need to build more power plants to meet peak demand, stabilizes prices, and promotes energy security. These avoided costs represent a net benefit for non-solar ratepayers.

These generally positive PUC conclusions about the benefits of net metering have been supported by research done by a national lab and several think tanks. Important lab research has examined how substantially higher adoption of distributed resources might look.

The five referenced studies are available at:

Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*, at 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

This subsection III.F raises the important question of what to do with the results of a cost-benefit study, should one be performed. Should the results impact policy or rate design choices? We recommend that the results of the study inform such choices. For example, if the benefits of rooftop solar generation exceed the costs, then use of the retail rate for netting in net metering is a good deal for other ratepayers. Conversely, if the benefits fall short, changes in rate design can help rebalance the equation. Finally, we note that the cost-benefit analysis should not be confined to the residential class of customers, but should be performed for commercial and industrial solar customers as well. If rate design changes are being considered as a result of the cost-benefit studies, such changes should not be confined to the residential class of customers.

To summarize our points regarding the benefits of DER, we recommend the Subcommittee reflect the following points in subsections III.F.:

- The benefits of DSG have been well studied and there is a growing consensus on positive benefits;
- The least biased studies are those sponsored by agencies without a financial self-interest;
- Cost-benefit studies should be performed for all rate classes in which customers have deployed DSG, and can inform rate design choices;
- Commissions should be clear that DSG integrated with other forms of DER can provide greater benefits and should be studied; and
- Rate design changes, if any, should <u>not</u> be confined to the residential and small commercial classes.

Finally, subsection III.G addresses issues of ownership and control including leasing, curtailment, and low-income related matters. Here again, the focus is on DER in the form of customer generation. The subsection closes with: "Though many of these issues are not directly related to rate design they are included here so regulators can ensure they are addressed when they become relevant for their jurisdiction." (page 27) We agree with this sentiment and reiterate two recommendations:

- Establish reasonable penetration thresholds for review.
- Consider integration of the full suite of DER, and the benefits of such integration to the utility grid.

Rate design considerations

Here we address Section IV of the manual, repeating a critical observation from the manual: "[o]ne of the biggest issues, if not currently the biggest, is the dearth of empirical data available on the impacts and specific pros and cons of the different ways regulators can address DER and rate design. Identifying and understanding these challenges will assist the regulator in determining an appropriate rate design for its utilities." (page 28)

Regulators are frequently faced with competing claims in formal proceedings, often based on intuition, speculation, and/or illustrative examples, yet historically Commissions have properly made decisions based on real data and analysis. We recommend the Subcommittee reflect in the manual:

- Data and analysis forms the basis of good decision-making.

Should there be a separate rate class?[11]

The manual states "[t]here is a strong argument to be made for changing the rate structure that applies to all customers, as sending all customers the most appropriate price signal should result in the most economically efficient outcomes related to electricity consumption, as well as decisions on the installation of DER." (page 28) We agree with this premise and note once again that data and analysis is necessary to demonstrate distinctive characteristics which MIGHT necessitate the separation of any subgroup of customers into its own class. For example, arguments have been made that on-site solar generation changes the energy consumption and the load factors of the host customers. Without judging these claims, the issue before regulators is whether these differences, <u>if supported with actual data</u>, are sufficiently distinct to call for a new rate class. Analysis of this question requires, for example, a comparison of the DSG customers energy consumption levels and load factors with those of customers in the same class that do not have on-site generation. Do the former fall generally within the bell-shaped curve of these characteristics of the latter? The second question regulators need to consider is whether there are other subgroups of the class that could also be segregated into a separate class. For example, are there other behind the meter technologies that have similar effects on loads and load factors? Are there other characteristics that could be used to subdivide the class such as apartment dwellers vs. homeowners, or rural vs. urban customers?

The manual also suggests separating DER customers into their own cost of service class would identify the different ways in which DER and non-DER customers contribute to costs, at least according to the traditional embedded cost of service approach utilized in many jurisdictions." (page 29) This raises the important issue related to the allocation of

[11] Discussed in the manual generally in subsection IV.A.1

costs in a rate process – regulators and stakeholders need to understand how costs are being assigned. For example, are the costs based on actual consumption of the DSG (or other DER) customer or on some adjusted basis? We have seen cost allocators based on consumption levels that treat solar customers as if their generation did not exist, under the theory that the utility must be ready to serve every kWh that every solar customer consumes in every hour of the year. This approach ignores the reality of geographic diversity and treats DSG/DER customers differently than all other types of customers in the cost of service study. Aggregated DSG is similar to aggregated load – individual profiles may appear volatile, but collectively present a smooth generation (or consumption) pattern. If DER customers are segregated in a cost of service study they should be allocated costs based on the services provided to them by the utility, not based on costs that would be incurred if their DER system did not exist.

The manual closes this subsection with a relevant summary that we fully support:

> "In the end, regulators must examine the particular load profiles associated with various customers, including DER customers and subsets thereof, and how those profiles correspond to costs, and decide whether or not those differences constitute a substantial enough difference in the service provided to justify their separation." (page 29)

Note that there is a discussion of this topic within the Grandfathering subsection (top of page 37) that addresses the potential for separate customer classes, listing factors for consideration. We recommend that these factors, listed below, be integrated into subsection IV.A.1.b.

Recommendations for subsection IV.A.1.b.:

- Integrate the following factors into subsection IV.A.1.b.
    - Do DER customers have a unique service, usage, or cost characteristics that would be tracked by a separate rate class;
    - Are there now or are there expected to be a sufficient number of customers to justify a new rate class; and,
    - Does the utility provider have sufficient capability/technology (such as metering/billing) to separate the customers and bill differently.
- Proposals for separate rate classes for a subgroup of small customers (e.g. residential DSG customers) should always be supported with data and analysis, and compared to other subgroups with equally different characteristics from the core group of customers.
- Separate rate classes should be analyzed in a manner similar to other rate classes and allocated costs based on the services provided to them by the utility.

Price signals subsection IV.A.2:

We also support the manual's discussion of price signals. The thoughts embodied therein should be considered as part of a regulator's deliberations about changes to rate design. We repeat it here for emphasis:

> "As previously mentioned, the more a rate structure reflects the costs associated with an activity, the more appropriately decisions can be made about how much of a service to use, when to use it, and whether other options for the provision of said service make economic sense. Ideally, rates are price signals for the consumption of electricity. Those same price signals are used to compare the utility's provision of said service against the alternatives. Regulators may wish to consider how appropriate the price signal provided by a particular rate structure is, in order to induce economically efficient consumption." (page 30)

Recommendation:

- Identify the degree of actionable price signal in the rate designs addressed in subsection II.B.1 of the manual, as modified by the recommendations herein.

Long-term vs. short-term costs and benefits subsection IV.A.3

In rate cases, it's obvious that reductions in load lead to a reduction in revenue, and will not likely lead to an immediate reduction in existing utility investment. This is true for load reductions from any source, be they technological or behavioral. Clearly the reverse is also true – increases in load do not lead to an immediate increase in utility investment. Because the cost allocation and rate design phase of a rate case spreads total utility costs, or revenue requirement, established in the first phase across customer classes, load increases generally lead to lower prices (fixed numerator divided by larger denominator), and load decreases generally lead to higher prices (fixed numerator divided by smaller denominator). The nature of ratemaking has, for many decades, based rates on this method with little concern for the actions of individual customers.

Since DER technologies, beginning with energy efficiency some 30 years ago, largely reduced consumption, it was important in the view of most regulators to take into account current and *future* savings. These savings largely came in the form of costs that could be avoided – such as fuel costs in the near term and generation, transmission and distribution assets in the long term. As such, benefit-cost ratios exceeded unity because future generations of retail customers would benefit from future avoided costs. Similarly with deployment of self-generation, future customers will benefit from the costs that the utility avoids in the future.

Many utilities make the argument that the self-generation form of DER must avoid costs that are known and measurable, implying that future avoided costs should be discounted or not counted at all. We urge the Subcommittee to clearly reject this argument. If the known and measurable standard was the basis for resource planning proceedings, utilities would no longer build centralized generating stations, but would only purchase short-term energy available on the market because resource planning data and modeling is not known and measurable. It's long been recognized that a benefit of the electric utility monopoly is the ability to take the long-term view, i.e. to acquire resources (generation and transmission assets in particular) that are determined through modeling and analyses with the best data available to result in the lowest long term revenue requirement for customers. When these large centralized assets are added to the utility rate base, utility rates and reserve margins increase. Both of these effects are found acceptable to the regulators because the assets are lowest cost in the long run. Thus, as in the case of energy efficiency and self-generation, current customers pay higher current rates related to the addition of oversized assets because future generations of retail customers will benefit from future avoided costs.

