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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
FEB 25 2016
DOCKETED BY

COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.

Docket No. E-00000J-14-0023

GCSECA'S NOTICE OF FILIN DIRECT TESTIMONY

Pursuant to the Procedural Order dated December 3, 2015 in this docket, attached is the direct testimony of David Hedrick on behalf of Grand Canyon State Electric Cooperative Association, Inc. ("GCSECA") and its electric distribution cooperative members.[1]

RESPECTFULLY SUBMITTED this 25th day of February, 2016.

GALLAGHER & KENNEDY, P.A.

By______________________

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[1] GCSECA's electric distribution cooperative members include Dixie Escalante Rural Electric Association, Inc.; Duncan Valley Electric Cooperative, Inc.; Garkane Energy Cooperative, Inc.; Graham County Electric Cooperative, Inc;, Navopache Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc.

Original and 13 copies filed this
25th day of February, 2016, with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE, Chairman
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BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	**DOCKET NO. E-00000J-14-0023**

DIRECT TESTIMONY OF DAVID HEDRICK

ON BEHALF OF

GRAND CANYON STATE ELECTRIC COOPERATIVE ASSOCIATION, INC.

FEBRUARY 25, 2016

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BACKGROUND AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David W. Hedrick, and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. BY WHOM ARE YOU EMPLOYED, AND WHAT IS YOUR POSITION?

A. I am employed by Guernsey Engineers, Architects and Consultants. I am Senior Vice-President and Manager of the Analytical Services group.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A, I have earned a Bachelor of Science degree from the University of Central Oklahoma in mathematics and a M.B.A degree from Oklahoma City University. I have been employed with Guernsey since 1981. My primary area of responsibility is rate analysis and cost of service work for electric distribution cooperatives and electric generation/transmission cooperatives. Attached hereto as Exhibit DWH-1 is my resume with a listing of the projects and clients with which I have been involved.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY COMMISSIONS?

A. Yes. I have testified before the Arizona Corporation Commission, the Arkansas Public Service Commission, the Colorado Corporation Commission, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, and the Wyoming Public Service Commission.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of Grand Canyon State Electric Cooperative Association, Inc. ("GCSECA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony provides GCSECA's position regarding the cost of solar distributed generation on its electric distribution cooperative members (the "Cooperatives").[1] My testimony will address:

a. The impact of Distributed Generation ("DG") and Net Metering on the Cooperatives;

b. The Cooperatives' Avoided Costs and the fact that their wholesale capacity costs are not reduced as a result of solar DG;

c. The lack of reduction in the Cooperatives' distribution costs as a result of solar DG;

d. The negative impact of DG on the Cooperatives is more significant than for other utilities;

e. The development of charges and/or credits for DG should be based on the same criteria used to develop the rates and charges for other customers;

f. Programs to mitigate the costs of DG should be fair and equitable to all customers; and

g. Legislation and other authoritative materials regarding the costs and benefits of solar DG.

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[1] GCSECA's electric distribution cooperative members include Dixie Escalante Rural Electric Association, Inc.; Duncan Valley Electric Cooperative, Inc.; Garkane Energy Cooperative, Inc.; Graham County Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc.

IMPACT OF DG AND NET METERING

Q. PLEASE PROVIDE AN OVERVIEW OF THE IMPACT THAT DG INSTALLED BY MEMBER CONSUMERS HAS ON THE COOPERATIVES AND THEIR MEMBERS.

A. The Cooperatives deliver electric service to their members using extensive distribution systems. Their distribution systems consist of electric facilities built to serve the total capacity of the electric load and customer-specific electric facilities that are required to provide service regardless of how much energy is consumed. The capacity-related facilities include substations, a portion of the overhead and underground lines, and a portion of the transformers. The customer-related facilities include a portion of the overhead and underground lines, a portion of the transformers, the service lines, and the meters. The costs of providing service associated with both the capacity- and customer-related facilities are fixed in nature. That is, these costs do not vary based on the amount of energy (kWh) consumed by the Cooperatives' members. While a customer density per mile of line will lessen the average per customer cost of these facilities, the Cooperatives have relatively few customers per mile of line. Most of the Cooperatives were formed in rural areas where the densities and operating margins were deemed too small to attract the necessary capital investment from investor-owned utilities ("IOUs") or even any nearby municipal utility. As a result, the number of customers per mile of line for the Cooperatives tends to be significantly lower and the fixed investment per customer significantly higher than most IOUs.

In addition to the fixed distribution costs of providing service, the Cooperatives also incur fixed wholesale capacity costs to provide electric service to their members from their wholesale power suppliers. These costs are associated with existing generation facilities that ensure the ability to provide continuous service to members. These fixed costs do not vary and are represented in a fixed charge billed by the wholesale suppliers.

Historically, the Cooperatives have recovered the costs of providing service to Residential members through rates that include a monthly service availability charge and an energy charge applied to the monthly kWh consumption. The monthly service availability charges approved by the Arizona Corporation Commission have historically been set at amounts well below the total customer-related cost of providing service per customer. The energy charges have historically been designed to recover the remainder of costs to provide service not included in the service availability charges (which include a portion of the customer-related costs, all of the fixed distribution demand costs, the fixed wholesale demand costs, and the variable energy costs).

This rate design recovers a major portion of the fixed costs in the variable component of the rate. It can function well for the recovery of costs where all of the customers being served in the Residential rate class are similar consuming entities receiving all or most of their energy from a single utility. However, this rate design does not provide for the appropriate recovery of the costs incurred in providing service to customers that have solar DG facilities.

Customers that install DG facilities will reduce the energy (kWh) that is purchased from the Cooperatives by an amount equal to the generation output of their facility.

This reduction in kWh purchased from the Cooperatives results in a loss of fixed costs being recovered through the energy component of the rate. The fixed distribution demand and customer costs that the Cooperatives incur to provide service are similar for all Residential customers, whether they have DG or not. These fixed distribution demand and customer costs incurred by the Cooperatives are not reduced as a result of the installation of DG. Yet, because of the existing rate structure and the reduction in kWh purchased by the DG customers, the fixed costs included in the energy component of the rate are not recovered. As a result, the Cooperatives' customers with DG do not pay the appropriate fixed demand and customer costs for the provision of electric service, while the remainder of customers pay more than their equitable share of those costs. The installation of DG initially results in recovery of less revenue than the existing rates were designed to recover. This inadequate recovery of lost fixed costs and under-recovery of authorized revenues must ultimately be recovered either from customers with DG or from all of the Cooperatives' remaining customers with consumption.

Q. ARE MEMBERS WITH DG CONTINUING TO UTILIZE THE GRID FOR SERVICE?

A. Yes. Members of the Cooperatives may believe that if their net power flow is zero that they are not using the grid. This is simply not true. First of all, those with DG systems don't produce power all of the time. When they are producing in excess of their own needs, the excess energy is put back on the grid. The Cooperatives' systems then serve essentially as a battery to provide energy when the DG customers are not producing power sufficient to meet their load requirements.

It is important to understand that the grid provides much more than power. The grid services that the Cooperatives and other utilities provide include reliability, reserves, frequency control, voltage control, and redundancy as physical quantities flowing through the grid. Members may have net zero power flows, but reliability is flowing into the members, and none is flowing out: not a net zero. Voltage control is flowing into the members, and none is flowing out: not a net zero. Frequency control is consumed by the members, and none is provided by the members: not a net zero. In short, while members may have reached a "net zero" threshold on energy (kWh), they are a large net negative on very expensive grid services that everyone else has to pay for. Stating that you don't use the grid because you are net zero is like saying, "I drive the same road to and from work each day, so I net zero mileage on the road and, therefore, I don't use the road."

Q. WHAT ARE "LOST FIXED COSTS" RELATED TO DG?

A. The energy charge in the Cooperatives' Residential rates include three cost components: purchased power demand costs, purchased power energy costs, and distribution wires costs. The purchased power demand costs and distribution wires costs are fixed costs that do not vary based on kWh consumption and are not reduced as a result of a member's reduced consumption, even though these costs are recovered in the energy charge of the Residential rate. Therefore, as energy consumption is reduced due to installed DG, these fixed costs are no longer recovered from these consumers. These costs not recovered from members with DG are known as "lost fixed costs."

Q. WHAT IS THE MAGNITUDE OF THE UNRECOVERED FIXED COSTS?

A. The impact on the various Cooperatives differs according to their member profile and specific costs. But, I do have two examples that demonstrate the impact. Exhibit DWH-2 provides a calculation of the lost fixed costs resulting from service provided to Residential members with DG under Sulphur Springs Valley Electric Cooperative, Inc.'s ("SSVEC") existing Net Metering Tariff NM-1. At the end of 2014, SSVEC provided service to 1,013 Residential members with DG. The average size of the DG system installed is 5.62 kW (AC) with a capacity factor of approximately 25%. The average monthly production for a unit of this size is 1,026 kWh. Pursuant to its Net Metering tariff, SSVEC must compensate the consumer for the total production from a DG unit at the full retail rate. As a result, every kWh generated by a consumer's DG unit results in the lost fixed costs to SSVEC identified on Exhibit DWH-2. The average monthly lost fixed costs associated with the purchased power demand costs is $43.85 per customer under the existing Residential rate. The average monthly lost fixed costs associated with distribution wires costs is $49.85 per customer under the existing Residential rate. The total average monthly lost fixed cost is $93.70 per customer. The estimated lost fixed costs for SSVEC's 1,013 customers for an annual period under the existing Residential rate would, therefore, be $1,139,013.

Exhibit DWH-2.1 provides a calculation of the lost fixed costs resulting from service provided to Residential members with DG under Trico Electric Cooperative, Inc.'s ("Trico") existing Net Metering Tariff. At the end of 2014, Trico provided service to 1,262 Residential members with DG. The average size of the DG system installed is 6.51 kW (AC) with a capacity factor of approximately 25%. The average monthly production for a unit of this size is 922 kWh. Pursuant to its Net Metering tariff, Trico must compensate the consumer for the total production from a DG unit at the full retail rate. As a result, every kWh generated by a consumer's DG unit results in the lost fixed costs to Trico identified on Exhibit DWH-2.1. The average monthly lost fixed costs associated with the purchased power demand costs is $45.57 per customer under the existing Residential rate. The average monthly lost fixed costs associated with distribution wires costs is $37.77 per customer under the existing Residential rate. The total average monthly lost fixed cost is $83.34 per customer. The estimated lost fixed costs for Trico's 1,262 customers for an annual period under the existing Residential rate would, therefore, be $1,262,079.

Q. WHAT IMPACT DOES ARIZONA'S EXISTING NET METERING POLICY HAVE ON THE COOPERATIVES?

A. The existing Net Metering policy is found in Arizona Administrative Code R14-2-2306, which provides as follows:

> A. On a monthly basis, the Net Metering Customer shall be billed or credited based upon the rates applicable under the Customer's currently effective standard rate schedule and any appropriate rider schedules.
>
> B. The billing period for Net Metering will be the same as the billing period under the Customer's applicable standard rate schedule.
>
> C. If the kWh supplied by the Electric Utility exceeds the kWh that are generated by the Net Metering Facility and delivered back to the Electric Utility during the billing period, the Customer shall be billed for the net

kWh supplied by the Electric Utility in accordance with the rates and charges under the Customer's standard rate schedule.

D. If the electricity generated by the Net Metering Customer exceeds the electricity supplied by the Electric Utility in the billing period, the Customer shall be credited during the next billing period for the excess kWh generated. That is, the excess kWh during the billing period will be used to reduce the kWh supplied (not kW or kVA demand or customer charges) and billed by the Electric Utility during the following billing period.

E. Customers taking service under time-of-use rates who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit during the next billing period during the on- or off-peak periods corresponding to the on- or off-peak periods in which the kWh were generated by the Customer.

F. Once each calendar year the Electric Utility shall issue a check or billing credit to the Net Metering Customer for the balance of any credit due in excess of amounts owed by the Customer to the Electric Utility. The payment for any remaining credits shall be at the Electric Utility's Avoided Cost. That Avoided Cost shall be clearly identified in the Electric Utility's Net Metering tariff.

As discussed above, members with installed DG reduce the energy (kWh) purchased from the Cooperatives and, thereby, cause lost fixed costs to be incurred. Arizona's existing Net Metering policy exacerbates the loss of fixed costs by requiring the Cooperatives to pay (via energy credits) the full retail rate for energy generated by the members, even though the retail rate far exceeds the value of the excess generation. Instead of full retail rates, Avoided Cost rates (discussed below) are the more appropriate form of compensation of excess generation. The current policy of over-compensation for DG energy creates a cost that all members of the Cooperatives must pay. The application of the Net Metering policy in its current form is not equitable.

AVOIDED COST RATE AND WHOLESALE CAPACITY COSTS

Q. WHAT ARE THE COOPERATIVES' AVOIDED COST RATES?

A. Avoided Costs are those costs that are eliminated as a result of power produced by DG resources. The Cooperatives' Avoided Cost rates are calculated based on the wholesale fuel and energy cost per kWh charged by the Cooperatives' wholesale power suppliers.

