

BEFORE THE CORPORATION COMMISSION 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**  
NOV 03 2015

COURT CLERK'S OFFICE - OKC  
CORPORATION COMMISSION  
OF OKLAHOMA

RESPONSIVE TESTIMONY

OF

JUSTIN R. BARNES

ON BEHALF OF

THE ALLIANCE FOR SOLAR CHOICE ("TASC")

November 3, 2015

**Prepared Responsive Testimony of Justin R. Barnes  
November 3, 2015**

**TABLE OF CONTENTS**

I.	Introduction .....	3
II.	Requirements of S.B. 1456 and E.O. 2014-07 .....	5
III.	Consideration of Potential DG Cost Shifts in Other Jurisdictions .....	8
IV.	Deficiencies on OG&E’s DG Tariff Application .....	15
V.	Deficiencies in OG&E’s Embedded Benefits and Subsidy Analysis .....	28
VI.	Conclusions and Recommendations .....	33

1 **I. INTRODUCTION**

2  
3 **Q. Please state your name, business address and current position.**

4 A. Justin R. Barnes, 401 Harrison Oaks Blvd Suite 100, Cary, North Carolina,  
5 27513. My current position is Director of Research with EQ Research LLC.

6  
7 **Q. Please describe your educational and occupational background.**

8 A. I obtained a Bachelor of Science in Geography from the University of Oklahoma  
9 in Norman in 2003 and a Master of Science in Environmental Policy from  
10 Michigan Technological University in 2006. I was employed at the North  
11 Carolina Solar Center at N.C. State University for more than five years, where I  
12 worked on the *Database of State Incentives for Renewables and Efficiency*  
13 (*DSIRE*) project, and several other projects related to state renewable energy and  
14 efficiency policy. In my current position I coordinate EQ Research's various  
15 research projects for clients, directly manage and perform research for a solar  
16 energy regulatory policy tracking service, contribute as a researcher to other  
17 standard policy service offerings, and perform customized research. I have  
18 testified on several occasions before the Public Service Commission of South  
19 Carolina as an expert in distribution generation and net metering policy. My  
20 *curriculum vitae* is attached as Exhibit JRB-1.

21  
22 **Q. Have you previously testified before the Oklahoma Corporation**  
23 **Commission?**

24 A. No.

25  
26 **Q. On whose behalf are you testifying?**

27 A. I am testifying on behalf of The Alliance for Solar Choice ("TASC"). TASC  
28 advocates for maintaining successful distributed solar policies nationwide.  
29 Founded by the largest rooftop companies in the nation, TASC represents the vast  
30 majority of the market, including Demeter Power; Silevo; SolarCity; Solar  
31 Universe; Sunrun; Verengo; and ZEP Solar. These companies are responsible for

1           tens of thousands of residential, commercial, school, and government solar  
2           installations across the country, and are engaged at the local, state, and national  
3           level. TASC's interest in this proceeding is to encourage customer choice and fair  
4           rate setting practices for solar powered distributed generation.

5  
6       **Q.     What is the purpose of your testimony in this proceeding?**

7       A.     The purpose of my testimony is to describe the deficiencies in the application of  
8           Oklahoma Gas and Electric ("OG&E" or the "utility") to implement distributed  
9           generation ("DG") tariff changes in response to 2014 Senate Bill No. 1456 ("S.B.  
10          1456") and accompanying Executive Order 2014-07 ("E.O. 2014-07"), and offer  
11          recommendations for how the Commission should proceed in its consideration of  
12          the application. More specifically, I first discuss what S.B. 1456 and E.O. 2014-  
13          07 collectively require for DG tariffs. I then describe how OG&E's DG tariff  
14          proposal fails to meet these requirements on the basis of its overall design and the  
15          utility's failure to fully consider the benefits of DG to non-DG customers in its  
16          evaluation of the supposed "subsidy" being provided from non-DG customers to  
17          DG customers. Finally, I offer recommendations on how the Commission should  
18          proceed in its consideration of OG&E's proposal and any future applications from  
19          other Oklahoma utilities. Mark Garrett, TASC's other witness, will discuss more  
20          specific cost of service issues related to OG&E's application.

21  
22       **Q.     Please summarize the specific recommendations you make in your testimony.**

23       A.     I recommend that the Commission take the following actions:

- 24  
25           1.    Reject OG&E's proposal for new DG tariffs because the utility fails to  
26           adequately demonstrate that: (a) such a subsidy exists, and (b) its  
27           proposed tariffs would not constitute a rate increase on DG customers  
28           that causes them to pay rates above their cost of service. Both elements  
29           are prerequisites for the adoption of new DG tariffs under S.B. 1456.

- 1                   2. Require the development of a more complete analysis of the cost to  
2                   serve DG customers and the benefits of DG that accrue to non-DG  
3                   customers prior to implementing any tariff changes. This in turn would  
4                   require the completion of an updated cost of service study with  
5                   specific analysis of the cost to serve DG customers, as well as the  
6                   development of comprehensive quantitative methodology for  
7                   determining the value of DG benefits. The purpose of this exercise is  
8                   to create a roadmap for reliably identifying the magnitude of any  
9                   subsidy that exists between DG customers and non-DG customers.
- 10                  3. Consider convening a renewed stakeholder process to arrive at the  
11                  comprehensive valuation methodology I recommend. The focus of this  
12                  process would be to define specific methods of calculating the various  
13                  benefits of DG, including all of the necessary inputs and assumptions.  
14                  The common methodology could be employed in future proceedings,  
15                  and updated as necessary to ensure that tariffs for DG customers  
16                  continue to comply with the strictures of S.B. 1456.
- 17                  4. Upon reaching any conclusion that DG customers are being subsidized  
18                  by non-DG customers, pursue rate reforms such as minimum bills or  
19                  modifications to time-of-use tariffs to mitigate the issue. These  
20                  reforms are superior to fixed charges and demand charges because  
21                  they allow customers to retain substantial control over their energy  
22                  bills. They therefore continue to encourage DG deployment in  
23                  alignment with the directive in E.O. 2014-07 and the policy goals of  
24                  the Oklahoma First Energy Plan.

25

26   **II.       REQUIREMENTS OF S.B. 1456 AND E.O. 2014-07**

27

28   **Q.       Please summarize what S.B. 1456 requires.**

29   **A.       S.B. 1456 obligates retail electric suppliers to, by December 31, 2015, implement**  
30       tariffs for DG customers only in the case that DG customers are found to be

1 subsidized by non-DG customers. Any DG tariff may recover no more than the  
2 costs necessary to serve those DG customers. This requirement only applies to  
3 customers that install DG systems on or after the November 1, 2014 effective date  
4 of the enacted bill. Based on the definition of “distributed generation” in S.B.  
5 1456, it also does not apply to customers that are enrolled on demand-based rate  
6 schedules. S.B. 1456 further provides that “higher fixed charges” on DG  
7 customers, as compared to non-DG customers, are a means to avoid intra-class  
8 subsidies. It defines a fixed charge as “any fixed monthly charge, basic charge, or  
9 other charge not based on the volume of energy consumed by the customer, which  
10 reflects the actual fixed costs of the retail electric supplier.”  
11

12 **Q. Does S.B. 1456 require that new tariffs for DG customers be adopted by**  
13 **December 31, 2015?**

14 A. S.B. 1456 only requires the adoption of new tariffs if they are necessary in light of  
15 the law’s other requirements. These requirements are that DG customers not be  
16 subsidized by non-DG customers in the same rate class, and that rates for DG  
17 customers not be increased above that necessary to recover their cost of service.  
18 This requires answers to the threshold questions of: (1) whether a long-term intra-  
19 class subsidy exists; (2) the magnitude of the subsidy; and (3) the direction in  
20 which any subsidy operates. Logically, appropriate tariffs cannot be devised until  
21 conclusions have been reached on these questions. Stated another way, the  
22 Commission cannot allow a subsidy to be present in a utility’s tariffs after  
23 December 31, 2015, but it is under no obligation to require tariff revisions prior to  
24 answering the subsidy question to its satisfaction.  
25

26 **Q. Does S.B. 1456 require the use of higher fixed charges to address any intra-**  
27 **class subsidies?**

28 A. No. S.B. 1456 simply states that higher fixed charges are a way to eliminate  
29 subsidies that may be determined to exist. It does not say that they are the only  
30 way to accomplish this, or even the preferred way. Moreover, the definition of a

1 fixed charge used in S.B. 1456 is broad enough to include other means “not based  
2 on the volume of energy consumed by the customer,” such as a minimum bill.

3  
4 **Q. Please elaborate on why you use the term “long-term” in reference to an  
5 analysis of any intra-class subsidy?**

6 A. A typical DG system, such as a solar photovoltaic (“PV”) system, has an  
7 operational lifetime of more than 25 years. Thus the operation of a DG system  
8 will affect the DG customer, non-DG customers (current and future), and the  
9 utility over that entire timeframe. Using an analytical timeframe consistent with  
10 the lifetime of a typical DG facility places current and future customers on the  
11 same playing field in terms of any benefits or costs they experience, and aligns  
12 with the long-term outlook used in utility resource planning.

