BEFORE THE
CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER GRANTING APPROVAL OF NEW DISTRIBUTED GENERATION TARIFFS PURSUANT TO TITLE 17, SECTION 156 OF THE OKLAHOMA STATUTES	))))))	CAUSE NO. PUD 201500274

FILED
JUL 31 2015
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

Direct Testimony

of

Roger D. Walkingstick

on behalf of

Oklahoma Gas and Electric Company

July 31, 2015

Q. **Would you please state your name and business address?**

A. My name is Roger Walkingstick doing business as RDSTICK Consulting, LLC. My business address is 13704 Oakhill Drive; Piedmont, Oklahoma 73078.

Q. **By whom are you employed and in what capacity?**

A. I am retained by the Oklahoma Gas and Electric Company ("OG&E" or "Company") on a contract basis to address items related to regulatory concerns. These concerns include testimony supporting issues such as wind power, rate design, utility product development, and in this Cause, distributed generation ("DG") related issues.

Q. **Would you please summarize your education and professional background?**

A. I have a bachelor's degree in electrical engineering from the University of Oklahoma. I also have a Masters of Business Administration from Oklahoma City University. I am a licensed professional engineer in the State of Oklahoma. I was an employee of OG&E for over 28 years, of which approximately 23 years was involved with rates, costing, rate administration, regulatory issues, and pricing functions for the Company. I retired from OG&E December 31, 2009 and have since worked with OG&E on a contract basis on various OG&E regulatory projects.

Q. **Have you previously testified before the Oklahoma Corporation Commission?**

A. Yes. I have testified before this Commission several times and this Commission has accepted my qualifications for the areas I cover in this testimony.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to support OG&E's application seeking Commission approval of appropriate tariffs that are in compliance with 2014 Senate Bill No. 1456 (hereafter referred to as the "Act") and the Governor's Executive Order 2014-07 enacting S.B. NO. 1456. Executive Order 2014-07 (hereafter referred to as the "Order"). A copy of the Act and the Order is attached to my testimony as Exhibits RDW-1 and Exhibit RDW-2.

Q. **How is your testimony organized?**

A. My testimony is organized according to the following outline:

I. The Act
II. Current Status of DG on the OG&E System
III. OG&E Response to the Act
IV. Tariff Development
V. Impacts of Solution on Participants and Non Participants
VI. Results from OG&E's proposed solution
VII. Addressing Commission Staff's Checklist in Addressing the Act

I. The Act

Q. **Please explain the Act and to whom it applies.**

A. The Oklahoma Senate introduced the Act in the 2014 to address certain subsidy issues prevalent in the DG marketplace. The Act applies to customers that have installed DG facilities on and after November 1, 2014. On the OG&E system, 15 customers (as of July 31, 2015) will be affected by the provisions of the Act.

Q. **Please describe the general requirements of the Act.**

A. The Act became effective November 1, 2014 and states that utilities must have supporting tariffs filed, approved, and implemented by January 1, 2016 to comply with the requirements set forth in the Act. I believe the relevant sections are 17 O. S. § 156(B)(C)(D)(E):

> *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.

Q. **Does the Act apply to DG customers that had DG facilities installed before the effective date of November 1, 2014?**

A. No. The Act does not address customers that installed DG facilities before the November 1, 2014 effective date. These customers are grandfathered and are not subject to the provisions of the Act. Note that customers served under tariffs who receive electric service which includes a demand based charge are not addressed by the Act.[1]

Q. **Please elaborate on of Paragraph B of the Act.**

A. Paragraph B is simply stating that a fee or a surcharge placed upon a customer's distributed generation must be cost based. The utility cannot include any charges onto the DG customer above the full costs associated in serving that customer. Paragraph B also stresses the full cost requirement applies to all customers served under non-demand tariffs that became DG customers on or after November 1, 2014.

[1] 17 O. S. 2011 Section 156, A.1.f.

Q. **Is OG&E proposing a surcharge on DG customers in this proceeding?**

A. No. In fact, instead of adopting a surcharge, OG&E is proposing rates based on embedded cost principles. The proposed tariffs properly align prices with underlying costs for each component of electric services. With this proper alignment, the standard rate recovers all of the embedded costs without any need of a surcharge.

Q. **Please elaborate on Paragraph C of the Act.**

A. Paragraph C is advancing the position that new DG customers cannot be subsidized by other customers. New DG customers cannot subsidize (from Paragraph B) or be subsidized (from Paragraph C).

Q. **Please elaborate on Paragraph D of the Act.**

A. Paragraph D is emphasizing that one way the utility could recover the full cost-based revenue requirement from a new DG customer is by the assessing a higher customer charge than what is currently being charged for existing DG customers. It is important to note that the Act language does not appear to mandate a higher customer charge for new DG customers; it merely states that this approach is an acceptable means to meet the full cost recovery requirement of the Act.

Q. **What is the significance of Paragraph E?**

A. The Act specifies that new tariffs must be filed and approved by the Commission no later than December 31, 2015.

Q. **Does OG&E have concerns with Paragraph E?**

A. No. OG&E believes there is ample time available for the Commission to review and accept or reject the provisions of OG&E's proposal in this proceeding.

Q. **Do you believe that subsidies exist in OG&E's existing DG tariffs and should be addressed?**

A. Yes, subsidy has been a long time issue associated with most DG installations. However, OG&E has not addressed the issue with the Commission because the number of total customers with DG installations was small and the sizes of most DG units were generally appropriately sized to offset the customer's usage without causing other issues on the distribution system. In the future, neither of these conditions may exist. As the price of DG units continue to decline, it is likely more and more DG units will be installed. Therefore, OG&E believes now is the time to address the issue before the number of DG customers becomes significant. If OG&E were to wait to address the issue when the DG customer count is significant, the impact would be economically disruptive to DG customers.

Q. **Given that the number of DG customers currently affected by the Act is small, would it prudent to just wait until the next rate case to address the issue?**

A. No, it would not be prudent. First, we have a statutory requirement to address the issue. As I understand it, the Act is quite clear concerning the timetable of establishing tariffs that eliminate subsidies and this filing should provide ample time in meeting those mandates. Second, it is unfair to local installers of DG facilities and potential DG customers to delay addressing this issue. As soon as possible, these parties need certainty in understanding how OG&E will address these issues. Third, the Company is convinced that offering new compliant tariffs is not only the fair and appropriate action, but it also allows interested parties the opportunity to adequately address the issues associated with DG without the distraction of other issues generally associated with a rate case.

Q. **Does OG&E believe the installation of more DG facilities to be a bad thing?**

A. No, not at all, but there is one issue that should be addressed. DG customers need to be credited at a level that is commensurate with the embedded benefit they provide to the utility and to other customers. The current rate structures as they apply to Net Energy Billing Option (NEBO) customers do not meet this standard. These current NEBO related tariffs tend to compensate customers at a level that is too high for the embedded benefit they provide.

Q. **How has OG&E supported the adoption of emerging renewable technology?**

A. OG&E has long been an advocate for testing and adopting cost effective renewable technology. For example, OG&E was an early adopter of wind energy as the market developed. In 2003, OG&E brought the 50 MW Sooner wind farm into its generation mix and introduced the Green Power Wind Rider offering to customers. In 2007, OG&E added the Centennial Wind farm. Subsequently in 2008, OG&E offered a program that allowed customers to purchase renewable energy credits. Next, as OG&E gained experience on how to integrate wind into the OG&E system, it acquired additional wind resources including: OU Sprit, Keenan, Taloga, Crossroads and Cowboy wind farms. Today, OG&E has a total of wind resources with nameplate capacity of 840 MW. This represents almost 12% of OG&E's total generation capability.

Q. **What do you mean by the term "embedded benefit"?**

A. The utility collects revenue requirement based upon the embedded costs that are caused by the customer using their product. If a customer "suddenly" becomes the seller of a product that they were buying, they should not be compensated at a level greater than what was being collected from them in the first place. Compensation should occur at a level commensurate with the embedded cost. I believe that is the directive that the Act was designed to accomplish.

Q. **Please explain why the level of compensation is a problem with the current DG related rate structures.**

A. The existing tariffs create the opportunity for subsidies between DG participants and non-participants which is contrary to the Act. Rates are made up of several components: production (generation) costs, customer costs, energy costs, demand related costs, and fuel costs. Current non demand rate structures tend to lump these components together which incorrectly provides DG customers with more credit than the actual embedded benefit that is supplied by their DG facilities.

Q. **Are the pre-November 1, 2014 DG customers receiving a subsidy?**

A. Yes, most existing DG customers are receiving embedded credit at a higher level than the embedded benefit they are providing to the utility system. However, this testimony and its associated tariffs do not address these grandfathered DG customers. This testimony only addresses customers that install DG facilities on or after November 1, 2014. Another way of emphasizing this point is to say that DG customers that were on the OG&E system before the effective date of the Act are grandfathered from meeting some of the requirements of the Act.

Q. **Why is grandfathering of these DG customers acceptable?**

A. These pre-November 1, 2014 DG customers committed to considerable expense to become a DG customer based upon the then current DG rates. The Act made provision to exempt these customers. Customers that entered into DG installations on or after November 1, 2014 should have been made aware by their DG installer that DG related rates were likely to change because of the Act.

Q. **Please describe what you mean by the "full cost recovery requirements" mentioned previously in your testimony.**

A. Functionally, tariffs, in conjunction with each customer's billing determinants, are used to generate a customer's monthly electric bill. Current non-demand based tariffs such as those found in residential and certain commercial-type classes (such as General Service, Public Schools Non Demand, Municipal Pumping, and Oil and Gas Pumping) have rate structures that do not currently include a demand charge. Because non-demand rates collect demand related costs through the energy charges, subsidies occur. Introduction of demand charges into these non-demand rate structures better enables full and appropriate cost recovery by the utility, and eliminate those subsidies.

Q. **Has proper cost recovery been nationally recognized as an issue for DG customers?**

A. Yes. In fact, 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, a previous attorney for the United States

Environmental Protection Agency's Office of Regional Counsel, authored a very thorough paper on the proper pricing methodology for establishing efficient DG retail rates. The paper was entitled Valuation of Distributed Solar: A Qualitative View.[2] As a preface to the paper, the authors' provide a short synopsis of the paper as follows:

> *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.*

A copy of the article is attached as an Exhibit RDW-13.

Q. **Do the authors agree that the methodology used by OG&E in establishing its proposed DG rates is an appropriate methodology?**

A. Yes, the authors have recognized embedded costs as one of the appropriate methods for establishing proper pricing of DG rates.

II. Current Status of DG on the OG&E System

Q. **Please discuss the current status of Oklahoma DG installations on the OG&E system.**

A. The following table reflects the current count of DG installations for OG&E's Oklahoma customers as of July 31, 2015.

[2] 1040-6190/# 2014 Elsevier Inc. All rights reserved., http://dx.doi.org/10.1016/j.tej.2014.11.005. December 2014 Vol. 27, Issue 10.

Table 1 – OG&E Current DG Customer Installations

Timeframe	Wind	Solar	Rate Type	Total	Facility Size (≤ 6 kW)
1985 through 2010	7 +3 Combo Wind/Solar	23	Res: COM:	27 6	25
2011 through 2014 Oct 31	15 +2 Combo Wind/Solar	180	Res: COM:	178 19	163
Post November 1, 2014	0 +1 Combo Wind/Solar	14	Res: COM:	8 7	13
Total	**28**	**217**		**245**	**201**
NEBO **QF**	24 4	216 1	NEBO QF	240 5	

Q. **According to Table 1, there are 245 DG installations in Oklahoma. Please explain the cells associated with NEBO and Qualifying Facility ("QF") customers.**

A. The cells to the right of the NEBO and QF labels represent customers that are either taking service under one of the net energy options by either choosing the NEBO or the QF option. NEBO is OG&E's net metering option. NEBO requires that participants subscribe to a time-differentiated base tariff such as RTOU or RVPP. QF is a purchase schedule that allows customers to sell their DG energy production to OG&E. A customer must select either NEBO or QF when they make application as a DG customer.