Q. WHY DO THE AVOIDED COST RATES INCLUDE ONLY THE WHOLESALE FUEL AND ENERGY COSTS?

A. Typically, the Cooperatives do not provide their own generation, but rather contract with third-party generators, such as Arizona Electric Power Cooperative, investor-owned utilities, or other providers for their wholesale power requirements. These existing contracts, which provide the vast majority of power used to serve the Cooperatives' customers, include a fixed charge payment for the cost of generation capacity. This fixed charge payment is constant and does not vary based on consumption. As a result, any potential reduction in capacity requirements created by the operation of DG does not translate into a reduction in generation capacity costs for the Cooperatives. Therefore, there is no capacity component included in the calculation of the Cooperatives' Avoided Cost rates. Only the variable components of the wholesale rate – fuel and energy – are included in the determination of the Avoided Cost rates. To the extent that a DG facility produces kWh that offset the wholesale supplier's delivery of kWh, only the associated fuel and energy costs are truly avoided.

DISTRIBUTION SYSTEM COSTS

Q. ARE THERE QUANTIFIABLE AVOIDED DISTRIBUTION SYSTEM COSTS ASSOCIATED WITH SOLAR DG?

A. The experience of the Cooperatives is that solar DG does not reduce their distribution costs of providing service. Because of the intermittency and lack of reliability of rooftop solar DG, a customer with rooftop solar must still rely on power provided from the electric grid during times when the DG unit is not operating or when the DG unit does not provide sufficient generation to serve the customer's entire load. As a result, the size of the facilities required to provide service to a customer with DG is no different than for a standard customer without DG. This means that the metering, transformer, and service drop at the customer's service location would be the same as for any other similarly situated customer. The sizing of the Cooperatives' substation facilities and overhead/underground primary distribution line facilities are, likewise, unaffected by the presence of rooftop solar DG. The planning process for construction of distribution facilities is affected by solar DG only to the extent that <u>additional</u> equipment and devices are required to address operational issues, such as circuit loading, voltage regulation, power factor problems, and protection coordination. Such equipment could include but not be limited to additional regulators, capacitors, breakers, reclosers, and fuses. The need for additional equipment to deal with operational issues becomes more significant as the number of customers with solar DG on an individual circuit increases.

IMPACT OF DG ON THE COOPERATIVES

Q. DO THE ISSUES RELATED TO THE RECOVERY OF COSTS ASSOCIATED WITH SOLAR DG HAVE A MORE PRONOUNCED IMPACT ON THE COOPERATIVES THAN ON THEIR INVESTOR-OWNED NEIGHBORS?

A. Yes. All utilities share cost recovery issues related to solar DG. However, there are two reasons why the recovery of the distribution costs of providing service to customers with solar DG is a bigger problem for the Cooperatives.

First, the Cooperatives are located in rural areas and, therefore, have a much lower number of customers per mile. As a result, they require a much higher level of plant investment per consumer to provide service. This leads to a higher distribution cost of providing service per kWh. Exhibit DWH-3 reflects the differences in line density and average cost for the more rural Cooperatives in comparison with APS and UNS. This higher level of distribution costs for the Cooperatives means that the level of lost fixed costs created by customers with solar DG is a more significant issue for the Cooperatives. Approving rates and charges that allow for a better recovery of the distribution costs associated with providing service to customers with solar DG is an essential step in ensuring that all customers pay their fair and equitable share of the costs for distribution service.

The second reason that the recovery of the distribution costs for service to solar DG customers is a more significant issue to the Cooperatives is their small size and the fact that the areas served by the Cooperatives are the most economically challenged counties in Arizona. Their small size means there are fewer customers over which to spread any subsidies created by solar DG. Furthermore, customers with lower incomes are less likely to participate in rooftop solar and least able to pay any subsidy caused by the lost recovery of fixed costs from those customers that do deploy rooftop solar.

DEVELOPMENT OF DG CHARGES AND CREDITS

Q. WHAT STANDARD SHOULD BE APPLIED TO DEVELOP THE CHARGES AND CREDITS FOR SOLAR DG?

A. There has been considerable discussion, not only in Arizona, but across the country, regarding methods for quantifying the future benefits of solar DG. It would be appropriate that the same standards used in the development of rates for Arizona utilities be applied in determining the value of solar DG. The primary standard in rate making is that a utility may include for recovery in its rates only those expenses that are known, measurable, and of a continuing nature. In addition, utilities have not been allowed to recover in current rates those costs that are for future periods. The Cooperatives do not have information or data regarding any future generation capacity savings, transmission savings, or environmental savings associated with the implementation of solar DG that would comply with the current rate-setting standard. Therefore, the Cooperatives are concerned by proposals to develop charges and credits for current rates that would be based on a different standard, specifically one that would require recognition of future unquantifiable benefits or potential future quantifiable benefits of solar DG.

PROGRAMS TO MITIGATE DG COSTS

Q. WHAT OTHER CONCERNS DO THE COOPERATIVES HAVE REGARDING THE RECOVERY OF COSTS ASSOCIATED WITH SOLAR DG?

A. The Cooperatives are concerned that programs or plans implemented to mitigate the impacts of solar DG could result in additional costs to all of their members. Discussions have taken place regarding the appropriate means by which to deal with the recovery of lost fixed costs in an equitable manner. One option discussed was the establishment of demand rates for all customers.

For utilities that have interval demand meters in place system wide, properly designed demand rates may provide a means of fixed cost recovery from customers based on how they use the grid. One significant concern with this option, however, is that most of the Cooperatives have demand meters installed and utilize demand rates only for commercial and industrial rate classes. The installation of demand meters and the other necessary communications equipment and software to establish demand rates for all customers would be prohibitively expensive for many of the Cooperatives and take years to implement and, thus, would not address the immediate issues. In addition, most of the Cooperatives have fixed generation costs that do not get reduced by lowering the demand of the individual cooperative. Thus, a demand rate would not result in any fixed cost savings to the cooperative which could be passed on to its members. To the extent the Commission is considering demand rates as one method to address the issues in this docket, it should provide the Cooperatives with flexibility based on each Cooperative's particular circumstances.

NON-ARIZONA AUTHORITIES

Q. ARE THE ISSUES RELATED TO DG CUSTOMERS LIMITED ONLY TO ARIZONA?

A. No. The issues related to DG customers and Net Metering are being addressed across the country. Other state regulatory bodies have developed laws and orders pertaining to the cost issues that are informative. Attached as Exhibit DWH-4 is legislation that was passed in Oklahoma that requires utilities in the state to eliminate subsidies to customers with DG. Specifically, the law states:

> *C. No retail electric supplier shall allow customers with distributed generation installed after the effective date of this act to be subsidized by customers in the same class of service who do not have distributed generation.*
>
> *D. A higher fixed charge for customers within the same class of service that have distributed generation installed after the effective date of this act, as compared to the fixed charges of those customers who do not have distributed generation, is a means to avoid subsidization between customers within that class of service and shall be deemed in the public interest.*

Exhibit DWH-5 is legislation that was passed in Arkansas to amend the requirements for utilities to compensate Net Metering customers. Section 3 of the act directs the Arkansas Public Service Commission to establish rates, terms, and conditions for net-metering contracts, including:

(A)(i) A requirement that the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers.

(ii) The electric utility's entire cost of providing service to each net metering customer within each of the electric utility's class of customers under subdivision (b)(1)(A)(i) of this section:

(a) Includes without limitation any quantifiable additional cost associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability; and

(b) Is net of any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, distribution system or transmission system.

In addition to the legislation passed in Oklahoma and Arkansas, the Wisconsin Public Service Commission has also recently provided comment on DG subsidies. On page 62 of the Order in Docket No. 05-DR-107 (December 23, 2014), the commission states:

> *As Wisconsin courts have long recognized, rate design is a quintessential legislative function firmly left to the discretion of the Commission. Other substantial state and federal programs are designed specifically to support the development and implementation of conservation and renewable energy resources. The Commission is not required to use rate design as a hidden subsidy for these resources. This Commission continues to support customers who want to own*

> *their own generation; however, the Commission also has an obligation to those customers who do not want to or who cannot afford to own generation to make sure these customers are not subsidizing the costs for those who choose to and are able to own their own generation.*

Q. WHAT ADDITIONAL INFORMATION HAVE YOU PROVIDED FOR CONSIDERATION WITH REGARD TO THE COST RECOVERY ISSUE FOR DG CUSTOMERS?

A. Attached as Exhibit DWH-6 is an article from the December 2014 *Electricity Journal* entitled "Valuation of Distributed Solar: A Qualitative View."[2] The article was written by Mr. Ashley Brown, the Executive Director of the Harvard Electricity Policy Group, former Commissioner of the Ohio Public Utility Commission, and former chairman of NARUC, and Jillian Bunyan, an attorney formerly with the United States Environmental Protection Agency's Office of Regional Counsel. The preface to the article provides insight regarding the content of the article:

> *A critical evaluation of the arguments used by solar DG advocates shows that those arguments may often overvalue solar DG. It is time to reassess the value of solar DG from production to dispatch and to calibrate our pricing policies to make certain that our efforts are equitable and carrying us in the right direction.*

These examples of legislation and commission orders, as well as the *Electricity Journal* article, confirm that (1) there are significant cost recovery issues associated

[2] 1040-6190/, http://dx.doi.org/10.1016/j.tej.2014.11.005.

with the provision of service to customers with installed solar DG and (2) the current use of Net Metering is not an effective or equitable means to compensate customers for that excess generation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

guernsey | ENGINEERS ARCHITECTS CONSULTANTS

DAVID W. HEDRICK
SENIOR VICE PRESIDENT /
MANAGER, ANALYTICAL SOLUTIONS

EDUCATION:

M.B.A., Oklahoma City University, 1993
B.S., Mathematics, University of Central Oklahoma, 1986

PERTINENT EXPERIENCE FOR THE PROJECT:

Mr. Hedrick specializes in the development of revenue requirements, cost of service, rate design, line extension analysis, special contract development, pole attachment rates, valuation analysis and other financial analysis for electric, water, and wastewater utility systems. He is also responsible for the preparation of rate filings and has presented expert testimony before state regulators, including Arizona, Arkansas, Colorado, Oklahoma, Texas and Wyoming. Mr. Hedrick's clients include both distribution providers and wholesale providers. He was instrumental in the development of the CoOPTIONS: family of computer software for use in unbundled utility cost of service studies and financial forecasting.

As Manager of the Analytical Solutions Group, Mr. Hedrick has oversight of all studies, analyses and filings that are developed by the group. He continues to represent clients before the appropriate regulatory authority and is responsible for the preparation of rate filings and other analytical studies.

SPECIFIC CONSULTING EXPERIENCE:

Acquisitions, Consolidations & Valuation Analysis

Mr. Hedrick has provided analytical support for consolidation studies in Texas and Wyoming. In addition, he has been involved in the valuation analysis of utility assets for purposes of acquisition and determination of fair market value for clients in Oklahoma and Kansas.

Retail Rate Analysis, Cost of Service Studies, and Line Extension Analysis

Mr. Hedrick's rate analysis and cost of service experience includes the following:

Arizona

- Navopache Electric Cooperative, Inc. - Regulated by Arizona Corporation Commission
- Sulphur Springs Valley Electric Cooperative, Inc. - Regulated by Arizona Corporation Comm.
- Trico Electric Cooperative, Inc. - Regulated by Arizona Corporation Commission

Arkansas

- Arkansas Valley Electric Cooperative Corporation - Regulated by Arkansas PSC and Oklahoma Corporation Commission
- Ouachita Electric Cooperative Corporation - Regulated by Arkansas PSC
- Ozarks Electric Cooperative Corporation - Regulated by Arkansas PSC

Colorado

- Colorado Rural Electric Association
- Delta-Montrose Electric Association
- Empire Electric Association, Inc.
- Grand Valley Rural Power Lines
- Holy Cross Electric Association, Inc.
- Mountain Parks Electric, Inc.
- Poudre Valley REA, Inc.
- San Luis Valley Rural Electric Cooperative, Inc.
- Yampa Valley Electric Association, Inc.

Iowa

- Corn Belt Power Cooperative
- Iowa Lakes Electric Cooperative, Inc.
- Midland Power Cooperative, Inc.

Kansas

- Ark Valley Electric Cooperative Association
- Caney Valley Electric Cooperative Association
- CMS Electric Cooperative, Inc.
- Flint Hills Rural Electric Cooperative Association
- Kansas Electric Power Cooperative
- Lyon-Coffey Electric Cooperative, Inc.
- City of Meade
- Ninnescah Rural Electric Cooperative Association, Inc.
- Pioneer Electric Cooperative, Inc.
- Sedgwick County Electric Cooperative Association, Inc.
- Western Cooperative Electric Association, Inc.

Louisiana

- Claiborne Electric Cooperative

Mississippi

- Southern Pine EPA
- Yazoo Valley EPA

Nebraska

- Dawson County Public Power District

New Mexico

- Farmers Electric Cooperative, Inc.
- Lea County Electric Cooperative, Inc.

Oklahoma

- City of Blackwell
- Caddo Electric Cooperative
- Central Rural Electric Cooperative, Inc.

