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ORIGINAL

1 Melissa M. Krueger
 2 Thomas L. Mumaw
 3 Thomas A. Loquvam
 4 Pinnacle West Capital Corporation
 5 400 North 5th Street, MS 8695
 6 Phoenix, Arizona 85004
 7 Tel: (602) 250-3630
 8 Fax: (602) 250-3393
 9 E-Mail: Thomas.Mumaw@pinnaclewest.com
 10 Melissa.Krueger@pinnaclewest.com
 11 Thomas.Loquvam@pinnaclewest.com

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Attorneys for Arizona Public Service Company

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

12 DOUG LITTLE, Chairman
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 14 BOB BURNS
 15 TOM FORESE
 16 ANDY TOBIN

Arizona Corporation Commission

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17 IN THE MATTER OF THE APPLICATION
 18 OF UNS ELECTRIC, INC. FOR THE
 19 ESTABLISHMENT OF JUST AND
 20 REASONABLE RATES AND CHARGES
 21 DESIGNED TO REALIZE A
 REASONABLE RATE OF RETURN ON
 THE FAIR VALUE OF THE PROPERTIES
 OF UNS ELECTRIC, INC. DEVOTED TO
 ITS OPERATIONS THROUGHOUT THE
 STATE OF ARIZONA, AND FOR
 RELATED APPROVALS.


DOCKET NO. E-04204A-15-0142

**ARIZONA PUBLIC SERVICE
COMPANY'S NOTICE OF FILING
SURREBUTTAL TESTIMONY**

22
 23 Arizona Public Service Company provides notice of filing the Surrebuttal
 24 Testimony of Ashley C. Brown, Ahmad Faruqui, Charles A. Miessner, and Cory Welch
 25 in the above-referenced matter.
 26
 27
 28

1 RESPECTFULLY SUBMITTED this 23rd day of February 2016.

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By: 
Melissa M. Krueger
Thomas L. Mumaw
Thomas A. Loquvam
Attorneys for Arizona Public Service Company

ORIGINAL and thirteen (13) copies
of the foregoing filed this 23rd day of
February 2016, with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

COPY of the foregoing mailed/delivered
this 23rd day of February 2016 to:

Jane L. Rodda
Administrative Law Judge
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Janice Alward
Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Brian Smith
Bridget Humphrey
Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Thomas Broderick
Utilities Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Bradley S. Carroll
UNS Electric, Inc.
88 East Broadway Blvd.
Mail Stop HQE910
P.O. Box 711
Tucson, AZ 85702

Kirby Chapman
Sulphur Springs Valley Electric
Cooperative, Inc.
311 E. Wilcox
Sierra Vista, AZ 85650

1 Steve W. Chriss
2 Wal-Mart Stores, Inc.
3 2011 S.E. 10th Street
4 Bentonville, AR 72716-0550

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.
2394 East Camelback Road, Suite 600
Phoenix, AZ 85016
Attorneys for Freeport-McMoRan and
AECC

5 Jeffrey W. Crockett
6 Crockett Law Group PLLC
7 2198 E. Camelback Road, Suite 305
8 Phoenix, AZ 85016-4747
9 Attorney for SSVEC

Kenneth R. Saline
K.R. Saline & Associates, PLC
160 N. Pasadena, Suite 101
Mesa, AZ 85201

10 Michael W. Patten
11 Jason D. Gellman
12 Snell & Wilmer L.L.P.
13 One Arizona Center
14 400 E. Van Buren Street, Suite 1900
15 Phoenix, AZ 85004-2202
16 Attorneys for UNS Electric

Rick Gilliam
Vote Solar
1120 Pearl Street, Suite 200
Boulder, CO 80302

17 Meghan Grabel
18 Osborn Maledon, P.A.
19 2929 North Central Avenue
20 Phoenix, AZ 85012
21 Attorney for AIC

Garry D. Hays
The Law Offices of Garry D. Hays, PC
2198 E. Camelback Rd., Suite 305
Phoenix, AZ 85016
Attorney for ADSA

22 Katie A. Dittelberger
23 Earthjustice
24 633 17th Street, Suite 1600
25 Denver, CO 80202
26 Attorneys for Vote Solar

Kevin C. Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, UT 84111

27 Timothy M. Hogan
28 Arizona Center for Law in the Public
Interest
514 W. Roosevelt Street
Phoenix, AZ 85003
Attorney for ACAA, Vote Solar, SWEEP
& WRA

Mark Holohan, Chairman
AriSEIA
2122 W. Lone Cactus Drive, Suite 2
Phoenix, AZ 85027