In sum, Vote Solar makes the following recommended additions for reflection in the manual in Section IV.A.3 (page 30) related to evaluating cost recovery and rate design practices:

- Note that interconnection related costs are typically recovered from the interconnecting customer, and other distribution costs are speculative and require supportive data and analysis.
- Current rates are based on broad class averages and do not reflect the costs to serve individual customers within the class;
- No costs (not paid by the DER customer) have been demonstrated to exist as a result of connecting DER to the grid;[12]
- Shortfalls in the recovery of short-term fixed costs are largely a myth, and current utility investments that provide long-term benefits but increase current rates have been a part of utility planning and ratemaking for decades. The manual should emphasize the long-term view.

Impacts on Other Customers subsection IV.b:

We note that several of the topics under this heading have been addressed elsewhere in the manual and urge the Subcommittee to address these issues in one place to avoid confusion. We also recommend focusing the manual on the information, data and analysis needed to objectively evaluate the potential impact noted, without providing arguments for one side or the other of the issue. The clear bias in a number of the subsections (as will be noted) is inappropriate. Finally, we continue to urge the Subcommittee to include a framework for evaluation of issues that reflects several elements:

[12] Note: outside of Hawaii.

Recommended framework for evaluating impacts on other customers:

- Evaluation should be based on actual data and analysis;
- Time frames for analysis: long-term, short-term, or both, and why;
- Comprehensiveness: the scope of customer classes to be reviewed and analyzed;
- DER technologies being scrutinized, and the degree of integration considered.

1. Does DER avoid utility infrastructure costs? (page 30)

This subsection appears to have relatively little built-in bias, however the evaluation framework identified above is applicable;

2. Cost shifting due to recovery of fixed costs through a volumetric rate. (page 31)

We are concerned that this subsection states cost-shifting as a fact, whereas such claims should be supported by data in the context of the evaluation framework and local conditions. For example, EVs may add sales and revenue without adding cost. Further, such claimed cost shifts should be evaluated in the context of other existing cost shifts inherent in the ratemaking structure. We urge removal of the inherent bias in this subsection.

3. Customer is still tied into the grid/utility is still responsible for delivery. (page 32)

There is implied bias in the statement that DER customers may not be paying for the costs of the grid under volumetric rates. Such customers may also be paying more than their share for the grid, depending on the circumstances. We urge a more neutral description.

4. DER customer may still be grid reliant during peak times. (page 32)

This subsection appears to have relatively little built-in bias, however the evaluation framework above is applicable;

5. Cost allocation inside classes. (page 32)

We are concerned here, as in #2 above that this subsection states cost-shifting as a fact, whereas such claims should be supported by data in the context of the three points above. We recommend the Subcommittee scrub this point for bias as well. Moreover, we recommend these two "cost-shift" bullets be combined since they address the same issue.

6. Lifespan of utility assets do not match lifespan of DER. (page 33)

We again recommend elimination of bias. More importantly, there is no impact identified and demonstrated in this component. We urge deletion of this "impact" entirely. Existing utility assets have lives that are different among themselves – different types of generation have different lives, and certainly different lives than most of the purchased power agreements into which utilities enter, and different than the lives of distribution and transmission assets. With respect to the on-site generation form of DER, as systems reach the end of their useful lives, be it the warranted life of 25 years for solar panels or something much longer, (1) they will not all stop working at the same time, but rather gradually generate less over time (typically by about 0.5%/year), (2) many if not most will be replaced as efficiency technologies are today, and (3) other DER may support or continue the DSG. It is difficult for anyone at this time to speculate what the energy landscape will look like in 15 to 40 years. This "impact" is extremely speculative at best, and of questionable relevance.

7. Stranded costs and dealing with stranded costs. (page 33)

The possibility of stranded costs is real, but DER deployment to date has been relatively minor, and unlikely to lead to stranded costs. However, all <u>new</u> utility investments seeking used and useful status from regulators should be carefully scrutinized within the context of expanded prospective deployment of all forms of DER. This impact is highly speculative as well, and should be identified as such in the manual.

In sum, Vote Solar recommends that the manual remind regulators that all alleged effects on other (i.e. non-DER) customers of the utility by evaluated in the framework outlined above. Beyond this framework, we recommend the following regarding the impacts on other customers:

- Combine like impacts, i.e. numbers 2 and 5.
- Strike impact number 6, Lifespan of utility assets do not match lifespan of DER, as not identifying an impact.
- Eliminate biases in each remaining impact.
- Compare DER impacts with those of existing inherent rate subsidies that have long been found reasonable.
- Avoid speculation on future impacts not well-grounded in facts.
- Evaluate impacts with a long term view.

Impacts on utility:

As with the section on impacts on customers, similar frameworks and guidelines should be established for evaluation. For example, the manual notes: "The utility may need to upgrade distribution equipment if circuits become exporters to the rest of the grid and begin acting as step up facilities." (page 34) The situation described only exists in Hawaii currently and even there has not resulted in large increased costs to the distribution grid. Such effects have been described elsewhere in these comments, and emphasize the need for the establishment of thresholds for evaluation. The manual also describes the impact on the utility of reduced investment resulting in reduced rate base and therefore the amount of return, as a problem. We highlight here that reduced cost is not a problem for customers of the utility, and for the utility reduced assets on the balance sheet will be accompanied by reduced liabilities, such as debt and equity, to maintain balance. There is no principle requiring assets to continually ratchet up, only to balance with liabilities.

We believe the Subcommittee provides useful insight in the second and final paragraph in this section: "Utilities have seized on the potential impacts on other customers as a justification for increasing fixed charges (discussed in more detail in other sections of this Manual). Utilities, however, have been using various justifications to attempt to get increases in fixed charges for a century. Their claims related to fixed charge increases and DER should be taken in that context and also with an eye toward authorized return if larger portions of revenue recovery shift to more fixed components, making the utility potentially less risky, all else remaining equal." (page 34)

Cross-subsidies

Subsidies and cross subsidies are raised in numerous places in the draft manual. We believe it would be helpful to regulators using this tool to organize these discussions into a single section or subsection. We ask again that alleged but unproven issues like cost-shifting or cross-subsidies be framed as such in the manual, so as to avoid implied bias. We do, however, appreciate the descriptions in this section as recognition is given to those effects inherent in rate making currently, both overt subsidies (e.g. C&I classes subsidizing residential customers) and indirect (such as large customers subsidizing small customers within the residential rate class). To aid in the regulators evaluation of cross-subsidies, we have attached a summary of other forms of cross subsidies for reference.[13]

Next, there are several references to "higher-income customers" ability to afford DER, whereas lower income customers cannot. (end of page 34) Besides the fact that this is no longer true, it should be evaluated on a case-by-case basis. Moreover, regulators should be careful to avoid the cure being worse than the condition, e.g. the addition of fixed charges. Indeed, the goal should be to increase access of lower income customers to the rate reducing and stabilizing effects of DSG.

Strong anti-NEM bias is introduced once again in the subsection on restructured jurisdictions:

> "The biggest cross subsidy in energy pricing in restructured jurisdiction is when a NEM customer has a net export from their system and is compensated at their retail rate. This is clearly a subsidy to the NEM customer paid for by the general body of ratepayers." (page 35)

This is a remarkable statement for a document that is intended to be an objective tool with information and guidance for the evaluation of DER compensation. It reads more like utility testimony than a fair assessment of the considerations for regulators to evaluate in their determination of the existence, direction and extent of subsidies based on actual data. We vociferously oppose this language specifically, and the drafting of this section generally. Preconceived biases must be scrubbed from here as well.

[13] Included as Attachment C.

Because of this bias, the "options" offered (middle of page 35) by the manual are one sided. We ask the Subcommittee to leave the spectrum of options open to the regulators evaluating the existence of subsidies and the need for remedies. Additionally, the final paragraph on page 35 under Restructured Jurisdictions is so fraught with pro-utility bias as to be completely unworkable. This paragraph must be stricken in its entirety.

In the next subsection, "Vertically Integrated," equally biased statements are made. One of the most egregious is:

> "From a cross subsidy viewpoint, the main difference between a restructured jurisdiction and a vertically integrated jurisdiction is that a vertically integrated utility has made investments in generation capacity to serve its customers and those customers have an obligation to provide the utility with the opportunity to recover those investments including a return on the investment. DER directly challenges that opportunity." (page 36)

We vehemently disagree with this notion. The customer is under no such obligation, and such a statement finding its way into a NARUC document that will ultimately be approved as a manual is outright dangerous. Customers can move, reduce or increase usage, and are under no obligation to the utility to purchase a minimum amount of electricity to support utility investment decisions. The regulator has an obligation to approve rates that provide the utility with a reasonable opportunity to recover its costs and earn a fair return on investment.