- Choctaw Electric Cooperative, Inc.
- Cimarron Electric Cooperative, Inc.
- Cookson Hills Electric Cooperative, Inc.
- Cotton Electric Cooperative, Inc.
- City of Duncan
- East Central Oklahoma Electric Cooperative
- Indian Electric Cooperative, Inc.
- Kay Electric Cooperative, Inc.
- Kiwash Electric Cooperative, Inc.
- Lake Region Electric Cooperative, Inc.
- City of Mangum
- Northeast Oklahoma Electric Cooperative, Inc.
- Northfork Electric Cooperative
- Northwestern Electric Cooperative, Inc.
- Oklahoma Electric Cooperative, Inc.
- City of Ponca City
- Rural Electric Cooperative, Inc.
- Southeastern Electric Cooperative, Inc.
- Southwest Rural Electric Association
- Tri-County Electric Cooperative, Inc.
- Verdigris Valley Electric Cooperative

<u>Texas</u>

- Bailey County ECA
- Bandera Electric Cooperative, Inc.
- Big Country Electric Cooperative, Inc.
- Bluebonnet Electric Cooperative, Inc.
- Central Texas Electric Cooperative, Inc.
- Concho Valley Electric Cooperative, Inc.
- Cooke County Electric Cooperative Assn.
- CoServ Electric
- Deaf Smith Electric Cooperative, Inc.
- Fannin County Electric Cooperative, Inc.
- Farmers Electric Cooperative, Inc.
- Fort Belknap Electric Cooperative, Inc.
- Grayson-Collin Electric Cooperative, Inc.
- Greenbelt Electric Cooperative, Inc.
- HILCO Electric Cooperative, Inc.
- Jackson Electric Cooperative, Inc.
- Lamar County Electric Cooperative, Inc.
- Lighthouse Electric Cooperative, Inc.
- Lyntegar Electric Cooperative, Inc.
- Magic Valley Electric Cooperative, Inc.
- Medina Electric Cooperative, Inc.
- Navarro County Electric Cooperative, Inc.
- Navasota Valley Electric Cooperative, Inc.
- North Plains Electric Cooperative, Inc.
- Nueces Electric Cooperative, Inc.
- Pedernales Electric Cooperative, Inc.

- Rita Blanca Electric Cooperative, Inc.
- San Bernard Electric Cooperative, Inc.
- South Plains Electric Cooperative, Inc.
- Southwest Rural Electric Association, Inc., Okla.
- Southwest Texas Electric Cooperative, Inc.
- Swisher Electric Cooperative, Inc.
- Taylor Electric Cooperative, Inc.
- Texas Electric Cooperatives, Inc., Statewide Association
- Tri-County Electric Cooperative, Inc.
- Trinity Valley Electric Cooperative, Inc.
- United Cooperative Services
- Wharton County Electric Cooperative, Inc.
- Wise Electric Cooperative, Inc.

Wyoming

- Big Horn REC - Regulated by Wyoming Public Service Commission until 2007
- Carbon Power & Light, Inc. - Regulated by Wyoming Public Service Commission until 2007
- High Plains Power, Inc. - Regulated by Wyoming Public Service Commission until 2007
- Powder River Energy Corporation - Regulated by Wyoming Public Service Commission
- Wyrulec Company - Regulated by Wyoming Public Service Commission until 2007

Wholesale Rate Analysis and Cost of Service Studies

- Corn Belt Power Cooperative, Humboldt, Iowa
- Kansas Electric Power Cooperative, Topeka, Kansas
- Grand River Dam Authority, Vinita, Oklahoma
- Oklahoma Municipal Power Authority, Edmond, Oklahoma
- Western Farmers Electric Cooperative, Anadarko, Oklahoma
- Central Electric Power Cooperative, Columbia, South Carolina
- Piedmont Municipal Power Authority, Greer, South Carolina
- Brazos Electric Cooperative, Waco, Texas
- Golden Spread Electric Cooperative, Amarillo, Texas
- Old Dominion Electric Cooperative, Richmond, Virginia
- Allegheny Electric Cooperative, Harrisburg, Pennsylvania
- South Mississippi Electric Power Association, Hattiesburg, Mississippi
- Minnkota Power Cooperative, Grand Forks, North Dakota
- Rayburn Country Electric Cooperative, Rockwall, Texas

Special Projects

Development of Distributed Generation Procedures and Guidelines Manual:

- Western Farmers Electric Cooperative, Anadarko, Oklahoma
- KAMO Electric, Vinita, Oklahoma
- Texas Electric Cooperatives, Austin, Texas

Energy Policy Act of 2005 / EISA 2007 - Testimony in Support of Cooperative Staff's Position in Consideration of new PURPA Standards:

- Central Rural Electric Cooperative, Stillwater, Oklahoma
- Cotton Electric Cooperative, Walters, Oklahoma
- Farmers Electric Cooperative, Greenville, Texas
- Grand River Dam Authority, Vinita, Oklahoma
- Grayson-Collin Electric Cooperative, Van Alstyne, Texas
- HILCO Electric Cooperative, Itasca, Texas
- Lake Region Electric Cooperative, Hulbert, Oklahoma
- Lyntegar Electric Cooperative, Tahoka, Texas
- Magic Valley Electric Cooperative, Mercedes, Texas
- Northwestern Electric Cooperative, Woodward, Oklahoma
- Oklahoma Electric Cooperative, Norman, Oklahoma
- Tri-County Electric Cooperative, Azle, Texas
- Tri-County Electric Cooperative, Hooker, Oklahoma
- United Electric Co-op Services, Cleburne, Texas

Testimony before Colorado State House and Senate Committees in support of the Colorado Rural Electrification Association with regard to HB1169, Mandating Net Metering for Electric Cooperatives.

The "Fresh Look" review of East Kentucky Power Cooperative on behalf of the cooperative's distribution members as required by the Kentucky Corporation Commission. 2011 - 2012

Education and Training

Mr. Hedrick provides educational seminars and training for cooperative staff and boards of directors, statewide associations, and professional organizations on the topics of Rate Analysis, Cost of Service, Rate Design, Line Extension Policy, and related issues.

Expert Witness

Mr. Hedrick has provided expert testimony related to the development of revenue requirements, cost of service, rate design, and special contract issues in Arizona, Arkansas, Oklahoma, Texas, and Wyoming.

Financial Forecasting & Analysis

Mr. Hedrick prepares and provides training in the development of financial forecast models for electric cooperatives and municipal utility systems.

Software Sales & Support

Mr. Hedrick provided assistance in the development of software for GUERNSEY's 10-year Financial Forecast, Cost of Service, and Financial Performance Analysis programs. Mr. Hedrick is proficient in the use of these software packages and provides support to client users.

Strategic Planning & Analysis

Mr. Hedrick has provided assistance to electric cooperative boards of directors in the development of strategic goals and objectives.

Publications and Presentations:

Articles:

Hedrick, David W. "Retail Rate Development: The Role of the Cooperative Board." *Management Quarterly*, published by NRECA's Education and Training Department. (Spring 2005): 20-35.

Presentations Made by Mr. Hedrick:

"Knowledge is Power: Financial Forecasting." Seminar written and presented by Guernsey personnel annually since 2006 in Oklahoma City, Okla. Mr. Hedrick has been a presenter for this seminar numerous times.

"Knowledge is Power: Understanding Rates and Cost of Service." Seminar written and presented by Guernsey personnel annually since 2005, in Oklahoma City, Okla., as well as other locations. Mr. Hedrick has been a presenter numerous times.

"Distributed Generation Net Metering Issues." Written for and presented at *TEC Engineers Association Annual Meeting.* September 2006.

"Net Metering Issues." Written for and presented at *G&T Planners Association Meeting,* Tucson. Arizona, September 2006.

"Development of Distributed Generation Policies and Procedures." Written and presented for *Texas Electric Cooperatives' Managers Meeting.* San Antonio, Texas, December 2, 2004.

"Rate Design in a Restructured Environment." Written and presented for *Texas Electric Cooperatives Accountants Association*. Austin, Texas, April 19, 2000.

EXPERIENCE RECORD:

1981-Present - C. H. Guernsey & Company, Oklahoma City, Oklahoma

2013 - Senior Vice President, Board of Directors
2008-2013 - Vice President for Guernsey
2005-Present - Manager, Analytical Solutions Group

SULPHUR SPRINGS VALLEY ELECTRIC COOPERATIVE

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE
ADMINISTERED IN CONJUNCTION WITH NET METERING TARIFF NM - 1 (EXISTING POLICY)

			Existing Rates
1	Total Residential Energy Charge including WPCA		$ 0.119768
2	Purchased Power Energy Cost included in Residential Rate		$ 0.028450
3	Purchased Power Demand Cost included in Residential Rate		$ 0.043493
	Remainder: Distribution Wires		
4	Component in Residential Energy Charge	L1 - L2 - L3	$ 0.047825
	<u>Lost Fixed Cost Calculation:</u>		
5	Total Residential DG Customers at TY End		1,013
	Monthly kWh Produced by 5.62 kW AC		
6	PV System with 25% Capacity Factor	5.62 kW x 730 Hrs x 25%	1,026
7	Purch Power Demand Lost Fixed Cost - Monthly	L6 x L3	$ 44.61
8	Distr. Wires Lost Fixed Cost - Monthly	L6 x L4	$ 49.05
9	Total Lost Fixed Costs - Monthly	L7 + L8	$ 93.66
10	Total Lost Fixed Costs Annual	L9 x L5 x 12	$ 1,138,552

Exihibit DWH - 2

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE

			Existing Rate
1	Energy Charge (Includes WPCA)		$ 0.121161
2	Purchased Power Energy Cost		$ 0.030795
3	Purchased Power Demand Cost		$ 0.049412
	Remainder: Distribution Wires		
4	Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040954
	Lost Fixed Cost Calculation:		
5	Total Residential DG Customers at TY End		1,262
	Monthly kWh Produced by 6.51 kW AC		
6	PV System (Estimated)	Estimated	922
7	PV System kWh Compensated at Full Retail		922
8	Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 45.57
9	Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 37.77
10	Total Lost Fixed Costs - Monthly	L8 + L9	$ 83.34
11	Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,262,079

Exihibit DWH - 2.1

COMPARISON OF LINE DENSITY AND DISTRIBUTION WIRES COST

	Number of Consumers	Distribution Miles of Line	Consumers Per Mile	Residential Distr. Wires ($/kWh) (3)
Duncan Valley (1)	2,327	453	5.1	
Graham County (1)	8,875	1,098	8.1	$ 0.03183
Navopache (1)	40,042	2,475	16.2	$ 0.03027
Sulphur Springs (1)	52,815	3,765	14.0	$ 0.04740
TRICO (1)	40,242	3,466	11.6	$ 0.03860
APS (1)	1,174,760	29,148	40.3	$ 0.02700
UNS(1)	91,821	2,309	39.8	$ 0.01430
TEP (2)	414,749	7,061	58.7	$ 0.00870

(1) Data for 2014
(2) Data for 2013
(3) Distribution wires cost for a 1,000 kWh customer included in energy charge per tariff

EXHIBIT DWH - 4

An Act

ENROLLED SENATE
BILL NO. 1456

By: Griffin of the Senate

and

Turner, Echols, Jackson, Newell, Schwartz, Murphey, Brumbaugh, Pittman, Rousselot and Fisher of the House

An Act relating to public utilities; amending 17 O.S. 2011, Section 156, which relates to distributed generation costs; defining terms; modifying prohibition relating to recovery of certain fixed costs from electric customers utilizing certain distributed generation; prohibiting subsidization of certain costs among customer class; requiring rate tariff adjustment by certain date; and providing an effective date.

SUBJECT: Electrical power distribution requirements

BE IT ENACTED BY THE PEOPLE OF THE STATE OF OKLAHOMA:

SECTION 1. AMENDATORY 17 O.S. 2011, Section 156, is amended to read as follows:

Section 156. A. As used in this section:

1. "Distributed generation" means:

   a. a device that provides electric energy that is owned, operated, leased or otherwise utilized by the customer,

b. is interconnected to and operates in parallel with the retail electric supplier's grid and is in compliance with the standards established by the retail electric supplier,

c. is intended to offset only the energy that would have otherwise been provided by the retail electric supplier to the customer during the monthly billing period,

d. does not include generators used exclusively for emergency purposes,

e. does not include generators operated and controlled by a retail electric supplier, and

f. does not include customers who receive electric service which includes a demand-based charge.

2. "Fixed charge" means any fixed monthly charge, basic service, or other charge not based on the volume of energy consumed by the customer, which reflects the actual fixed costs of the retail electric supplier.

3. "Retail electric supplier" means an entity engaged in the furnishing of retail electric service within the State of Oklahoma and is rate regulated by the Oklahoma Corporation Commission.

B. No ~~public utility~~ retail electric supplier shall increase rates charged or enforce a surcharge ~~on the basis of the use or installation of a solar energy device by a consumer~~ above that required to recover the full costs necessary to serve customers who install distributed generation on the customer side of the meter after the effective date of this act.

C. No retail electric supplier shall allow customers with distributed generation installed after the effective date of this act to be subsidized by customers in the same class of service who do not have distributed generation.

D. A higher fixed charge for customers within the same class of service that have distributed generation installed after the effective date of this act, as compared to the fixed charges of those customers who do not have distributed generation, is a means to avoid subsidization between customers within that class of service and shall be deemed in the public interest.

E. Retail electric suppliers shall implement tariffs in compliance with this act no later than December 31, 2015.

SECTION 2. This act shall become effective November 1, 2014.

Passed the Senate the 12th day of March, 2014.

Presiding Officer of the Senate

Passed the House of Representatives the 14th day of April, 2014.

Presiding Officer of the House of Representatives

OFFICE OF THE GOVERNOR

Received by the Office of the Governor this 15th day of April, 2014, at 3:46 o'clock P M.

By: Audrey Rockwell

Approved by the Governor of the State of Oklahoma this 21st day of April, 2014, at 3:43 o'clock P M.

Governor of the State of Oklahoma

OFFICE OF THE SECRETARY OF STATE

Received by the Office of the Secretary of State this 21st day of April, 2014, at 5:40 o'clock P. M.