Q. **The table indicates that most customers with DG installations are residential and have DG facilities of 6 kW or less. Is this what is expected?**

A. Yes. Most of the customers that install DG facilities are residential customers choosing to partially offset their customer load with small DG units. While a customer could choose to install larger units, it seldom makes economic sense to install more capability than what their kWh usage would have been before they became a DG customer.

Q. **What is your opinion of the customers' economics of DG installations?**

A. The grandfathered customers' net metering arrangements include subsidies. With the implementation of revised tariffs, new DG installations can provide appropriate compensation while eliminating subsidies. While I believe that most DG installations are not cost effective, I understand that cost may not be the only motivating factor for many customers choosing DG.

Q. **Why then do customers choose DG?**

A. The first and foremost factor is the right-of-choice that DG brings to customers. Choice is a good thing, but it also brings the caveat of increased responsibility. The second motivating factor is much of DG emphasizes solar and wind which offer a sustainable resource and smaller environmental footprint. Finally, some customers like DG such as solar because it is technologically "cool". While some would contend that cool is not a valid reason for committing to DG, for many that do commit, technologically cool is important. I believe that early adopters often are motivated to become involved with a project because of their perception that something is new and innovative, not because it is economically justified.

Q. **What did you mean by the caveat of "increased responsibility" on the part of the customer?**

A. When I said that choice brings responsibility I meant that choice has consequences. For example, I have the choice of buying a car, but realize that if I want to haul items around with me, a truck may better suit my needs. Similarly, I am likely to have car payments that may have a detrimental impact on my budget.

In the case of DG, I realize that the installation of DG comes with consequences of its own which include: paying for the system, maintaining the system, aesthetics (others may not like looking at my DG installation), increased maintenance of my roof, impact and modification of my electrical system design, and the DG facility may not be cost effective. DG consequences should be weighed and evaluated fully before decisions are made. That responsibility falls on the buyer to take in consideration when making a purchase decision...caveat emptor. Essentially, buyers must perform their due diligence when purchasing an item or service.

Q. Do you know of any other Commissions that have recently dealt with some of the issues associated with DG, and specifically, subsidies in their respective jurisdictions in the last few months?

A. Yes. The Wisconsin Public Service Commission has noted with the following language:

> *...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.*[3]

Q. Do you concur with this portion of the Wisconsin Order?

A. Yes, I believe the Oklahoma Act is endeavoring to address some of the same issues concerning DG that the Wisconsin Commission addressed in its Order. OG&E supports the addition of DG facilities on the OG&E system, but only if the bill reduction is consistent with the embedded benefit. The Oklahoma legislature has provided a framework for the Oklahoma Corporation Commission ("OCC") to address the very issues raised in Wisconsin. The OCC has traditionally used the embedded cost of service study to set revenue requirements by customer group and identify cross subsidies.

[3] Order covering Docket 05-UR-107 (dated December 23, 2014), p. 62.

III. OG&E's Response to the Act

Q. **How does this testimony and OG&E's proposed tariffs address the mandates of the Act?**

A. OG&E is proposing four new tariffs including: a commercial TOU tariff (COM-TOU-kW) and a residential TOU tariff (R-TOU-kW), a new net metering rider (NEBO-kW), and an additional qualifying facilities tariff, Renewable Power Purchase Option (RPPO). The residential and commercial tariffs include demand billing charges, appropriately priced customer charges, and appropriately priced time-differentiated energy charges. These tariffs were all developed using Unit Cost components from the last approved rate case. These tariffs are attached as Exhibits RDW-3 through RDW-6. In addition, the existing NEBO tariff, Exhibit RDW-9, will be closed and no longer available to new DG facilities.

Q. **Please explain how OG&E's proposed tariffs comply with the Act.**

A. OG&E's proposed tariffs eliminate subsidies by collecting the functional costs through the proper billing determinants: customer related costs are collected through the fixed monthly connection charge; transmission and distribution costs are collected through the demand based demand charge; supply costs are collected through the time-differentiated energy charge. Table 2 shows how various cost components of a customer's bill were collected in current rates and how those same cost components are proposed to be collected in the new tariffs.

Table 2 – Functional Cost Recovery Comparison

Functional Cost Component	Cost Components of Rates		Collected in Current DG Non Demand TOU Rates Paired with Current NEBO Rider	Proposed Collection for New COM-TOU-kW or R-TOU-kW Paired with New NEBO-kW Rider
Transmission Demand	A	Transmission Demand	**Energy (kWh Charge)** • On Peak - (A,B,C,D,E and part of H,I,J,K,L) • Off Peak - (A,B,C,D,E and part of H,I,J,K,L)	**Demand (kW Charge)** – • Transmission Demand - (A) • Distribution Demand - (B)
Distribution Demand	B	Distribution Demand		
Production Demand	C	Production Excess Demand		**Energy (kWh Charge)** • On Peak Energy (kWh Charge) – (C,D,E) • Off Peak Energy (kWh Charge) – (D,E)
	D	Production Average Demand		
Production Energy	E	Non Fuel Energy		
	F	Fuel Related On Peak Energy	**Fuel (kWh Charge)** • On Peak Fuel - (F) • Off Peak Fuel - (G)	**Fuel (kWh Charge)** • On Peak Fuel - (F) • Off Peak Fuel - (G)
	G	Fuel Related Off Peak Energy		
Distribution Customer	H	Portion of Transformer	**Customer Charge -** (parts of H,I,J,K,L)	**Customer Charge -** (all of H,I,J,K,L)
	I	Service drop		
	J	Meter		
Customer	K	Customer Billing		
	L	Administration		

Q. **Please discuss how the table is structured and how to interpret the data.**

A. Column 1 is the functional cost component breakdown of the costs based upon the service that is provided. Column 2 mimics Column 1 except it further breaks down the functional components even a bit further. Column 3 reflects how the functional breakdown is recovered in OG&E's current rate structures. Finally, column 4 reflects how the functional costs will be collected in the proposed rate structures of the tariffs associated with this testimony.

Q. **What are the components included in the new TOU-kW tariffs?**

A. Referring to Table 2, the proposed COM-TOU-kW and R-TOU-kW tariffs include a demand based *demand charge* (recovering Transmission and Distribution Demand functional cost), a *customer charge* consisting of the associated costs as detailed in the table, *energy charges* which are further divided into "On" and "Off Peak" energy charges, and *fuel charges* which also are divided into On and Off Peak fuel charges.

Q. **What is the production demand functional cost component?**

A. Production demand is the level of demand required in meeting a customer's instantaneous power needs (generally measured over 15 minute periods) to operate his equipment and must be met by company or grid generation resources. Sometimes production demand is further divided by using allocation methods referred to as "Production Average Demand" and "Production Excess Demand". The "Average" production demand portion is usually calculated to reflect a customer's usage over a longer timeframe (usually a year), which gives some indication of what generation resources are needed to meet a customer's average demand usage. "Production Excess Demand" reflects usage above the Production Average Demand usually for a 15 minute peak period and it reflects what generation must be available to meet a customer or a customer class' peak demand need. The difference between peak demand and average demand is often referred to as "Excess" production demand. The excess production demand is proposed to be collected in the On Peak energy component of the rate and the average production demand component is collected across all hours and all kWh of a customer's bill.

Q. **What are the benefits of collection of production demand costs in this manner?**

A. Collecting production demand costs in this manner recognizes the benefits provided by distributed energy. This proposed design allows production from other sources (DG) to receive recognition of any contribution provided during the On Peak periods. This design signals customers to use less during higher cost On Peak periods. Since it is unlikely that most DG facilities can provide electricity across the entire On Peak period, using an energy charge recognizes DG production when it is available.

Q. **Please explain why certain types of billing components are better than others for accurately recovering certain costs.**

A. Some costs vary with customer usage and other costs do not vary with customer usage. Therefore, costs that do not vary with customer usage are best recovered by a fixed billing determinant. For example, assume the cost of connecting a customer to the grid is $20 a month. Now assume that this $20 covers billing administration, customer service, fixed costs of service drop, metering costs, and some portion of transformer costs required to serve the customer. Further, assume the customer chooses not to use any electricity (kWh consumption) for the next 12 months. If all of the customer connection cost collection was priced on variable kWh consumption component, the bill rendered to the customer each month would be $0 because the customer used no kWh during the month. Yet, the utility would still incur those customer connection costs. The result of using a variable billing determinant (kWh) to collect the customer connection costs for the customer above is that the utility would need to recover those costs from other customers.

Q. **How should demand costs be recovered?**

A. Demand costs, or transmission and distribution ("T&D") functional costs, are most appropriately recovered through a demand charge. Returning to the previous example, assume the same customer did not use any electricity for 11 of the 12 months. In that twelfth month, assume the customer used 20 kWh and 20 kW for one hour. Let's further assume the customer was paying a kWh rate of $.10 per kWh for all kWh used, and there was no demand charge included in the tariff. The customer's bill would be $2.00, or 20 kWh X $.10 per kWh = $2.00.

If the demand costs were $2.68 per kW, then the costs to supply service would have been $53.60, or $2.68/kW X 20kW = $53.60. As is clearly evident, $2.00 received from the customer is not sufficient to recover the demand costs of $53.60 imposed by his usage. The $51.60 difference would have to be recovered from other customers. These examples illustrate why tariff design is best served by properly incorporating and pricing each billing component.

Q. **Can these new tariffs be designed using the existing Cost of Service Study?**

A. Yes. The new tariffs which include R-TOU- kW, COM-TOU-kW, NEBO-kW and RPPO have been designed using unit cost information from the GS (commercial) and Residential customer classes from the last approved general rate case (Cause No. PUD 201100087). It is appropriate to use this cost study as it is the basis for our existing tariffs.

Q. How were the unit costs determined?

A. The unit costs were calculated by dividing the functional revenue requirements by the associated billing units (such as demand and time-differentiated kWh). These costs are used to establish the prices in the proposed tariffs. When these prices are applied to TOU-kW billing determinants, appropriate, non-subsidized customer bills are created.

The following charts show the functional costs for residential and small commercial customers. Workpapers supporting the calculation of the unit costs are attached as Exhibit RDW-7 and Exhibit RDW-8. *Note that fuel costs are not included in these charts.*

Chart 1: Unit Costs for Residential Customers

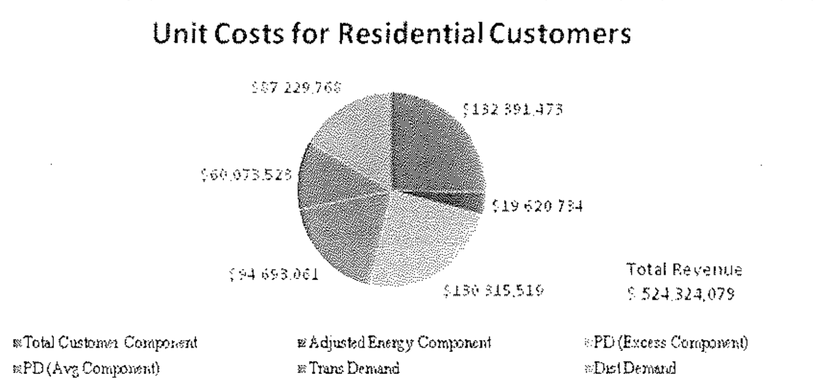
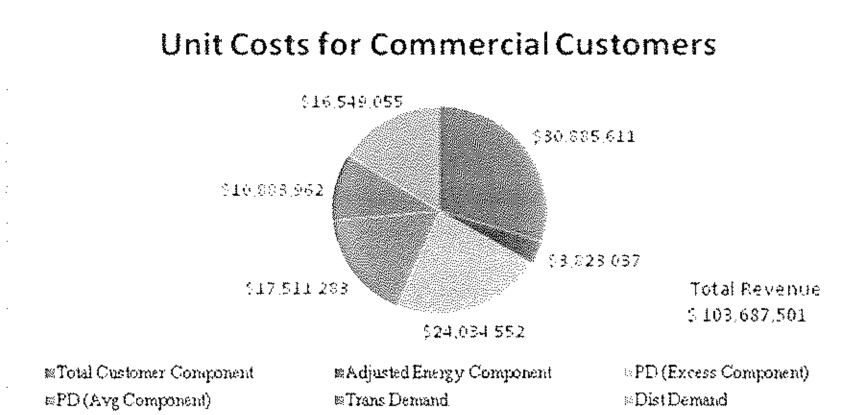


Chart 2: Unit Costs for Commercial Customer



IV. Tariff Development

Q. Please discuss the proposed R-TOU-kW tariff.

A. The R-TOU-kW tariff is available to residential customers that have installed DG facilities on or after November 1, 2014.