The purpose of this manual is to provide tools to regulators to use in their evaluation of the effects of multiple types of DER, across all applicable customer classes, and across appropriate time frames. It's very disconcerting to see this level of bias in a public draft of the manual. To the extent subsidies are found to exist by a regulator after proper evaluation and using relevant data, analysis and processes, solutions appropriate to the effects found can be designed. These may include revised rates that recover from DER customers an appropriate amount to compensate the utility for the investments it has made, or it may result in additional credits to DER customers for services provided to the utility.

While not intended to be a comprehensive rebuttal of all of the utility-oriented statements in this subsection, below we respond to several specific statements in subsection IV.D.2:

"[T]he basic problem is that utilities do not recover sufficient funds from DER customers to compensate them for the investments they have made on their behalf." (page 36)

Response: With the exception of a few very large customers, utilities do not make investments on behalf of specific customers. Particularly in the residential class, the diversity is great and such a claim is irresponsible.

"The solution is to design rates that recover from DER customers an appropriate amount to compensate the utility for the investments it has made. The key here is how to determine the "appropriate" amount." (page 36)

Response: Every customer compensates the utility an "appropriate" amount for the investments it has made. This is the underlying purpose of establishing rate based on cost causation. As discussed elsewhere, if a customer or group of customers consumes less energy, less cost is allocated to the class (and to the jurisdiction in some cases), and the new rates established compensate utilities for the investments it has made. It's important for regulators to carefully scrutinize those investments, especially new investments, in the light of expanded deployment of DER of all types, for prudency in the evolving market.

"Utilities often claim that they need to be able to supply their entire DER customer's needs at a moment's notice and should be compensated on that basis. However, that does not take into account DER diversity of outages or loads." (page 36)

Response: We agree with this diversity perspective and would expand the DER reference to assure that complementary DER integrated onto the grid can not only mitigate revenue reduction concerns of utilities, but also provide valuable grid services.

"Any charges over and above the class based kWh energy charge should be compensatory not punitive. Such a charge can be developed either by creating a DER rate class or by creating a DER surcharge within a rate class. Such a charge can be fixed, equivalent to a demand charge, or variable but should be designed to just compensate the utility and keep it whole." (page 36)

Response: We strongly oppose, once again, the presumption of a problem that needs to be fixed without evaluation. These sentences represent the recent perspective of certain utilities. We point back to the point made a few pages earlier in the manual for context:

> "Utilities, however, have been using various justifications to attempt to get increases in fixed charges for a century. Their claims related to fixed charge increases and DER should be taken in that context and also with an eye toward authorized return if larger portions of revenue recovery shift to more fixed components, making the utility potentially less risky, all else remaining equal." (page 34)

Finally, in the "Other Cross Subsidy Issues" subsection IV.D.3 (page 36), an example is provided that reflects some rather extreme assumptions. If the subcommittee wants to include illustrative examples, they must be fair and balanced.

Summary of recommendations for the entire subsection beginning on page 34 and running nearly to the bottom of page 36:

- Avoid regulatory changes that would decrease access to DER technologies for low-income customers (reference bottom of page 34).

- The entire subsection IV.D presumes outcomes to evaluation processes that have not been conducted, and without data, evidence, or analysis must be stricken due to extreme anti-DER bias.[14]

Grandfathering (subsection IV.E, page 36)

At the outset, we believe that the manual would benefit by a more precise definition of grandfathering. For example, Black's Law Dictionary (Sixth Edition) defines grandfathering, in part, as follows: an exception to a restriction that allows all those already doing something to continue doing it even if they would be stopped by the new restriction. In the case of DER, and especially DSG, the "restriction" is the change in rate structure that significantly impacts the economics of DER. We agree that a normal[15] change in rates like those that have occurred for many years before the advent of DER would not be considered a change in rate structure that rises to the level of being a "restriction." However a change in structure that results in a major increase in monthly customer charges (e.g. 50-100% and sometimes more) or new billing mechanisms like demand charges would cross that threshold for which the regulator should consider the grandfathering of existing customers.

In our view, the grandfathering section goes beyond the information and guidelines necessary to assist regulators in making a narrow decision about the grandfathering of existing DER customers. For example, the concept of a separate rate class is raised several times in this subsection but has already been addressed earlier, near the beginning of Section IV. In addition, there is further discussion about subsidies, the likelihood of yielding total utility revenue requirements, and so on, all of which is addressed elsewhere in the manual and does not need to be repeated here, especially given the inconsistency with other sections. We urge the Subcommittee to remain objective and to strike these extraneous and biased comments.

The manual provides some guidelines and considerations in six subsections. We provide our comments on these subsections below.

1. Payback periods: (page 38) "The choice for a customer to invest in DER is made once, new rates can only affect customer investment and behavior going forward, but not the choice to invest/not invest in DER. However, the value of DER may factor into the decision whether or not to maintain the DER system."

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[14] Alternatively, the entire subsection could be thoroughly scrubbed to remove the pervasive anti-DER bias.

[15] "Normal" as used here means the more typical rate changes that roughly coincide with inflationary pressures over the years between rate cases, without disproportionate changes to the specific charges like the monthly customer charge.

Comment: Payback periods provide a useful milepost for consideration. For example, if the rate structure change extends a payback period from 10 to 25 years, regulators may find this unfair to those who have already made the investment. We find it problematic for the manual to suggest that the customer may choose "not to maintain" the system as a result of the rate structure change, as if this was as simple as removing an efficient light bulb. Most solar systems are nearly maintenance free, so the real choice is whether to disconnect the DER system in which the customer has invested substantial resources. The payback period can provide some insight into the impact of the rate change.

2. Type and degree of rate change: (page 39) "Are the changes between rate regimes mild or severe? Are there ways to mitigate the severity such as staggering the implementation dates?"

Comment: The severity of the changes between rate regimes is also a useful guideline. It can be tested in several ways – for example using the payback periods, or the calculated bill impacts across a spectrum of customers. We urge Commissions not to fall into the trap of reviewing only the "average" customer. Mitigating the severity can be accomplished through phasing-in the changes. We don't understand how staggering the implementation dates would lessen the severity at all. (page 39)

3. Differential DER customers: (page 39) "If certain DER customers are to be moved to another rate regime while others remain on a different regime, is it appropriate to use the billing data/usage of 'grandfathered' customers to set the rates going prospectively for other, non-grandfathered customers? Is the use of a proxy group in that circumstance appropriate? Does the utility have the appropriate billing structure in order to distinguish between different types or generations of DER customers? And if not, does this add additional costs to the class?'

Comment: This is <u>not</u> a useful guideline for the evaluation of grandfathering, and truly has nothing to do with grandfathering, but rather how to treat new DER customers.

If the rate regime changes, new DER customers will take the economics of the new regime into account when designing their systems. If the payback periods are longer, or less value is provided for exports, systems will be designed accordingly, i.e. to maximize the benefit for the host customer for the amount of investment. In some cases, we have seen new rate regimes result in very dramatic reductions in deployment of new systems. Thus, existing DER systems will <u>not</u> be reflective of systems installed under the new structure.

4. Billing considerations: (page 39) "Should the rate structure being 'grandfathered' stay with the customer, the premise, the utility account, or some combination thereof for the duration? Does this allow for transactions between customers, such as the sale of the house or panels?"

Comment: This is not a guideline to help determine if grandfathering should be allowed, but rather a consideration for how to implement a grandfathering policy.

In our view, grandfathered customers should have the option of taking their systems with them if they move or leaving them on the original premise. Thus, the grandfathering policy should be tied to the system as that is what was built as part of the RPS compliance (e.g.), with an incentive, based on certain payback periods, etc.

5. Dynamic changes to a system: (page 39) "Can a 'grandfathered' customer add panels and have the new panels also be under the grandfathered rate? Is there a limit that the regulator should set on additions/replacements and how is that to be enforced?"

Comment: This is also not a guideline for grandfathering, but rather a consideration for how to implement a grandfathering policy.

Generally, no, except in configurations where the customer was staging their system, or replacing defective panels/equipment. In such situations, the customer should notify the Company.

6. Other questions: (page 39) "How should the regulator value the tradeoffs between stability of customer investment and the dilution of appropriate forward price signals or potential cross-subsidization? Is there a regulatory precedent that could be used to guide this decision?"

Comment: This is an odd consideration, as the existing DER customer has already made their one-time investment decision based upon the price signals at the time of the investment. If those signals change substantially, the customer cannot undo or remake its investment decision, but only effectively pay a penalty under the new regime. Grandfathering should be considered a valued statewide business policy of not changing the rules and policies under which legacy customers have invested in DSG or other DER. If legacy DER customers are saddled with the impact of rate design changes and other fees (i.e. grandfathering not allowed), then the regulator should consider the utility fully protected from any impacts, even those it may have supported in earlier times, and should not be able to make any claims for stranded cost recovery.