By: Chris Benge

Stricken language would be deleted from and underlined language would be added to present law.
Act 827 of the Regular Session

State of Arkansas *As Engrossed: H2/26/15 H3/17/15*
90th General Assembly
Regular Session, 2015

A Bill

HOUSE BILL 1004

By: Representative S. Meeks

For An Act To Be Entitled

AN ACT TO REQUIRE ELECTRIC UTILITIES TO COMPENSATE NET-METERING CUSTOMERS FOR NET EXCESS GENERATION CREDITS IN CERTAIN CIRCUMSTANCES; AND FOR OTHER PURPOSES.

Subtitle

TO REQUIRE ELECTRIC UTILITIES TO COMPENSATE NET-METERING CUSTOMERS FOR NET EXCESS GENERATION CREDITS IN CERTAIN CIRCUMSTANCES.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF ARKANSAS:

SECTION 1. Arkansas Code § 23-18-603(6), concerning a definition used under the Arkansas Renewable Energy Development Act of 2001, is amended to read as follows:

(6) "Net-metering facility" means a facility for the production of electrical energy that:

(A) Uses solar, wind, hydroelectric, geothermal, or biomass resources to generate electricity, including, but not limited to, fuel cells and micro turbines that generate electricity if the fuel source is entirely derived from renewable resources;

(B) Has a generating capacity of not more than:

(i) The greater of twenty-five kilowatts (25 kW) or one hundred percent (100%) of the net-metering customer's highest monthly usage in the previous twelve (12) months for residential use; or ~~three~~

(ii) Three hundred kilowatts (300 kW) for any other

use unless otherwise allowed by a commission under § 23-18-604(b)(5);

(C) Is located in Arkansas;

(D) Can operate in parallel with an electric utility's existing transmission and distribution facilities; and

(E) Is intended primarily to offset part or all of the net-metering customer requirements for electricity; and

SECTION 2. The introductory language of Arkansas Code § 23-18-604(b), concerning the authority of the Arkansas Public Service Commission, is amended to read as follows:

(b) Following notice and opportunity for public comment, ~~the Arkansas Public Service Commission~~ a commission:

SECTION 3. Arkansas Code § 23-18-604(b)(1), concerning the authority of the Arkansas Public Service Commission, is amended to read as follows:

(1) Shall establish appropriate rates, terms, and conditions for net-metering contracts, including ~~a~~:

(A)(i) A requirement that the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers.

(ii) The electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers under subdivision (b)(1)(A)(i) of this section:

(a) Includes without limitation any quantifiable additional cost associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability; and

(b) Is net of any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system; and

(B) A requirement that net-metering equipment be installed to accurately measure the electricity:

~~(A)~~ (i) Supplied by the electric utility to each

net-metering customer; and

~~(B)~~ <u>(ii)</u> Generated by each net-metering customer that is fed back to the electric utility over the applicable billing period;

SECTION 4. Arkansas Code § 23-18-604(b)(5) and (6), concerning the authority of the Arkansas Public Service Commission, are amended to read as follows:

(5) May increase the ~~peak~~ <u>generating capacity</u> limits for individual net-metering facilities if doing so results in distribution system, environmental, or public policy benefits; ~~and~~

(6) Shall provide that:

(A)<u>(i)</u> The net excess generation credit remaining in a net-metering customer's account at the close of ~~an annual~~ <u>a</u> billing cycle~~, up to an amount equal to four (4) months' average usage during the annual billing cycle that is closing, shall be credited to the net-metering customer's account for use during the next annual billing cycle;~~ <u>shall not expire and shall be carried forward to subsequent billing cycles indefinitely.</u>

<u>(ii) However, for net excess generation credits older than twenty-four (24) months, a net-metering customer may elect to have the electric utility purchase the net excess generation credits in the net-metering customer's account at the electric utility's estimated annual average avoided cost rate for wholesale energy if the sum to be paid to the net-metering customer is at least one hundred dollars ($100).</u>

<u>(iii) An electric utility shall purchase at the electric utility's estimated annual average avoided cost rate for wholesale energy any net excess generation credit remaining in a net-metering customer's account when the net-metering customer:</u>

<u>(a) Ceases to be a customer of the electric utility;</u>

<u>(b) Ceases to operate the net-metering facility; or</u>

<u>(c) Transfers the net-metering facility to another person; and</u>

~~(B) Except as provided in subdivision (b)(6)(A) of this~~

~~section, any net excess generation credit remaining in a net-metering customer's account at the close of an annual billing cycle shall expire; and~~

~~(C) Any~~ (B) A renewable energy credit created as the result of electricity supplied by a net-metering customer is the property of the net-metering customer that generated the renewable energy credit~~.~~; and

SECTION 5. Arkansas Code § 23-18-604(b), concerning the authority of the Arkansas Public Service Commission, is amended to add an additional subdivision to read as follows:

(7) May allow a net-metering facility with a generating capacity that exceeds three hundred kilowatts (300 kW) if:

(A) The net-metering facility is not for residential use; and

(B) Allowing an increased generating capacity for the net-metering facility would increase the state's ability to attract businesses to Arkansas.

SECTION 6. Arkansas Code § 23-18-604, concerning the authority of the Arkansas Public Service Commission, is amended to add additional subsections to read as follows:

(c)(1) As used in this section, "avoided costs":

(A) For the Arkansas Public Service Commission, means the same as defined in § 23-3-702; and

(B) For a municipal utility, is defined by the governing body of the municipal utility.

(2) Avoided costs shall be determined under § 23-3-704.

(d)(1) Except as provided in subdivision (d)(2) of this section, an electric utility shall separately meter, bill, and credit each net-metering facility even if one (1) or more net-metering facilities are under common ownership.

(2)(A) At the net-metering customer's discretion, an electric utility may apply net-metering credits from a net-metering facility to the bill for another meter location if the net-metering facility and the separate *meter location are under common ownership within a single electric utility's service area.*

(B) Net excess generation shall be credited first to the

net-metering customer's meter to which the net-metering facility is physically attached.

(C) After applying net excess generation under subdivision (d)(2)(B) of this section and upon request of the net-metering customer under subdivision (d)(2)(A) of this section, any remaining net excess generation shall be credited to one (1) or more of the net-metering customer's meters in the rank order provided by the net-metering customer.

/s/S. Meeks

APPROVED: 03/31/2015

Valuation of Distributed Solar: A Qualitative View

A critical evaluation of the arguments used by solar DG advocates shows that those arguments may often overvalue solar DG. It is time to reassess the value of solar DG from production to dispatch and to calibrate our pricing policies to make certain that our efforts are equitable and carrying us in the right direction.

Ashley Brown and Jillian Bunyan

Ashley Brown *is Executive Director of the Harvard Electricity Policy Group and Of Counsel in the Boston office of the law firm Greenberg Traurig LLP. Mr. Brown is a former Commissioner of the Public Utilities Commission of Ohio and former Chair of the National Association of Regulatory Commissioners Electricity Committee.*

Jillian Bunyan *is an associate in the Philadelphia office of Greenberg Traurig LLP. Prior to joining the firm, Ms. Bunyan was an attorney in the United States Environmental Protection Agency's Office of Regional Counsel in Seattle, Washington.*

I. Assessing the Value of Distributed Solar Generation – An Overview

The purpose of this article is to assess the value of residential distributed generation (DG) solar photovoltaics (PV) and appropriate pricing for its value and output. In particular, the article will address the question of whether retail net metering, the way that it is presently applied in most states, is an equitable way to compensate customers who own or lease solar DG. The article will also critically examine the argument for the "value of solar" approach to compensating residential solar DG customers. The article will conclude that retail net metering and "value of solar" are severely flawed schemes for pricing solar DG.

Retail net metering overvalues both the energy and capacity of solar DG, imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent consumers. The "value of solar" approach being advanced by

 1040-6190/ http://dx.doi.org/10.1016/j.tej.2014.11.005

some solar DG advocates subjectively, and often artificially, inflates the value of solar DG and discounts the costs. This article also concludes that proposals for market-based energy prices, as well as demand and fixed charges as applied to solar DG hosts, are reasonable ways to rectify the cross-subsidies in net metering. It suggests that market-based prices for solar DG provide the best incentives for making solar more efficient and economically viable for the long term.

Solar PV has some very real benefits and long-term potential. The marginal costs of producing this energy are zero. If one looks at environmental externalities, then the carbon emissions from the actual process of producing this energy itself, without taking the secondary effects into consideration, are also zero. Significantly, the costs of producing and installing solar PV have declined in recent years, adding to the potential long-term attractiveness of solar. Those are very real benefits that would be valuable to capture. In its current, most common configuration, however, solar DG has some drawbacks that inhibit it from capturing its full value.

Solar PV is intermittent and thus requires backup from other generators and cannot be relied on to be available when called upon to produce energy. Thus, its energy value is entirely dependent on when it is produced and its capacity value is, at best, marginal. To fully develop the resource, therefore, it is imperative to provide pricing that will incent the fulfillment of solar PV's potential, by linking itself to storage, more efficient ways of catching the sun's energy, or with other types of generation (e.g. wind) that complement its availability. Thus, it is critical that prices be set in such a fashion as to provide incentives for productivity and reliability and not to subsidize solar DG at a decidedly low degree of optimization. Currently, rates for most residential consumers are based on volume. That is, residential customers are simply billed based on the number of kilowatt-hours that they consume based on average costs to serve all residential consumers. Solar has huge potential, but to attain it, solar DG needs to receive the price signals to actually fulfill its potential.

In its current, most common configuration, solar DG has some drawbacks that inhibit it from capturing its full value.

Not only does net metering deprive solar PV of the price signals necessary to capture its full value, it also leads the changes in retail pricing that undermine the promotion of energy efficiency. As solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with diminution of revenues required to support the distribution system that is caused by the use of net metering. That concern will inevitably lead utilities and regulators to recover more of their costs through the fixed, rather than the variable, components of their rates. Thus, the price signal to be more efficient will be substantially diluted.

Many in the solar industry have come to recognize that retail net metering (NEM) is, in this age of smart grid and smart pricing, no longer a defensible method for pricing solar DG. Having recognized the inevitable demise of a pricing system that favors solar DG through cross-subsidization by other customers, many solar DG advocates have shifted to an argument that pricing should be based on consideration of the "value of solar." While the authors do not subscribe to that point of view, as the argument is being included in the national conversation, it seems appropriate to address it.

II. Solar DG and Retail Net Metering – Definition of Terms

Powering your home with clean energy generated from the

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solar panels on your roof, and selling the excess energy to the utility, are appealing prospects to a public increasingly attuned to environmental, energy efficiency, and self-sufficiency considerations. It is not hard to see why solar DG has substantial public appeal.

To begin, it is necessary to note that the terms "net metering," "retail net metering," and "net energy metering" will be used interchangeably and synonymously throughout the article. Net metering refers to when electricity meters run forward when solar DG customers are purchasing energy from the grid. When those customers produce energy and consume it on their premises, the meter slows down and then simply stops, and when the customer produces more energy than is consumed on the premises, the meter runs backwards. Thus, the solar DG customer pays full retail value for all energy taken off the grid, pays nothing for energy or distribution when self-consuming energy produced on the premises, and is paid the fully delivered retail price for all energy exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due, or the utility pays the customer for excess energy delivered. The reconciliation is made without regard to when energy is produced or consumed. This is how transactions between owners of residential DG and utilities have traditionally been handled.

There are other forms of net metering such as wholesale net metering, where exports into the system are compensated at the wholesale price, often the local marginal price (LMP). There are other variations as well, but for purposes of the article, when the terms NEM or net metering are used, they refer to the retail variety.

There are, conceptually, four possible approaches to pricing energy produced by solar DG.

There are, conceptually, four possible approaches to pricing energy produced by solar DG. One market-based approach is to set the price to reflect the market clearing price in the wholesale market at the time the energy is produced. A second approach would be a cost-based approach, where the price is set based on a review of the costs or according to standard costing methodology. A third approach, already defined above, would be net metering. Finally, a fourth approach would be to administratively derive a "value of solar" based on analysis of avoided costs and whatever else the evaluators believe to be worthy of measure.

As you will see, while the authors do not believe this fourth approach to be appropriate, analysis of the criteria its advocates believe are important should be conducted and evaluated – not to set the price, but simply to establish the context for evaluating the reasonableness of the pricing methodology approved.

III. 'Value of Solar' vs. Wholistic Analysis

Optimally, prices for electricity are determined by a competitive market or, absent competitive conditions, should be derived from cost-based regulation. In both cases the prices are subjected to an external discipline that should result in efficient resource decisions devoid of arbitrary or "official" biases. Subjective consideration of the "value" of particular technologies and where they may rank in the merit order of "social desirability," effectively removes the discipline that is more likely to produce efficient results. Moreover, even where non-economic externalities are thrown into the valuation mix, the pricing of an energy resource must still be disciplined by examination of the economic merit order in attaining the externality objective. Whereas both the marketplace and transparent cost-based regulation are likely to produce coherent pricing that

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allows us to enjoy a degree of comfort knowing that efficient performance will likely lead to productivity, subjective consideration of soft criteria, like "value of solar," are a step away from economic coherence and efficiency.

Economics are critical and efficiency is of vital importance. There are also other economic values, besides efficiency, including those that go beyond short-term efficiency. Certainly, many people believe that other, non-economic factors need to be considered. Similarly, the fairness of the impact on customers also needs to be factored into any decision. There has, for many years, been a running debate in electricity regulation as to whether externalities ought to be factored into regulatory decisions. This article does not intend to join that debate, nor express any point of view as to what is permissible or impermissible under applicable law. Rather, this article suggests that if externalities are to be considered, then all relevant ones deserve attention, as opposed to "cherry picking" the issues to best protect a particular interest. Further, if non-economic objectives are to be factored into ratemaking, then it is wise to carefully consider the most economically efficient ways of attaining those objectives.