Briana Kobor
Vote Solar
360 22nd Street, Suite 730
Oakland, CA 94612

Eric J. Lacey
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St., NW, 8th Fl.
West Tower
Washington, DC 20007-5201
Attorney for Nucor

1 Craig A. Marks
2 Craig A. Marks, PLC
3 10645 N. Tatum Blvd., Ste. 200-676
4 Phoenix, AZ 85028
5 Attorney for AURA

Robert J. Metli
Munger Chadwick, P.L.C.
2398 East Camelback Road, Suite 240
Phoenix, AZ 85016
Attorney for Nucor

6 Jay I. Moyes
7 Jason Y. Moyes
8 Moyes Sellers & Hendricks Ltd.
9 1850 N. Central Ave., Suite 1100
10 Phoenix, AZ 85004
11 Attorneys for FPAA

Cynthia Zwick
Arizona Community Action Association
2700 N. 3rd Street, Suite 3040
Phoenix, AZ 85004

12 Vincent Nitido
13 Trico Electric Cooperative, Inc.
14 8600 W. Tangerine Road
15 Marana, AZ 85653

Jill Tauber
Chinyere A. Osuala
Earthjustice Washington DC Office
1625 Massachusetts Avenue, NW,
Suite 702
Washington, DC 20036-2212

16 Daniel W. Pozefsky
17 Chief Counsel
18 RUCO
19 1110 W. Washington, Suite 220
20 Phoenix, AZ 85007

Pat Quinn
AURA
5521 E. Cholla St.
Scottsdale, AZ 85254

21 Court Rich
22 Rose Law Group pc
23 7144 E. Stetson Drive, Suite 300
24 Scottsdale, AZ 85251
25 Attorney for TASC

Lawrence V. Robertson, Jr.
Attorney At Law
2247 E. Frontage Road, Suite 1
P.O. Box 1448
Tubac, AZ 85646
Attorney for Noble Americas

26 Gary Yaquinto
27 Arizona Investment Council
28 2100 N. Central Avenue, Suite 210
Phoenix, AZ 85004

Ken Wilson
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, CO 80302

Ellen Zuckerman
SWEEP Senior Associate
4231 E. Catalina Drive
Phoenix, AZ 85018

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, AZ 85704-3224

1
2
3
4
5
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8
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10
11
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13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28

Scott Wakefield
Hinton & Curry, P.L.L.C.
5045 N. 12th Street, Suite 110
Phoenix, AZ 85014-3302
Attorney for Wal-Mart

Timothy J. Sabo
Snell & Wilmer L.L.P.
One Arizona Center
400 E. Van Buren Street
Phoenix, AZ 85004
Attorney for Trico



1
2
3
4
5
6
7
8
9
10
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12
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SURREBUTTAL TESTIMONY OF ASHLEY C. BROWN
On Behalf of Arizona Public Service Company
Docket No. E-04204A-15-0142

February 23, 2016

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**SURREBUTTAL TESTIMONY OF ASHLEY C. BROWN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-04204A-15-0142)**

1
2
3 I. INTRODUCTION

4 **Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.**

5 A. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy
6 Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a
7 “think tank” on electricity policy, including pricing, market rules, regulation,
8 environmental and social considerations. HEPG, as an institution, never takes a position
9 on policy matters, so my testimony today represents solely my opinion, and not that of
10 the HEPG or any other organization with which I may be affiliated.

11 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.**

12 A. I am an attorney with extensive experience in infrastructure, especially energy and
13 regulatory matters. I served 10 years as a Commissioner of the Public Utilities
14 Commission of Ohio (1983-1993), where I was appointed and re-appointed by
15 Democratic Governor Richard Celeste. I also served as a member of the NARUC
16 Executive Committee and as Chair of the NARUC Committee on Electricity. I was a
17 member of the Advisory Board of the Electric Power Research Institute. I was also
18 appointed by the U.S. Environmental Protection Agency as a member of the Advisory
19 Committee on Implementation of the Clean Air Act Amendments of 1990, where I
20 served on the subcommittee charged with implementing emissions trading. I am also
21 a past member of the Boards of Directors of the National Regulatory Research Institute
22 and the Center for Clean Air Policy. I have served on the Boards of Oglethorpe Power
23 Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light
24 Advisory Board in Belmont, MA. I serve on the Editorial Advisory Board of the
25 *Electricity Journal*.