Recommendations related to grandfathering:

- Strike the following three paragraphs: the last full paragraph on page 37, the paragraph that flows from page 37 over to page 38, and the first full paragraph on page 38.
- Scrub unrealistic customer choices such as "whether or not to maintain the DER system."
- Regulators should consider the impacts on a spectrum of customers, not just the average or typical customer.

- Create a new subsection that addresses the implementation of grandfathering policy under which points 3, 4, and 5 belong.
- Regulators should not use the DER systems installed under one pricing regime as a proxy for new systems after that regime changes significantly.
- No grandfathering should be accompanied by no opportunity for related stranded cost recovery.

Summary of Recommendations related to the Rate Design Sections

Recommendations for Rate Design Section II.B.1:

- Identify the degree of actionable price signal in each of the rate designs addressed.

Flat rates:

- We recommend noting that flat rates do not require any special type of meter.

Block rates:

- We recommend noting here too that inclining block rates do not require any special type of meter.
- We recommend striking any discussion of declining block rates as we believe these are not in the public interest, and discouraged by PURPA.

Time variant rates:

- We recommend noting here that time-variant rates (including PTR, CPP, and RTP) do require an electric meter capable of measuring the timing of customer consumption.
- We recommend specifying time varying rates better reflect cost causality, provide an actionable price signal, and cost reductions related to customer response.

Three part rate/Demand charges:

- The link between individual small customer peak demands and cost incurrence is limited and weak;
- For small customers with limited technological capability, demand charges do not provide an actionable price signal and effectively act as a fixed charge.
- Demand charges require an electric meter capable of measuring the timing of maximum customer consumption.

Fixed charges and minimum bills:

- Striking a balance between price signals and cost recovery requires consideration of multiple perspectives.
- There is no requirement or even economic theory supporting fixed charges for the recovery of costs that are fixed in the short term.

Revenue Decoupling (Section II.C.2):

- Regulators should carefully consider the structure and implementation of decoupling to avoid unintended consequences;
- Regulators should consider changes in the utility risk profile resulting from the implementation of decoupling.

Recommendations for additions to the rate reform subsections III.E.1 through 3:

- Rate setting is a snapshot of relationships among assets, expenses, and customer class characteristics, and does not set required individual customer revenue contributions. These relationships will begin to change immediately following a rate case based on economic conditions, fuel prices, uptake of DER, and personal behavioral changes. This narrow issue can be addressed through mechanisms like decoupling.
- The revenue/cost relationship must be viewed over the long term.
- Charges for revenue shortfalls should be complemented with credits for revenue windfalls.
- Significant deployment of DER technologies can result in revenue erosion or enhancement in the short term.
- Thresholds for review should be established

Recommendations for additions to the Technology and physical issues subsections III.E.4:

- At current levels of penetration of customer-sited generation, no deleterious effects have been documented;
- The current strategies of proper use of interconnection standards and increased visibility into the distribution system mitigate these concerns;
- As penetration levels of customer-sited generation grow, strategic deployment of other DER technologies including advanced inverters that can mitigate the impacts of concern;
- Establish reasonable penetration thresholds for review.

Recommendations for additions to the Benefits subsection III.F:

- The benefits of DSG have been well studied and there is a growing consensus on positive benefits;
- The least biased studies are those sponsored by agencies without a financial self-interest;
- Cost-benefit studies should be performed for all rate classes in which customers have deployed DSG, and can inform rate design choices;
- Commissions should be clear that DSG integrated with other forms of DER can provide greater benefits and should be studied; and
- Rate design changes, if any, should not be confined to the residential and small commercial classes.

Recommendations for additions to the Ownership and control subsection III.G:

- Establish reasonable penetration thresholds for review.
- Consider integration of the full suite of DER, and the benefits of such integration to the utility grid.

Rate Design Considerations (Section IV): Overall recommendation

- Data and analysis forms the basis of good decision-making.

Recommendations for additions to the Different customer classes subsection IV.A.1.b:

- Integrate the following factors into subsection IV.A.1.b.
  - Do DER customers have a unique service, usage, or cost characteristics that would be tracked by a separate rate class;
  - Are there now or are there expected to be a sufficient number of customers to justify a new rate class; and,
  - Does the utility provider have sufficient capability/technology (such as metering/billing) to separate the customers and bill differently.
- Proposals for separate rate classes for a subgroup of small customers (e.g. residential DSG customers) should always be supported with data and analysis, and compared to other subgroups with equally different characteristics from the core group of customers.
- Separate rate classes should be analyzed in a manner similar to other rate classes and allocated costs based on the services provided to them by the utility.

Recommendations for Long-term vs. short-term costs/benefits/outlooks Section IV.A.3 (page 30):

- Note that interconnection related costs are typically recovered from the interconnecting customer, and other distribution costs are speculative and require supportive data and analysis.
- Current rates are based on broad class averages and do not reflect the costs to serve individual customers within the class;
- No costs (not paid by the DER customer) have been demonstrated to exist as a result of connecting DER to the grid;
- Shortfalls in the recovery of short-term fixed costs are largely a myth, and current utility investments that provide long-term benefits but increase current rates have been a part of utility planning and ratemaking for decades. The manual should emphasize the long-term view.

Recommended framework for evaluation of Impacts on other customers subsection IV.B:

- Evaluation should be based on actual data and analysis;
- Time frames for analysis: long-term, short-term, or both, and why;
- Comprehensiveness: the scope of customer classes to be reviewed and analyzed;
- DER technologies being scrutinized, and the degree of integration considered.

Recommendations for changes to the subsections under Impacts on other customers Section IV.B:

- Combine like impacts, i.e. numbers 2 and 5.
- Impact number 6, Lifespan of utility assets do not match lifespan of DER, identifies no impact, and should be stricken.
- Eliminate biases in each remaining impact.
- Compare DER impacts with those of existing inherent rate subsidies that have long been found reasonable.
- Avoid speculation on future impacts not well grounded in facts.
- Evaluate impacts with a long-term view.

Recommendations for changes to the subsections under Impacts on utility Section IV.C and Cross subsidies, including cross-class Section IV.D:

- Avoid regulatory changes that would decrease access to DER technologies for low-income customer (reference bottom of page 34).
- The entire subsection IV.D presumes outcomes to evaluation processes that have not been conducted, and without data, evidence, or analysis and must be stricken due to extreme anti-DER bias.

Recommendations for changes to the Grandfathering Section IV.E:

- Strike the following three paragraphs: the last full paragraph on page 37, the paragraph that flows from page 37 over to page 38, and the first full paragraph on page 38.
- Scrub unrealistic customer choices such as "whether or not to maintain the DER system."
- Add regulators should consider the impacts on a spectrum of customers, not just the average or typical customer.
- Create a new subsection that addresses the implementation of grandfathering policy under which points 3, 4, and 5 belong.
- Add regulators should not use the DER systems installed under one pricing regime as a proxy for new systems after that regime changes significantly.
- No grandfathering for customers should be accompanied by no opportunity for related utility stranded cost recovery.

Compensation Methodologies[16]

We believe the Subcommittee must draw a distinction between the compensation methods reviewed in this section, and the rate structures described in the introduction to rate design Section II.B.1 of the manual (page 8). It is clear that demand charges are a rate design, and not a compensation methodology. We therefore recommend the Subcommittee strike the entirety of subsection IIV.C on demand charges beginning at the bottom of page 48 through the end of page 53. It is addressed in the manual's subsection on rate design.

Next, subsection V.D related to fixed charges and minimum bills also addresses general ratemaking practices and principles and properly belongs in the rate design section of the manual. We recommend moving this entire subsection to section II.B.1 Introduction to Rate Design.

To set up the contextual guidelines for evaluation of various methodologies by regulators, Vote Solar recommends that the Subcommittee assure that the manual eliminate bias and include the following key elements:

(1) <u>Appropriate time frames:</u> DER technologies provide benefits in both the near and long term. Compensation methodologies under evaluation should include consideration of those long term benefits.

(2) <u>Comprehensive view of customer classes</u>: While much attention is focused on small customers and rates based primarily on variable charges, changing compensation methods for only those classes without a review and evaluation of the effects of DER hosted by larger commercial and industrial customers would be incomplete. Larger customers with DSG often provide much greater benefits to the grid than do smaller customers in relation to revenue reduction, and consideration should be given to appropriate compensation to reflect those impacts.

(3) <u>Full set of possible DER technologies</u>: The manual defines DER comprehensively but much of the analysis is focused on distributed solar generation. While we understand DSG to be the driver of much of the utility concerns currently, we urge the Subcommittee remain strong on the need to evaluate the effects of all relevant forms of DER, with efficient integration of these technologies in mind. Energy efficiency and demand response technologies have been around for some time, while DSG is a relatively recent market entrant and others, like storage, are coming down the cost curve towards market adoption. Integrating these technologies can result in lower cost sources of generation and loads with higher load factors that are generally lower cost to serve.