There are a number of criteria that are important to the full valuation of solar PV. One should begin by looking at the cost of producing energy. Beyond that, the criteria would include availability/capacity, reliability, energy value, impact on system operations and dispatch, transmission costs and effects, distribution costs and effects, and hedge value. Solar DG proponents often phrase these issues in terms of avoided costs. In addition to those dimensions, there are also the following: degree of subsidization and cross-subsidization, efficiency considerations, impact on alternative technologies, market price impact, reliability, and social effects including the environmental, customer, and social class impacts. There is also the issue of whether solar DG enhances the level of competition in the industry.

Certainly, many people believe that other, non-economic factors need to be considered.

IV. Net Energy Metering – Why Are We Paying More for Less?

Retail net energy metering, as practiced, does not capture all of the value enumerated above. NEM significantly overvalues distributed solar generation. More specifically, it does the following:

1. Creates a cross-subsidy from non-solar to solar customers;
2. Fails to reflect the inefficiency of small-scale solar PV relative to other forms of generation, including alternative renewable resources;
3. Constitutes price discrimination in favor of an inefficient resource;
4. Significantly overvalues both the capacity and reliability value of solar DG;
5. Adversely impacts the degree of competitiveness in the industry;
6. Artificially inflates the transmission value of solar DG;
7. Fails to account for the fact that the value of energy varies widely depending on when it is actually produced;
8. Distorts price signals for energy efficiency;
9. Causes socially regressive economic impact;
10. Assumes system benefits from solar DG that, in fact, may not exist;
11. Overvalues its contribution to carbon reduction;
12. Vastly inflates its value as a fuel hedge; and
13. Undervalues and underfunds the distribution system.

Despite failing to capture these values, NEM has become the prevalent form of tariff for residential solar DG in

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the United States. This is because NEM was never developed as part of a fully and deliberatively reasoned pricing policy. NEM was simply never a conscious policy decision. It is basically a default product of two (no longer relevant) considerations, one practical and the other technological. The practical reason is that residential distributed generation had such an insignificant presence in the market that its economic impact was marginal at best. Thus, no one was seriously concerned about "getting the prices right." The second, technological reason is that until recently the meters most commonly deployed, especially at residential premises, have had very little capability other than to run forward, backward, and stop. Thus, for technical reasons, NEM was simple to implement and administer and, as a practical matter given the paucity of DG, there was no compelling reason to go to the trouble of remedying a clearly defective pricing regime. Many states have recognized the problems with NEM but, seeing no alternatives, put in place production caps to limit any harm caused by a clearly deficient pricing regime.

V. Residential Retail Net Metering Sets Up Unfair and Counterproductive Cross-Subsidies

Beyond failing to capture the values above, there are other problems with NEM. Under NEM, when DG providers export energy to the system, consumers are required to pay them full retail rates for a wholesale product. What everyone agrees upon is that solar DG provides an energy value, but there is considerable disagreement about what that value is. Solar proponents argue that solar DG has a capacity value as well. That value, if it exists at all, is minimal. While there may well be reasons to treat DG differently with respect to wholesale transmission there is, absent a solar host leaving the grid, absolutely no reason to discriminate between wholesale and DG products with regard to the fixed costs of the distribution system and its operations.

If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not.

Under NEM, however, solar DG providers are compensated at full retail prices for what they provide. That includes the not-insignificant cost of services that they do not provide, including distribution costs, administrative, and back office operations. There can be no justification for forcing consumers to pay a provider for service that they not only do not provide but, in fact, have no capability to provide.

Solar DG producers remain connected to the grid and are fully reliant upon it during the many hours of the day when solar energy is not available. Under NEM, that solar DG producer is excused from paying his/her share of the costs of the distribution system when energy is being produced on the premises. If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not. Distribution costs are fixed, and do not vary with energy production or consumption. Thus, excusing solar DG customers from paying for their own distribution costs when their solar units are producing energy has no justification in either policy or economics. Making matters worse, the costs solar DG providers do not pay under NEM are either reallocated to non-solar customers or have to be absorbed by the utility. Both outcomes are unacceptable and unjustifiable. There is no reason why solar DG customers should receive free backup service, compliments of either their neighbors or the utility.

Utilities are obliged to provide full requirements service to all of their customers, including, of course, their solar host

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customers. In regard to solar hosts, the utility is obliged, in case the on-premises generation does not cover their full demand, to fill the gap between the full demand and the amount of self-generation. Utilities are also obliged to purchase energy and/or capacity so that solar hosts may rely on the utility when solar units are not generating. Given that solar PV units are intermittent and unpredictable regarding when they will produce, providing that backup is an ongoing responsibility and cost to utilities. Compounding those costs is the fact, as stated elsewhere in the article, peak times of electricity use (i.e. when prices are highest) are trending later in the day, when solar PV does not produce. As such, utilities must provide electricity to solar hosts at times when demand is high and energy prices are high. It would violate a the fundamental principle of regulation that cost causers should pay for the costs they impose, not to recognize the actual costs of that backup service in the rates paid by solar hosts.

Another cross-subsidy relates to the intermittent nature of solar energy. No utility with an obligation to serve can be fully reliant on the availability of solar when it is needed. Indeed, no solar host who values reliability can afford to be dependent on his/her own solar DG unit. While this point will be discussed further *infra* suffice it to say that this gives rise to two types of demand charge related cross-subsidy. The first arises when the distributor relies on the availability of solar for making day-ahead purchases and the other arises when it does not do so. When it does rely on the availability of solar and it turns out that solar energy is not available when called upon, the

utility is compelled to purchase replacement energy in the spot market at the marginal cost, which is almost certainly higher than the price of the solar energy on whose availability it had relied. In notable contrast to what happens in the wholesale market when a supplier who is relied upon fails to deliver, those incremental costs have to be borne by the utility, which passes them on to all customers, as opposed to being borne by the specific solar DG customer whose failure to deliver caused the costs to be incurred.

If the distributor, in recognition of solar's intermittency, instead chooses to hedge against the risk of solar's unavailability, the cost of the hedge is likewise passed on to all customers rather than simply those whose supply unpredictability caused the cost to be incurred. Both of these forms of cross-subsidy violate a bedrock principle of regulation – costs should be allocated to the cost causer. The function of that principle, of course, is to provide price signals to improve performance, but NEM fails to provide such signals and essentially holds solar DG providers harmless for their own very low capacity factors and inefficient performance.

NEM cross-subsidies, in large part, provide short-term benefits to the solar DG industry, but are highly detrimental to the value of solar in the long term. In the short term they constitute a wealth transfer from non-solar customers to the solar industry. In the long term, however, they are actually harmful to solar energy because NEM provides absolutely no incentive to improve the performance of a generating resource that, among renewables, already ranks last in efficiency and in cost effectiveness for reducing carbon emissions. In effect, the solar DG industry is putting its short-term profits ahead of the long-term value of solar energy. If solar DG advocates prevail in seeking to maintain NEM, that victory will be short-lived, because markets, both regulated and unregulated, do not prop up inefficient resources over the long term.

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NEM is also woefully ineffective at providing the appropriate price signals. Electricity prices can be quite volatile over the course of every day and vary seasonally as well. Rather than reflecting those prices, NEM simply treats all energy the same regardless of the time during which it is produced. For example, NEM fails to differentiate between energy produced on-peak and off-peak. In one scenario, it prices off-peak solar DG at a level that is averaged with on-peak prices, thus effectively over-valuing the energy. Conversely, if solar DG were actually produced on-peak, NEM would average that price with off-peak prices, thus undervaluing the energy. Any form of dynamic pricing, ranging from time of use to real-time, could address this issue with more precision than flat, averaged prices. Interestingly, under the first scenario, cross-subsidies would be paid to solar producers, while in the second scenario, solar producers would be cross-subsidizing the other ratepayers. In short, the price signal, and the efficiency that would flow from that, is rendered incoherent.

Some may argue that cross-subsidies are necessary to promote the growth of renewable energy, and certainly that can be debated. However, modernizing NEM to provide appropriate price signals would not remove the tax credits and other government-sanctioned or -sponsored subsidies. The fact that conscious subsidies and/or cross-subsidies are designed to promote a particular technology raises two key issues. First, many would argue that the government, including regulators, should not be picking winners and losers in the marketplace. While there may be merit to that view, it must also be recognized that, there may be

circumstances where, for policy reasons, government might want to provide support for a socially and economically desirable technology and/or assist it with research funding and to get it over the commercialization hump. That leads inexorably to the second and more relevant issue concerning solar DG: namely, that subsidies and cross-subsidies need to be designed as near-term boosts rather than a permanent crutch, and should be transparent. In other words, subsidies/cross-subsidies should be designed to serve as both a stimulus for the designated technology and an incentive to the producers and vendors of the technology to become more efficient. It might also be noted that subsidies from the Treasury are more appropriate for achieving broad social benefits that are cross-subsidies derived from a subset of the full society deriving the benefit.

In the case of solar DG, the objective of a subsidy/cross-subsidy would be to attain grid parity, assuming reasonably efficient operations, with other resources. The objective is to assist a technology to achieve commercial viability. The problem with NEM, of course, is that it is effectively an arbitrary financial boost of potentially endless duration, with absolutely no built-in incentive to increase efficiency and/or to achieve grid parity. In effect it requires non-solar customers to pay more for the least efficient renewable resource in common use and provide the solar industry with no economic incentive to improve its productivity or availability or wean itself off dependence on the cross-subsidy. It also has the effect of putting more efficient resources, particularly other renewables, at a competitive disadvantage. In short, NEM effectively substitutes political judgment for economic efficiency to determining marketplace success.

The reason why solar DG vendors and providers cling to cross-subsidies is because they find more comfort in receiving substantial cross-subsidies than

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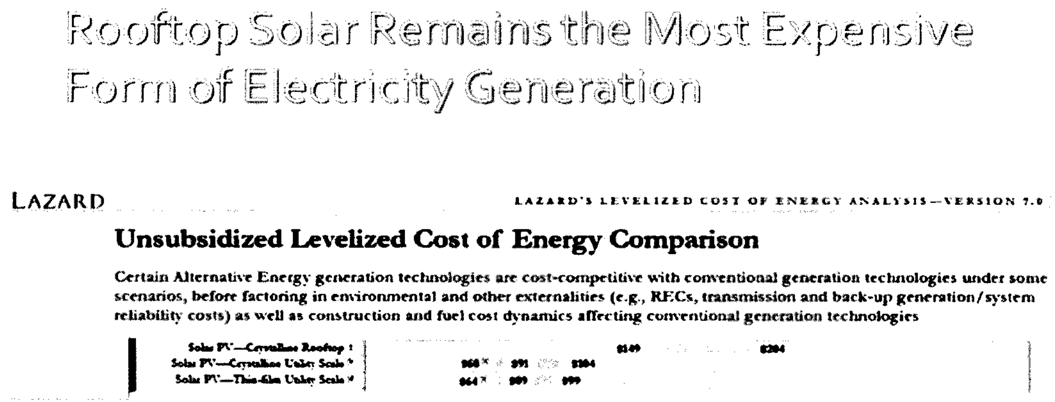

Figure 1: Rooftop Solar Remains the Most Expensive Form of Electricity Generation

they do in the prospect of becoming competitive. Solar DG is the most expensive form of renewable generation that is widely used today (Figure 1).

The technological and practical reasons for permitting such incoherent pricing are no longer present in the marketplace. We now have pricing methods that are capable of measuring DG production as well as consumption on a more dynamic basis. In addition, solar DG market penetration has dramatically increased to the point that it can no longer be dismissed as marginal, so appropriate pricing is now a non-trivial issue. In addition, we now have very precise, location-specific energy and transmission price signals that provide a very transparent market price by which one can measure the economic value of distributed generation. These new developments, plus the fact that NEM was put in place on a default basis, mean that it is now time for a full-blown policy consideration of the most appropriate pricing policy for distributed generation.

For all of the reasons noted, NEM pricing results in large cross-subsidies, offers no incentives for efficiency – indeed, may even provide disincentives to invest in efficiency improvements – and results in consumers paying energy prices for solar DG that are far in excess of its market value and not even subject to cost-based oversight. Moreover, its *raison d'être* – inability to more accurately price solar DG facilities and low market penetration by solar energy – no longer exists. Solar energy is penetrating the market in greater numbers and is likely to continue to do so. Secondly, more sophisticated pricing enables us to measure solar energy and customer behavior on a much more efficient, dynamic basis. The fundamental reality is that NEM completely fails to capture the value of the product being priced.

VI. Placing a Value of Solar DG – Pricing and Economic Efficiency

Needless to say, pricing is of critical importance. It is important to address pricing in the context of tangible, enumerated values. Such an analysis is in contrast to certain efforts by solar DG advocates to attach a subjective value to solar and then derive prices from that value. It is preferable to derive prices from the values established by either costs or market, not ephemeral and subjective considerations.