13  
14 **Q. Please describe E.O. 2014-07.**

15 A. E.O. 2014-07 provides direction to the Commission in its implementation of S.B.  
16 1456. Among other things, it states that implementation requires “strict  
17 compliance...with the goals and intent of the Oklahoma First Energy Plan and  
18 this Bill [S.B. 1456]” and that S.B. 1456 allows the Commission to consider  
19 “prior to the implementation of any fixed charges...all available alternatives,  
20 including other rate reforms such as increased use of time-of-use rates, minimum  
21 bills and demand charges.” It further provides guidance on how the Oklahoma  
22 First Energy Plan (the “State Energy Plan”) relates to the implementation of S.B.  
23 1456, as follows:

- 24  
25 • The State Energy Plan promotes wind and solar power;  
26 • DG is an essential element of the plan;  
27 • S.B. 1456 “encourages” increased reliance by individuals and businesses  
28 on DG systems; and

- 1           • A proper examination of rate reforms will ensure appropriate  
2           implementation of the State Energy Plan while protecting future DG  
3           customers.

4  
5  
6     **III. CONSIDERATION OF POTENTIAL DG COST SHIFTS IN OTHER**  
7     **JURISDICTIONS**

8  
9     **Q. Please elaborate on how other states have addressed the potential cost-shift**  
10    **or DG subsidy issue.**

11    A. Most states have approached the topic from the perspective of the relative costs  
12    and benefits of DG or the policy of net metering. The rationale for this type of  
13    framework is that if DG or net-metered installations yield long-term benefits that  
14    exceed the costs, non-participating ratepayers ultimately benefit from their  
15    deployment. Stated another way, if the long-term costs avoided by DG exceed the  
16    compensation provided to DG customers (e.g., retail rate compensation under net  
17    metering), there is no subsidy being provided by non-DG customers to DG  
18    customers. Rather, a net-benefit finding indicates that DG customers are  
19    subsidizing non-DG customers.

20           These studies and investigations have arisen for different specific reasons  
21    (e.g., legislative requirements, utility rate requests) but ultimately they can be  
22    seen as attempts to better understand the relative costs and benefits of DG as a  
23    precursor to any efforts to reform rates or net metering policies. Quantitative cost-  
24    benefit studies have been completed in states including California, Louisiana,  
25    Maine, Massachusetts, Minnesota, Mississippi, Nevada, and Vermont, while  
26    investigatory proceedings are ongoing in Arizona, New York, Oregon, and Utah.  
27    The Colorado Public Utilities Commission also recently concluded an  
28    investigation into similar issues, though it did not conduct a formal quantitative  
29    study. Several of the completed studies were preceded by or involved regulatory

1 proceedings intended to elicit stakeholder input on the appropriate cost-benefit  
2 methodology (e.g., in Maine and Minnesota) prior to the completion of the study.  
3 The ongoing proceedings in New York, Oregon and Utah are likewise devoted to  
4 this purpose.

5  
6 **Q. Why do you believe that the investigations in other states are relevant in the**  
7 **context of the present proceeding?**

8 A. They are important because they point to an emerging set of best practices for  
9 evaluating the existence of cross-subsidies between DG customers and non-DG  
10 customers. These best practices include procedural elements, such as the  
11 solicitation of stakeholder input to define a methodology and the deferral of rate  
12 reforms until a reliable analysis can be completed. They also include the actual  
13 details of an appropriate methodology, the requisite inputs, and assumptions.  
14 While each of the completed studies employ somewhat different methodologies,  
15 they display many common elements and can serve as valuable resources for  
16 informing the Commission's own evaluation. A publication from the Interstate  
17 Renewable Energy Council ("IREC") provides an excellent qualitative description  
18 of a thorough cost-benefit methodology, the relevant cost-benefit components,  
19 and the different ways that values may be calculated for these components.<sup>1</sup> This  
20 guidance, which was co-authored by a former Commissioner with the Public  
21 Utilities Commission of Texas and utility executive, should be used in  
22 conjunction with the completed studies to establish a solid analytical approach for  
23 a cost-benefit evaluation.

24  
25 **Q. What conclusions have the completed studies reached?**

26 A. By and large they have found that DG and net metering have positive net benefits  
27 for ratepayers, meaning that if anything DG customers are actually subsidizing

---

<sup>1</sup> See IREC. A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation. October 2013. <http://www.irecusa.org/a-regulators-guidebook-calculating-the-benefits-and-costs-of-distributed-solar-generation/>

1 non-DG customers. Table 1 provides brief descriptions of the conclusions reached  
2 in several recent studies initiated or completed by state regulatory agencies.

3  
4 **Q. Does the testimony of OG&E Witness Walkingstick accurately portray the**  
5 **scope of regulatory investigations of potential cost-shifts associated with DG**  
6 **deployment?**

7 **A.** No. Mr. Walkingstick references only a single proceeding, a general rate case  
8 request brought by We Energies in the state of Wisconsin.<sup>2</sup> He omits the many  
9 other similar investigations that have taken place in other states and produced  
10 different outcomes, as I describe above, and fails to note that the Wisconsin  
11 Public Service Commission did not conduct a full cost-benefit analysis of DG as  
12 part of the proceeding. This decision was vacated on October 30, 2015, on the  
13 basis that the record lacked sufficient evidence and justification for the additional  
14 charges.<sup>3</sup> Thus the relevance of this particular proceeding is confined to the fact  
15 that it failed to withstand judicial scrutiny.

16  
17 **Table 1: State Cost-Benefit Study Results**

<b>State (Year)</b>	<b>Summary of Outcome</b>
Colorado <sup>4</sup> (2015)	Declined to make any changes to net metering or on-site solar generation rules upon the conclusion of an 18-month inquiry.
Maine <sup>5</sup> (2014)	After completing a stakeholder process on the appropriate methodology, a consultant developed study found a 25-year levelized value of 33.7 cents/kWh for solar DG resources.
Massachusetts <sup>6</sup> (2014)	Consultant study found that under two different policy scenarios, DG solar provides net benefits of 1.5 – 2.1 cents/kWh to ratepayers (excluding the cost of the state incentive programs).
Mississippi <sup>7</sup> (2014)	A consultant developed study found that net metering would have net benefits to

---

<sup>2</sup> See Walkingstick Direct, p. 12, lines 4-18.

<sup>3</sup> See Dane County Circuit Court, Case No. 15-cv-153.

<sup>4</sup> See Colorado Public Utilities Commission Decision C15-0990, September 15, 2015, Proceeding Number 14M-0235E.

<sup>5</sup> See “Maine Distributed Solar Valuation Study,” Clean Power Research, Prepared for the Maine Public Utilities Commission, March 2015. Available at <https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2014-00171>.

<sup>6</sup> See “Massachusetts Net Metering and Solar Task Force: Final Report to the Legislature,” see Task 3- Evaluating the Costs and Benefits of Alternative Net Metering and Solar Policy Options in Massachusetts, Grace, Robert, Michelman, Thomas, Sustainable Energy Advantage, April 27, 2015. Available at <http://www.mass.gov/eea/docs/doer/renewables/final-net-metering-and-solar-task-force-report.pdf>.

	all ratepayers in 10 of 11 sensitivity scenarios, and a 25-year levelized value of 17 cents/kWh for net metering generation in the base case scenario.
Minnesota <sup>8</sup> (2014)	Developed a value of solar methodology through a stakeholder process, and ultimately calculated a value of solar rate of 14.7 cents/kWh.
Nevada <sup>9</sup> (2014)	A consultant developed cost-benefit study found that net metering benefits exceeded costs by \$37 million over 20 years, even with the inclusion of utility solar rebates separate from net metering as costs.
Vermont <sup>10</sup> (2014)	Found that net metering generation had a 20-year levelized value of 23.7 cents/kWh to ratepayers and 25.6 cents/kWh to society, leading to a conclusion that net metering holds net benefits for both.
California <sup>11</sup>	Consultant study found that the total net cost of the NEM program, at full subscription (5,256 MW) in the year 2020 would be \$1.09B annually, though it noted that this is heavily influenced by the tiered rate design. The study also found that net metering customers in aggregate pay the cost of their electric service.

1

2 **Q. How do you respond to Mr. Walkingstick’s reference to a recent Harvard**  
3 **paper suggesting that solar advocate studies overvalue solar DG?**

4 **A.** I believe that these collective studies and regulatory proceedings belie the  
5 inference Mr. Walkingstick makes in citing the paper from the Harvard Electricity  
6 Policy Group. Though solar and DG advocates have commissioned a number of  
7 such solar valuation studies, the proceedings and studies I note above were, or are,  
8 being conducted by neutral regulatory agencies, not solar advocates. They  
9 represent vetted, credible approaches to such an evaluation, not the type of  
10 skewed assessment that Mr. Walkingstick implies.

11

---

<sup>7</sup> See “Net Metering in Mississippi: Costs, Benefits and Policy Considerations,” Synapse Energy Economics, prepared for the Mississippi Public Service Commission, September 2014, at 36. Available at <http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf>.