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[16] Addressing Section V of the manual.

Recommendations for DER Compensation Section V:

- Strike subsection C, demand charges, as it is addressed in the manual's subsection on rate design.
- Move subsection D, fixed charges and minimum bills, to section II.B.1 as these are rate design issues.
- Eliminate bias in the descriptions of DER compensation policies.
- Evaluate DER compensation alternatives with full consideration given to the following framework elements:
  - Appropriate time frame: short term, long term, or both;
  - Comprehensive review of all customer classes with DER
  - Full complement of stand alone and integrated DER technologies

<u>Net Energy Metering subsection V.A:</u>

We believe that Net Energy Metering or "NEM" requires consideration of DSG power flows and the rights of customers. The manual provides an example of billing under Net Energy Metering on page 41. This is a helpful example, and we recommend a slight expansion to delineate the two possible generation/load situations. During times that the customer's load exceeds the amount of on-site generation, that generation is used instantaneously and the customer purchases its remaining needs from the utility. The "instantaneous use" of on-site generation is like any other technology that affects load – the customer invests in a PV system or efficient light bulb, or electric vehicle and uses more or less electricity as a result. The utility, as a monopoly power supplier with a franchised service territory, has an obligation to serve the aggregated load of its customers as it may change over time. There is no obligation to buy. The customer has a right of self-determination to consume grid-generated power in varying quantities, or not.

At times when the on-site generation exceeds the customer load, the excess generation is exported from the premises. Whether the meter is analog or digital, the meter reading, which is cumulative will decrease as energy flows out of the home or business. We believe it is important and highly relevant to consider where that electricity goes. Some stakeholders, notably utilities, tend to argue that the utility buys the excess and distributes it to other customers. However, this is not an accurate representation. Excess power from the solar home (or business) flows instantaneously a short distance to a neighboring house (or business) where it is immediately consumed by the nearby load. The neighbor sees no difference in supply, is oblivious to the source, and continues to pay the utility the full retail value of all its consumed energy, even thought the utility did not generate it, transmit it, and only played a minor role in delivering it. Therefore, the utility has received payment at the full retail rate for power it did not generate or transmit.

Under net metering, the customer that did generate that power receives the credit by virtue of the meter reduction (the net in net metering). Thus the utility is kept whole and effectively transfers the payment from the non-solar customer to the solar generating customer. There is no storage on the grid of excess energy. Thus, the customer does not use the utility as a "bank for energy" (page 42) but rather to transfer payment from the energy consumer (the neighbor) to the energy producer (the customer-generator).

We recommend the manual include the following guidelines for evaluating NEM:

- Customers have the right to reduce consumption through use of DER;
- Full consideration must be given to the compensation received by the utility from the actual consumer of excess solar energy generation.
- Clarify that excess energy is not physically "banked."

The manual describes NEM's development history in part as follows: "As long as only a very small fraction of households were connecting PV or other self-generation systems, and as long as the quantities of energy moving from customers to the grid were very small, it seemed reasonable to allow customers to hook up their behind-the-meter solar panel systems without mandating additional costs for more precise metering systems." (page 42)

- It's important for the manual to note that the situation of "a small fraction of households" remains applicable today in many states and supports the concept of establishing threshold penetration levels for NEM review.

The NEM subsection runs through a series of "complications" related to this policy, beginning at the bottom of page 42. Our suggestion is to remove bias and in a number of cases to eliminate the unsubstantiated and speculative claims. Regulators should evaluate genuine complications through a factual, analytical structure. Below we provide specific comments in response to each issue.

1. Over a longer period, such as a year, it is possible for a customer would achieve a negative net balance for the whole period, thereby avoiding all charges associated with electricity service. (page 43)

Comment: "All" charges would not be avoided – only those billed on a kWh basis. The cost of connecting to the grid (meter, billing, service drop, etc.) would still be paid by the NEM customer. Further, the situation described is likely to occur in only a few months of the year, and generally those months that have higher overall system loads and consumption. It is very rare on an annual basis. See also the discussion of excess energy being consumed by a neighbor, above.

2. NEM does not account for any difference in value between the cost of service associated with the tariff rate for kWh and the value of the kWh itself. (page 43)

Comment: This perspective overlooks the fact described above that the value of the kWh to the neighbor is the same as a kWh from the utility, and is paid as such. The utility is not buying the excess kWh (except in some cases at the end of the year), the neighbor is. The utility simply transfers payment from consumer to generator. The manual should also recommend the Regulator consider the relative magnitudes of impacts of other matters described in this "complication."

3. NEM does not account for time or locational differences in costs or value of energy. The simplicity associated with a single monthly meter reading provides no information about a customer's pattern of generation or consumption, or the location of the customer. (page 43)

Comment: The complication correctly notes that time and location differences in costs or value of energy are not a function of NEM, but rather billing systems. In addition, this complication is incorrect in the context of TOU rates with NEM. Customers on TOU rates with NEM are provided rates that account for the time differences in costs and value of energy. We recommend this paragraph be stricken.

4. NEM customers do not compensate the system for the operational costs they impose on it. They force the system operator to absorb their excess during peak generating periods, and they force the system operator to ramp generators and adjust the system to "repay" the customer generation at other hours/days/seasons. This means the costs of the system are higher even though the NEM customers are not charged for those additional costs.

Comment: We have no objection to flagging operational costs as an issue to be addressed by regulators, but the bias in the assumption that there *are* additional operational costs must be eliminated. As we have said many times in these comments – regulators have made, and should make decisions on the basis of data-driven facts and analysis. The conjecture reflected here must be factually supported. Without factual support, it must be stricken.

5. By overcompensating the NEM participants through their avoidance of kWh charges, NEM necessarily is imposing those avoided costs on the nonparticipants. In this view the nonparticipants are subsidizing the NEM participants.

Comment: Here too, we have no objection to flagging for regulators the issue of cross-subsidization that appears many times in the draft manual, but the built-in assumption of a subsidy is improper. This bias must be eliminated. Allegations of cost-shifting must be factually supported. This discussion should be stricken.

6. [NEM] fails to account for the complexity of grid operations. For grid stability to be maintained, there may be a need for the ability of the grid operator, such as the distribution utility, to curtail the operation of the generating system, essentially overriding the desire of the customer to generate as much as possible. The effects of any one customer's actions are negligible and make little difference to grid operations.

However, NEM detractors argue that as greater amounts of customer generation are connected to the system, any savings to the system may be overwhelmed by greater costs. Customer-side PV generation peaks in the afternoon, and the grid operator accommodates the customer surplus flowing onto the grid by lowering the load service of dispatchable power plants down to minimum load, the lowest level of operation consistent with an ability to stay on line and be available to provide service. This action has a cost and, in the future, may strain the abilities of conventional plants. NEM detractors argue that NEM customers, far from saving costs to the system, may actually increase system costs.

Comment: We remind the Subcommittee of several points we have raised multiple times in these comments. First, in most states penetration rates of DSG (customer-side PV) is very low and it would be both unfair and short-sighted for regulators to erect barriers to DER technologies just at the time when integration of such technologies can dramatically lower costs when penetrations increase. Second, regulators should establish penetration thresholds that would trigger more in-depth review of the effects of DER. Third, we agree that the utility landscape is changing, but the claims embodied in this “complication” should be stricken as biased and speculative without data. There is no doubt that grid operations will change with more and more DER of all types being deployed, but we are confident that utility engineers are up for the challenge as they have been so many times before.

7. NEM may reduce the total amount of utility generation, but it does little to encourage customers to use less electric service overall. In fact, under a situation of inclining-block rates, the charges that the NEM customers avoid are the in the highest blocks.

Comment: We do not believe this is a complication, or a problem of any sort, as the implication is that other customers are not impacted by NEM. We recommend striking this issue, as well.

Recommendations regarding the manual’s NEM “complications:”

- The complications of NEM described on pages 42 (near bottom) through the end of the NEM subsection on page 44 of the manual are largely biased and not supported by facts. The manual should provide topical guidance for regulators for evaluation of NEM, but should not reflect assumptions and effects that are not supported by facts and analysis relevant to the regulator’s state, practices, and policies.

<u>Valuation methodology subsection V.B</u>

The draft manual describes this method properly as a buy all/sell all (“BA/SA”) framework. As such, it is not net metering and the customer does not offset electricity purchased from the utility with any self-generation. Indeed, the customer continues to purchase 100% of its consumption from the utility, and sells 100% of its generation to the utility in what is effectively a wholesale transaction – a sale to the utility for resale to its customers. The customer, under current models, has no market opportunity for selling its power to any entity other than the incumbent utility.