It is worth re-emphasizing just how imperfect NEM actually is. The price of electric energy is not constant. Wholesale markets reflect that reality. Net metering and many forms of incentives do not reflect the values established by the market. Rather, a net metering regime relieves the solar panel host of any obligation to pay for the costs of the distribution system when energy is being produced, even though he/she

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Table 1: Rooftop Solar Subsidies Heavily Utilize Funding from Non-Solar Customers

DTE Energy

Consumers Energy
Count on Us

SolarCurrents and Net Metering funding mechanism for residential customers

	SolarCurrents (Phase 1)	SolarCurrents (Phase 2)	Funding Mechanism
Up-front solar subsidy	**$2.40/W**	**$0.20/W**	**Renewable Surcharge**
On-going solar subsidy	$0.11/kWh	$0.03/kWh	Renewable Surcharge
Net metering subsidy (unrecovered fixed cost)	$0.09/kWh	$0.09/kWh	*Unrecovered fixed costs are funded by non-solar customers
Total SolarCurrents and Net metering subsidy	**$0.20/kWh**	**0.12/kWh**	

remains reliant on it and, when the meter runs backwards, is effectively paid the full retail price for energy exported from the customer's premises. As a point of illustration, see Table 1 for a funding mechanism for residential customers presented by DTE Energy to the Michigan Public Service Commission. According to DTE, the 9 cent per kilowatt-hour (kWh) net metering credit represents a differential that non-participating customers must pay.

Under NEM, compensation at retail rates is not cost-reflective because net metering means that solar DG energy exported into the distribution network is compensated at the full bundled retail rate rather than at a price based on the unbundled cost of producing the energy. In almost all jurisdictions, that retail rate is flat and constant. Thus, it does not reflect the obvious fact that the energy has greater value at peak demand than it does off-peak. It is a deeply flawed value proposition. The fact is that the wholesale market produces hour-by-hour prices that provide generators, renewable and non-renewable alike, and consumers with important price signals that reflect real-time values. Both generators and demand responders are compensated according to those real-time prices. Solar DG-produced energy, by contrast, is compensated on a basis that lacks a foundation in either market or cost. The compensation is out of market because it is a flat price regardless of when it is produced or, for that matter, fails to reflect that many hours of the day that solar panels produce absolutely nothing. It is hard to avoid the conclusion that on an economic basis, the NEM-derived price paid for solar DG energy completely misses the value of solar during most hours of the day. Interestingly, part of the cause for this incorrect valuation is that rooftop solar units have generally been installed facing south, as opposed to west. Because demand peaks have been trending later in the day (as illustrated in the California and New England figures below), this southern exposure has proven to render peak production for solar even less coincident with demand. Had the appropriate market prices been in effect, it is highly unlikely that such a costly error would have occurred.

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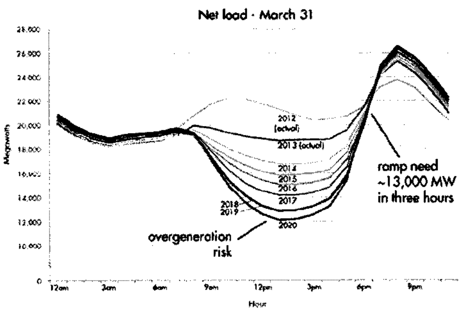
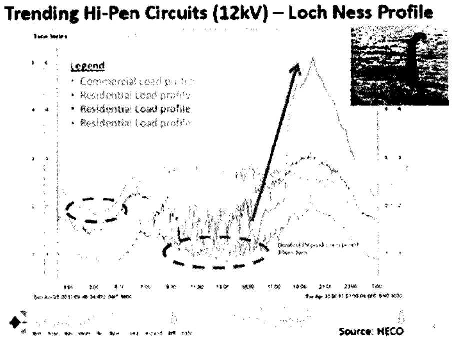
The Duck Curve - California



http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

The Nessie Curve - Hawaii

Trending Hi-Pen Circuits (12kV) – Loch Ness Profile



www.greentechmedia.com/articles/read/hawaiis-solar-grid-landscape-and-the-nessie-curve.

Figure 2: Ramping Needs Increased Due to Lack of Solar Prodution During Peak Demand

As is dramatically illustrated in the graph at left in Figure 2, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in the Golden State has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the dropoff in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. linking it with storage) is simply something that can no longer be tolerated. Not coincidentally, the charts from both the California and New England ISOs (found further *infra*), as well as that from DTE, illustrate the wisdom of compensating solar DG at LMP, so its price accurately reflects its value at the time of actual production and avoids requiring non-solar customers to pay prices for energy that far exceed its value.

A. Capacity value

The capacity value of a generating asset is derived from its availability to produce energy when called upon to do so. If a generator is not available when needed, it has little or no capacity value. By its very nature, solar DG on its own, without its own backup capacity (e.g. storage), can only produce energy intermittently. It is completely dependent on sunshine. Unless sunshine is guaranteed at all times solar DG is called upon to produce, it cannot be relied upon to always be available when needed. Moreover, even if all days were reliably sunny, the energy derived from the sun is only accessible at certain times of the day. In many jurisdictions, the presence and potency of sunshine is not coincident with peak demand. Frequently, for example, solar DG capacity is greatest in the early afternoon, while peak demand occurs later in the afternoon or in early evening. The two charts in Figure 3 illustrate the lack of coincidence of solar production and peak demand in New England.[1]

These two charts dramatically demonstrate that, on the days chosen as representative of summer and winter in New England, solar PV is completely absent during the winter peak, reaches its peak production as peak demand is rising in the summertime, and drops off dramatically during almost the entire plateau period when demand is at peak. It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

The Electric Power Research Institute (EPRI) graphs in Figure 4 reveal similar patterns on a national level. The first graph

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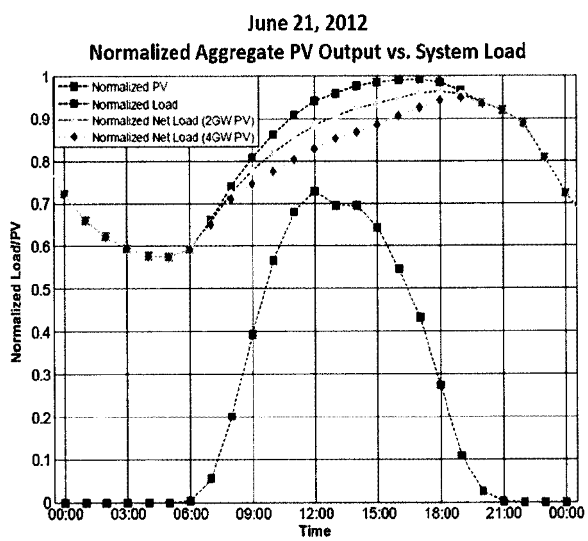


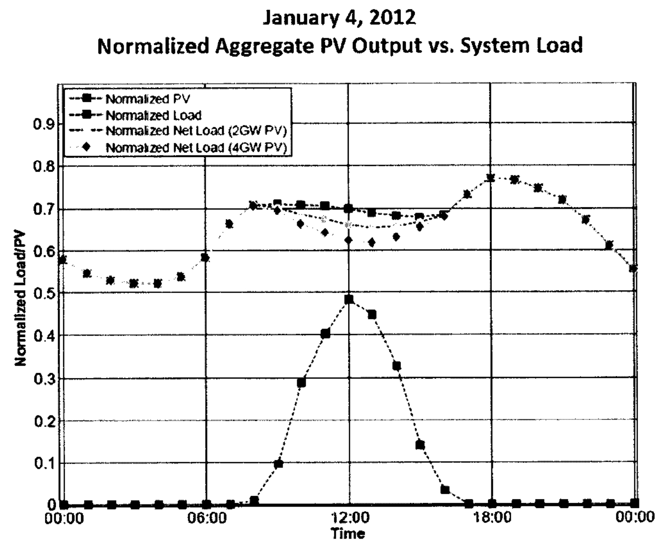
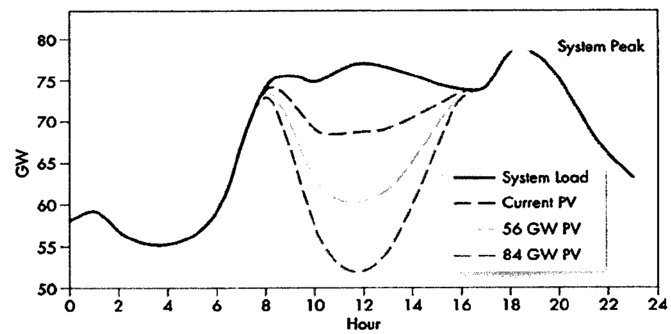


Figure 3: Lack of Coincidence of Solar Production and Peak Demand in New England

depicts the peak load reduction and ramp rate impacts resulting from high penetration of solar PV. The second illustrates the fact that because residential load and PV system output do not match, solar DG hosts use the grid for purchasing or selling energy most of the time.

As noted above, providers of capacity in the wholesale market may also have availability issues. In their case, however, if they are not available when called upon to produce, they are typically obligated to either provide replacement energy or to pay the



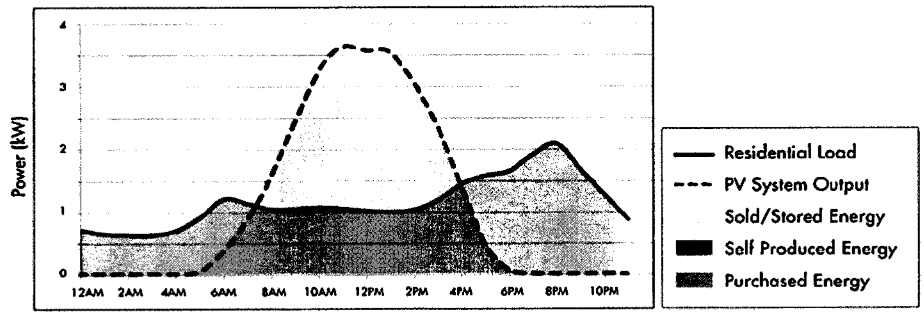


Figure 4: Increased Ramp Rates, Peak Load Reduction and Reliance on the Grid

marginal cost of energy that they failed to deliver. Unless a similar obligation is imposed on solar DG providers, the capacity value of solar DG is reduced even further. Good pricing policy would suggest that DG prices should be fully reflective of the value of the type of capacity that is actually provided. As currently implemented, net metering does not adequately reflect how the capacity availability measures up to demand.

B. Availability and reliability

Many advocates of solar DG assert that it enhances overall reliability because the units are small, widely distributed but close to load, and not reliant on the high-voltage transmission system. It is argued that they are less impacted by disasters and weather disturbances. At best, these claims are highly speculative and, for the reasons noted below, quite dubious. It would be a mistake to attribute added value to solar DG because of reliability.

Solar DG is subject to disaster as much as any other installations. High winds, for example, can harm rooftop solar as much as any other facility connected or unconnected to the grid. Cloudy conditions can disrupt solar output while not affecting anything else on the grid.

Solar DG has more reliability benefit in some places than others. In Brazil, for instance, a system that largely relies on large hydropower plants with large storage reservoirs, solar has considerable long-term reliability value because whenever it generates energy it conserves water in the reservoirs, thereby adding to the reliability of the system. However, in a thermal-dominated system (like much of the United States), where there is little or no

storage, reliability has to be measured on more of a real-time basis. Therefore, solar's intermittency makes it unable to assure its availability when called upon to deliver energy. Indeed, it is far more likely that a thermal unit will have to provide reliability to back up a solar unit than the other way around.

It is also important to examine rooftop solar reliability issues in two contexts: that of the individual customer and that of the system as a whole. Solar DG vendors, as part of their sales pitch, claim that reliability is increased for a specific customer with a rooftop solar unit because on-site generation provides the possibility of maintaining electric power when the surrounding grid is down. When the sun is shining, this claim may be true. Conversely, without the sun, the claim has no validity. However, that argument only applies to the solar host.

On a technical point, a power inverter is an electronic device or circuitry that changes direct current to alternating current. During a system outage the power inverter is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line workers and the public from encountering live voltage they do not anticipate. Thus, if a solar DG unit is functioning properly, when the grid is down, the solar DG customer's inverter will also go down, making it impossible to export energy. If the solar DG unit is not functioning properly, then the unit may be exporting, but will do so at considerable risk to public safety and to workers trying to restore service. The result is that the solar panel provides virtually no reliability to anyone other than perhaps to the solar host.

Attributing reliability benefits to an intermittent resource is a stretch. By definition, intermittent resources are supplemental to baseload units. The only possible exceptions to that are, as noted above, where there are individual reliability benefits or where the availability of the unit is

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coincident with peak demand or has the effect of conserving otherwise depletable resources. Absent those circumstances, and absent storage, it is almost certainly the case that the system provides reliability for solar DG, rather than the other way around. That is particularly ironic given that in the context of net metering, solar DG hosts do not pay for that backup service while generating electric energy. In essence, in a net metering context, non-solar customers pay solar DG providers for reliability benefits that solar DG does not provide them, while solar DG customers do not pay for the reliability benefits they actually do receive.

From an investment perspective, solar DG pricing methods, like NEM, which redirect distribution revenues from distributors to solar PV providers who offer no distribution services are detrimental to reliability as they either deprive the sector of capital needed to maintain high levels of service or demand additional revenues from non-solar DG users who would ordinarily not have to pay such a disproportionate share of the costs. For utilities, the diversion of funds leaves them with a Hobson's choice of either delaying maintenance and/or needed investment, or seeking additional funds – in effect, a cross-subsidy from non-solar users. It is also relevant to reliability to again note that the prevalence of intermittent resources on the grid, including solar DG, may well cause new, cleaner, and more efficient generation to appear less attractive to investors. Over the long term, that effect could lead to reliability problems associated with inadequate generating capacity, especially at times of peak demand.