Q. What are the prices for the billing components for R-TOU-kW?

A. The prices for service are as follows:

- Customer charge: $18.00 a month
- Demand Charge: $2.68 per kW per month
- Supply Charges:
  - On Peak energy: $.173 per kWh
  - Off Peak energy: $.0137 per kWh

Fuel charges by On Peak and Off Peak time periods are also added to each of the energy charges at time of billing. All applicable riders will also apply. The R-TOU-kW tariff is attached as Exhibit RDW-4.

Q. Please discuss the proposed COM-TOU-kW tariff.

A. The COM-TOU-kW tariff is available to non-residential customers that have installed DG facilities on or after November 1, 2014. Non-residential customers are defined as GS customers, Oil and Gas Pumping, Public Schools Non-demand, and Municipal Pumping customers. These customers that have all have been part of the GS class in the past. The COM-TOU-kW tariff is attached as Exhibit RDW-3.

Q. Is the COM-TOU-kW structured similar to the R-TOU-kW tariff?

A. Yes. The billing component prices are different for each tariff, but the pricing structure is virtually the same. As was the case in the development of R-TOU-kW pricing, the component prices for COM-TOU-kW are determined by taking unit cost information from the last approved general rate filing and applying it to the new DG rate structures. The component pricing is:

- Customer charge: $34.75 a month

- Demand Charge: $3.30 per kW per month
- Supply Charges:
  - On Peak energy: $.1875 per kWh
  - Off Peak energy: $.0143 per kWh

Fuel charges by On Peak and Off Peak time periods are also added to each of the energy charges at time of billing. All applicable riders will also apply.

Q. **How is the DG facility output measured?**

A. The billing determinants, kWh and kW by time period, are measured by the customer's Automated Metering Infrastructure ("AMI") meter. Maximum billing demand is captured by the demand register of the meter and kWh usage is captured by timeframe for the On Peak kWh and the Off Peak kWh determinants. To measure gross output, an additional meter should be added between the customer's load and the customer's generation. This additional metering capability will enable customers to better understand their DG output and how it impacts their usage. While an additional meter is not a requirement, it is the preferred metering arrangement for DG installations.

Q. **Please discuss the NEBO-kW rider.**

A. The NEBO-kW Rider is OG&E's proposed net metering solution for customers post November 1, 2014. As with the existing NEBO rider, customers must execute an interconnection agreement with the Company. The NEBO-kW Rider is used in conjunction with the proposed tariffs of R-TOU-kW for new DG residential customers and COM-TOU-kW for new DG commercial customers. NEBO-kW rider is attached as Exhibit RDW-5.

Q. **Are there any changes to the existing NEBO rider?**

A. Yes. It will be closed to new DG customers post November 1, 2014. It is attached as Exhibit RDW-9.

Q. **Please discuss the new RPPO purchase schedule.**

A. The qualifying facility tariff, RPPO, is a new optional purchase schedule that allows a customer to sell all of the DG facility output to the utility.

Q. **How is that different from the QF rider that is part of OG&E's current rate offerings?**

A. This RPPO tariff is an optional tariff that allows smaller DG facilities, 300 kW or less, to sell all of their output to OG&E. It provides time differentiated power purchase prices without regard to capacity factor for customers who agree to sell their gross output to OG&E. A second meter is required under RPPO to measure gross output.

V. Impacts of Solution on Participants and Non Participants

Q. **How many customers will be affected by the addition of these proposed tariffs?**

A. If the new tariffs went into effect today, the total number of DG customers affected by the new designs would be 15 (as of July 31, 2015, please refer to Table 1).

Q. **Who benefits from the adoption of the proposed tariffs?**

A. All customers benefit. Those customers that are currently paying subsidy to DG customers should benefit since future subsidies to new DG customers are eliminated or minimized. Since the overall revenue collected from all customers in total should be the same between rate cases, no future customer should receive unfair positive or negative treatment (subsidy) under the new rate structures. I believe that any rate structure that truly reflects underlying costs, benefits customers as a whole.

Q. **What about the other benefits or "externalities" that exist to all customers because of renewable energy resources such as those provided by DG facilities?**

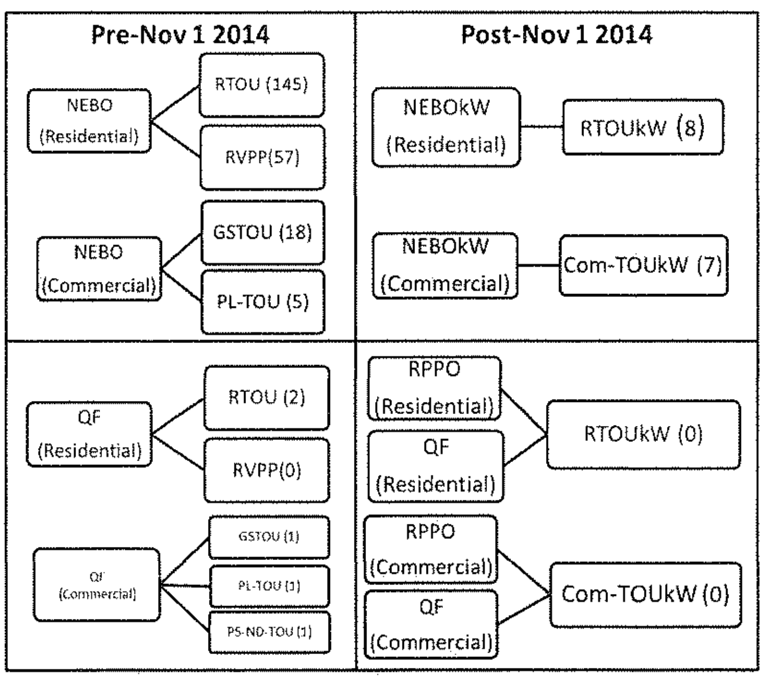
A. While I recognize that there may be externalities that are not addressed in the proposed tariffs, I strongly believe that those concerns should be addressed outside of the ratemaking process. We know that the federal and state governments have provided tax credits to encourage development of these resources. I not only applaud this effort, I have been a longtime supporter of this effort. But I agree with the Wisconsin Commission that a subsidy is best reflected by openly acknowledging a subsidy and allowing it to exist outside the ratemaking process. Wind and solar have long been the beneficiary of tax credits at both the federal and state level. These credits have allowed the development of renewable resources and may continue to do so. I do not, however, propose that the ratemaking process itself be involved with the creation of new or the continuation of existing subsidies. The Act does not appear to emphasize a continuation of this practice either. Therefore, the new tariffs do not address externalities but instead endeavor to remove subsidies that may be created through the continuation of the existing net metering arrangement.

VI. Results from OG&E's proposed solution

Q. **Please explain how the existing tariffs and the NEBO and QF riders work together and how the proposed tariffs and riders work together.**

A. A current customer having DG facilities would choose between the current NEBO or QF rider and then pair it with a time differentiated tariff. See the chart below.

Chart 3 Rate Pairing Options



For customers who install DG facilities post November 1, 2014, their choice is between the NEBO-kW, RPPO, or the current QF rider, paired with R-TOU-kW or COM-TOU-kW.

Q. **The existing demand rates of PLTOU, LPLTOU, and PS-D-TOU are not reflected in the proceeding chart. How has their tariff pairings changed?**

A. They still have the flexibility of pairing with the existing riders of QF or NEBO, but also have the added option of pairing with RPPO.

Q. **What is the impact of these new pairings on typical residential DG customers?**

A. A current residential DG subscriber's, with a 4 kW rooftop solar system producing about 475 kWh per month, receives a bill reduction of approximately $43 a month. That same customer with the same DG facility under the proposed R-TOU-kW tariff would receive about a $28 per month reduction to their overall bill.

Q. **Do you believe this adjustment is appropriate?**

A. Yes. OG&E is still required to provide delivery and connection facilities for this customer to supply their electric service. When the customer reduced their kWh usage by 475 kWh, their monthly maximum demand did not change. The proposed arrangement eliminates the subsidy that existed under the current arrangement, as required by the Act.

Q. **What is the impact under the proposed arrangement if the customer did reduce their monthly maximum demand?**

A. If the residential customer reduces their maximum demand, they will receive full credit for their reduction. The AMI metering allows OG&E to measure customer's monthly maximum demand and provide customers full credit for any reductions to their monthly maximum demand. OG&E believes this is a preferable alternative to adopting a large fixed monthly customer charge. If OG&E were to recover the T&D functional cost through the monthly fixed charge, the monthly fixed charge would increase by about $21 a month for a typical customer. For a residential customer that successfully reduced their monthly demand, there would be a corresponding $2.68 per kW reduction on their bill.

Q. **Would you expect similar results for a commercial customer?**

A. Yes, typical commercial customers are about 50% larger than a typical residential customers but the impact to commercial customers is similar.

Q. **Will the DG customer be billed the demand associated with their customer usage or the demand associated with their maximum generation production?**

A. If information is available for both the maximum customer demand and the maximum generation demand, the maximum value shall be used for billing.

Q. **Are there any other tariff changes that will be required to incorporate the proposed tariffs?**

A. Yes, the standard purchase agreement ("SPA") will require minor revisions to the references of applicable tariffs (Exhibit RDW-10). The first update to the SPA is in Article II, part A. that provides the rate options for a DG customer. For Option 3, a note has been added stating that Option 3 is closed to new subscribers as of November 1, 2014. A fourth Option has been added to provide the NEBO-kW rate schedule. Also, a fifth Option has been added to provide the RPPO rate schedule. The second update to the SPA is that Article II, part D regarding reading meters and invoicing the Company is being eliminated.

VII. Addressing Issue Checklist

Q. **Are you aware of certain issues that have been brought to the attention of the Commission staff by interested parties?**

A. Yes, I am aware of certain issues brought forth to the Commission staff. I have attached the checklist of the concerns raised as Exhibit RDW-11.

Q. **Please describe the first issue listed on Checklist for DG Tariff Filings.**

A. The first issue addresses the class cost of service study ("COSS"), including computing unit costs by function, and incorporating a separate class for DG customers in the COSS.

OG&E computed unit costs by function for this filing using the compliance COSS from the 201100087 rate case. Since DG customers on OG&E's system are captured within the existing residential rate class, the unit cost for that class can be used to price DG service. A separate class within the COSS for DG customers is not needed at this time. OG&E will consider incorporating DG subclasses within its next COSS.

Q. **Does OG&E need a new COSS to price the proposed tariffs?**

A. No. The proposed tariff is intended to be a companion tariff to the currently effective residential and general service tariffs. It is appropriate to establish the proposed DG tariffs based on the same COSS used to establish the existing tariffs. When OG&E submits its next general rate case, a new COSS and revised tariffs for all classes including DG will be submitted.

Q. **Please describe the second issue: Governor's Order 2014-07.**

A. The Order stated that time of use rates, demand rates and minimum bills and unbundled rates should all be considered before increasing fixed monthly charges. OG&E believes all of these concerns have been considered and addressed in the tariffs that have been proposed. OG&E's proposal incorporates a time of use structure, a demand rate, and is, for all practical purposes, unbundled by functional cost component.