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1 I have been at Harvard continuously since 1993. During that time I have also been
2 Senior Consultant at the firm of RCG/Hagler, Bailly, Inc. and have been Of Counsel to
3 the law firms of Dewey & LeBouef and Greenberg Traurig. I have also taught in
4 training programs for regulators at Michigan State University, University of Florida, and
5 New Mexico State University (the three NARUC sanctioned training programs for
6 regulators), as well as at Harvard, the European Union School of Regulation, and a
7 number of other universities throughout the world. I have advised the World Bank and
8 the Inter-American Development Banks on energy regulation and have advised
9 governments and regulators in more than 25 countries around the world, including
10 Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Tanzania, Namibia, Ghana,
11 Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia,
12 and the Philippines. I have written numerous journal articles and chapters in books on
13 electricity markets and regulation, and I am co-author of the World Bank's *Handbook*
14 *for Evaluating Infrastructure Regulatory Systems*.

15 I hold a B.S. from Bowling Green State University, an M.A. from the University of
16 Cincinnati, and a J.D. from the University of Dayton. I have also completed all work,
17 except for the dissertation, on a Ph.D. from New York University. My current CV is
18 provided as Attachment ACB-1SR.

19 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA**
20 **CORPORATION COMMISSION?**

21 A. No. I have testified, however, before FERC and various state commissions as well as
22 before Congressional and state legislative committees.

23 **Q. ON WHOSE BEHALF DO YOU OFFER TESTIMONY?**
24

25 A. On behalf of the Arizona Public Service Company.
26
27
28

1 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 A. The purpose of my testimony is to rebut objections to UNS Electric’s (UNSE) proposed
3 rate design for solar DG customers. This includes addressing issues discussed in the
4 testimony of TASC witness Mark Fulmer, Vote Solar witness Briana Kobor, and
5 Western Resource Advocates witness Ken Wilson about Retail Net Metering, the value
6 of solar, and what is in the long-term interests of solar as a technology and of the
7 Arizona economy.

8 My testimony will be organized as follows:
9

- 10 • I will begin by examining and refuting suggestions by witnesses Kobor and
11 Wilson that the proposed changes might somehow harm low income customers,
12 showing that what hurts low income customers is the current net energy metering
13 pricing system;
- 14 • In the next section of my testimony, I will address claims about the likely impact
15 of UNSE’s proposal on the future of solar power in Arizona. Solar witnesses
16 argue the proposed reform is bad for the future of solar in the state; I will show
17 that the proposed reform is in the true long-term interest of solar energy and
18 solar DG customers (as opposed to the short-term rent seeking of current big
19 solar DG installation firms, given their subsidy-based business model); and that
20 there is no reasonable ground for the argument that the reform will have an
21 overall negative impact on jobs. In fact, there is good evidence that the existing
22 policy has a significant negative impact on jobs and on the Arizona economy as
23 a whole;
- 24 • I will go on to examine various arguments for delay and inaction presented by
25 Ms. Kobor and Mr. Fulmer, showing why none of these arguments present an
26 adequate reason to continue with the existing unjust and inefficient net energy
27

1 metering system, especially given that the difficulty of changing this system
2 increases the longer it is allowed to remain in place; and

- 3
- 4 • Finally, I will refute arguments presented by witnesses Fulmer and Kobor
5 against UNSE's proposal for a renewable credit rate, and show that the UNSE
6 proposal is not only reasonable, but introduces healthy market discipline to
7 establishing fair compensation for DG energy.

8 **Q. ARE THERE OTHER RECURRING PROBLEMS WITH THE ARGUMENTS**
9 **PRESENTED IN OPPOSITION TO UNSE'S PROPOSED SOLAR DG RATE**
10 **REVISION THAT SHOULD BE HIGHLIGHTED?**

11 A. Yes. There are three recurring flaws with the testimony.

12 First, a lack of evidence, and failure to assume any responsibility for proving, or even
13 establishing the plausibility of, their assertions. The testimony provided is often more of
14 the rhetorical flourish one might expect in a political campaign, rather than the type of
15 thoughtful and evidence-based analysis appropriate for a regulatory commission.

16 Second, one-dimensional thinking. Witnesses frequently selectively present one piece of
17 a whole picture, without acknowledging real effects that go in different, and often polar
18 opposite, directions.