The manual focuses on the price paid by the utility to the host customer in the wholesale transaction, such price set by either a value of resource method, a value of service BA/SA method, or through transactive energy. Regulators should be aware that some believe this method could create a taxable transaction for the customer. In other words, the revenue paid by utility to customer-generator might be taxable.

The ***value of resource*** method reflects a valuation process that has occurred many times.[17] The manual provides a reasonable description, although the use of "attempts to" several times introduces bias. It should also be noted that the illustrative list of costs and benefits is not necessarily comprehensive.

The ***value of service*** method has not been used anywhere to our knowledge, and little analytical work has been done to comprehensively value these services. The lack of analytical underpinnings should be noted in the description.

Valuation based upon ***transactive energy*** is an effort to capture services and value streams across a highly interactive grid. This is an interesting concept and may not be ready for prime time today, but allowing customer-generators and DER hosts effective open access to their neighbors to maximize value is a market-based approach that might make sense in the future. For example, a customer generator could provide excess solar energy to a neighbor directly using existing infrastructure as a virtual extension cord.

In sum, Vote Solar reiterates its view that the customer should receive full value for the DER in which they have invested. If one of these valuation methods is used, regulators should be clear that the netting of kWh transaction under net metering is being separated into two transactions. The wholesale transaction becomes an investment decision – does the rate to be paid for the energy generated provide a fair return on that investment or would the customer be better off investing in rental property, for example. Finally, we urge the Subcommittee to recommend to regulators contemplating a change in compensation to allow the retail customer to make the choice between a Buy All/Sell All arrangement and the current net metering program, at least at the outset.

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[17] The benefits study referenced in the previous section for Minnesota is the value of resource basis for a BA/SA alternative to NEM at the option of the utility. Thus far, no utility has switched to this model of DER deployment.

Recommendations for the valuation methodology DER compensation approach:

- The manual should note that the BA/SA framework results in a separate sale of energy, effectively at wholesale, from customer to utility and may have unintended consequences.
- The manual should note the utility has monopsony power over the customer as the only purchaser in the market.
- The manual should recommend regulators allow DER customers, and not the utility, the option of switching to a BA/SA framework from a net metering regime, rather than imposing such a dramatic change.

<u>Demand Charges:</u>
We strongly recommend this entire subsection be deleted from Section V, as it is a rate design option and not a compensation method, and addressed in the Introduction to Rate Design subsection II.B.1.d. In addition, there have been a number of papers addressing demand charges relevant to this discussion of DER produced over the past year or so, a couple of which are footnoted in the manual. One such report, "Charge Without a Cause?" was released just prior to this draft manual and is attached to the comments of former Illinois Commissioner John T. Colgan, filed separately. This report addresses many of the issues and question raised in this subsection and can provide guidance to the Subcommittee if it chooses to expand the discussion in the Rate Design section.

We also wish to highlight the last subsection under demand charges here: "At the time of writing this Manual empirical data for demand-based rate designs that are being implemented on a mandatory basis for large investor-owned utilities is limited. Thus, regulators should be wary of counting on unsupported, promised benefits and cautious when plausible harm may represent itself." (page 53) Indeed, no regulator has approved mandatory demand charges for residential customers to date.

<u>Fixed Charges and Minimum Bills</u>

We recommend that this rate design subsection be consolidated with the other rate designs addressed in Subsection II.B. and our comments can be found there.

<u>Standby and Backup Charges</u>

These types of charges are not a compensation mechanism for DER, but rather a penalty, so a further explanation as to the rationale for their inclusion on this list is warranted. As explained in this subsection, such charges are a type of rate design for certain specific types of customers. Historically, "[o]nly large non-utility generators, such as combined heat and power systems, faced fees for standby service." (page 55) These charges were justified because the load that was being self-served by large customers was substantial, and the utility truly needed to have the ability to meet that load when the customer's generation was down for maintenance, for example. In the words of the manual:

> "Historically, [standby and backup charges] are most associated with non-utility generating systems, such as large self-generation systems at industrial plants and with combined heat and power cogeneration systems. They exist so that utilities and system operators are not saddled with costs of maintaining large reserves beyond mere prudence." (page 56)

DER is a very different type of onsite generation. The generation of the DER system is not under the control of the customers, yet the utility knows fairly well when it will generate and frequently installs production meters on the generation. For the residential and small commercial classes, the systems are quite small and geographically diversified, usually less than 10 kW on the former and less than 75 kW on the latter. Thus, the utility does not need to maintain standby resources to support unexpected outages of these systems. In this regard, the report points out "[standby and backup charges] have not generally been associated with intermittent generating sources except for large commercial-sized projects whose output (or lack of output) could alter system operations and requirements." (page 56)

However, the discussion goes on to propose the following:

> "Even though most DER are small and operate independently, a large number of small DER in aggregate, if they all do the same things at the same time, whether planned or not, could rise to the level of an important contingency. For example, a large number of household PV systems, just a few kilowatts each, spread throughout a service territory, and all responsive to the same sun and the same clouds, could, and should, be considered an important planning contingency." (page 57)

Here the manual lays out an implausible scenario suggesting a "large number of small DER in aggregate" "doing the same things at the same time" "spread throughout a service territory," but "all responsive to the same sun and the same clouds." In our experience across the country, we have yet to see this scenario or anything close happen in reality. We do not oppose regulators studying this or other possible situations, but it must be done using facts, data, and proper analysis. Finally, the biased phrase "and should" (in the final line) should be stricken.

Finally, the manual describes another scenario that raises different concerns. "Since PV generation is concentrated in the early afternoon, and their production drops off in a very predictable manner as the afternoon wears on, it may be difficult for the system operator to manage the system. The resulting net load, the load that the electric system must dispatch, can be counted on to vary up and down each day in response to the pattern of the PV systems. Sudden system changes, such as a change in cloud conditions, could make for a combined reduction in output that would be worthy of system operators' attention." (page 57)

Ultimately, the manual observes the following: "However, there does not seem to be a call for specific standby charges for small distributed energy resources, particularly for behind-the-meter resources, at this time." (page 57) This is telling and should give the regulator pause when considering such charges. Indeed, this subsection closes with "Any charge would need to be justified directly and not be allowed to discourage the investment by customers." (top of page 58)

Lastly, we provide below an excerpt of recent testimony[18] from Scott Brockett, Director, Regulatory Administration, Xcel Energy Services, Inc. addressing the topic of DSG and standby charges:

> While the more traditional generators described above [in his testimony]are still with us, to an increasing degree customers are installing behind-the-meter generation that is markedly different. Solar panels are the salient example. On an annual basis, they provide energy at a much lower capacity factor. Moreover, solar panels cannot be effectively dispatched; their production is determined by factors – such as cloud cover and time of day – outside of the owner's control.
>
> Customers with solar panels do not require traditional backup service. Instead, they require the utility to provide a significant share of their electrical service. Stated differently, they usually require the utility to generate and deliver electricity to them during at least some hours every day. This utility service cannot be properly construed as "standby" service. Instead, the utility is working hand-in-hand with, or "supplementing" on a continual basis, the service provided by the customer's solar panels.
>
> Of course, there are other potential types of on-site generation such as biomass or hydro-electric applications. The reliability and capacity factors of these generators can vary significantly. In some cases customers with this generation require traditional standby service, while in other cases customers require service on a more frequent or supplemental basis.

We recommend the Subcommittee clarify several important takeaway points from this section in the manual:

- ➢ Solar production is predictable, and sudden changes in cloud conditions impacting the production of more than a few systems is not supported by facts;
- ➢ Any proposal for imposition of standby or backup charges must be based upon

[18] Direct Testimony of Scott B. Brockett in Docket No. 16AL-0048E before the Colorado Public Utilities Commission.

real data and factual analysis;

- Regulators should evaluate the extent to which DER could alter system operations and requirements, based upon facts and data from actual experience;
- Consideration should be given to integrated DER technologies, and the geographic diversity of DER systems.

Interconnection Fees and Metering Charges (page 58)

This section is fairly written for the most part. We urge the Subcommittee to remind regulators that most interconnection standards require the interconnecting customer to pay for any incremental costs caused by the interconnection. Thus allegations of distribution costs imposed by the interconnection of DER must be scrutinized very carefully.

We propose the Subcommittee include two additional recommendations to regulators in this subsection on interconnection fees and metering charges.

- The interconnection standards utilized by the State should be updated to reflect the most current FERC Small Generator Interconnection Procedures set forth in Order No. 792.
- Individual customers should not be required to pay for production meters on their DER systems for research or information gathering purposes, particularly given the asset-deploying incentives built in to the regulatory model. We do not dispute the need or customer cost responsibility for production meters to determine generation for the purposes of tallying renewable energy credits.