<sup>8</sup> See “Minnesota Value of Solar: Methodology,” Clean Power Research, Prepared for the Minnesota Department of Commerce, Division of Energy Resources, January 2014. Available at <http://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf>.

<sup>9</sup> See “Nevada Net Energy Metering Impacts Evaluation,” Energy and Environmental Economics (E3) Consulting, July 2014. Available at [http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media\\_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study](http://puc.nv.gov/uploadedFiles/pucnv.gov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study).

<sup>10</sup> See “Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012,” Vermont Public Service Department, January 15, 2013. The staff of the Vermont PSC performed an extensive literature search in its January 2013 Evaluation. Available at [http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable\\_Energy/Net\\_Metering/Act%20125%20Study%2020130115%20Final.pdf](http://publicservice.vermont.gov/sites/psd/files/Topics/Renewable_Energy/Net_Metering/Act%20125%20Study%2020130115%20Final.pdf).

<sup>11</sup> See “California Net Energy Metering Ratepayer Impacts Evaluation,” California Public Utilities Commission Energy Division and E3 Consulting, October 2013. Available at <http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf>.

1 Q. **Based on your preceding testimony, how would you describe the**  
2 **Commission's obligations in implementing S.B. 1456?**

3 A. In order to properly implement S.B. 1456 the Commission must first reliably  
4 determine whether a long-term subsidy from non-DG customers to DG customers  
5 exists, or vice versa. This should involve a long-term analysis consistent with the  
6 expected lifetime of a customer-sited DG installation, and should consider the full  
7 suite of potential costs and benefits consistent with the approaches used in other  
8 states and the aforementioned IREC guidance document. The Commission is not  
9 required to institute tariff revisions until after it determines to its satisfaction that  
10 a subsidy exists in one direction or the other.

11           Once the Commission has reached a conclusion on the subsidy question, it  
12 has substantial leeway to decide on the best way to address the subsidy. In this  
13 respect, the Commission is not bound by the proposal put forth by OG&E or any  
14 other utility. For instance, it could be that DG customers are subsidizing non-DG  
15 customers, in which case the OCC could take any number of remedial actions.  
16 That could include allowing rollover of credits for monthly net excess generation,  
17 as all other states with net metering policies do.<sup>12</sup> Alternately, it could be the case  
18 that any subsidy flowing from non-solar customers to solar customers, or vice  
19 versa, is less than the administrative costs of implementing rate reforms. In this  
20 case the Commission could simply opt to maintain current rates.

21           The Commission has however been directed by E.O. 2014-07 to ensure  
22 that its S.B. 1456 implementation efforts align with the goals of the state Energy  
23 Plan, which promotes the development of wind and solar power, including DG  
24 applications of these technologies. In light of this direction, I recommend that the  
25 Commission exercise great care in making sure that any rate reforms continue to  
26 encourage DG deployment. This could include exploring alternative rate design  
27 options such as minimum bills, or directing the revision of existing tariffs to

---

<sup>12</sup> Monthly rollover rates differ among states, but all other states with net metering policies require utilities to compensate the customer in some way for monthly excess.

1 provide additional compensation to DG customers if the cost-benefit analysis  
2 shows that they are subsidizing non-DG customers.  
3

4 **Q. Are you suggesting that the Commission should conduct a comprehensive**  
5 **DG cost-benefit analysis in the current proceeding?**

6 A. Not necessarily, for two reasons. First the present schedule does not allow enough  
7 time to complete a thorough study. Second, I think it is reasonable to question  
8 whether the magnitude of the alleged problem is sufficient to justify pursuing a  
9 comprehensive study in the near term.

10 Mr. Walkingstick indicates that as of July 31, 2015 only 15 DG  
11 installations would be subject to S.B. 1456.<sup>13</sup> Though I disagree with his  
12 calculation of the “excess compensation” provided to existing net metering  
13 customers, if one scales the calculations he makes for 68 existing net metering  
14 customers to 15 customers, the result is a purported subsidy of less than \$3,000  
15 annually. Divided among OG&E’s roughly 740,000 Oklahoma customers, the  
16 cost shift, assuming OG&E’s numbers, is negligible. Even under a significant  
17 increase in solar penetration in the next few years, such an alleged cross-subsidy  
18 would remain de minimis. The cost of the completion of a comprehensive DG  
19 cost-benefit analysis would likely be at least an order of magnitude greater than  
20 the \$3,000 annual figure, while also requiring substantial time commitments on  
21 the part of staff, utilities, and other stakeholders. I do not believe that such a  
22 substantial cost is warranted or in the interest of ratepayers and other parties at  
23 this time.  
24

25 **Q. How then do you recommend the Commission proceed in meeting the**  
26 **requirements of S.B. 1456?**

27 A. As I have already discussed, a comprehensive study is necessary if the  
28 Commission is to institute new tariffs that address any subsidy and do not result in  
29 rate increases on DG customers above that necessary to recover their cost of

---

<sup>13</sup> See Walkingstick Direct, p. 10, Table 1

1 service. With this in mind, the Commission could nevertheless conclude that it  
2 does not possess the information necessary to identify and quantify any subsidy  
3 with the degree of precision required to justify new tariffs for DG customers. It  
4 could then specify some type of benchmark (e.g., number of DG installations,  
5 installed capacity, next rate case) that would trigger reconsideration of the issue. It  
6 would be reasonable for the timing and frequency of reconsideration to take into  
7 account the legal and administrative costs of such a proceeding, which are  
8 ultimately passed to ratepayers.

9 In the meantime, I believe that it could be productive for the Commission  
10 to conduct a renewed stakeholder process to establish protocols for analyzing the  
11 existence of a subsidy. A process like this would create a common playing field  
12 for utilities subject to S.B. 1456, and identify the information the Commission  
13 needs to reach a decision. This would be beneficial because it would avoid the  
14 prospect of having to re-litigate similar issues in multiple proceedings, and  
15 provide utilities with a framework that they can rely upon in assembling  
16 information and evidence to support any proposed tariff changes. Since S.B.  
17 1456 states that rate increases on DG customers may not result in the recovery of  
18 costs in excess of their cost of service, I believe that the appropriate venue for a  
19 final determination on tariff changes is a general rate case.

20  
21 **Q. Didn't the Commission already conduct a stakeholder process in anticipation**  
22 **of utility filings in response to S.B. 1456, resulting in a "checklist" for utility**  
23 **tariff filings?**

24 **A.** It did, but what I envision is an extension of that process. The past process was an  
25 excellent first step in sorting through the various issues presented by S.B. 1456.  
26 However, with respect to analyzing the benefits of DG systems, it stopped short  
27 of precisely defining protocols and methods for how the specific benefit  
28 categories should be analyzed. While it may have seemed reasonable at the time  
29 to confine the output of this process to qualitative analytical issues, based on  
30 OG&E's DG tariff filing, it was evidently not sufficient to lead to a full and

1 detailed benefits study. The supplemental process I suggest would be focused on  
2 defining a quantitative methodology for analyzing DG benefits, including the  
3 necessary inputs and assumptions used for each category. One possible output  
4 could be a formulaic framework for the benefits calculation that only requires the  
5 filling in of utility-specific numbers.

#### 8 IV. DEFICIENCIES ON OG&E'S DG TARIFF APPLICATION

9 Q. **Please describe OG&E's DG tariff proposal.**

10 A. OG&E proposes to revise its existing tariffs to require DG installations placed in  
11 service after November 1, 2014 to take service under tariffs with increased  
12 customer charges, a demand component, and time-of-use ("TOU") energy charges  
13 that differ from existing tariffs. It also proposes to allow DG customers on these  
14 tariffs to enroll in either a net energy billing option ("NEBO-kW") or a new  
15 standard purchase rate schedule for systems of 300 kW or less, designated as rate  
16 RPPO.

17 The NEBO-kW option allows a customer to offset onsite energy needs  
18 using the DG system and be billed only for net energy purchases for each monthly  
19 billing period. It does not provide the customer with compensation for any  
20 production in excess of monthly use, and does not allow any excess production  
21 during a month to offset the monetary fixed or demand charges. The RPPO option  
22 is a buy-all, sell-all arrangement where the customer purchases all of their energy  
23 needs from the utility at the applicable residential or commercial tariff rate, and  
24 receives compensation for all energy produced by the system at the RPPO rate.

25 Under the residential version of the DG tariff, designated as R-TOU-kW,  
26 the customer would be subject to a fixed customer charge of \$18.00/month, a  
27 \$5.00/month increase compared to the utility's other residential rate schedules.  
28 Residential DG customers would also be subject to a demand charge of \$2.68/kW  
29 of 15-minute maximum demand. Energy supply charges would be set at  
30 \$0.173/kWh for on-peak periods and \$0.0137 for off-peak periods. These differ

1 substantially from the utility's existing residential TOU rates. Under the  
2 commercial version of the tariff, designated as COM-TOU-kW, a small General  
3 Service customer would be subjected to an increase of roughly \$10/month in the  
4 fixed monthly charge (from \$24.70 to \$35.00/month), a 15-minute demand charge  
5 of \$3.33/kW, and energy supply rates of \$0.1875/kWh for on-peak periods and  
6 \$0.0143/kWh for off-peak periods. The commercial energy supply rates likewise  
7 differ from the existing General Service TOU tariff rates.<sup>14</sup>

8  
9 **Q. What problems do you foresee with OG&E's proposal to place DG**  
10 **customers on demand rates?**

11 **A.** First, I believe that there is reason to question whether S.B. 1456 even allows the  
12 use of demand rates for DG customers. The definition of "distributed generation"  
13 in S.B. 1456 excludes customers that receive service on rates with demand-based  
14 charges. If DG customers were required to enroll on demand-rate tariffs, they  
15 would fall outside of the definition of distributed generation, and hence not be  
16 subject to the requirements of the law. This is a legal issue that the Commission  
17 needs to resolve before it considers the other contents of OG&E's application. Mr.  
18 Garrett discusses the implications in greater detail.