19 Third, their arguments presuppose that solar DG, unlike any other resource in the state's
20 portfolio, including other renewables, is entitled to be compensated at retail, rather than
21 wholesale rates, that it should be insulated from cost and market pressures that discipline
22 the prices of all other resources, and that any policy that delivers less than that
23 privileged position in the marketplace is unduly discriminatory. As a corollary here,
24 witnesses Ms. Kobor and Mr. Fulmer seem to assume that pricing and public policy in
25 regard to solar should be judged entirely by one criterion: how much solar DG is sold.
26 As I will argue below, they give no adequate reason why regulators should embrace
27 such a self-serving, myopic view of public policy. Legitimate regulatory objectives,
28

1 such as efficient markets, fair and reasonable prices for consumers, incentives for
2 productivity and efficiency gains, enabling effective competition between resources,
3 even the long term economic viability of solar DG, all seem to give way, in the
4 testimony of Ms. Kobor and Mr. Fulmer, to the single minded objective of selling solar
5 DG.

6 II. THE EFFECT UNSE'S PROPOSAL WILL HAVE ON LOW INCOME CUSTOMERS

7 **Q. VOTE SOLAR WITNESS BRIANA KOBOR EXPRESSES CONCERN THAT UNSE'S PROPOSAL MAY HURT LOW INCOME CUSTOMERS. PLEASE RESPOND.**

9 A. I disagree with the statement that Ms. Kobor makes on page 40 of her testimony. It is
10 unsupported and speculative. And upon review, it is clear that the opposite is true. The
11 current rate design and net metering tariff overly-subsidizes rooftop solar, and, in the
12 aggregate, transfers wealth from less affluent to more affluent customers.

13 **Q. HOW DO ROOFTOP SOLAR SUBSIDIES HURT LOW INCOME CUSTOMERS?**

14 A. Higher income customers are more likely to install rooftop solar, and all other
15 customers, including low income customers, pay the subsidies in question in the form of
16 higher rates.¹ This is, in effect, a wealth transfer from lower income customers to higher
17 income customers. All available analysis indicates that the cross-subsidies inherent in
18 the current suite of net metering and volumetric rate design subsidies transfer wealth
19 from low income customers to high income customers. A 2013 study by E3 Consulting
20 of net metering in California found that the median income of net metering customers
21 was 168% of the median California household income—and the system as a whole was
22 projected to see another \$1.1 billion annually in costs by 2020—costs, which would
23
24

25 ¹ Low income customers lack the capital to invest in solar themselves, are less likely to live in a dwelling
26 whose roofs they own, and, do not meet the stringent credit requirements solar DG lessors impose on
27 customers. Moreover, even where low or fixed income households do own their own homes, many,
28 particularly seniors, cannot accept the limitations solar lessors impose on selling their homes. Thus, in
effect, low income people are almost systematically unable to participate in the solar DG market. It is the
almost exclusive domain of more affluent households.

1 have to be borne by those (on average, poorer) households not participating in net
2 metering.² The Center for American Progress has also done some recent work on this
3 issue, looking at median-income data in relation to solar installation patterns from
4 Maryland, Massachusetts, and New York and (in a separate article) in California,
5 Arizona, and New Jersey. Although the main conclusion they emphasize is that solar
6 installations are not limited to areas with predominantly “rich” households, there is a
7 clear and important pattern in the data they show of few or no solar installations among
8 areas with the lowest income households, and relatively many among the highest-
9 income households.³

10 In specific regard to Arizona, the Staff of the Arizona Corporation Commission itself
11 found, based on a review of the locations of customer DG installations within APS
12 service territory, that there “may be a tendency for DG systems to be located in areas of
13 higher income” in their analysis of the APS net metering proposal.⁴ Low income
14 customers are beginning to notice and object to the financial burden they are bearing to
15 support better-off households. In my own state of Massachusetts, low income customers
16 have recently filed a petition seeking relief from having to subsidize solar DG
17 customers.⁵

19 ² Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*.
20 Prepared for the California Public Utilities Commission by Energy and Environmental Economics
21 (October 28, 2013). It should be acknowledged here that the cross-subsidy impact of net metering in
22 California from lower-income to higher-income customers is strengthened considerably by California’s
23 tiered rate system, under which the highest-consuming customers have the greatest financial motivation
24 to install solar DG systems. However, I note that Ms. Kobor opposes UNSE’s proposal to eliminate their
25 highest rate tier (*see* Kobor Testimony at pp. 63-64), making the California cost-shift information
26 relevant to this discussion.

24 ³ Hernandez, Mari. “Rooftop Solar Adoption in Emerging Residential Markets.” Center for American
25 Progress, May 29, 2014 and Hernandez, Mari, “Solar Power and the People: The Rise of Rooftop Solar
26 Among the Middle Class.” Center for American Progress, October 21, 2013.

25 ⁴ *See* Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013, memo
26 titled “Arizona Public Service Company – Application for Approval of Net Metering Cost Shift
27 Solution.”