Q. **Please describe the third issue: Metering.**

A. Since OG&E has AMI installed for all customers, extensive metering information is available to support the proposed tariff designs. AMI metering provides interval data as well as demand data on all OG&E customers. Requiring metering of the DG gross output is desirable (and is a requirement for most QF facilities), but is not a requirement that must be met for NEBO customers or addressed in this Cause. A separate meter for DG customer's facility gross output would provide additional information that the customer, the Company and the Commission could use to evaluate the performance of the specific DG facility. However, not having a separate meter for all DG customers does not keep the proposed tariffs from meeting the needs set out in designing rates and rendering an appropriate customer bill.

Q. **Please describe the fourth issue: Additional Cost of DG Interconnection.**

A. I believe the current interconnection agreement is sufficient to address the cost concerns of safety and reliability. If a customer's facility requires additional investment by the Company to accommodate interconnection, the DG customer is responsible for paying the additional cost of interconnection[4]. If a DG facility connection is made by a customer to the OG&E system without notification, OG&E has the obligation to immediately disconnect that customer until the connection is compliant and an interconnection agreement has been executed.

Q. **The fifth issue addresses how the proposed rate design in this Cause will impact other customers. Please explain how OG&E's proposal affects other customers.**

A. In the short term, since fifteen DG customers will be affected by the tariff proposals I have submitted, the impact of reducing other customers' bills will be minimal. In the long term, the proposed tariffs should minimize any subsidy related to new DG customers.

Q. **The sixth concern relates to lost revenue. Please explain how OG&E's proposal addresses this issue.**

A. Because of the small number of affected DG customers (15 as of July 31, 2015), no lost revenue calculation was made. OG&E will address the lost net revenue issue in a future proceeding if needed.

Q. **Did you review the potential benefits listed as item number 8 on the checklist?**

A. Yes. After reviewing the checklist, OG&E believes the list of benefits have already been considered and where appropriate recognized in our proposal.

Q. **Please discuss how you evaluated the benefits listed on the checklist.**

A. OG&E has addressed the list as follows:

a) OG&E's avoided energy costs is the SPP integrated market price for energy.

---

[4] 165:35-29-2(c)

b) OG&E's avoided generating capacity cost is addressed in OG&E's most recent Integrated Resource Plan (2014 IRP Update). OG&E files its avoided capacity cost with the Arkansas Public Service Commission by June 30th of every even numbered year. An informational copy is provided to the Oklahoma Corporation Commission staff.

c) T&D line loss reduction has already been recognized and is reflected in retail rates. OG&E's most recent approved line loss study was performed on a 2012 annual period.

d) Environmental compliance benefits (and costs of compliance) are already incorporated in OG&E's capacity and energy costs. OG&E's future capacity and energy will incorporate all required environmental compliance costs. Therefore, the payments made to DG customers already include environmental benefits. There is no additional environmental compliance benefit.

e) OG&E believes any benefits from avoided purchased power risk are insignificant since avoided energy is available at the SPP market price. Power resources must compensate for the intermittent nature of wind and solar resources. Since the wind doesn't always blow and the sun doesn't always shine on the earth's surface, other resources are required to supplement solar and wind resources.

f) Regarding recognition of grid benefits or additional grid costs, OG&E has determined that benefits or costs are specific to each individual distribution circuit. OG&E believes it is inappropriate to provide a generic distribution circuit benefit to DG customers.

g) OG&E acknowledges there is economic benefit in growth but OG&E doubts that the benefit changes whether it is provided from OG&E supplied generation versus anything provided from distributed generation.

Q. **Please further discuss the avoided line losses.**

A. OG&E recognizes that line losses (whether at transmission, distribution, or at secondary voltages) are occurrences that exist on the network and should be considered in rate design. That is exactly what occurs in the rate making process. When power is displaced at a specific point on the system by a new generation source, what is delivered by the new source of power equals what is being displaced. It doesn't matter how far the power had to come to reach that point of delivery, it only matters that it is being compensated correctly at the delivery point. That occurs when service level rates are adjusted to reflect differences of voltage levels in rates. The following illustration demonstrates the difference in pricing at various service points on the OG&E system:

- Transmission Service Level 1 (above 50 kV) - $.035
- Distribution Service Level 3 (above 2 kV) - $.036
- Distribution Secondary Service (SL 5 below 2 kV) - $.037

If a customer can take service at any one of these points of delivery, they pay the price that is set for that specific point. So if their DG generation occurs at Service Level 5, they are compensated at SL 5 pricing; not at some other pricing point.

Q. **Please address the ninth issue, the effect of net exported kWh.**

A. OG&E addresses this issue through its QF and RPPO tariffs. Customers, who expect to sell their output to OG&E, should subscribe to the QF and RPPO tariffs and not the NEBO tariffs. Net metering has never been about building private generation that exceeds a customer's expected usage. OG&E offers other programs to address a DG customer's desire to sell kWh to the network: those programs are the QF riders.

However, to address the "effect" of net exported kWh, I have prepared Exhibit RDW-12 to reflect an estimate of the effect of net exported kWh for OG&E's Oklahoma NEBO customers that produce more kWh than they use. OG&E reviewed the data from its existing NEBO customers. Existing DG NEBO customers (approximately 68 customers) have over produced around 133,500 kWh a year for the last two years. Nearly a quarter of these kWh are associated with one customer. These uncompensated kWh were estimated to be worth between $.05 per kWh to $.07 per kWh. For the analysis, the uncompensated value per kWh of the exhibit was modeled at $.065 per kWh. This produces a yearly value of $8,700 not received by the DG customers. However, I also calculated the excess compensation received by these same customers from the net metering. I calculated excess compensation to be $.09 per kWh minus the estimated benefit of \$.065 per kWh which results in an excess value of \$.025 per kWh. When this \$.025 per kWh is applied to an average customer's estimated kWh usage, the customer excess compensation approaches \$320 annually per customer. Multiplying \$320 times 68 customers equals about \$21,700 per year of excess compensation. If the "excess compensation" of \$21,700 is compared to the "benefit not received" of \$8,700, the result is still favorable to the 68 customers of over \$13,000 per year.

These customers may choose between the NEBO and QF tariffs. If they desire to be paid for every kWh that they produce, they should choose the QF tariff or the new RPPO tariff.

Q. **Item 10 of the checklist refers to the benefits to safety/reliability due to DG. Do you believe there are benefits to safety due to DG?**

A. No. While new DG installations are required to meet certain standards set by the Standard Purchase Agreement and the National Electric Code (as enforced by the City or state) for DG installations behind the meter; some DG installations long term operational worthiness may suffer degradation. While some DG customers may have a robust routine of maintenance service and care, I believe others may not. This lack of maintenance and care by some DG customers may actually have some level of detrimental impact on safety. To the extent that recommended maintenance practices are not performed, some of the older installations may have some operational safety concerns.

Q. **What is your opinion on reliability benefits?**

A. I do not believe that a blanket endorsement or rejection concerning the benefits of reliability can be made about DG installations without a thorough investigation of each DG installation and its impact on the specific utility distribution circuit in which the DG installation is placed.

Based on the above, I believe it is inappropriate to include a blanket benefit in any evaluation for either safety or reliability.

Q. **What is your recommendation to the Commission?**

A. I recommend the Commission approve OG&E's proposed tariffs. I believe they are consistent with the Act and the Governor's Order and are fair to all customers.

Q. **Does this conclude your testimony?**

A. Yes, it does.

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

Exhibit RDW-2

FILED

APR 2 1 2014

OKLAHOMA SECRETARY OF STATE

Mary Fallin
Governor

EXECUTIVE DEPARTMENT
EXECUTIVE ORDER 2014-07

Today, I have signed into law Senate Bill 1456. This Bill amends Section 156 of Title 17 of the Oklahoma Statutes by requiring retail electric suppliers to bring a tariff application to the Oklahoma Corporation Commission to determine the appropriate way to account for the infrastructure cost of distributed generation.

The intent of this Bill is to constrain the Corporation Commission's consideration and approval of tariff applications with respect to distributed generation customers. This Bill does not mandate tariffs or other increases for distributed generation customers.

Therefore, I hereby order all executive agencies to implement this Bill in the following manner:

All executive entities shall support all forms of energy, including both traditional fossil fuels and renewable energy sources like wind and solar power, as outlined and mandated by the Oklahoma First Energy Plan. This plan promotes wind and solar power as important forms of clean energy which have a significant place in Oklahoma power generation. An essential element of this plan is distributed generation. Senate Bill 1456 must be construed in a manner that is consistent with the Oklahoma First Energy Plan.

Currently, approximately 350 Oklahoma individuals and businesses rely on distributed generation produced by small wind turbines or solar power generators. While these customers will not be affected by this Bill, this number will grow significantly in the future. This is an exciting development and one this Bill encourages.

The proper incorporation of distributed power generation will require strict scrutiny from the Corporation Commission. Appropriate implementation by executive entities will require strict compliance by the Corporation Commission in accord with the goals and intent of the Oklahoma First Energy Plan and this Bill.

This Bill requires the Corporation Commission to conduct a transparent evaluation of distributed generation consistent with the Oklahoma First Energy Plan. The intent of this Bill is to protect all Oklahoma customers and encourage all forms of Oklahoma energy use.

Further, this evaluation mandates inclusion of all stakeholders, including representatives of the solar and distributed wind industries, and utilities. Prior to implementation of any fixed charges, this Bill allows the Commission to consider the use of all available alternatives, including other rate reforms such as increased use of time-of-use rates, minimum bills, and demand charges. A proper and required examination of these and other rate reforms will ensure that Oklahoma

STATE CAPITOL BUILDING • 2300 N. LINCOLN BOULEVARD, SUITE 212 • OKLAHOMA CITY, OKLAHOMA 73105 • (405) 521-2342 • FAX: (405) 521-3353

appropriately implements the Oklahoma First Energy Plan while protecting future distributed generation customers.

This Executive Order shall be distributed to the Oklahoma Corporation Commission and the Secretary of Energy and Environment, who shall cause the provisions of this Order to be implemented as herein directed.

IN WITNESS WHEREOF, I have set my hand and caused the Great Seal of the State of Oklahoma to be affixed at Oklahoma City, Oklahoma, this 21st day of April, 2014.

BY THE GOVERNOR OF THE STATE OF OKLAHOMA

Mary Fallin

MARY FALLIN

ATTEST:

SECRETARY OF STATE

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

Original Sheet No. X.XX

Issued January X, XXXX

STANDARD PRICING SCHEDULE: COM-TOU-kW **STATE OF OKLAHOMA**
COMMERCIAL TIME-OF-USE KW DEMAND **Code No. xxT**

EFFECTIVE IN: All territory served.

AVAILABILITY: Alternating current service. This tariff is available for commercial Net Energy Billing Option (NEBO) customers that have become Renewable Distributed Generation ("DG") customers after October 31, 2014. This tariff is applicable to the customers that were previously served from the following tariffs: GS-TOU, GS-VPP, GS-CPP, OGP-ND-TOU, OGP-ND-VPP, PS-ND-TOU, PS-ND-VPP, PM-TOU, and PM-VPP.

No commercial, resale, breakdown, auxiliary, or supplementary service permitted.

APPLICATION OF FUEL COST ADJUSTMENT (FCA): The FCA_{on}, FCA_{off} and FCA_{w} as defined in the FCA rider shall apply to the energy components within this tariff as follows: The FCA_{on} shall apply to all On-Peak kWh sales; the FCA_{off} shall apply to all Off-Peak kWh sales; and, the FCA_{w} shall apply to kWh sales during the seven revenue months of November through May.

Customer Charge: $34.75 per customer per month.

Distribution & Transmission Max Demand Charge: $3.30 per kW per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.

On-Peak Hours: 18.75¢ per kWh per month. From June 1 through September 30, beginning each day at 2:00p.m. through 7:00 p.m. local time, excluding Saturdays, Sundays, Independence Day (as observed) and Labor Day.