19 Second, as I will elaborate on further, there are a number of reasons why  
20 mandatory demand rates on small customers are strongly disfavored nationally,  
21 and universally so in the residential context. OG&E's existing rates for residential  
22 and small commercial customers bear this out. The residential rate schedules do  
23 not contain demand rates – even as an option – and the non-residential tariffs  
24 allow customers with maximum annual demands of up to 400 kW to remain on  
25 non-demand rates.<sup>15</sup> Non-demand rate options are common for small non-  
26 residential customers throughout the country. I am aware of no state-regulated  
27 utility that imposes mandatory demand rates on residential customers as a whole,  
28 or imposes them universally on DG customers. OG&E seeks a rate design that is

---

<sup>14</sup> See Walkingstick Direct, Exhibits RDW-3, RDW-4 and RDW-5.

<sup>15</sup> See OG&E rate schedules R-1 & GS-1 for example.

1           unprecedented on a national level. Even if the Commission were to conclude that  
2           precedent in other states carries no weight, the reasons for this lack of precedent  
3           remain compelling.

4  
5       **Q.     Why are mandatory demand rates inappropriate for residential and small**  
6       **non-residential customers?**

7       **A.**    The reasons are numerous. First, demand rates themselves will be difficult for  
8           many small customers to understand. The simple conceptual difference between a  
9           kW and a kWh is hard for these customers to grasp, let alone the meaning of a  
10          “15-minute average maximum demand,” or how each individual electric load  
11          contributes to their electric demand.

12                 This lack of understanding leads to the second drawback, the customer’s  
13           inability to reliably manage electric demand and, as a consequence, their  
14           electricity bills. Any customer can be expected to understand that the more they  
15           use electric appliances, the greater their electricity bill will be. It is far harder for  
16           customers to understand that even if they set their thermostat at a high  
17           temperature, it could cycle on coincident with the compressor in their refrigerator  
18           and their use of a television, hair dryer, oven or other appliance. Even a  
19           knowledgeable, diligent customer who desires to reduce their electric demand  
20           could be saddled with a high electricity bill on the basis of a single lapse in  
21           attention during a month. The burden is likely to fall most heavily on families  
22           because as difficult as it may be for a single person to manage demand in this  
23           fashion, it is even harder to manage the actions of other users, including children.  
24           For many small customers, the effect of a demand charge is effectively equivalent  
25           to a higher fixed charge, an aspect I will address in more detail later in my  
26           testimony.

27                 Third, demand charges directly and indirectly discourage energy  
28           conservation. Directly, the demand component reduces rates for the remaining  
29           volumetric components, making energy savings less valuable for the customer.  
30           Indirectly, a customer that makes efforts to reduce their electricity bill but sees

1 little change due to high demand charges is likely to conclude that further efforts  
2 to invest in energy efficiency or conservation are unattractive.

3

4 **Q. Would these same drawbacks apply if demand rates were only made**  
5 **mandatory for DG customers?**

6 A. Yes. Residential and small non-residential DG customers are no different than a  
7 typical non-DG customer in these rate classes; accordingly, the rationale for not  
8 placing these classes on demand rates applies equally to DG customers. A  
9 customer that installs DG in an effort to manage their energy use is no different  
10 than a customer that installs a geothermal heat pump system, additional  
11 insulation, or energy efficient lighting. Like these types of energy efficiency  
12 improvements, a solar DG system is a low-maintenance improvement that allows  
13 customers who are not able or inclined to more actively manage their energy  
14 consumption to nevertheless save on energy costs.

15 DG customers rely *passively* on the improvement to produce cost savings.  
16 As “passive” customers, they are no different from a customer that chooses not to  
17 invest in energy saving technologies, or a customer that makes energy efficiency  
18 improvements that require little or no active management—for example, installing  
19 CFL or LED light bulbs. There is no basis for an assumption that DG customers  
20 are somehow superior to other customers in terms of energy management skills.

21

22 **Q. Are there elements in OG&E’s DG demand tariff proposal that remedy any**  
23 **of these issues?**

24 A. No, and in fact there are components that exacerbate the problem and would make  
25 it even more difficult for customers to understand and manage their energy bills.  
26 As noted above, OG&E proposes a higher fixed charge, which itself diminishes  
27 the customer’s ability to control their energy bills. Furthermore, the utility  
28 proposes a tariff that relies on a non-time-differentiated demand charge and TOU  
29 energy charges. This is problematic in two ways.

1 First, the flat, non-coincident demand charge does not reflect cost  
2 causation. A customer would be required to pay the same demand charge  
3 regardless of whether their demand is coincident with the system peak (i.e.,  
4 transmission) or the local circuit peak (i.e., distribution). Both portions of the  
5 system are built to handle the respective maximum coincident peaks of all  
6 customers to which they are providing service. Charging a customer based on  
7 their non-coincident peaks for system costs that are caused by coincident peaks  
8 does not align the customer's rates with the cost to serve that customer.

9 Second, the combination of a TOU energy charge and non-time-  
10 differentiated demand charge will make it even more difficult for customers to  
11 manage their energy bills. The TOU energy rate motivates a customer to avoid  
12 using electricity during on-peak periods, defined as weekdays from 2 – 7 PM  
13 during the months of June – September. It therefore compels customers to  
14 concentrate their energy use during off-peak periods during the summer months  
15 or manage their consumption based on the real-time output of their DG system.

16 Yet concentrating energy use in certain time periods is likely to result in  
17 higher demand charges. This is particularly true in the late evening when a solar  
18 DG system will be producing little or no energy. It is likewise implausible that a  
19 customer could align consumption with DG system production day in and day out  
20 without deviating for a single 15-minute period during a month.  
21 Correspondingly, during the winter season, the energy rates are so low that a  
22 customer has little incentive to conserve energy or utilize self-generation.

23 Finally, since the NEBO-kW option does not allow for excess generation  
24 to be carried over from month to month or monetized at the end of a billing period  
25 and used to offset other monetary charges, the customer is unable to fully benefit  
26 even when they produce an excess of highly valuable on-peak energy. This could  
27 produce a somewhat counterintuitive response in customer behavior, where the  
28 customer attempts to avoid forfeiture of excess on peak energy by actually  
29 attempting to use more energy at on-peak times (i.e., reduce the bank to zero).  
30 This could actually exacerbate stress on the system during high load periods. The

1 practical effect of these collective elements is to send the customer a mixed set of  
2 pricing signals, make it extremely difficult for a DG customer to avoid high  
3 energy bills during the summer, and minimize the value of the DG system during  
4 the winter months, while charging them for system use in a manner that is not  
5 aligned with their true cost of service.

6  
7 **Q. What impact would the proposed R-TOU-kW tariff have on residential DG**  
8 **customers?**

9 A. The workpapers of Mr. Walkingstick indicate that on average the new tariff rate  
10 would reduce first year customer savings associated with a fixed tilt (i.e., rooftop)  
11 4 kW residential solar PV system by roughly \$13 per month, from \$41 per month  
12 to \$28 per month.<sup>16</sup> These workpapers are attached as Exhibit JRB-2.

13 This estimate is misleading due to the way in which OG&E performs the  
14 analysis, and uses assumptions that diminish its accuracy. It is *not* a comparison  
15 between what a customer's total average monthly electric bill would be under the  
16 existing tariff and the proposed tariff. Instead it compares only monthly savings  
17 after the installation of DG under the two tariffs without recognizing that the  
18 starting point (i.e., the customer's bill without DG) would be different. In other  
19 words, if a customer had an average bill before DG of \$100 a month under the  
20 existing tariff, and would have average bill of \$110 per month under the proposed  
21 tariff, the average bill after DG would be \$57 per month under the existing tariff  
22 and \$82 per month under the proposed tariff (i.e., a difference of \$25 per month).  
23 An accurate estimate of the impact that the proposed tariffs would have on DG  
24 customers requires a comparison between average monthly customer bills under  
25 the existing DG tariff and the proposed DG tariff.

26 I have made such an estimate for residential customers modeled on the  
27 savings analysis and data provided by OG&E.<sup>17</sup> I estimate that compared to the  
28 current residential NEBO rate, the proposed R-TOU-kW tariff would reduce

---

<sup>16</sup> See OG&E Response to TASC Data Request 1.5

<sup>17</sup> This is based on data and formulas supplied by OG&E in response to TASC Data Request 1.5.