C. Solar DG does not avoid transmission costs

It is nearly impossible to demonstrate that solar DG will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit. Of course, there is a simple way to calculate any actual transmission savings, and that is by compensating solar DG providers in the organized markets at the locational marginal cost of electricity at their location. That compensation model would have the benefit of capturing both the energy value and the demonstrable transmission value of solar DG. Absent that formulation, efforts to calculate actual transmission savings would be a difficult, perhaps entirely academic, task.

Solar DG advocates assert that real transmission savings are achieved through the deployment of DG, especially in systems that use locational marginal cost pricing. The argument is that by producing energy at the distribution level, less transmission service will be required, thereby reducing or deferring the need for new transmission facilities. It is also often contended that DG will reduce congestion costs, and perhaps even provide some ancillary services. All of that is theoretically possible but certainly not uniformly, or even inevitably, true.

Of course it is true that DG, absent any adverse, indirect effect it might have on the operations of the high-voltage grid, does not incur any transmission costs in bringing its energy to market. However, that is quite different than asserting that DG provides actual transmission savings. In fact, it would be incorrect to simply conclude across the board that solar DG will achieve transmission savings. It is possible that there could be transmission savings associated with solar DG deployment, but that can only be ascertained on a fact- and location-specific basis. Such savings would most likely be derived from reducing congestion or providing ancillary services of some kind. It is also theoretically

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possible, but highly unlikely, that massive deployment of solar DG will eliminate (or, more likely, defer) the need to build new transmission facilities. For a variety of reasons, including the complexities of transmission planning, the time horizons involved, the complex interactions of multiple parties, and economies of scale in building transmission, it is improbable that solar DG actually saves any investment in transmission capacity.

Indeed, a mere glance at the California ISO duck graph showing the need for ramping capacity to make up for the intermittent availability of solar DG provides a *prima facie* case for believing that the opposite is true and that solar DG may cause a need for more transmission to be built. These and other charts also show that as long as solar does not reduce peak energy use, transmission is likely needed to serve peak hours. Regardless, it is virtually impossible to demonstrate that, other the possibilities of reducing congestions costs (a value fully captured by LMP), there is very little likelihood of transmission saving being derived from solar DG.

D. Solar DG does not avoid distribution costs

It is more likely that solar DG will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require more controls, adjustments, and maintenance. Moving from a one-way to a two-way system will certainly increase the need for technical equipment to manage the reliability of the system. While DG solar may not be the only cause of this move the intermittent nature of solar makes

it particularly difficult to manage. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless a solar DG host leaves the grid, to envision a circumstance where solar DG would effectuate distribution savings.

Regarding distribution line losses, DG offers value only to DG providers when they consume what they produce because any DG output exported to the system is subject to the same line loss calculations that any other generator experiences. If there were locational prices on the distribution system, there might be line loss benefits that could be captured by DG but, since those price signals do not exist, the argument is purely academic.

VII. Lower Hedge Value

The theory advanced by some solar DG proponents is that because the marginal cost of solar is zero, it serves as a hedge against price volatility. In theory, that might make sense. In reality, however, solar is an intermittent resource that cannot serve as a meaningful hedge unless such zero-cost energy is both sufficiently and timely produced. Thus, solar DG is the equivalent of a risky counterparty whose financial position renders him incapable of assuring payment when required. Moreover, the value of a hedge depends on the amount of money the purchaser of the hedge is obliged to pay for the insurance and the amount and probability of the price he/she seeks to avoid paying. With a NEM system (or the high-priced "value of solar" approach that solar DG advocates seek), the price paid is highly likely to exceed the fuel or energy price most utilities would hedge against. In short, the argument ventures into the realm of the absurd. It amounts to: *Pay me a fixed price that is higher than the price you want to avoid, in order to avoid price volatility.*

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The argument that solar DG provides a valuable hedge function is reduced to virtual absurdity by the fact that the so-called hedge is not callable. In short, if the price rises to the level against which the hedge purchaser wants to be insured against, the solar provider of the hedge is not obliged to pay. That being the case, there is no hedge whatsoever.

VIII. Effects of Solar DG on Other Renewable Resources

A. Impact of a low capacity factor

Since 2008, as Figure 5 from the United States Energy Information Administration (EIA) points out, solar PV has had the lowest capacity factor of any commonly used renewable energy resource in the U.S. It is also worth noting that while the overall costs of installing solar panels has declined (as noted above) the productivity of solar PV has remained constant at consistently low levels. It should be noted that the chart below compares only "utility-scale" projects. As noted in the Lazard study above, distributed solar is even less cost effective than utility-scale solar, which already occupies last place on the Department of Energy (DOE) ratings.

The stark reality of solar PV's combination of high prices and poor capacity factor carries over into the cost of reducing carbon emissions. An interesting dialog occurred recently between Charles Frank, an economist at the Brookings Institution, and Amory Lovins of the Rocky Mountain Institute.[2] Their dialogue, while contentious on many points, reflects similar views on the realities depicted in the EIA chart. Frank analyzed five non- or low-emitting generation resources by their cost effectiveness in reducing carbon and concluded that nuclear and natural gas, followed by hydro, wind, and solar were, in that order, the most cost-effective types of generators for reducing carbon. Lovins took issue with Frank for using outdated data and for not looking at energy efficiency. He also argued that nuclear ranked last in cost effectiveness, and expressed some reservations about the ranking of natural gas. However, what is significant is that, among renewable resources, Lovins concurred with Frank that solar DG is the least efficient renewable resource for reducing carbon. Thus, in the view of both men – who hold quite divergent views on how best to reduce carbon emissions – not only is solar DG expensive, it is the least cost-effective renewable resource for reducing carbon emissions.

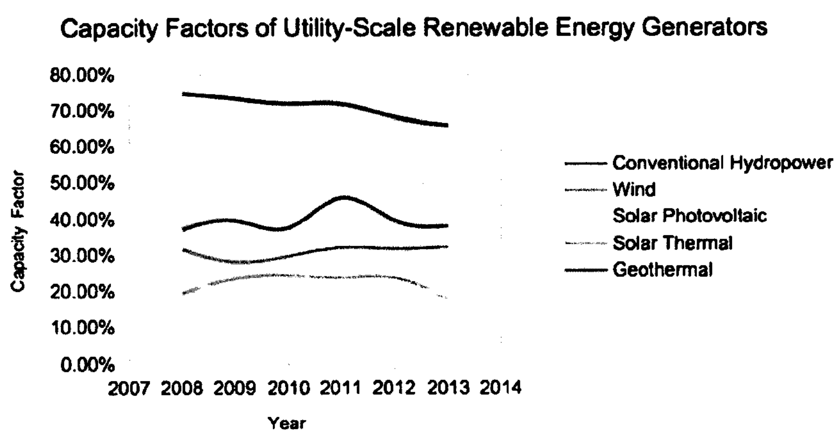

Figure 5: Capacity Factors of Utility-Scale Renewable Energy Generators

B. Impact of higher-than-market price

Higher-than-market prices paid for solar DG has adverse effects on other renewable resources. All wholesale generators, renewable and otherwise, have to incorporate transmission and distribution costs into the price of energy delivered to customers. As mentioned above, it is true that transmission issues play out differently for distributed generation than for wholesale generation. Since DG, by definition, does not rely on transmission capacity, although DG might impact congestion costs in various ways, wholesale energy's delivered cost reflects transmission capacity

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costs while DG's does not. Thus, any competitive advantage for DG on that score is quite natural. However, under the net metering scheme, DG providers also do not have to incorporate distribution costs into their end product, and that results in a serious economic distortion of the generation markets in general as well as specifically in renewable markets. In fact, as noted *supra*, solar DG providers under NEM are actually paid for delivering their energy even though they provide no such service. Wholesale generators, unlike their DG counterparts, enjoy no such comparable enrichment for service they do not provide. The effect of NEM's highly inefficient and non-cost-reflective rates is to distort market prices in ways that reward inefficiency and will likely distort price signals that are essential for an efficient marketplace.

In addition, at a critical mass, artificially elevated solar DG prices are highly likely to create distortions and inefficiencies in the capacity and energy prices found within organized markets. An environment with two parallel pricing regimes, one market- or cost-based, and the other an arbitrary one neither market- nor cost-based, is simply economically incoherent and unsustainable. The overall effect of net metering is to increase the prices consumers pay for energy overall, without any assurance of any long-term benefit. Solar DG is artificially elevated to a preferential position above more-efficient, larger-scale generation, including all other renewables. The disparity in treatment between solar DG and other forms of energy suggests that net metering is not only federal preemption bait (as further discussed below); it is fundamentally anti-competitive as well. Indeed, it compels consumers to both cross-subsidize less efficient producers and to pay higher prices

than necessary for energy. It will also entice investors to allocate their capital to toward more profitable but less efficient generation. In terms of efficiency and public benefit, the incentives inherent in NEM are simply perverse.

Large-scale bulk power renewables (e.g. large-scale wind and solar farms, geothermal) are put at a particular disadvantage by NEM pricing of solar DG independent of costs or market for two basic reasons. First, large-scale renewables are more efficient and more cost-effective than DG, yet net metering provides a subsidy only to the less efficient form of generation. In fact, solar DG providers are compensated for the energy they export at a price that can range from two to six times the market price for energy. Second, in those states with renewable portfolio standards (RPS), the entry of a critical mass of non-cost-justified solar DG units into the market could have the effect of driving more efficient, large-scale renewables out of a fair share of the RPS market. The effect, in a competitive market, is to bias the market to incentivize highly inefficient small-scale solar to the detriment of less costly larger-scale solar.

C. Comprehensive environmental analysis

Any analysis of the environmental impact of the generation mix should include an examination of the least-cost, most efficient ways to get to the desired results. Problematically, the preferential pricing of less efficient solar DG imposes an unnecessarily high-cost approach to reducing carbon. Results such as that cannot be justified on the basis of externalities, which are no different between DG and larger-scale renewables. Indeed, it seems probable that overpayments for DG have the effect of squeezing more efficient forms of renewable energy out of RPS markets by using preferential pricing to grab a disproportionate share of the RPS market and driving up the cost of reducing carbon.

In the long run, of course, the inherent favoritism in pricing DG

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at levels arbitrarily higher than other renewable energy sources does not bode well for either the future of renewables or the objective of efficiently reducing carbon emissions. Discrimination in favor of inefficient resources on a long-term basis is simply not sustainable. The inevitable backlash in both the marketplace and public perception has the potential to sweep away public support for renewable energy and perhaps for strong environmental controls as well, an outcome no one concerned about the environment would want. One of the most notable ironies emanating from the use of net metering to price solar DG is that it will almost certainly lead to changes in retail pricing that will undermine the promotion of energy efficiency. The reason for this is that as solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with the diminution of revenues required to support the distribution system that is caused by the use of net metering.

Those concerns are derived from the fact that under NEM, when solar DG is being self-consumed at the host premises, no revenues are being paid by that host to the utility for providing what essentially amounts to a battery to supplement their self-generation. Since the costs of the distribution are fixed and not variable with the use of "behind the meter" generation, net metering results in a delta of revenue that is either made up for by non-solar customers or constitutes a loss for the utility. Neither outcome is likely to be satisfactory to either the utility or the regulators. Inevitably there will be ratemaking consequences. That problem is compounded, of course, by the fact that when the excess output of rooftop solar is being exported into the grid the solar provider is

being paid as if he/she was delivering the energy, a service obviously provided by the distribution utility. Thus, not only are solar hosts not paying their fair share of fixed costs, they are, by the operation of net metering, actually taking revenues away from the entity that actually provides the service. From the standpoint of the utility and of the non-solar ratepayers who have to bear the burden of such uneconomic and inequitable revenue allocation, rate design remedies will be sought.

One likely remedy to be proposed is to modify the fixed/variable ratio in rates. While distributions are indisputably fixed costs, regulators have generally divided the recovery of those costs on a different basis. Some have been recovered on a fixed basis, while others have been recovered on a variable, volumetric basis. There are two critical policy reasons why this has been the case. The first is that fixed charges tend to impose a disproportionate burden on low-income households and on customers whose consumption is relatively light. The other reason is that volumetric-based charges send a signal to end users that the more they consume, the more they pay. Stated succinctly, the price signal promotes the efficient use of energy. If the revenue stream to cover distribution costs is diminished through mechanisms like net metering, utilities concerned about revenue requirements and regulators, concerned about reliability will, almost inevitably, shift more costs into non-by passable fixed charges, thus imposing more of a burden on low-income households and, equally important, diluting price signals for energy efficiency. In short, net metering will almost certainly, at some point, serve to both cause cost recovery to be socially regressive, and to discourage energy efficiency. In effect, net metering will likely become a classic case of anti-green pricing.

The anti-green pricing aspect of net metering is also exemplified by the behavioral pattern it incents among solar hosts. As shown on both the California and New England

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graphs above, solar production slacks off and ultimately disappears as demand reaches its peak. Despite that, solar hosts are never signaled through prices that their consumption is no longer being supported by zero-marginal-cost solar production. Indeed, in most cases net metering determines prices on an average-cost basis, even though solar production, even in the best of circumstances, is only available a fraction of the time period used for averaging. Thus, solar hosts are essentially lulled into a pattern induced by low marginal prices, which continue in periods of peak demand, thereby driving the peak demand even higher, a result that is truly perverse, both economically and environmentally. In short, net metering and energy efficiency are simply not compatible.