Off-Peak Hours: 1.43¢ per kWh per month. All hours not defined as On-Peak hours.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.

All kWh per month: 1.43¢ per kWh.

Rates Authorized by the Oklahoma Corporation Commission:
(Effective) (Order No.) (Cause/Docket No.)
PUD 201500XXX

Public Utilities Division Stamp

DETERMINATION OF MAXIMUM DEMAND: The customer's Maximum Demand shall be the maximum rate at which energy is used for any period of 15 consecutive minutes of the month for which the bill is rendered as shown by the Company's demand meter.

LATE PAYMENT CHARGE: A late payment charge in an amount equal to 1.5 percent of the total balance for services and charges remaining unpaid on the due date stated on the bill shall be added to the amount due. The due date as stated on the bill shall be 20 days after the bill is issued.

MINIMUM BILL: The minimum monthly bill shall be the Customer Charge plus the Transmission and Distribution Maximum Demand Charges plus any applicable fees and taxes.

The Company shall specify a larger minimum monthly bill, calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission, when necessary to justify the investment required to provide service.

FRANCHISE PAYMENT: The above stated rates do not include any amount for franchise payments levied upon the Company by a municipality.

When a municipality, by a franchise or other ordinance approved by the qualified electors of the municipality, levies or imposes upon the Company franchise payments or fees (based upon a percent of gross revenues) to be paid by the Company to the municipality, such franchise payment will be added as a percentage of charges for electric service to the bills of all customers receiving service from the Company within the corporate limits of the municipality exacting said payment.

RIDERS: All applicable riders apply. Please refer to the Applicability section of individual Riders to determine if it is relevant to this Pricing Schedule.

TERM: One Year.

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

Original Sheet No. X.XX

Issued January X, XXXX

STANDARD PRICING SCHEDULE: R-TOU-KW **STATE OF OKLAHOMA**
RESIDENTIAL TIME-OF-USE KW DEMAND **Code No. xxT**

EFFECTIVE IN: All territory served.

AVAILABILITY: Alternating current service for all customer classes that is available to all domestic use in a residence or apartment dwelling unit. This tariff is available to Residential Net Energy Billing Option (NEBO) customers that have become Renewable Distributed Generation ("DG") customers after October 31, 2014.

No commercial, resale, breakdown, auxiliary, or supplementary service permitted. Where existing duplexes or apartment houses are served through one meter under this rate, the blocks of this rate shall be multiplied by the number of apartments in the building. Rooming houses in which more than 50 percent of the rooms are held for rent shall not be served under this schedule but under the General Service Rate, except when the number of such rooms for rent is four or less, a single application of this schedule shall apply.

APPLICATION OF FUEL COST ADJUSTMENT (FCA): The FCA_{on}, FCA_{off} and FCA_{w} as defined in the FCA rider shall apply to the energy components within this tariff as follows: The FCA_{on} shall apply to all On-Peak kWh sales; the FCA_{off} shall apply to all Off-Peak kWh sales; and, the FCA_{w} shall apply to kWh sales during the seven revenue months of November through May.

Customer Charge: $18.00 per customer per month.

Distribution & Transmission Max Demand Charge: $2.68 per kW per month.

Energy Charge:

Summer Season: The five OG&E Revenue Months of June through October.

On-Peak Hours: 17.3¢ per kWh per month. From June 1 through September 30, beginning each day at 2:00p.m. through 7:00 p.m. local time, excluding Saturdays, Sundays, Independence Day (as observed) and Labor Day.

Off-Peak Hours: 1.37¢ per kWh per month. All hours not defined as On-Peak hours.

Winter Season: The seven OG&E Revenue Months of November through May of the succeeding year.

All kWh per month: 1.37¢ per kWh.

DETERMINATION OF MAXIMUM DEMAND: The customer's Maximum Demand shall be the maximum rate at which energy is used for any period of 15 consecutive minutes of the month for which the bill is rendered as shown by the Company's demand meter.

LATE PAYMENT CHARGE: A late payment charge in an amount equal to 1.5 percent of the total balance for services and charges remaining unpaid on the due date stated on the bill shall be added to the amount due. The due date as stated on the bill shall be 20 days after the bill is issued.

MINIMUM BILL: The minimum monthly bill shall be the Customer Charge plus the Transmission and Distribution Maximum Demand Charges plus any applicable fees and taxes.

The Company shall specify a larger minimum monthly bill, calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission, when necessary to justify the investment required to provide service.

FRANCHISE PAYMENT: The above stated rates do not include any amount for franchise payments levied upon the Company by a municipality.

When a municipality, by a franchise or other ordinance approved by the qualified electors of the municipality, levies or imposes upon the Company franchise payments or fees (based upon a percent of gross revenues) to be paid by the Company to the municipality, such franchise payment will be added as a percentage of charges for electric service to the bills of all customers receiving service from the Company within the corporate limits of the municipality exacting said payment.

RIDERS: All applicable riders apply. Please refer to the Applicability section of individual Riders to determine if it is relevant to this Pricing Schedule.

TERM: One Year.

OKLAHOMA GAS AND ELECTRIC COMPANY
P. O. Box 321
Oklahoma City, Oklahoma 73101

1st Revised Sheet No. XXXX
Original Sheet No. XXX
Date Issued XXXX XX, 2015

STANDARD PRICING SCHEDULE: NEBO-kW **STATE OF OKLAHOMA**
NET ENERGY BILLING OPTION-kW DEMAND RIDER

EFFECTIVE IN: All territory served.

DEFINITIONS:

Net Energy - for the purpose of the NEBO-kW rider, Net Energy shall be defined as the difference of energy produced by the site specific Renewable Distributed Generation ("DG") facility less the energy consumed by the TOU-kW customer located at that same site by time period as defined in the applicable TOU-kW tariff.

AVAILABILITY:

The NEBO-kW Rider is applicable to customers that installed DG facilities on or after November 1, 2014 that take service under the R-TOU-kW or COM-TOU-kW tariffs, and have installed a DG facility and signed a Standard Interconnection Agreement for Net Energy Facilities with the Utility. Such facilities must be located on the customer's premise and intended primarily to offset some or all of the customer's energy usage at that location. NEBO-kW Rider is also available for PL-TOU, LPL-TOU, PS-D-TOU customers (regardless of install date) that request to be placed on the rider. Customer's usage may not be aggregated from multiple usage points to qualify for kWh offsets under this tariff.

DG subscribers who installed renewable generation prior to November 1, 2014 may elect to subscribe to this tariff.

The NEBO-kW is available to all qualifying small power producers who installed DG facilities on or after November 1, 2014 and:

1a) Are Commercial, Industrial, or Public Authority Customers who have an annual energy output of 1,000,000 kWh or less and a generator nameplate rating of 300 kW or less. The energy producer shall provide at OG&E's request engineering evidence documenting the annual energy output calculation; or

1b) Are Residential customers who have an annual energy output of 200,000 kWh or less and a generator nameplate rating of 100 kW or less. Net energy producer shall provide at OG&E's request engineering evidence documenting the annual energy output calculation; and

2) Employ equipment compatible with the particular OG&E line segment providing service to the Net Energy premise; and

3) Sign the Company's Standard Electricity Purchase Agreement (PA) for Small Power and Cogeneration Facilities Standard Interconnection Agreement for Net Energy Facilities as attached to this tariff; and

4) Have kWh generation output metered in a manner that provides adequate billing data to provide compliance with the billing provisions of the NEBO-kW rider. Failure to provide adequate billing determinant information shall constitute sufficient grounds for refusing customer's the right to participate in billing under the NEBO-kW rider. Metering for NEBO-kW customers shall, where practical, provide total monthly customer usage information and DG facility output production information to the Company. This information may require additional metering (a second meter) or some equivalent wiring configurations to render such information available to the Company

Customers may not take service under this tariff and simultaneously take service under the provisions of any other alternative source generation or co-generation tariff.

To avoid circuit operational concerns, OG&E retains the right to limit the total number of DG energy producing locations occurring on any individual distribution circuit or individual distribution substation.

MONTHLY BILLING:

On a monthly basis, the TOU-kW customer shall be billed the applicable charges under their standard TOU-kW (either R-TOU-kW tariff, COM-TOU-kW tariff, PLTOU tariff, LPLTOU tariff, or PS-D-TOU tariff whichever is applicable) rate schedule and any applicable rider schedules. Customer usage as determined by the annual billing period before the customer became a NEBO-kW customer shall be used in determination of the applicable standard TOU-kW tariff used for the customer's billing. The NEBO-kW rider is not a bill, but used in association with the customer's base TOU-kW tariff or existing demand TOU tariffs and will render a credit to their energy usage.

If the kWh supplied by the electric utility to the NEBO-kW customer exceeds the energy provided by the net energy facility during the monthly billing period, the NEBO-kW customer shall be billed for the net kWh supplied by the electric utility in accordance with the rates and charges under the applicable TOU-kW rate schedule.

If the electricity generated by the NEBO-kW customer by TOU period exceeds the electricity consumed by the net energy customer during the same TOU period for the billing month, the customer shall not receive any compensation for excess net energy kWh produced by the DG facility above the customer's monthly usage level.

MINIMUM BILL:

The kWh credit rendered from the NEBO-kW rider and applied to the customer's applicable base bill shall not reduce the customer's total TOU-kW bill to a level less than the applicable franchise fees; local, state, or federal income taxes; applicable tariff or rider charges; monthly customer charges; meter charges (if any); and applicable demand charges.

TERM: One Year.

STANDARD PURCHASE RATE SCHEDULE
FOR PRODUCERS OF 300 kW OR LESS

EFFECTIVE IN: All territory served.

AVAILABILITY: The standard optional purchase rate set forth in this tariff shall be available by request to all qualifying cogenerators and qualifying small power producers who:

1) Have a maximum rated capacity of 300 kW or less; AND

2) Employ equipment compatible with the particular line segment of the Company to which they are connected; AND

3) Sign the Company's Standard Electricity Purchase Agreement (PA) for Small Power and Cogeneration Facilities as attached to this tariff.

A Producer, as defined in the Standard Terms and Conditions of Purchase from Producers of 300 kW or Less (Standard Terms and Conditions), may sell the gross production of energy from the generating unit under the following purchase rate provisions.

PURCHASE RATE:

A Producer shall have the option to sell the energy produced from their qualifying generation facility under the following Time Differentiated Purchase option.

Time Period definitions:

On Peak hours are defined as the hours from 2:00 p.m. until 7:00 p.m., June 1 through September 30, except Saturdays, Sundays, Independence Day (as observed) and Labor Day.

Off-Peak hours are defined as all other hours of the year.

Time Differentiated Purchase Rates:

A Producer electing this tariff shall be paid as follows:

Service Level 5 On Peak Price:

Applies to energy produced during the On Peak hours.

On Peak kWh Price for secondary voltage delivery = 14.7¢ per kWh

Service Level 5 Off Peak Price:

Applies to energy produced during the Off Peak hours.

Off Peak kWh Price for secondary voltage delivery = 4.6¢ per kWh

Other Service Level Prices:

Power delivered at another service level will have the purchase price reduced by an adjustment for losses.

TERM: One Year.

TERMS AND CONDITIONS:
The Terms and Conditions associated with this tariff are set forth in the Standard Terms and Conditions adopted by the Commission in its Order No. 326195 issued in Cause No. 27208 and the Company's Terms and Conditions as the same may be from time-to-time amended and which are incorporated herein by reference.

Separate metering must be installed to measure the entire output of the qualifying facility and the entire production must be sold to the utility.

DESIGN, OPERATION AND MAINTENANCE DATA: In addition to the requirements of the Standard Terms and Conditions, the Producer shall maintain (1) a diary of the facility including installation date, date and nature of any changes, non-routine maintenance and repair, and the date and reason for any extended periods of non-generation, and (2) such other information as is reasonably necessary to evaluate the facility and its potential impact on the electrical system. The

Producer shall make such records available and to the Company and to the Commission upon the request of either party.