1 customer savings by an average of roughly \$24.50 per month for the reference 4  
2 kW rooftop system. Thus the customer may still “save” \$28 per month on R-  
3 TOU-kW compared to being on the same rate without DG, but the rate itself  
4 would increase the customer’s bill compared to the standard residential TOU  
5 tariff by \$11.50 per month. Thus \$11.50 per month in savings is lost to the bill  
6 increase and the customer would pay only \$16.50 less per month with DG under  
7 rate R-TOU-kW compared to what they would pay under the standard residential  
8 TOU rate without a DG system. Over the course of the life of a DG system, this  
9 would cost the customer thousands of dollars in foregone savings.

10 It should be noted that these calculations are based on an assumption that  
11 residential DG customers are identical to the average residential customer. A  
12 more precise estimate of DG customer impacts requires the use of data specific to  
13 DG customers.

14  
15 **Q. Why is the comparison between monthly customer costs under the standard  
16 residential TOU tariff and R-TOU-kW important?**

17 **A.** First, as I describe above, this comparison more accurately describes the impact of  
18 the R-TOU-kW tariff on DG customers than the estimate Mr. Walkingstick  
19 includes in his testimony. Second, I think it creates a serious question on the  
20 design of the R-TOU-kW tariff as it relates to cost of service. I am not aware of  
21 precisely how the standard residential TOU rate was designed, but I would  
22 assume that it is more or less aligned with the cost to serve residential customers.  
23 If the same is true for R-TOU-kW, I would expect that an average residential  
24 customer’s monthly bill under either rate would be similar. Yet by my  
25 calculations, an average residential customer’s bill under R-TOU-kW would be  
26 meaningfully higher. This discrepancy is among the reasons why an updated cost  
27 of service study is needed to inform the development of any DG tariffs.

28  
29 **Q. Has OG&E made any impact estimates using DG customer billing data?**

1 A. Yes, though from a slightly different perspective. OG&E performed an analysis of  
2 monthly bills for DG customers under the current net billing rider, compared to  
3 monthly bills under its proposed residential and non-residential DG tariffs.

4 It provided one analysis of this type in response to a request from the  
5 Public Utilities Division, showing that if the proposed DG tariff was applied to all  
6 net billing accounts that existed as of November 1, 2014, the average residential  
7 bill increase would be \$19.87 per month (\$238 per year), or 22.9%.<sup>18</sup> It separately  
8 provided TASC with an estimate that for residential DG customers that subject to  
9 the tariff, the bill increase would average \$12.70 per month.<sup>19</sup> The \$19.87 per  
10 month number is likely to be more accurate because it involves a sample size of  
11 200 residential customers, while the latter is a partial year estimate for only eight  
12 residential customers.

13

14 **Q. Can you provide any examples that illustrate the effect that increased**  
15 **customer charges and demand charges can have on PV deployment?**

16 A. Examples are extremely limited, because as I have already noted, the design in  
17 unprecedented among major utilities. However, the Salt River Project (“SRP”), a  
18 self-regulated publicly owned utility in Arizona, has deployed a new rate for  
19 residential solar customers in that includes a demand charge and an increased  
20 customer charge. The new rate is effective for all residential solar interconnection  
21 applications submitted after December 9, 2014.

22 Unofficial statistics from Arizona Goes Solar, a collaborative effort by the  
23 Arizona Corporation Commission and the state’s utilities, indicate that new  
24 interconnection applications in the SRP’s territory fell by almost 96% after the  
25 imposition of the rate changes. Specifically, the generating capacity associated  
26 with new residential interconnection applications during the period from January

---

<sup>18</sup> See OG&E Response to Staff Data Request KJC-1, attached as Exhibit JRB-3.

<sup>19</sup> See OG&E Response to TASC Data Request 2.4, attached as Exhibit JRB-4.

1 – September 2015 was 4.2% of the residential capacity volume submitted from  
2 January – September 2014.<sup>20</sup>

3  
4 **Q. Does this outcome align with the requirements of S.B. 1456 and E.O. 2014-**  
5 **07?**

6 A. No. It is contrary to the directive in E.O. 2014-07 that the implementation of S.B.  
7 1456 should encourage DG deployment. There is also strong reason to question  
8 whether the proposed DG tariff establishes a rate increase on DG customers that  
9 would result in them paying more than their cost of service, which is contrary to  
10 Paragraph C of S.B. 1456.

11  
12 **Q. Please elaborate on your assertion that the proposed DG tariffs could result**  
13 **in DG customers paying more than their cost of service.**

14 As I have already described, the residential DG tariff would increase customer  
15 costs by \$11.50 per month relative to the standard residential TOU tariff before  
16 accounting for the effects of DG, and would increase DG customer costs relative  
17 to the current net billing tariff by an average of \$20 per month. Attached Exhibit  
18 JRB-5 shows that according to OG&E's data, existing DG customers pay on  
19 average about \$3 a month less than non-DG customers for electric service.<sup>21</sup> This  
20 leads to the conclusion that DG customers tend to be higher use customers that,  
21 under rates dominated by volumetric charges, would likely have been paying  
22 *more* than their cost of service. In other words, prior to the installation of DG, DG  
23 customers were likely subsidizing other customers.

24 The installation of a DG system in this instance simply reduces this built-  
25 in subsidy, bringing a DG customer back to the average residential usage profile  
26 upon which rates are based—an average that is based on a range of energy users  
27 including renters, rural residents, and vacation home owners. Based on this I think  
28 there is substantial reason to question whether a potential subsidy exists even if

---

<sup>20</sup> See Arizona Goes Solar. Salt River Project: Installations.  
<http://www.arizonagoessolar.org/UtilityIncentives/SaltRiverProject.aspx>

<sup>21</sup> OG&E Response to TASC Data Request 1.9.

1 one only looks at the cost side of cost-benefit equation and entirely disregards the  
2 benefits that DG provides to other customers.

3 Yet under the new rates, DG customers would end up paying substantially  
4 *more* than non-DG customers. The intent of the S.B. 1456 was surely not to have  
5 DG customers paying more on average than non-DG customers. In fact, a DG  
6 customer would unavoidably be subsidizing non-DG customers every month for  
7 customer-related costs, because as a result of the increased fixed charge, they  
8 would be obligated to pay a greater fixed amount towards the customer-related  
9 cost of service.

10

11 **Q. If the Commission did determine that a subsidy exists from non-DG**  
12 **customers to DG customers, what rate reforms do you recommend for**  
13 **addressing it?**

14 **A.** First, I recommend that the Commission identify the existence or degree of such a  
15 subsidy after accounting for both the costs and benefits, and whether the  
16 administrative act of addressing it would in and of itself create a larger subsidy to  
17 non-DG customers. It may be the case that the outcome of an analysis of cross-  
18 subsidization leads to non-action and a commitment to revisit the topic in several  
19 years' time.

20 Above that, should the Commission elect to take immediate action, I  
21 believe any subsidy should be addressed using a minimum bill rate design as  
22 opposed to fixed charge increases and demand charges. A minimum bill operates  
23 in a manner similar to the way a minimum demand or contract demand clause  
24 would operate, except that it would be applied to customers on non-demand rates.  
25 It could be implemented with or without a fixed customer charge.

26 A minimum bill differs from a fixed charge insofar as it only increases the  
27 payments due from the customer if the charges otherwise due fall below the  
28 designated amount, while fixed charges are included in the customer's bill  
29 regardless of what they pay in other charges. For example, if a customer owed  
30 \$20 in energy charges during a month and the minimum bill was \$13 per month,

1 the customer would pay only \$20 because what they owe is above the minimum.  
2 If the same customer was subject to a \$13 fixed customer charge instead of a \$13  
3 minimum bill, they would pay \$20 in energy charges plus the \$13 fixed charge,  
4 for a total of \$33 for that month.

5 Minimum bills are superior to fixed charges and demand charges for the  
6 reasons below.

- 7
- 8 • They operate under a simple concept that would be more easily  
9 understood by customers than demand charges.
  - 10 • They better allow the customer to manage their energy bill compared  
11 to fixed charges and demand charges, because they allow for bill  
12 reductions based on usage characteristics that a customer can actually  
13 control. In this respect, they can continue to encourage the customer to  
14 conserve energy and/or install DG if properly designed.
  - 15 • They directly address the issue of DG cost avoidance since they create  
16 a minimum payment obligation (i.e., when energy use is low).
  - 17 • They can ensure that the customer does not pay rates above their cost  
18 of service because they are only triggered when the customer avoids  
19 payments.

20

21 Because S.B. 1456 places a mutual non-subsidization obligation between  
22 DG and non-DG customers, I also recommend that this type of rate reform be  
23 used across an entire class of customers, not as a mechanism specific to DG  
24 customers.

25

26 **Q. Is there precedent to the use of minimum bills as opposed to fixed charges or**  
27 **increases in fixed charges in residential rates?**

28 **A.** The state of California recently decided that minimum bills were preferable to  
29 increases in fixed customer charges for investor-owned utility customers after

1 completing an extensive residential rate reform proceeding.<sup>22</sup> Rate-regulated  
2 utilities in Alaska, the District of Columbia, Hawaii, Louisiana, Maine, Nebraska,  
3 and Utah also employ minimum bills, as do a number of unregulated competitive  
4 retailers in Texas. Minimum bills have a much greater precedent than residential  
5 demand rates.