Summary of Recommendations to DER Compensation Section:

Overall recommendations to the DER Compensation Section:

- Strike subsection V.C, demand charges, as it is addressed in the manual's subsection on rate design.
- Move subsection V.D, fixed charges and minimum bills, to section II.B.1 as these are rate design issues.
- Eliminate bias in the descriptions of DER compensation policies.
- Evaluate DER compensation alternatives with full consideration given to the following framework elements:
    - Appropriate time frame: short term, long term, or both;
    - Comprehensive review of all customer classes with DER
    - Full complement of stand alone and integrated DER technologies

Recommended framework for evaluation of Net Energy Metering Section V.A:

- Customers have the right to reduce consumption through use of DER;
- Full consideration must be given to the compensation received by the utility from the actual consumer of excess solar energy generation.
- Clarify that excess energy is not physically "banked."
- It's important for the manual to note that the situation of "a small fraction of households" remains applicable today in many states and supports the concept of establishing threshold penetration levels for NEM review.
- The complications of NEM described on pages 42 (near bottom) through the end of the NEM subsection on page 44 of the manual are largely biased and not supported by facts. The manual should provide topical guidance for regulators for evaluation of NEM, but should not reflect assumptions and effects that are not supported by facts and analysis relevant to the regulators state, practices, and policies.

Recommendations for changes to the <u>Valuation methodology</u> Section V.B:

- The manual should note that the BA/SA framework results in a separate sale of energy, effectively at wholesale, from customer to utility and may have unintended consequences.
- The manual should note the utility has monopsony power over the customer as the only purchaser in the market.
- The manual should recommend regulators allow DER customers the option of switching to a BA/SA framework from a net metering regime, rather than imposing such a dramatic change.

Recommendations for changes and additions to the Standby and back up charges Section V.E:

- Sudden changes in cloud conditions impacting the production of more than a few systems is not supported by facts;
- Any proposal for imposition of standby or backup charges must be based upon real data and factual analysis;
- Regulators should evaluate the extent to which DER could alter system operations and requirements, based upon facts and data from actual experience;
- Consideration should be given to integrated DER technologies, and the geographic diversity of DER systems.

Recommendations for two additional recommendations to regulators in Interconnection fees and metering charges Section V.F.

- The interconnection standards utilized by the State should be updated to reflect the most current FERC Small Generator Interconnection Procedures set forth in Order No. 792.
- Individual customers should not be required to pay for production meters on their DER systems for research or information gathering purposes, particularly given the asset-deploying incentives built in to the regulatory model. We do not dispute the need or customer cost responsibility for production meters to determine generation for the purposes of tallying renewable energy credits.

End.

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VOTE SOLAR

Attachments

Good process letter (5 pages)	A
Bonbright Criteria for a Sound Rate Structure (1 page)	B
Summary of inherent cross-subsidies (3 pages)	C

June 23, 2016

Hon. Travis Kavulla, President
National Association of Regulatory Utility Commissioners
1101 Vermont Ave., NW
Suite 200
Washington, D.C. 20005

Dear President Kavulla:

We are a representative group of consumer, low-income, environmental and technology-specific advocates who have joined forces to have frank discussions and increase understanding of the rapidly evolving electricity rate-design issues arising in today's fast-changing energy landscape. We believe in an electric power future that protects consumers and provides for the continued growth of clean, efficient and renewable energy. These changes will require regulators to pay close attention to how customers interact with and pay for the energy and services they use, as well as how utilities finance their capital investments.

Our organizations have not traditionally seen eye to eye on everything. But more and more these days, we're finding and forging common ground. For example, we agree that increases in fixed charges are among the least effective ways for utilities to adapt, particularly in light of the well-documented impacts on customer costs, conservation, equity and the ability for customers to control their energy bills. We think the fact that organizations from environmental, consumer and renewable energy perspectives are now working closely together on this issue speaks volumes about its importance, and it signals the inclusive and collaborative path forward needed to get good rate design done right.

As we've talked with one another, the conversation has increasingly turned to a more expansive notion of what "good" rate design looks like:

- It should include a *good process*; one that is transparent, fair, accessible and accountable.
- It should be based on *good data* and *transparent modeling* that are credible and available to all parties.
- And it should have a *good sense of timing*. Instead of the traditional confrontation in a contested rate-case proceeding, we should look for opportunities to engage collaboratively in formal, constructive stakeholder processes that explore new ways of moving forward together, even if it takes a little longer.

Regulatory Process Recommendations:

Outlined below are several regulatory process recommendations that we believe would improve the likelihood of success and manage any risk associated with change. Regulatory process was not a topic covered by NARUC's recent survey, so we are approaching it outside the survey and hope some of our recommendations and examples can find a place in the upcoming Manual. This will also serve as a response to some of the views that Edison Electric Institute expressed in its

Feb. 14, 2016, letter to NARUC's Subcommittee on Rate Design regarding rate design for residential distributed generation.

We are discussing this topic at this time because of the impact of new technologies on the utility business model, utility regulation and the allocation of utility system costs and benefits to consumers. It is broader than the impact of solar PV and net metering. The increased prevalence of energy efficiency, demand response, storage and electric transportation should also be explored as they continue to grow and more innovations and choices enter the market. We believe that with appropriate and equitable allocation of costs, these new technologies and customer options can provide many benefits, and we therefore support their cost-effective development and deployment.

We also believe that all customers should pay an equitable share for their use of the grid. But some in the utility industry have initially reacted to load loss from new technologies by citing solar customers and cost-shifts as equity reasons to impose new fixed charges or untested demand charges on *all* customers. Laying blame on any one technology and responding with short-term Band-Aids rather than long-term solutions is a missed opportunity. We are also concerned that imposing increased fixed charges or untested demand charges on all customers may stifle deployment of nascent technology, discourage innovation, reduce customer control over electricity costs and disproportionately harm low-use and low-income customers. Reviewing rate design and small-scale generation pricing options, given the changes taking place in the electricity sector, is a necessary and laudable act, but it should be put in perspective and done in a mindful, holistic way that is informed by substantiating data, particularly at the relatively low levels of solar penetration that currently exist in many of our states.

To that end, we applaud NARUC's action to establish the Subcommittee on Rate Design and its development of a Manual to assist state commissions. We advance a range of process ideas below to inform the development of that Manual because there is importance in doing it right – and risks to doing it wrong.

It is important to note that we, as a group, have discussed the 1961 Bonbright principles as a useful starting point in the analysis of a fair rate design. (The original 1961 Bonbright principles are more consumer- and small-customer oriented than the revised 1988 principles that EEI cites in its Feb. 14, 2016, letter.) However, application of the Bonbright principles is not formulaic and should not dictate any one specific answer. We believe it is prudent and necessary to augment the 1961 Bonbright principles to include important public policy objectives, including equity and environmental objectives, and parameters for deployment of energy saving, management, storage and generation technologies. Different state commissions may weigh the importance of the principles differently, depending on their goals. Options for change may also differ depending on factors like the availability of advanced metering. For these reasons, we do not reach consensus on a "best" solution for every state.

We do, however, offer specific recommendations on what a good regulatory *process* looks like in evaluating rate-design changes. They include the following and are discussed in more detail below:

- Assessment and analysis of state conditions and sound data when determining the need and pace for rate-design change;

- Collaborative, upfront, open, docketed processes that explore the range of rate-design options in advance of or in lieu of rate cases;
- Data-driven rate-design inquiries;
- Pilots and testing for novel or untested rate designs prior to wide-scale adoption;
- Consideration and accommodation for low-income and vulnerable customers in rate design; and
- Sufficient opportunity to educate customers on new/shifting rate designs well in advance of their implementation and the development of tools to do so.

Assessment and analysis. Understanding the pace for making change should be a first step. Do state-specific conditions require immediate action, or should state regulators continue with intentional monitoring and establish guideposts and goals for taking future action? Rate design changes come with the risk of unintended consequences and should not be undertaken lightly or in *anticipation* of a future problem. Iowa and Minnesota are good examples of states that are carefully assessing state-specific conditions and sound data when determining the need and pace for rate-design change.

Collaboration. Commissions should have processes available to discuss goals and assess different methodologies and their impacts outside traditional, contested rate cases. In an open, docketed process, stakeholders and regulators can evaluate the pros and cons of different rate-design alternatives based on clear policy goals. Regulators should require utilities to share any models upon which they base claims for cost shifts or other impacts so that stakeholders can run alternative scenarios. An open process can help regulators assess trade-offs and choose designs that meet the majority of goals, rather than being locked into binary yes/no choices. Mitigation measures can be taken in those areas where compromise needs to be pursued. These processes should be open and collaborative, designed to understand the pace of change, options available and impacts. In contrast, proposals in rate cases limit frank discussions, often have gaps in data, and by their very nature are adversarial. It is to all parties' benefit to avoid the public, adversarial rate-case confrontations that have taken place recently in states like Arizona, Utah, Nevada, Wisconsin and New Mexico.