RIGHTS OF PRODUCER: The Producer has the right:

1) To generate in parallel with the Company in a manner which does not degrade the integrity of the Company's system. The Company shall make reasonable effort to operationally accommodate the Producer's facility;

2) To good faith negotiation with the Company; AND

3) To bring complaint or dispute to the Commission for mediation, hearing or other resolution.

MODIFICATIONS: The Standard Purchase Agreement, Purchase Rate Schedules and Conditions of Purchase may be changed from time-to-time as approved by the Commission. The purchase rates will change as additional information becomes available on avoided costs, reliability of technologies and other pertinent factors.

OKLAHOMA GAS AND ELECTRIC COMPANY
COST OF SERVICE UNIT COST CALCULATION
Residential - Service Level 5 From Cause 201100087

Row	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	Unit Cost Components	Revenue Requirement		Unit Cost Components	Revenue Requirement	Units		Revenue Collection from Proposed Rates
1	Total Customer Component	$ 143,530,213		PD (Excess Component)	$ 130,315,519			
2	Total Energy Component	$ 258,883,034		PD (Avg Component)	$ 94,693,061			
3	FCA Embedded Removal	$ 239,262,300	Exclude FCA from Total Energy Comp.	Trans Demand	$ 60,073,523			
4	Adjusted Energy Component	$ 19,620,734		Dist Demand	$ 87,229,768			
5	Total of Cust. and Adj Energy	$ 163,150,947		Total Demand Component	$ 372,311,871			
6				(Row 5) - (Col 5 + Col 2)	$ 535,462,818			
7				Customer Misc. Revenue	$ 11,138,740			
8				Adj Total Rev	**$ 524,324,078**			

Row		Annual Billing Units	Miscellaneous Revenue	Revenue Requirement	Revenue Req. Less Misc. Revenue	Unit Cost Price for Component	Units	Proposed Rates	Revenue Collection
9	Cust. Charge Calculation	7,371,480	$ 11,138,740	$ 143,530,213	$ 132,391,473	$ 17.96	Per Month	$ 18.00	$ 132,686,640
10	On Peak kWh (PD Excess)	821,039,719	$ -	$ 130,315,519	$ -	$ 0.15872	Per kWh*	$ 0.1730	$ 142,039,871
11	All kWh (PD Average)	8,250,424,150	$ -	$ 94,693,061	$ -	$ 0.01148	Per kWh		
12	Non Fuel Energy Charge	8,250,424,150	$ -	$ 19,620,734	$ -	$ 0.00238	Per kWh	$ 0.01370	$ 101,782,567
13	Trans. and Dist. Dmd Charge	55,169,772	$ -	$ 147,303,291	$ -	$ 2.67	Per kW**	$ 2.68	$ 147,854,989
14								Total	**$ 524,364,067**

Notes:

* From Customer Data an On Peak kWh Split of 20.3% to 79.7% Off Peak kWh for Summer Season.

** From Customer Data, a Monthly Max Demand rate developed from T&D Rev Req to create a Maximum T&D Demand rate per kW.

*** On Peak Charge = On PD Excess + PD Avg + Non Fuel Energy = $.1726; Off Peak = PD AVG + Non Fuel Energy = $.01386

OKLAHOMA GAS AND ELECTRIC COMPANY
COST OF SERVICE UNIT COST CALCULATION
General Service - Service Level 2,3,4,5 From Cause 201100087

Row	Column 1 Unit Cost Components	Column 2 Revenue Requirement	Column 3	Column 4 Unit Cost Components	Column 5 Revenue Requirement	Column 6 Units	Column 7	Column 8 Proposed Rate Rev. Collection
1	Total Customer Component	$ 31,607,178		PD (Excess Component)	$ 24,034,552			
2	Total Energy Component	$ 47,022,916		PD (Avg Component)	$ 17,511,283			
3	FCA Embedded Removal	$ (43,199,878)	Exclude FCA from Total Energy Comp.	Trans Demand	$ 10,883,962			
4	Adjusted Energy Component	$ 3,823,038		Dist Demand	$ 16,549,055			
5	Total Customer and Adj Energy	$ 35,430,216		Total Demand Component	$ 68,978,852			
6				(Row 5) - (Col 5 + Col 2)	$ 104,409,068			
7				Customer Misc. Revenue	$ 721,567			
8				Adj Total Rev	**$ 103,687,501**			

Row		Annual Billing Units	Miscellaneous Revenue	Revenue Requirement	Revenue Req. Less Misc. Revenue	Unit Cost Price for Component	Units	Proposed Rates	Revenue Collection
9	Cust. Charge Calculation	889,044	$ 721,567	$ 31,607,178	$ 30,885,611	$ 34.74	Per Month	$ 34.75	$ 30,894,279
10	On Peak kWh (PD Excess)	138,850,429	$ -	$ 24,034,552	$ -	$ 0.17310	Per kWh*	$ 0.1875	$ 26,034,455
11	All kWh (PD Average)	1,489,650,978	$ -	$ 17,511,283	$ -	$ 0.01176	Per kWh		
12	Non Fuel Energy Charge	1,489,650,978	$ -	$ 3,823,038	$ -	$ 0.00257	Per kWh	$ 0.0143	$ 19,316,448
13	Trans. and Dist. Dmd Charge	8,312,561	$ -	$ 27,433,017	$ -	$ 3.30	Per kW**	$ 3.30	$ 27,431,453
14								Total	**$ 103,676,635**

Notes:

* From Customer Data an On Peak kWh Split of 19.3% to 80.7% Off Peak kWh for Summer Season.

** From Customer Data, a Monthly Max Demand rate developed from T&D Rev Req to create a Maximum T&D Demand rate per kW.

*** On Peak Charge = On PD Excess + PD Avg + Non Fuel Energy = $.1874; Off Peak = PD AVG + Non Fuel Energy = $.01433

CLOSED TO NEW ENROLLMENT OF PRODUCERS

This rider is closed to new QF installations and producers. Producers requesting service on or after November 1, 2014 are not eligible for this rider. Only producers on demand tariffs and existing QF installations (prior to November 1, 2014) on non-demand tariffs are eligible for continued enrollment under this rider. Continued enrollment under this rider is not transferrable to new owners of an existing QF facility on or after November 1, 2014.

STANDARD RATE SCHEDULE FOR NET ENERGY BILLING OPTION (NEBO) FOR PRODUCERS OF 300 kW OR LESS

EFFECTIVE IN: All territory served.

DEFINITIONS:

Net Energy - for the purpose of the NEBO rider, net energy shall be defined as the difference of energy produced by the site specific net energy producing facility less the energy consumed by the customer located at that same site.

AVAILABILITY:

NEBO customers must take service under their applicable TOU rate schedule, and have installed a Net Energy producing facility and signed a Standard Interconnection Agreement for Net Energy Facilities with the Utility. Such facilities must be located on the customer's premise and intended primarily to offset some or all of the customer's energy usage at that location. Customer's usage may not be aggregated from multiple usage points to qualify for kWh offsets under this tariff. Monthly energy produced from the net energy producing facility that is greater than the customer's monthly consumption shall not receive compensation by the utility.

Customers may not take service under this tariff and simultaneously take service under the provisions of any other alternative source generation or co-generation tariff.

OG&E retains the right to limit the total number of Net Energy locations occurring on any individual distribution circuit or individual distribution substation due to possible operational concerns.

The Net Energy Billing Option is available to all qualifying small power producers who:

1a) Are Commercial, Industrial, or Public Authority Customers who have an annual energy output of 1,000,000 kWh or less and a generator nameplate rating of 300 kW or less. The energy producer shall provide at OG&E's request engineering evidence documenting the annual energy output calculation;

1b) Or are Residential customers who have an annual energy output of 200,000 kWh or less and a generator nameplate rating of 100 kW or less. Net energy producer shall provide at OG&E's request engineering evidence documenting the annual energy output calculation;

2) Employ equipment compatible with the particular OG&E line segment providing service to the Net Energy premise;

3) Sign the Company's Standard Electricity Purchase Agreement (PA) for Small Power and Cogeneration Facilities as attached to this tariff; AND

4) Have kWh generation output metered in a manner that provides adequate billing data to provide compliance with the billing provisions of the Net Energy tariff. Failure to provide adequate billing determinant information shall constitute sufficient grounds for refusing customer's the right to participate in billing under the NEBO tariff.

Subscribers to OG&E standard TOU rate schedules other than those previously listed who want to be considered for NEBO service must make that request in writing to their OG&E Service Representative. Final selection and participation of these additional TOU tariffs shall be at the sole discretion of OG&E.

MONTHLY BILLING:

On a monthly basis, the NEBO customer shall be billed the applicable charges under their standard TOU rate schedule and any applicable rider schedules. Annual customer usage as determined by the annual billing period before the customer became a NEBO customer shall be used in determination of the applicable standard TOU tariff used for the customer's billing. Under NEBO, only the kilowatt-hour (kWh) portion of a customer's standard TOU bill are affected.

If the kWh supplied by the electric utility to the NEBO customer exceeds the energy provided by the net energy facility during the monthly billing period, the NEBO customer shall be billed for the net kWh supplied by the electric utility in accordance with the rates and charges under OG&E's standard applicable TOU rate schedule.

If the electricity generated by the net energy customer exceeds the electricity consumed by the net energy customer during the monthly billing period, the customer shall not receive any compensation for excess net energy kWh produced by the Net Energy facility above the customer's monthly usage level.

PURCHASE PRICE:

Purchased price for Net Energy shall be credited against the time-differentiated energy portion of the customer's bill at the applicable TOU Seasonal or hourly TOU kWh pricing of the customer's Standard TOU bill.

MINIMUM BILL:

A NEBO customer's total monthly billing shall not be less than applicable franchise fees; local, state, or federal income taxes; applicable tariff or rider charges; monthly customer charges; meter charges (if any); and applicable demand charges.

TERM: One Year.

Exhibit RDW-10

STANDARD ELECTRICITY PURCHASE AGREEMENT
FOR
SMALL POWER AND COGENERATION FACILITIES
(300 Kilowatts or Less)

This agreement made this ____ day of____________, 20___, between Oklahoma Gas and Electric Company, hereinafter referred to as the "Company", and ______________________, hereinafter referred to as the "Producer."

ARTICLE I
PURPOSE OF AGREEMENT

A. Producer intends to own and/or operate an electric generating facility using fuels derived from biomass, waste or renewable energy source, including wind, solar energy, or water to produce electricity, or a cogeneration facility having a maximum rated electrical output of 300 kW or less. Producer desires to operate such generation parallel with the Company's system and sell a portion or all of the electricity produced to the Company. The Company has no direct financial involvement in the investment, construction, operation or maintenance of Producer's generation facility. The Producer has notified its insurance carrier of the existence of this generator installation. A copy of this notification is attached to this agreement as Appendix "A".

B. Producer's generating facility is located_________________________________and will be ready to produce and either deliver electricity for sale or operate in parallel with the Company's system on or about_________.

C. Producer's generating facility is described as:
Make______________, Model___________, Serial No.___________,
fuel or energy source______________, and having a nominal output rating of_______kW, volts,______phase, 60 Hertz.

D. The Company is willing to permit Producer to operate its generating facility in parallel with Company's system for the purpose of either delivering of self-consuming electricity produced. The Company will provide supplemental and/or standby services to the Producer in accordance with tariffs approved by the Oklahoma Corporation Commission.

E. The Standard Terms and Conditions of Purchase from Producers of 100 kW or Less (Standard Terms and Conditions), as approved by the Oklahoma Corporation Commission in Order No. 326195 in Cause No. 27208, are incorporated by reference in this Agreement. Any changes or modifications to this Agreement shall require specific approval of the Commission as provided in OAC 165:40-1-4 of the Standard Terms and Conditions of Purchase for Producers of 100 kW or less, which are consonant with the Commission's Standard Terms and Conditions, as approved by the Commission are also incorporate by reference in this Agreement.