6  
7 **Q. Do you believe that OG&E's proposal to apply the demand rates to buy-all,  
8 sell-all customers that choose rate RPPO is reasonable?**

9 A. No, this element of the proposal does not make sense. A customer that elects this  
10 rate will continue to purchase all of their electricity requirements from the utility.  
11 Under this rate design the customer is not avoiding any purchases from the utility,  
12 has identical load characteristics before and after the installation of DG, and is  
13 simply being compensated for the energy produced by their DG system. There is  
14 no possibility that a subsidy could exist under this rate design and therefore no  
15 basis for subjecting these customers to different rates.

16  
17 **Q. Has OG&E offered any rationale for applying the proposed DG tariffs to  
18 customers that do not offset on-site use with DG?**

19 A. In response to a data request from TASC Mr. Walkingstick stated, "It has always  
20 been appropriate to have a demand charge for any customer..." and that the only  
21 reason demand charges are not applied to all customers is because collecting  
22 demand data for mass customer classes has historically not been cost effective. He  
23 goes on to state that with the rollout of advanced metering infrastructure ("AMI"),  
24 this is no longer the case.<sup>23</sup>

25  
26 **Q. How do you respond to these statements?**

27 A. As I have previously discussed, there are a number of other reasons why demand  
28 charges are disfavored for residential and small commercial customers. The

---

<sup>22</sup> California Public Utilities Commission Decision 15-07-001. July 3, 2015.

<sup>23</sup> OG&E response to TASC Data Request 2.11, attached as Exhibit JRB-6.

1           appropriateness of demand charges for small customers is one of the primary  
2           issues in the current proceeding. Even if the statements made by Mr. Walkingstick  
3           were entirely accurate, the implementation of demand rate designs for all  
4           customers must be considered in a general rate case. If OG&E believes that  
5           demand charges are an appropriate measure for eliminating intra-class subsidies  
6           (associated with DG or otherwise), it should withdraw its present application and  
7           seek such a reform in its next rate case. I see little reason to force such a  
8           significant issue to be considered under the short time frame of the present  
9           proceeding, only to have it re-litigated in the larger context of a future rate case,  
10          especially since—as Mr. Garrett discusses—OG&E’s rate case filing is imminent.

11  
12       **Q.    Since you claim that no subsidy is possible under this arrangement, are you**  
13       **suggesting that this design is appropriate for all DG customers in light the**  
14       **requirements of S.B. 1456?**

15       A.    I do not recommend this rate design for all DG customers. Data from OG&E  
16       indicates that almost all current DG customers are enrolled in the NEBO rider as  
17       opposed to the existing qualifying facilities (“QF”) rate. Only five out of the  
18       utility’s 245 DG customers as of July 31, 2015 have chosen the QF rate.<sup>24</sup> DG  
19       customers clearly display a preference for net energy billing when given an option  
20       between it and a buy-all, sell-all arrangement. I agree with Mr. Walkingstick that  
21       a customer’s “right-of-choice” is an important customer motivation for installing  
22       DG.<sup>25</sup> Requiring DG customers to take service under a buy-all, sell-all  
23       arrangement would likely act to discourage DG deployment by eliminating their  
24       option to generate *and use* clean energy.

25               Furthermore, TASC believes this rate structure could constitute a sale of  
26       electricity that would result in taxable income, and therefore increased income  
27       taxes for a DG customer.<sup>26</sup> This prospect is a significant drawback of the

---

<sup>24</sup> See Walkingstick Direct, p. 10, Table 1.

<sup>25</sup> See Walkingstick Direct, p. 11, line 9.

<sup>26</sup> See, e.g., Arizona Corporation Commission Docket No. E-01345A-13-0248, Public Comment Letter of the Alliance for Solar Choice re Application of Arizona Public Service Company for Approval of Net

1 arrangement beyond concerns over limiting a customer's right of choice. Even  
2 just the prospect of additional taxes complicates the decision a customer makes to  
3 install a DG system. Many small DG customers, and residential customers in  
4 particular, likely do not possess the information or knowledge necessary to make  
5 informed decisions on tax issues.

6  
7  
8 **V. DEFICIENCIES IN OG&E'S EMBEDDED BENEFITS AND SUBSIDY**  
9 **ANALYSIS**

10  
11 **Q. What does OG&E calculate as the "embedded benefit" of DG resources?**

12 **A.** Mr. Walkingstick never expressly identifies a value for the embedded benefit, but  
13 he does use a figure of 6.5 cents/kWh in his calculation of the uncompensated  
14 value of DG exports.<sup>27</sup> The context suggests that this represents an average value  
15 for embedded benefits though the lack of documentation makes it difficult to be  
16 certain.

17  
18 **Q. Is the utility's analysis of the embedded benefits of DG sufficient to make a**  
19 **determination of whether a subsidy from non-DG customers to DG**  
20 **customers exists?**

21 **A.** No. OG&E's analysis appears to only include two components, avoided energy  
22 and avoided capacity costs. The utility disregards the series of other potential  
23 benefits that were listed in the benefits study checklist developed by the  
24 Commission, and that have been identified and quantified in other studies. These  
25 include line losses, avoided transmission and distribution costs, and reliability

---

Metering Cost Shift Solutions (Aug. 15, 2013) (filing a legal memorandum from Skadden, Arps, Slate, Meagher & Flom LLP, explaining that payments received by taxpayers for sale of electricity under feed-in tariffs likely fall within the definition of taxable gross income); Hawai'i Public Utilities Commission Docket No. 2014-0192, Hawai'i Solar Energy Association's, Hawai'i PV Coalition's, Hawai'i Renewable Energy Alliance's, Ron Hooson's, Life of the Land's, Sunpower's and the Alliance for Solar Choice's Final Statement of Position (2015) (filing a legal memorandum from Chun Kerr LLP explaining that feed-in tariff payments would likely be considered gross income).

<sup>27</sup> See Walkingstick Direct, p. 25, lines 26-28.

1 benefits. It supplies no meaningful information on how it determined that these  
2 benefits have a zero value. Moreover, virtually no information is provided on how  
3 it arrived at the values it did include, what those values are, and the time frame  
4 under which the analysis took place. As a whole, the treatment it gives to  
5 embedded benefits is superficial and insufficient.

6  
7 **Q. Please discuss why OG&E's treatment of line losses as an embedded benefit**  
8 **is inappropriate.**

9 A. OG&E states that line losses are already reflected in retail rates based on service  
10 voltage, and therefore considers line losses avoided by DG to have no added  
11 value. In other words, the utility is arguing that because a customer avoids paying  
12 the retail rate for energy used for on-site consumption during a billing period, they  
13 are being compensated for these avoided line losses.<sup>28</sup> This argument is a red  
14 herring that distorts the purpose of assessing avoided line losses in the context of  
15 a cost-benefit analysis.

16 In a cost-benefit analysis, the retail rate compensation provided to a DG  
17 customer falls within the cost category, while avoided line losses fall within the  
18 benefit category. If the compensation provided to a DG customer is the ultimate  
19 cost basis it is inappropriate to eliminate the concurrent system benefit that  
20 avoided line losses have from the benefit category. Avoided line losses are a  
21 system benefit, regardless of whether they are reflected in some form in the  
22 compensation provided to a DG customer. They should ultimately be reflected as  
23 an adder to other benefit categories such as avoided energy, avoided capacity, and  
24 avoided transmission and distribution capacity. Furthermore, because line losses  
25 are influenced by system load, they should be accounted for on a basis that  
26 reflects higher loss avoidance during higher load periods (i.e., in terms of  
27 marginal line losses).

28  

---

<sup>28</sup> See Walkingstick Direct, p. 26, lines 6-8

1 Q. **Does OG&E’s analysis account for avoided transmission and distribution**  
2 **(“T&D”) capacity benefits?**

3 A. Mr. Walkingstick states that grid costs and benefits are specific to each individual  
4 grid circuit.<sup>29</sup> I agree that at distribution level benefits are location-specific and  
5 depend on how the output from a DG system correlates to local cost-causing  
6 conditions. However, the same is not true for the transmission system, which  
7 serves broad sections of the customer base with diverse load characteristics. Even  
8 small systems contribute to reduced demand at the transmission and substation  
9 level when system production is coincident with system peaks. This load  
10 reduction may allow a utility to defer upgrades and capital investments that  
11 ultimately cost money for all system users.

12 Moreover, even though some benefits are location-specific, it does not  
13 mean that they should be assigned a universal zero value. OG&E is proposing a  
14 DG tariff that would apply to all new DG customers on a system-wide basis  
15 regardless of whether they are installed in high or low value locations. The  
16 purpose of performing a cost-benefit study to identify a subsidy is to discover  
17 whether the benefits of DG outweigh the costs *on average*, over an extended time  
18 frame throughout the entire system. The concept of averaging is foundational to  
19 cost recovery and ratemaking. The same is true for an assessment of DG benefits  
20 that may be used to design future rates.