D. Net metering and energy efficiency are incompatible

Many experts from all facets of the renewable energy discussion will assert that energy efficiency is an important, if not the most important, means to increase carbon reductions. Assuming those experts are correct, it is important to consider the ways in which net metering impacts incentives for energy efficiency. While solar DG and energy efficiency are not inherently anathema, net metering is not compatible with energy efficiency. As discussed above, net metering is a compensation mechanism that causes utilities and regulators to move costs into the fixed category, thereby diluting the price signals that would encourage energy efficiency.

E. Possible federal preemption

State regulators, in setting prices for solar DG, should also be

conscious of the potential for jurisdictional disputes should DG prices cause any dislocation in wholesale markets. Because of the economic distortions caused by NEM, there are some who are calling for DG to be under the control of the Federal Energy Regulatory Commission (FERC) rather than state public utilities commissions' jurisdiction.[3] Unless states begin to remedy the price distortions inherent in net metering, it would be surprising if many aggrieved wholesale generators did not seek relief from FERC. In a somewhat analogous situation, New Jersey and Maryland sought to use state subsidies/mandates to support the construction of new power plants in order to manipulate and/or bypass the PJM capacity market. FERC, in a decision which was later affirmed by the Third Circuit Court of Appeals, struck down the state program by preemption. State commissions that continue to prop up a net metering regime with no basis in either market-based pricing or cost-of-service regulation may well discover the prospect of preemption hanging over them.[4] Further foreshadowing preemption are several other examples of state net metering programs running contrary to federal pricing regimes.

The Public Utility Regulatory Policies Act (PURPA) places an avoided-cost ceiling on power purchases; net metering evades that ceiling. Under net metering arrangements, not only are purchases of excess power mandated at levels well in excess of avoided costs, but they also include a cross-subsidy from non-solar customers for the distribution costs of solar DG providers. Bulk power renewables are subject to all of the rules of the wholesale market, which may include such costs as congestion costs, ancillary services, penalties for no availability, and others. Under net metering, solar DG providers are subject to none of these disciplines. In addition, some wholesale renewable generators complain that the arbitrarily high prices paid under net metering have the effect of attracting enough solar DG providers to fill up the RPS market, so that they

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are being effectively squeezed out of the portfolio entirely.

What is particularly ironic about this effect is that, as noted above, distributed, small-scale solar is the least efficient form of commonly used renewable energy sources in the United States. All of these factors indicate that an increasing number of parties are likely to be motivated to ask FERC to preempt net metering and other state-mandated regimes that allow for unreasonably discriminatory and anti-competitive pricing.

IX. Factors Mitigating Environmental Benefits

Expectations of environmental externality benefits may be the biggest motivator for supporting and subsidizing solar DG. Proponents of solar DG note that solar has zero carbon or other harmful emissions from the process of producing energy. Additionally, to the extent that wide deployment of solar PV avoids the need to invest in technologies that do have carbon and other undesirable emissions, there is an environmental benefit that avoids the social costs associated with pollution. In the absence of legal limits on relevant emissions such costs, solar DG advocates correctly point out, are not captured in the internalized costs of the competing technologies. Therefore, solar DG advocates suggest that regulators and policymakers should take these external social costs into consideration in setting prices for various forms of energy.

The use of external social costs, as opposed to solely the internalized economics of various forms of energy is a controversial subject. Many oppose the use of externalities as a factor in pricing because it distorts the market and makes social judgments economic regulators may not be

empowered to make. In the views of such opponents, the only externalities that ought to be incorporated into pricing are those that are internalized by legal mandate. Proponents of incorporating externalities into rates contend that doing so is the only way to accurately reflect all social costs. They also contend that factoring in environmental externalities is a form of insurance against future regulatory requirements. While this article takes no position as to the merits of incorporating externalities into ratemaking, it will address this issue, on the assumption that at least some regulators and policymakers will look at externalities for purposes of assessing the value of solar DG.

Before delving into this issue any further, it is important to note that the United States Environmental Protection Agency (EPA), whose jurisdiction over carbon emissions has been affirmed by the U.S, Supreme Court,[5] has proposed new rules under Section 111(d) of the Clean Air Act that would, if promulgated, internalize the costs of carbon into electricity ratemaking, so the issue of whether or not to consider the costs of carbon would no longer be debatable. Thus, there is a great deal of uncertainty which, in the short term, effectively strengthens the hand of those who contend consideration of carbon emissions would be a form of insurance against future regulation. In the longer term, however, the likelihood that carbon emissions will be internalized gives rise to very serious questions as to the value of including externalities which, over time may run contrary to the economics of internalized carbon costs. It is also worth noting that there are already several states that have adopted controls on carbon emissions. In those states, it is especially important to make certain that renewable policy and pricing enhances efficiency in compliance, as opposed to confusing means and ends. Regardless, the environmental issue, in terms of solar DG, is

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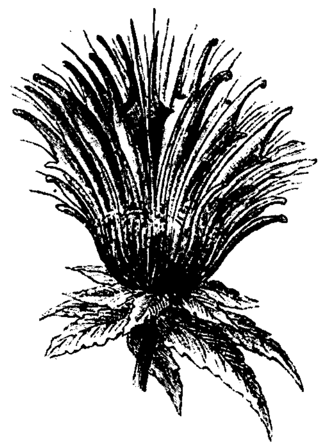
how cost effective such installations are for reducing carbon.

There is little dispute that solar DG is the least efficient of all renewable energy resources in common use in this country. As noted, there is even a consensus, which includes Amory Lovins, that agrees that solar DG is the least efficient renewable resource for reducing carbon. That view is fully supported by the facts in the California duck graph, as well as the ISO-New England and EPRI Value of the Grid data, which demonstrate conclusively that solar DG is consistently off-peak. When priced at net metering levels, it is also the most expensive renewable resource, thereby producing a perverse paradigm that where the least efficient resource costs the most. Therefore, it is evident, without considering any other factors, that solar DG is the least cost-effective use of renewable energy to reduce carbon emissions. There is also the reality that, as a general rule the least efficient and "dirtiest" plants are most likely getting dispatched at times of peak demand. Thus, in the rare instance that solar DG is available at peak in the United States, it is not displacing the most carbon emitting plants. Instead, it is displacing more efficient, less polluting generating units. Moreover, as an intermittent resource, its availability is highly uncertain and fossil plants are often called upon to operate on a less efficient, more carbon-emitting basis than if they were running as pure baseload. Thus solar DG is not only expensive, it is also much more likely to displace low-emitting, more efficient generation than less efficient, dirtier units. In addition, as noted earlier, net metering significantly dilutes the price signals for environmentally benign energy efficiency.



Those conclusions have been borne out by developments in Germany. In that country, where there has been a very dramatic increase in reliance on intermittent energy, prices have risen 37 percent since 2005, and were accompanied by spikes in both carbon emissions and the use of brown coal (lignite). While there are very significant difference between most states and Germany, perhaps most notably that Germany has decided to close down its nuclear plants (although it has replaced much of the domestic nuclear with imported nuclear energy), the experience in that country is very telling.[6] The German example clearly demonstrates that increased dependence on renewable energy resources, particularly intermittent resources, does not, as many solar DG proponents claim, *ipso facto,* mean fewer carbon emissions, and may, in fact, cause the opposite to occur. It also demonstrates that prices will escalate dramatically if the feed in tariffs are as far in excess of market as NEM prices are, as shown by the DTE graph above. The Germans, incidentally, have recognized their miscalculations and are dramatically recalibrating their strategy.

X. Regressive Social Impact

There are social effects beyond the environment that have to be taken into account if externalities are to be factored into ratemaking. Any failure to examine environmental externalities without recognizing that there are other social externalities to be considered as well will yield highly skewed results. Perhaps the most important of those is the social impact.

The social impacts of solar DG are caused by three main factors. First, as noted above, solar DG users have their electricity costs cross-subsidized by their neighbors who completely rely on the grid. Second, some data suggests that solar DG users are unusual electricity users. Third, not everyone can afford to be a solar DG user. To address the second point, unlike typical residential customers, in some regions solar

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DG users use little or no grid power at midday but quickly ramp up demand on peak, when PV production wanes (as is demonstrated by the charts in from the New England and California ISOs). Utilities must be able not only to serve full load on days when solar PV is not performing, but also to ramp up resources quickly to address the peak created by solar DG users. In order to ramp up as needed, utilities will purchase energy at the marginal price and then distribute those costs across all users, not just solar DG users. Thus, users without solar DG may be penalized for the use patterns of their solar DG neighbors. A comparison of residential electricity consumers in the western United States may be found below in Figure 6.[7]

Further, the impact of net metering is not simply the creation of a cross-subsidy from non-solar PV customers to solar PV customers but, as has been pointed out in a recent study by E3,[8] it is a cross-subsidy from less affluent households to more affluent ones. Indeed, the average median household income of net energy metering customers in California is 68 percent higher than that of the average household in the state, according to the study. In a recent proceeding, the staff of the Arizona Commerce Commission noted the same consequence.[9] As one wry observer in California noted, net metering is not "Robin Hood" but rather it is "robbin' the hood." In order to install rooftop solar panels, often individuals must be homeowners with high credit ratings or sufficient capital. Leasing arrangements are also widespread, but are generally available only to customers who own their own premises and they require the assignment of most of the rooftop solar benefits to the lessor. Many electricity customers, particularly less affluent ones, do not own homes or lost their homes in the most recent recession. The electricity customers who are unable to afford rooftop solar are forced to subsidize those who are already in a more favorable financial position. Thus, it is entirely fair to characterize NEM as a wealth transfer from less affluent ratepayers to more affluent ones.

Tariffs with a regressive social impact are certainly worthy of consideration from a policy and rate-making perspective. Thus, if externalities are to be weighed in setting pricing for solar DG, then it is important to avoid inordinate cost shifting and, in particular, to avoid adding new burdens to the less affluent in order to provide benefits to those further up on the income scale.

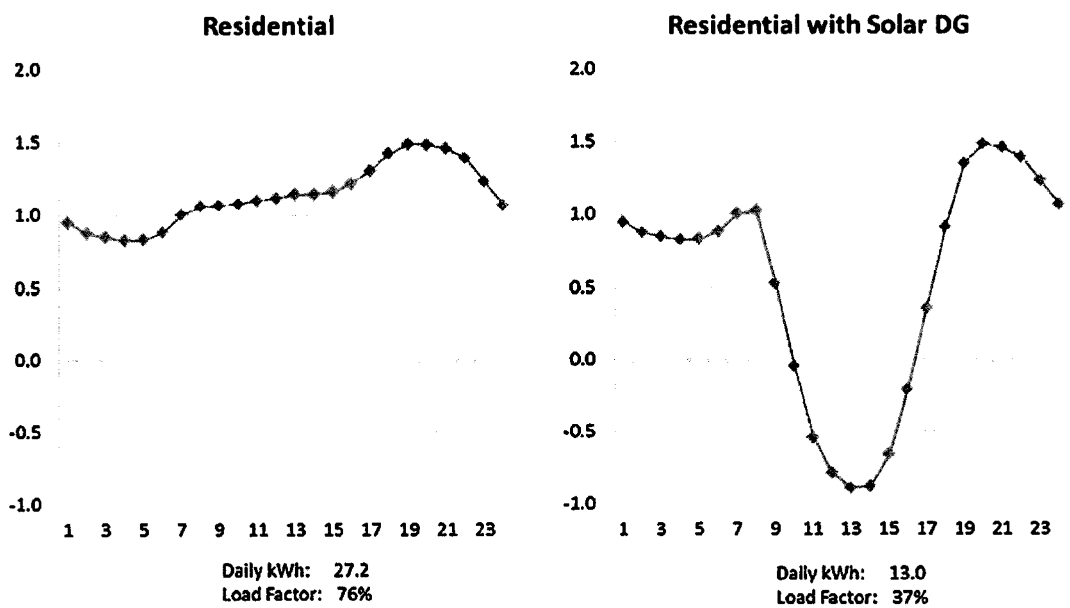

Figure 6: Typical Residential Loads Average Day – Iowa

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EXHIBIT DWH -6

XI. Impact on Job Creation

The impact of solar PV on jobs is often cited as an externality benefit. Any analysis of the job impact must be comprehensive and not an effort to cherry pick data. For instance, merely citing the number of solar installers employed does not tell us much. Many aspirations for more jobs manufacturing PV units in the United States have not materialized due to China's capture of the market. Other impacts to be considered are the effect of solar PV on electric rates and the impact of that on the job market, not only in terms of what happens with rates, but also in terms of the rate structure that is implemented as a result of more market penetration by solar DG. For example, it is conceivable that any movements toward more fixed costs could discourage energy efficiency work thus displacing jobs in manufacturing and installing energy efficiency technology.

XII. Conclusion

There is value in solar DG, but that value is severely diminished and placed in peril if its pricing discourages efficiency improvements and distorts critical price signals in the marketplace. It is similarly counterproductive to the future of solar DG if its pricing has socially regressive effects and if it sucks needed revenue away from the essential distribution grid. From an economic point of view solar DG has energy value, the potential for reducing some transmission costs, and perhaps under the right circumstances, some capacity value, and ought to be compensated accordingly. With regard to externalities, it is not entirely clear, when viewed in the entire scope of its impact, that solar DG, has positive environmental value, but it is absolutely

clear that when net metering is deployed, it is simply not a cost-effective means for reducing carbon emissions. In fact, it is possible that solar DG might do more harm than good if it has the effect of removing price incentives for energy efficiency, and if it causes older plants to extend their lives and to operate inefficiently on a ramping basis for which they were not designed. It seems clear that if we are to capture the full value of solar DG, net metering must be discarded and replaced with a market-based pricing system that values the resource appropriately and includes incentives for making it more efficient over the long run.■

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