F. Each Party hereto shall indemnify and save the other Party harmless from any loss of damage to the facilities of the said other Party due to the sole negligence of said Party, provided however, that the Producer shall provide, install and maintain at its own expense all electrical wiring and apparatus, including any protective equipment, required either by the National Electric Code and/or the applicable municipal code and with all requirements prescribed by any governmental authority having jurisdiction thereof, and compliance with such duty shall be a condition to liability of the Company under this indemnity.

Neither Party is liable for revenue loss resulting from interruption or partial interruption of service.

Should the Producer dispute the interpretation by the Company of the requirements of the National Electrical Code and/or any applicable municipal code, such Producer may request the dispute be resolved by the Commission.

The Company reserves the right to refuse to connect to any wiring or apparatus which does not meet these requirements and the Company may, without advance notice, discontinue its connection with any Producer's wiring or apparatus when a dangerous condition of wiring or equipment upon the premises of the Producer is discovered.

ARTICLE II
RATE

A. The Producer hereby selects the following Rate Option for the term of this Agreement by placing his/her initials in the space provided for the Rate Option selected and by lining through those Rate Options which are not selected:

____ OPTION 1:
Initials

Producer hereby elects to provide Firm Energy to the Company and to be paid Purchase Rate Number 1 as set forth in Rate Schedule QF which is attached hereto as Appendix

"B". Firm Energy means energy delivered to the Company with at least a 25 percent on-peak season capacity factor as the on-peak season is defined in Rate schedule QF. In selecting this option, the Producer understands it has the obligation to deliver Firm Energy to the Company. Failure to meet this capacity factor shall result in the penalty specified in Appendix "B".

____ OPTION 2:
Initials

Producer hereby elects to provide as delivered energy and to be paid therefore at the Seasonal Purchase Rate (Purchase Rate Number 2) as set forth in Rate Schedule QF which is attached hereto as Appendix "B".

____ OPTION 3:
Initials

Producer hereby elects to be paid for energy delivered to the Company on a Net Energy Billing basis as set forth in Rate Schedule NEBO which is attached hereto as Appendix "B". Note that NEBO is closed to new subscribers as of November 1, 2014.

Comment [CG1]: AT

____ OPTION 4:
Initials

Producer hereby elects to be compensated for energy delivered to the Company on a Net Energy Billing basis as set forth in Rate Schedule NEBO-kW which is attached hereto as Appendix "B".

Comment [CG2]: AT

____ OPTION 5:
Initials

Producer hereby elects to deliver energy and to pay therefore at the Time Differentiated Purchase Rate as set fourth in Rate Schedule RPPO which is attached hereto as Appendix "B".

Comment [CG3]: AT

B. Power and energy delivered to the Producer by the Company as well as any standby services provided shall be sold under the provisions of the Company's applicable rate schedules.

C. Billing for electric purchases by the Company shall be accomplished in the same manner as billing for electric service sold to the Producer. Invoices for purchases shall be prepared by the Company and submitted at the same time to the Producer as a separate statement or as a separate item on the bill for electric service.

~~D. If the Producer selects OPTION 1 or OPTION 2, purchase meters shall be read by the Producer on the last business day of each month. The Producer shall prepare and submit an invoice to the Company within ten (10) days of the meter reading date, and the Company shall make payment within its usual payment cycle.~~

Comment [CG4]: DT

ARTICLE III
MISCELLANEOUS PROVISION

A. Term - This Agreement shall become effective on completion of the installation of facilities required for parallel operation and shall remain in effect for a period of one year. At the end of the primary term and for each succeeding year thereafter, this Agreement shall be automatically renewed for a period of one year unless canceled or terminated by instructions or direction of the Commission; provided, however, that the Producer may terminate this Agreement at any time by giving thirty (30) days written notice of its intent to terminate to the Company. Producer shall not terminate this Agreement for the purpose of selecting a new or different Rate Option except at the end of the primary term or at the end of any subsequent year.

B. Installation of facilities required for parallel operation shall be deemed to be complete when the Company provides the Producer with its written consent to commence parallel operation.

C. The following appendices, which are attached to this Agreement, are incorporated herein by reference:

Appendix A - Copy of Insurance Carrier Notification

Appendix B - Rate Option

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed by their duly authorized representatives on the day and year first above set forth.

____
Producer

By ______________________________

Title ______________________________

~~ATTEST:~~ ______________________________

RT

______ ~~Title~~ ______________________________

____
~~Secretary~~

OKLAHOMA GAS AND ELECTRIC COMPANY

By ______________________________

Title ______________________________

RT

FOR COMPANY USE ONLY

~~ATTEST:~~ ______ ~~Title~~ ______________________________

____

______ ~~Secretary~~

______________________________ UNIQUE NUMBER ______________________________

~~FOR COMPANY USE ONLY~~

~~UNIQUE NUMBER~~______________________________

		Checklist for Distribution Generation Tariff Filings	Governor's Executive Order 2014-07			Senate Bill 1456			
			Protect all	Encourage all forms	Evaluate optional rates	Actual Fixed Cost	Full cost only	No Subsidizies within classes	Higher fixed charge for participants
		Distributed Generation - Items to be included in Tariff Application							
		How to measure subsidies:							
		Costs:							
	1	**Class Cost of Service Study**							
		a) Separate class for Distributed Generation(DG) customers							
		b) unit costs to unbundle functions and allocation reporting							
	2	**) Rate Design - Governors order 2014-07 (SB 1456) - consider rates before increasing fixed charge**							
		a) Time of Use (TOU) rates							
		b) Demand rates							
		c) minimum bills							
		d) unbundled rates - separate charges for customer,delivery, supply							
	3	**Metering**							
		a) Metered loads before/after DG installation							
		b) Demand/interval readings available from installed meters?							
		c) Separate meter for DG installation							
*	4	**Additional Costs of DG - Interconnection cost due to Safety & Reliability**							
	5	**Impact of rate design proposal on other customers**							
	6	**Lost revenue calculation due to DG for both demand and non-demand DG customers**							
		a) workpapers showing lost revenues over last three years as percent of total revenues							
		b) projected lost revenues with proposed rate design changes							
	7	**Lost revenue calculation due to Energy Efficiency (Demand Programs)**							
		a) workpapers showing lost revenues as percent of total revenues							
		Benefits:							
	8	**Benefits Study (high,medium,low scenarios when specifics are unknown)**							
		a) avoided energy cost							
		b) avoided generating capacity costs							
		c) Transmission & Distribution (T&D) line loss reduction (avoided transmission/distribution investment)							
		d) Environmental benefits (emission mitigation costs)							
		e) avoided purchased power/risk							
		f) avoided grid support							
		g) Economic development							
	9	**Effect of net exported kWhs - no carryover - with existing rate**							
		a) how many kWhs are net exports (aborbed and receive no credit)							
		b) revenue received by utility for excess kWhs sold							
		c) value of excess kWh - avoided costs							
**	10	**Benefits to safety/reliability due to Dg.**							

Changes from initial distribution:

* 4 ***Description modified to clarify additional safety/reliability costs due to interconnection of DG***

** 10 ***Item added to reflect the safety/reliability benefits that occur to the system due to DG.***

Benefit/Cost Calculation for DG Customers with Excess Generation
(Using Approximate Average Customer Sizes)

	Description	# of DG Customers with Excess Generation	Approximate 2-year Total Activity	Estimate of 2-Year Per Cust Total kWh	Annualized kWh Average per Customer
1	kWh from OG&E to Customer	68	152,303	2,240	1,120
2	kWh from Customer to OG&E	68	419,206	6,165	3,082
3	Non Comp kWh from Cust to OG&E	68	266,926	3,925	1,963
4	Annual Non Comp kWh from Cust to OG&E	68	133,463	1,963	

4	Approximate Average Cust Usage	Annual kWh	Supplied by OG&E	Not Supplied by OG&E	Assume Present DG Customer Compensation @ $.09 per kWh	$ Value of Excess Cust Comp of $.025 per kWh for DG Supplied by Cust	Estimated Compensation at Non-Subsidized Price per Cust
	Residential Annual	13,000	1,120	11,880	$ 1,069	$ 297	$ 772
	Commercial Annual	20,000	1,120	18,880	$ 1,699	$ 472	$ 1,227
	Weighted Average	13,916	1,120	12,796	$ 1,152	$ 320	$ 832

5	Favorable Benefit for DG Customer with Excess Generatiopn under Current Net Metering Billing	Estimated Compensation at Non-Subsidized Price per Cust	$ Value of Non Compensated kWh @ $.065	$ Value of Excess Cust Comp of $.025 per kWh for DG Supplied by Cust	Approx per cust Benefit Subtracting Non Comp $ From Excess Compensated $	# of DG Customers with Excess Generation	Favorable Total Benefit To DG Customers with Excess Generation
a	Residential Annual	$ 772	$ 128	$ 297	$ 169	68	$ 11,521
b	Commercial Annual	$ 1,227	$ 128	$ 472	$ 344	68	$ 23,421
c	Weighted Average	$ 832	$ 128	$ 320	$ 192	68	$ 13,078

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

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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 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

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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

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

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.

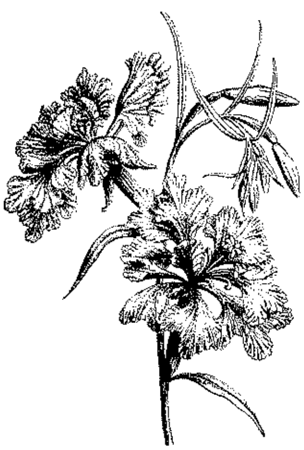
If the distributor, in recognition of solar's intermittency, instead chooses to hedge against the risk of solar's unavailability, the cost of the hedge is likewise passed on to all customers rather than simply those whose supply unpredictability caused the cost to be incurred. Both of these forms of 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.

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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

  http://dx.doi.org/10.1016/j.tej.2014.11.005

Rooftop Solar Remains the Most Expensive Form of Electricity Generation

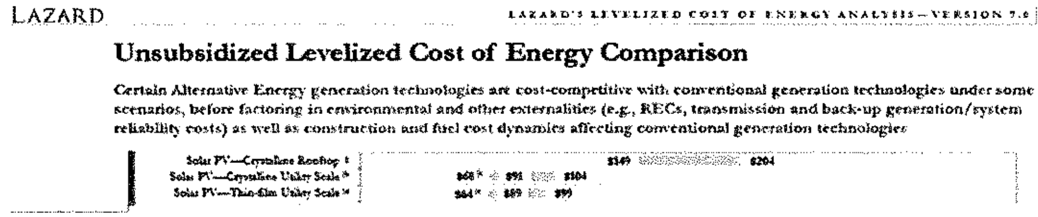


Figure 1: Rooftop Solar Remains the Most Expensive Form of Electricity Generation

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

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

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

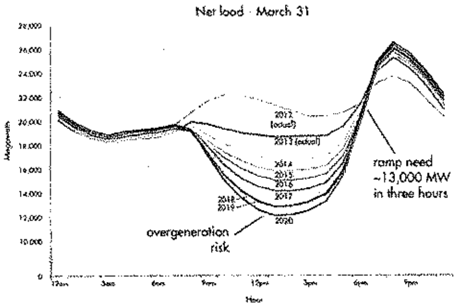
	SolarCurrents (Phase 1)	SolarCurrents (Phase 2)	Funding Mechanism
Up-front solar subsidy	$2.40/W	$0.20/W	Renewable Surcharge
On-going solar subsidy	$0.11/kWh	$0.03/kWh	Renewable Surcharge
Net metering subsidy (unrecovered fixed cost)	$0.09/kWh	$0.09/kWh	*Unrecovered fixed costs are funded by non-solar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