21 Recognizing that it may not be possible to develop granular location  
22 specific values for avoided T&D costs, the previously referenced IREC  
23 guidebook on solar DG value analysis lays out several methods for system-wide  
24 analysis of potential benefits. Several states, including California, Maine,  
25 Minnesota, Mississippi, and Vermont have used system-wide modeling to assign  
26 a value to avoided T&D capacity costs. OG&E has not provided any  
27 substantiation for its assertion that all grid benefits are location specific, or  
28 demonstrated any attempt to perform a system-wide analysis. These potential  
29 benefits should not be ignored, therefore I recommend that the Commission

---

<sup>29</sup> See Walkingstick Direct, p. 28, lines 24-29.

1 consider the use of a system-wide estimation methodology for avoided T&D  
2 capacity costs.

3

4 **Q. Does OG&E's application adequately address potential reliability-related**  
5 **benefits from DG?**

6 A. No. As with T&D capacity benefits, the utility suggests that reliability-related  
7 benefits are circuit specific, but fails to substantiate this assertion. Mr.  
8 Walkingstick even goes to far as to imply that inadequate maintenance of DG  
9 systems may be having detrimental impacts on safety and reliability.<sup>30</sup> The  
10 suggestion that DG systems may be having adverse impacts on safety and  
11 reliability is entirely unsupported.

12

13 **Q. How do you respond to the suggestion that lack of maintenance is**  
14 **contributing to adverse safety and reliability impacts from DG?**

15 A. If OG&E is aware of any specific safety or reliability issues associated with  
16 existing DG systems, due to lack of maintenance or otherwise, it has not  
17 documented them in its application or its responses to data requests. Moreover,  
18 the accusation defies common sense, insofar as customers only benefit from their  
19 DG system when it is functioning properly and compliant with existing standards  
20 for grid connection. Customers therefore have a substantial incentive to keep their  
21 DG system in good working order so as to avoid conditions that cause it to under-  
22 produce, result in on-site safety hazards, or subject it to potential disconnection  
23 for violating interconnection standards.

24

25 **Q. What sorts of reliability-related benefits might a DG system provide?**

26 A. Reliability-related benefits are a broad catch-all that may include potential  
27 benefits that are somewhat intangible and difficult to quantify, or are achievable  
28 only with the use of on-site energy storage. However, the proliferation of so-  
29 called "smart" inverters with advanced functionality has the potential to allow DG

---

<sup>30</sup> See Walkingstick Direct, p. 28, lines 15-21.

1 systems to provide some reliability-related services, most notably voltage support  
2 functions.<sup>31</sup> While existing DG systems may not be equipped with smart inverters,  
3 many newer inverters have advanced capabilities, even if they are not currently  
4 being used due to a lack of clearly defined technical standards.<sup>32</sup> In the long term,  
5 however, it can be expected that smart inverters will be installed on most new DG  
6 systems, as well as existing systems that require an inverter replacement.<sup>33</sup> A  
7 long-term cost-benefit analysis of the type I recommend needs to consider the  
8 value of these future benefits.  
9

10 **Q. What other concerns do you have about OG&E's analysis of DG embedded**  
11 **benefits?**

12 **A.** OG&E does not provide any analysis of potential risk reduction attributable to  
13 DG or provide anything resembling a sensitivity analysis in its assessment of DG  
14 value. Risks could take many forms, but the most notable exclusions are  
15 purchased power price risks and the risk of future compliance costs under the  
16 EPA's Clean Power Plan or another carbon regulation scenario. The utility  
17 justifies the exclusion of purchased power risk on the basis that purchased power  
18 is available at the Southwest Power Pool ("SPP") market price. It is true that  
19 power would be available for purchase at the SPP market price, but OG&E  
20 ignores the potential for DG to contribute to reductions in the future market price  
21 for power. It likewise ignores possible future carbon risks by failing to consider  
22 the potential compliance value of DG in carbon regulation scenarios, or the effect  
23 that carbon regulations could have on market prices.  
24

25 **Q. Does OG&E consider these risks in other contexts?**

---

<sup>31</sup> See California Public Utilities Commission Decision 14-12-035. December 22, 2014.

<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF>

<sup>32</sup> See Greentech Media. California Launches Its First Real-World Smart Inverter Test. September 10, 2015. [https://www.greentechmedia.com/articles/read/california-launches-its-first-real-world-smart-inverter-test?utm\\_source=Storage&utm\\_medium=Headline&utm\\_campaign=GTMDaily](https://www.greentechmedia.com/articles/read/california-launches-its-first-real-world-smart-inverter-test?utm_source=Storage&utm_medium=Headline&utm_campaign=GTMDaily)

<sup>33</sup> DG systems typically require an inverter replacement at least once during the lifetime of the system.

1 A. Yes. OG&E’s 2014 Integrated Resource Plan (“IRP”) filed with the Arkansas  
2 Public Service Commission addresses both issues. The IRP incorporates a  
3 sensitivity analysis of market prices under scenarios that include both a carbon tax  
4 scenario in 2020, and a low load scenario attributable to rapid adoption of  
5 distributed generation within the SPP footprint over the next 10 years. Both  
6 scenarios result in material changes to its market price forecasts.<sup>34</sup> OG&E further  
7 concludes that continuing to “aggressively pursue demand-side resources” will  
8 ultimately provide substantial benefits to its customers.<sup>35</sup> I see a profound  
9 disconnect between the analysis that OG&E uses to making long-term planning  
10 decisions -- and the conclusions it reaches -- and the superficial nature of the  
11 analysis it has presented in this proceeding.  
12

13 **VI. CONCLUSIONS AND RECOMMENDATIONS**

14  
15 **Q. Please summarize your conclusions and recommendations.**

16 A. I recommend that the Commission take the following steps:

- 17
- 18 • Reject OG&E’s proposal for new DG tariffs because the utility fails to  
19 adequately demonstrate that: (a) such a subsidy exists, and (b) its proposed  
20 tariffs would not conflict with the S.B. 1456 requirement that DG rates be  
21 based on the cost to serve DG customers.
  - 22 • Require the development of a more complete analysis of the cost to serve DG  
23 customers and the benefits of DG that accrue to non-DG customers prior to  
24 implementing any tariff changes.

---

<sup>34</sup> See OG&E 2014 Integrated Resource Plan Update (pg. 38.) <https://oge.com/wps/wcm/connect/342cf742-9bb6-48f1-aaa9-34a4174b8c16/2014+IRP+-+Oklahoma+Report.pdf?MOD=AJPERES&attachment=true&CACHE=NONE&CONTENTCACHE=NO>

<sup>35</sup> Ibid, (pg. 50).

- 1           • Consider renewing the past stakeholder process to arrive at the comprehensive  
2           valuation methodology I recommend, in order to identify all of the necessary  
3           inputs and assumptions involved in the requisite calculation.
- 4           • If the Commission reaches the conclusion that DG customers are being  
5           subsidized by non-DG customers—and that the identified subsidization  
6           necessitates immediate action—pursue rate reforms such as minimum bills or  
7           modifications to time-of-use tariffs that mitigate the issue while continuing to  
8           encourage DG deployment in line with E.O. 2014-07.

9

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

11   **A.    Yes, it does.**

# Exhibit JRB-1

## Justin R. Barnes

401 Harrison Oaks Blvd Suite 100 Cary, North Carolina 27513, (919) 825-3342, jrbarnes@eq-research.com

---

### EDUCATION

---

**Michigan Technological University** Houghton, Michigan  
*Master of Science*, Environmental Policy August 2006  
Graduate-level work in Energy Policy.

**University of Oklahoma** Norman, Oklahoma  
*Bachelor of Science*, Geography, December 2003  
Area of concentration in Physical Geography.

### EXPERIENCE

---

**EQ Research, LLC and Keyes, Fox & Wiedman, LLP** Cary, North Carolina  
*Director of Research*, July 2015 – present, *Senior Analyst & Research Manager*, March 2013 – July 2015  
Oversee state legislative and regulatory policy tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage. Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, incentives, and renewable portfolio standards. Provide expert witness testimony. Manage the development of a solar power purchase agreement (PPA) toolkit for local governments and the planning and delivery of associated outreach efforts.

**North Carolina Solar Center, N.C. State University** Raleigh, North Carolina  
*Senior Policy Analyst*, January 2012-May 2013; *Policy Analyst*, September 2007-December 2011  
Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States. Managed state-level regulatory tracking for private wind and solar companies. Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets. Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort. Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis. Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies. Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits. Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

## SELECTED ARTICLES and PUBLICATIONS

---

Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.

Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. 2013. Article in Solar Today.

Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. 2013. For the U.S. Department of Energy SunShot Solar Outreach Partnership.

Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina; and Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. Department of Energy SunShot Solar Outreach Partnership.

Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards I Live On*. 2013. For Keyes, Fox & Wiedman.

Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.

Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.

Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.

Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.

Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.

Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

## TESTIMONY

---

- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

## AWARDS, HONORS & AFFILIATIONS

---

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

## Exhibit JRB-2

# OG&E Response to TASC Data Request 1.5: Solar Model Res Sandbox - New Fixed Savings

FIXED Array Savings (4.0 kW DC)		Component Annual Savings
GPSR TOU Pricing	\$ 0.02961	\$ 61.98
Average Fuel Costs (Summer Off-Peak Fuel)	\$ 0.05018	\$ 21.30
Average Fuel Costs (Summer On-Peak Fuel)	\$ 0.03281	\$ 105.49
Rate Design Winter Fuel (kWh)	\$ 0.01370	\$ 44.06
Rate Design Winter (All) Price (kWh)	\$ 0.01370	\$ 28.68
Rate Design Summer Off-Peak Price (kWh)	\$ 0.1730	\$ 73.43
Rate Design Summer On-Peak Price (kWh)	\$ 2.68	\$ -
Max Demand for T&D (kW)		\$ -
		Total \$ 334.93

Solar Rooftop Savings 4kW DC		Solar Generated kWh Savings GPSR TOU	Benefit per kWh
Solar Generated kWh Savings GPSR TOU	\$ 334.93	\$ 382.86	
Mthly Bill Savings due to Solar 1st Yr	\$ 27.91	\$ 31.91	
			Benefit per kWh
			0.067

SAXIS Savings (2.73 kW)		Solar Generated kWh Savings GPSR TOU	Benefit per kWh
Solar Generated kWh Savings GPSR TOU	\$ 382.86	\$ 382.86	
Mthly Bill Savings due to Solar 1st Yr	\$ 31.91	\$ 31.91	
			Benefit per kWh
			0.067

Regular Residential Billing for Typical Residential Customer		Reg Residential Pricing Components	Component Costs
Average Fuel Costs Summer per kWh	\$ 0.032805	\$ 210.17	\$ 210.17
Average Fuel Costs Winter per kWh	\$ 0.038050	\$ 274.61	\$ 274.61
Rate Design Winter Price 1st 600 kWh	\$ 0.057300	\$ 206.28	\$ 206.28
Rate Design Winter Price > 600 kWh	\$ 0.017300	\$ 52.20	\$ 52.20
Rate Design Summer First 1400 kWh	\$ 0.057300	\$ 306.08	\$ 306.08
Rate Design Summer > 1400 kWh	\$ 0.068000	\$ 17.93	\$ 17.93
Rate Design Shoulder Price All kWh	\$ 0.057300	\$ 97.76	\$ 97.76
Customer Charge	\$ 13.00	\$ 156.00	\$ 156.00
		Total	\$ 1,321.04

Rooftop Fixed Array Solar Savings (Approx 4 kW DC)		GPSR TOU Pricing	Component Annual Savings
Average Fuel Costs (Summer Off-Peak Fuel)	\$ 0.02961	\$ 61.98	\$ 61.98
Average Fuel Costs (Summer On-Peak Fuel)	\$ 0.05018	\$ 21.30	\$ 21.30
Rate Design Winter Fuel (kWh)	\$ 0.03281	\$ 105.49	\$ 105.49
Rate Design Winter > 600 kWh	\$ 0.01730	\$ -	\$ -
Rate Design Winter <=600 kWh	\$ 0.05700	\$ 183.30	\$ 183.30
Rate Design Summer Off-Peak Price (kWh)	\$ 0.02700	\$ 56.52	\$ 56.52
Rate Design Summer On-Peak Price (kWh)	\$ 0.1400	\$ 59.42	\$ 59.42
Max Demand for T&D (kW)	\$ 2.40	\$ -	\$ -
		Total	\$ 488.01

# Exhibit JRB-3

**OG&E'S RESPONSE TO STAFF'S DATA REQUEST KJC-1-1 ATT. 2**

*PUD 201500274 Data Request KJC-1 (1-1)*

**Net Energy Billing Option (NEBO) Customer Impact Analysis**

**Commercial NEBO Customers (bill amount excluding riders other than FCA)**

	Under <u>Current Tariff</u>	Under <u>Proposed Tariff</u>	<u>Change</u>	
			\$	%
Monthly Impact - Average Bill	\$ 273.87	\$ 298.58	\$ 24.72	9.0%

**Residential NEBO Customers (bill amount excluding riders other than FCA)**

	Under <u>Current Tariff</u>	Under <u>Proposed Tariff</u>	<u>Change</u>	
			\$	%
Monthly Impact - Average Bill	\$ 86.92	\$ 106.80	\$ 19.87	22.9%

# Exhibit JRB-4

## OG&E Response to TASC 2-4: Summary

### Potential Monthly Rate Impact

Month	General Service Customers					
	GS-001	GS-002	GS-003	GS-004	GS-005	GS-006
2014-11						
2014-12						
2015-01						
2015-02		\$ 9.66	\$ 12.56	\$ 11.60		\$ 6.70
2015-03		\$ 11.11	\$ 11.13	\$ 12.19		\$ 8.57
2015-04	\$ (5.65)	\$ 11.91	\$ 11.63	\$ 12.04		\$ 7.02
2015-05	\$ 11.38	\$ 11.45	\$ 10.71	\$ 12.09		\$ 8.84
2015-06	\$ 17.70	\$ 11.87	\$ 11.06	\$ 13.65	\$ 29.63	\$ 10.81
2015-07	\$ 18.67	\$ 12.03	\$ 11.57	\$ 12.47	\$ 17.08	\$ 9.21
2015-08	\$ 20.90	\$ 11.06	\$ 10.87	\$ 11.17	\$ 31.31	\$ 9.24

General Service Monthly Average  $\blacktriangledown$  \$ 12.37

Month	Residential Customers							
	RES-001	RES-002	RES-003	RES-004	RES-005	RES-006	RES-007	RES-008
2014-11						\$ 8.51		
2014-12						\$ (0.01)		
2015-01					\$ (7.13)	\$ (4.02)		
2015-02		\$ 8.33			\$ (2.92)	\$ 3.88		
2015-03		\$ 12.05			\$ (0.91)	\$ (0.11)		
2015-04		\$ 19.34			\$ 2.40	\$ 12.40		
2015-05	\$ 2.42	\$ 0.60	\$ (7.22)	\$ 8.33	\$ (6.14)	\$ 8.44	\$ 17.62	
2015-06	\$ 23.11	\$ 23.53	\$ 8.52	\$ 23.82	\$ 20.78	\$ 18.59	\$ 19.49	
2015-07	\$ 26.05	\$ 23.86	\$ 15.24	\$ 22.79	\$ 21.72	\$ 21.91	\$ 22.65	\$ 21.09
2015-08	\$ 22.01	\$ 16.28	\$ 14.16	\$ 23.49	\$ 23.96	\$ 26.97	\$ 22.85	\$ 7.50

Residential Monthly Average  $\blacktriangledown$  \$ 12.70

# Exhibit JRB-5

**OG&E Response to TASC Data Request 1-9**

Month	1-9a: Average kWh consumption per residential customer	1-9b: Average kWh consumption per DG residential customer	1-9c: Average bill per residential customer	1-9d: Average bill per DG residential customer	1-9e: Average maximum kW demand per residential customer	1-9f: Average maximum kW demand per DG residential customer
Jan-14	1,385	1,791	\$ 110.29	\$ 144.10	9.0	12.5
Feb-14	1,284	1,845	\$ 104.67	\$ 136.51	8.9	12.1
Mar-14	1,050	1,174	\$ 90.87	\$ 104.42	8.7	12.0
Apr-14	776	602	\$ 74.81	\$ 76.08	8.2	10.8
May-14	817	679	\$ 88.95	\$ 77.35	8.3	10.4
Jun-14	1,109	1,020	\$ 115.44	\$ 100.17	8.3	10.6
Jul-14	1,374	1,056	\$ 141.92	\$ 119.87	8.5	10.6
Aug-14	1,366	1,086	\$ 150.47	\$ 124.62	8.6	10.6
Sep-14	1,440	1,114	\$ 154.94	\$ 124.86	8.6	10.5
Oct-14	967	746	\$ 103.41	\$ 80.55	8.1	10.1
Nov-14	897	773	\$ 85.54	\$ 80.32	8.5	11.5
Dec-14	1,113	1,317	\$ 98.90	\$ 114.09	8.6	11.7
	13,577	13,204	\$ 1,320.22	\$ 1,282.96	8.55	11.11

# Exhibit JRB-6

**The Alliance for Solar Choice**  
**Data Request TASC-2**  
***Cause No. PUD 201500274***

**2-11 Please explain why a demand charge is an appropriate method of cost recovery for residential customers that will sell all energy generated by their DG system to OGE through the proposed RPPO tariff.**

Response\*: It has always been appropriate to have a demand charge for any customer. It is a component of providing service that has traditionally not been separately measured in the mass customer classes such as residential and general service customers because the cost of collecting customer demand data was not considered to cost effective. That is no longer the case since the deployment of the AMI on the OG&E system. Please refer to Page 16 lines 10 through 23 of Mr. Walkingstick's testimony.

Response provided by: Roger Walkingstick  
Response provided on: September 21, 2015  
Contact & Phone No: Bryan Scott 405-553-3452

\*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.