Data-driven. During collaboration, commissions should start the process of defining and collecting the data necessary to inform future policy discussions. For solar PV, this data may include, but is not limited to, deployment rates and locations; diversity of system sizes deployed; load shapes; hourly production profiles, including south and west arrays; hourly line losses; distribution costs; and hourly load data for individual circuits. As EEI recognized in its letter, "The electric system benefits (e.g. cost savings) attributable to DG can include energy, capacity, transmission and distribution (T&D) system deferral and line loss reductions, as well as environmental and other benefits as assessed in each jurisdiction." Collecting data to put actual numbers to these costs and benefits is an important step. The Iowa Utilities Board, for example, recently required utilities to conduct pilot projects and collect data to help inform the development of future policy or rule changes related to distributed generation. Minnesota's

Department of Commerce-led Value of Solar methodology process is another good example of an open, data-driven process.

Testing**.** Pilots, shadow-billing and opt-in rates are all widely accepted methods for testing new rate designs and managing risk prior to wide-scale adoption.

Special attention to low income/vulnerable population impact. While any process should include thorough analysis of anticipated impacts of rate design changes, particular attention should be given to low-income and vulnerable populations to ensure that rate design or the imposition of new costs do not undermine the home energy security of these households. The process should incorporate review and approval of effective programs and policies to mitigate these impacts.

Consumer education**.** Some rate designs strive to change customer behavior through price signals. Customers must be able to respond and – critically – *understand* how to respond for these designs to be effective. Customer education is also a topic that should be mindfully explored.

There are many examples in the last few years of states making significant rate-design changes in a preemptive manner and without adequate support, creating a backlash that limits choices in the future. Such experiences incite political intervention and discourage consumers from reducing or shifting their energy use and investing in cleaner sources, even when warranted. Our organizations have expertise in this complex arena, and we are eager to engage with commissioners, utilities and other stakeholders nationwide to find common ground, limit areas of disagreement, and manage the risk associated with change for the benefit of customers, the environment and society.

Thank you for the opportunity to provide these process recommendations, and we encourage you to consider them for inclusion in the forthcoming rate design Manual.

Sincerely,

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cc: Hon. Nancy Lange, Chair, Committee on Energy Resources and the Environment

Hon. Edward S. Finley, Jr., Chair, Committee on Electricity

Hon. Brandon Presley, Chair, Committee on Consumer Affairs

Hon. Stan Wise, Chair, Committee on Gas

Hon. Alaina Burtenshaw, Chair, Committee on Water

Mr. Greg R. White, Executive Director

Mr. Christopher Villarreal, Chair, Staff Subcommittee on Rate Design

Members of Staff Subcommittee on Rate Design

Criteria for a Sound Rate Structure
James Bonbright, 1961

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers . (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different customers
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on peak versus off peak electricity, Pullman travel versus coach travel, single party telephone service versus service from a multi party line, etc.).

Examples of cross-subsidies inherent in cost allocation and rate design

Customer sizes, loads, and load patterns

- **Multi-family** subsidizes **Single-family**; an apartment building is served by a single transformer bank, and the utility never sees the individual demand of individual units – only the consolidated demands of the group. Yet, a large apartment building, under high fixed charge rate design, will pay much more than an otherwise identical-to-serve load (undiversified and coincident kW, monthly kWh, hourly usage patterns) at a hotel or office building served through a single meter. Multi-family is less expensive than single family, due to the wider sharing of transformers and the service drop, the large number of customers per span of primary distribution, load diversity, and lower meter-reading costs (for utilities without remote metering).
- Residential and small commercial customers who consume <u>more</u> energy than average for the class contribute more revenue towards fixed cost recovery than those using less than average energy, all else being equal. Those larger customers also contribute more to the costs of generation, transmission and distribution than do smaller customer. Consuming more results in higher fixed cost contributions, which helps cover higher costs incurred by the utility to provide service. Depending on rate design and cost patterns, small customers may subsidize large customers, or vice versa. A close review of residential load factors, diversity and individual load patterns through load research can reveal improper cost allocation assumptions by the utility.
- In new single-home residential areas, the distribution system is generally sized based on the expected usage of the homes in the area (with simple adjustments for square footage and electric appliances), not on the expected usage of any one home (e.g., recognizing the efficiency of the home and the appliances). Line extension policies generally provide for a larger line extension investment by the utility if expected usage is higher. New customers with expected low usage are generally required to pay a significant part of the line extension. The allowances are typically based on expected usage or expected revenue. Therefore, the investment by the utility in distribution systems is generally tied to expected sales. To recover these costs uniformly on a per-meter basis will double-charge customers who have paid a contribution in aid of construction for their line extension.
- In an established residential area, increased consumption requires increases in the number and size of line transformers, in the number and size of distribution lines, and in the transmission and substation facilities serving. Increases in consumption can be due to:
  - New appliances and technologies, from home entertainment to added refrigeration and freezer space, to electric vehicles.

  - Expansion of existing homes.
  - Behavioral and lifestyle changes, e.g., adding children, housemates or aging parents to the household; working a business from home. Expansion of internet-based businesses and telecommuting can fundamentally change the load and load shape of residential customers from what existed when the circuit was constructed.
- Existing residential and small commercial customers who reduce their energy contribute less revenue towards fixed cost recovery than those using more, but contribute less to the need for new transmission and distribution capacity, extend the lives of the transformers and underground lines that serve them, reduce the need for new generation resources, allow retirement of existing resources, and lower competitive market prices for energy and capacity. Consumption reductions can be due to:
  - Behavioral changes, including using energy more carefully, and changing lifestyle (e.g., as shrinking household size, working outside the home).
  - Investing in energy efficiency and clean distributed generation (mostly solar).
- System costs are not uniform across all customers, yet postage-stamp rates charge the same rates to all customers.
  - Customers served with (cheaper) **overhead** distribution subsidize customers served with (more expensive) **underground** distribution, who actually receive more reliable service (fewer outages due to storms, treefalls, vehicles, animal contact). Depending on the utility, overhead distribution may be primarily located in more affluent suburban areas, with most low-income customers served by underground service in urban centers; alternatively, undergrounding may be found mostly in recent higher-income suburban developments, with overhead in less affluent areas.
  - Line losses vary with the distance from the distribution substation to the customer, the loading on the line, the peak-concentration of the load, and the location of the substation on the transmission system, but utilities charge all customers in a rate class the same loss factor.
  - The distance from a distribution substation to a large customer may affect the amount of equipment (and investment) required of the utility to serve that customer, yet postage-stamp rates charge the same rates to all customers.
  - **Urban** customers generally subsidize **suburban** and **rural** customers, since a mile of distribution serves more urban customers than suburban customers, and rural distribution serves even fewer customers per mile.

Economic and Business Factors Affecting Load Patterns and Cost Causation

- Customers whose usage is **stable** over the business cycle (schools, hospitals, government buildings) tend to subsidize customers with loads that are **volatile** with respect to the business cycle (industry), if all classes pay the same return. The volatile loads leave temporarily stranded costs that are reallocated to the remaining loads, and increase the utility's financial risk and required return. Residential consumer usage varies with weather, which adds "non-systematic" risk, which is very different because portfolio theory addresses how a diversified portfolio of investments can manage non-systematic risk. The loss of one industrial customer can have a serious economic impact on utility earnings; the loss of one residential customers has an inconsequential impact.
- Customers served on demand charge rates that have sporadic and mostly **off-peak load** (stadiums, arenas, many churches) subsidize customers with high load factors and predominantly **on-peak usage** (office buildings) served on the same tariff.
- Economic Development rates: the discounting of rates to attract, or sometimes retain, businesses to a state or region is frequently based on an explicit reduction in full cost of service revenue recovery. Commissions however will sometimes strive to assure the discount is not picked up by other customers.

Cost of Service Models and Gradualism

- A cost-of-service study may indicate that various rate classes or customer classes are generating different overall return, equity return, or revenue-to-cost ratio. These results do not mean that the various rate classes are paying more or less than their *fair* share of costs. Cost-of-service studies only roughly apportion costs among classes, using numerous simplifying assumptions, including that assumption that risk is the same across all classes. Regulators frequently refrain from moving all customer classes to a uniform indicated return, due to the lack of precision in cost allocation (many regulators allocate revenue increases proportionately, so long as class returns fall within some predetermined range) and in part because the underlying risks are different. Even where regulators do find that one customer class has a revenue deficiency, regulators generally move in the direction of cost causation in a measured fashion, in the interest of gradualism.
- Individual residential demands are less coincident with system or distribution demands than are commercial/industrial demands. Failure of utilities to properly account for the greater diversity of residential customers, e.g. applying commercial demand charge rate designs to residential customers, have created a mismatch between revenue recovery and cost incurrence (at least based on standard allocation methods).