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

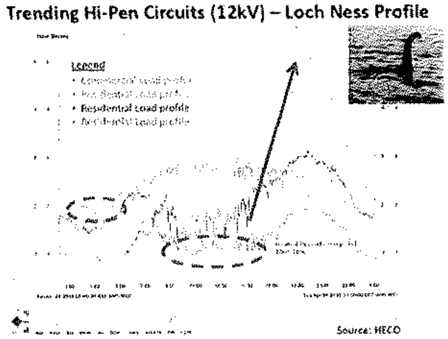
The Duck Curve - California



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

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

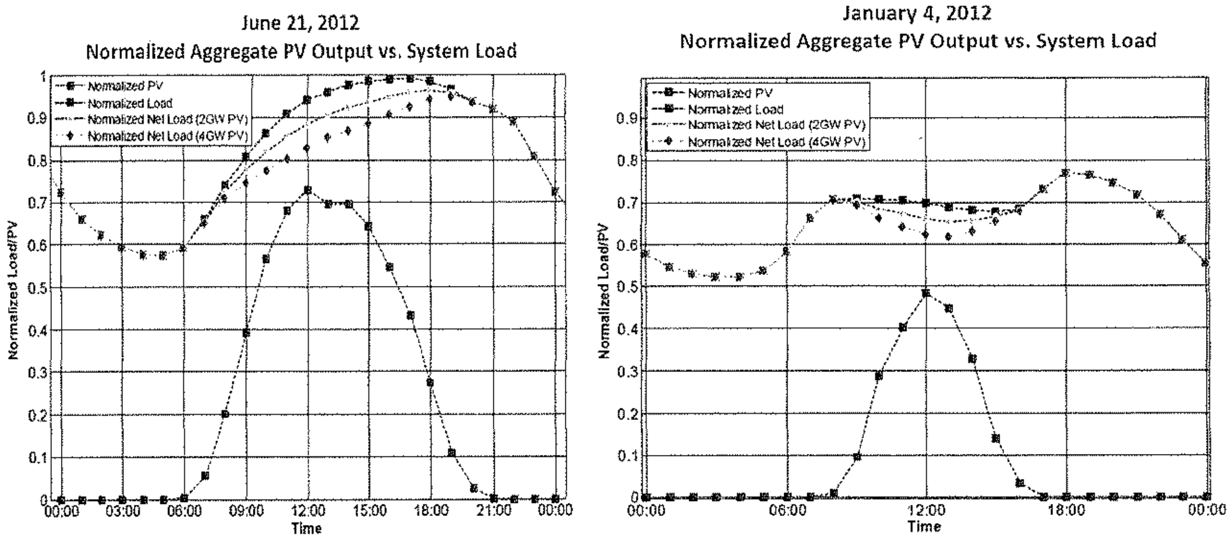


Figure 3: Lack of Coincidence of Solar Production and Peak Demand in New England

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

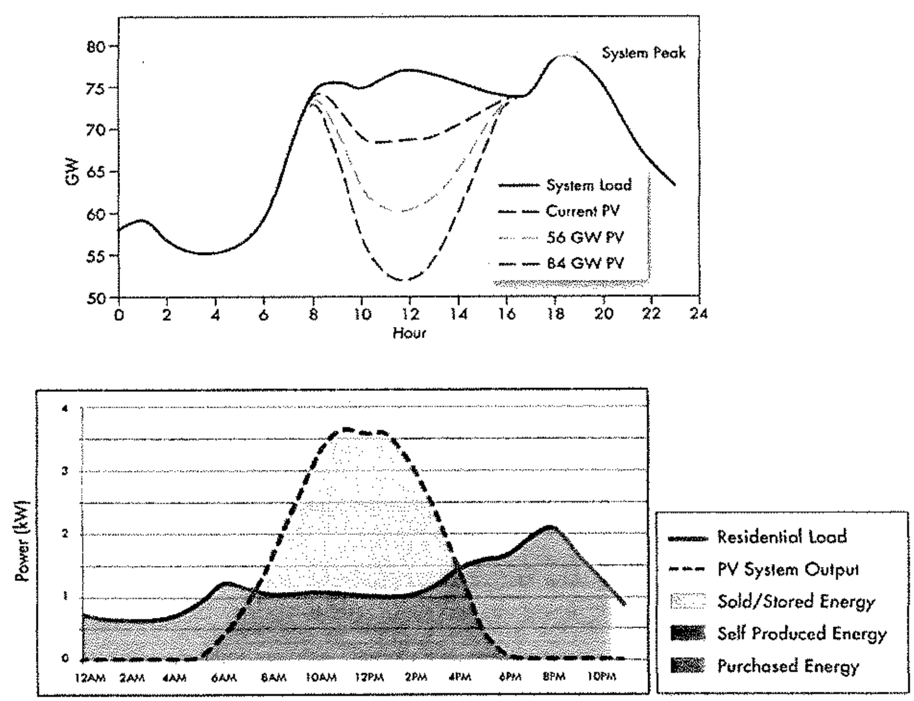


Figure 4: Increased Ramp Rates, Peak Load Reduction and Reliance on the Grid

 1040-6190/© 2014 Elsevier Inc. All rights reserved., http://dx.doi.org/10.1016/j.tej.2014.11.005

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.

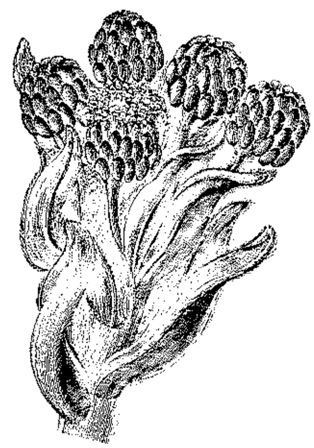
On a technical point, a power inverter is an electronic device or circuitry that changes direct current to alternating current. During a system outage the power inverter is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line 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

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

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

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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.*

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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.

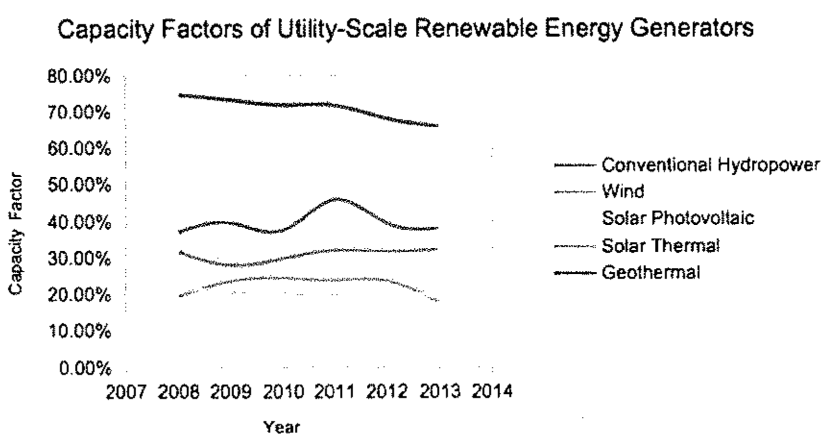


Figure 5: Capacity Factors of Utility-Scale Renewable Energy Generators

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

  http://dx.doi.org/10.1016/j.tej.2014.11.005

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

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

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

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

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

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

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

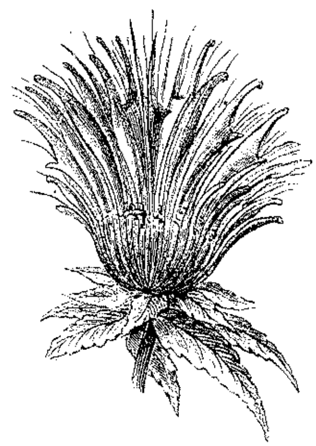
empowered to make. In the views of such opponents, the only externalities that ought to be incorporated into pricing are those that are internalized by legal mandate. Proponents of incorporating externalities into rates contend that doing so is the only way to accurately reflect all social costs. They 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

1040-6190/© 2014 Elsevier Inc. All rights reserved., http://dx.doi.org/10.1016/j.tej.2014.11.005

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

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

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.

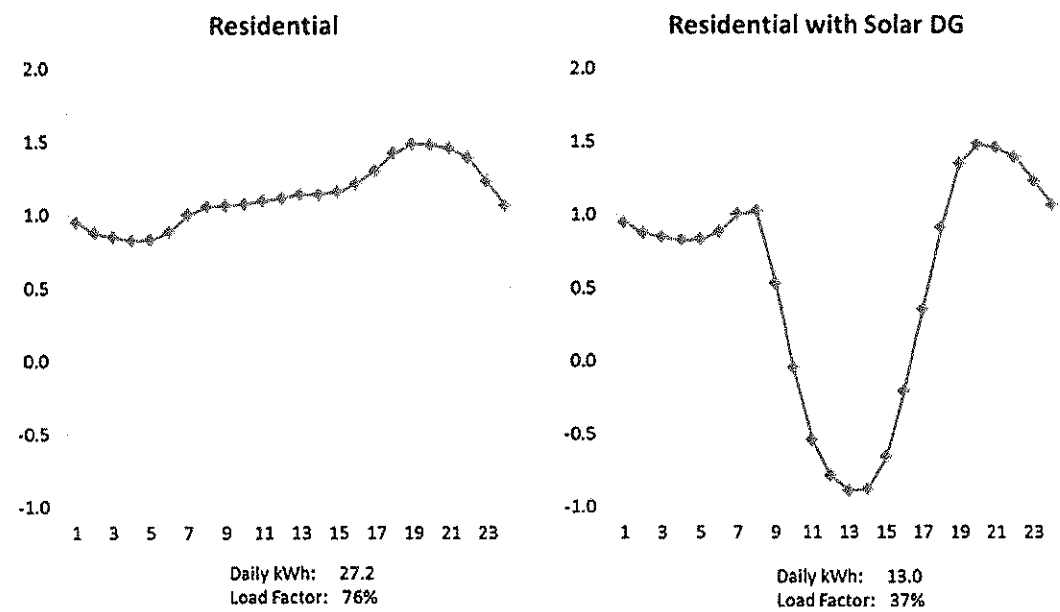


Figure 6: Typical Residential Loads Average Day – Iowa

1040-6190/© 2014 Elsevier Inc. All rights reserved., http://dx.doi.org/10.1016/j.tej.2014.11.005

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.■

Endnotes:

1. Black, John. Update on Solar PV and Other DG in New England. ISO New England (June 2013).

2. *See* Frank, Charles R., Lovins, Amory B., 2014, September. Alternative Energies Debate – The Net Benefits of Low and No-Carbon Electricity Technologies: Better Numbers, Same Conclusions. The Brookings Institution. *See also* Frank, Charles R., 2014. The Net Benefits of Low and No-Carbon Electricity Technologies. The Brookings Institution Global Economy and Development Program, 1939–9383 *see contra* Lovins, Amory B., 2014, July. Sun, wind, and drain. The Economist; Lovins, Amory B., 2014, August. Sowing confusion about renewable energy. Forbes.

3. See e.g. David B. Raskin, The Regulatory Challenge of Distributed Generation, 4 Harv. Bus. L. Rev. Online 38 (2013).

4. 135 FERC 13 61,022, April 12, 2011 *affirmed* New Jersey Board of Public Utilities et al. v. FERC, 744 F.3d 74 (2014).

5. Massachusetts v. U.S. Environmental Protection Agency, 549 U.S. 497 (2007).

6. See Melissa Eddy, *German Energy Push Runs into Problems*. N.Y. Times, March 19, 2014, http://www.nytimes.com/2014/03/20/business/energy-environment/german-energy-push-runs-into-problems.html.

7. Gale, Brent. *A Seven Step Program for Embracing DG/DER.* Berkshire Hathaway Energy (October 2013).

8. Energy and Environmental Economics, Inc. *California Net Metering Draft Cost-Effectiveness Evaluation.* Prepared for California Public Utilities Commission, Energy Division. Sept. 26, 2013.

9. Arizona Commerce Commission. Open Meeting re: Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution (Docket No. E-0135A-13-0248). Sept. 30, 2013.

  http://dx.doi.org/10.1016/j.tej.2014.11.005