26 ⁵ Petition of the Low-Income Weatherization and Fuel Assistance Program Network to Apply G.L. c.
27 164, sec. 141, submitted to the Commonwealth of Massachusetts Department of Public Utilities,
28 November 17, 2015. National Grid Rate Case, D.P.U. 15-155.

1 As a former legal services lawyer, I find it troubling, to say the least, that we condone
2 the continued existence of a tariff that consciously and deliberately forces lower income
3 households to subsidize higher income households. I can see no justification for such an
4 economically regressive policy.

5 **Q. IS MS. KOBOR CORRECT THAT UNSE'S PROPOSAL MIGHT CREATE A**
6 **SLIPPERY SLOPE, AT THE END OF WHICH LOW INCOME CUSTOMERS**
7 **ARE HARMED?**

8 A. The slippery slope argument is a red herring. Indeed, the real harm to low income
9 customers, as already noted, is by perpetuating net metering. In general economic
10 theory, of course, cross-subsidies are best avoided, but there may be circumstances
11 where they cannot be. Thus, it is undeniable that some are embedded in tariffs, many of
12 them inadvertent and/or economically insignificant, but also some that result from
13 conscious policy decisions. Each one must be judged on its own merits and be narrowly
14 targeted to meet a clearly articulated policy objective, and to do so in a way that neither
15 asymmetrically inflates profits to particular actors in the marketplace at the consumers'
16 expense, unduly dilutes price signals, renders markets less efficient, nor provides
17 perverse incentives that discourage attainable productivity gains. Thus, cross subsidies
18 designed to assure universal service, such as those supporting rural electrification or
19 assisting low income households, support well-articulated policy objectives. They are
20 generally designed to avoid the pitfalls noted, and are subject to regulatory oversight and
21 review, as well as potential reformulation, to make certain that they continue to be
22 effective in changing circumstances and that they do not have adverse social effects. In
23 short, each cross-subsidy, and whether it needs to be retained and/or modified, stands on
24 its own.

25 Thus, net metering must stand or fall on its own merits, not in the context of other cross-
26 subsidies. The policy developed in a time when meters were dumb, energy price signals
27 were less precise and solar panels cost far more than they do today, when the tax
28

1 subsidies were less certain, where storage technology was just a dream, where the social
2 effects were largely unknown, and when solar DG market penetration was so small that
3 price distortions were insignificant. All of those circumstances have changed
4 dramatically, and net metering needs to be reassessed in its own context, and with
5 reference to the standards I just mentioned. It can and should be done without regard to
6 what other cross-subsidies may or may not exist. The slippery slope mentioned by Ms.
7 Kobor simply does not exist.

8 **Q. WRA WITNESS KEN WILSON ALSO ARGUES THAT A DEMAND CHARGE**
9 **COULD HARM LOW INCOME CUSTOMERS. IS HE CORRECT?**

10 A. No. First, Mr. Wilson fails to recognize that demand charges do not increase rates. They
11 are revenue neutral since the demand costs are already embedded in tariffs. What
12 demand charges do is make those costs transparent, and by doing so, enable all
13 customers, low income included, to shape their demand in ways that can reduce their
14 bill. It also provides an opportunity for programs like LIHEAP⁶ to design their low
15 income subsidies to capture that increased opportunity for saving.

16 Second, Mr. Wilson argues generally that low income customers would be penalized
17 because their less efficient appliances cause higher loads.⁷ He offers no empirical
18 evidence to support this claim—it seems more likely, in the aggregate, that low income
19 users, having fewer electrical appliances, have smaller loads than other customers. The
20 future of solar after UNSE's proposal.

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27 ⁶ LIHEAP – Low Income Home Energy Assistance Program.

⁷ Wilson Direct Testimony at p. 9.

1 III. THE FUTURE OF SOLAR AFTER UNSE'S PROPOSAL

2 Q. TASC WITNESS MARC FULMER SUGGESTS THE UNSE PROPOSAL WILL
3 "STIFLE" DG SOLAR; MS. KOBOR SAYS THAT IT WOULD "VERY LIKELY
4 CURTAIL FUTURE DG GROWTH." WHAT, IN YOUR VIEW, IS THE
5 IMPACT OF THE PROPOSAL ON THE FUTURE OF SOLAR IN AZ?

6 A. To assess the possible impacts of the UNSE proposal on the future of solar in Arizona, it
7 is important to first disentangle four things that Mr. Fulmer and Ms. Kobor conflate: the
8 financial interests of solar installation companies, the financial interests of solar DG
9 customers, the long-term prospects for solar DG in the electricity markets, and, of
10 course, the public interest.

11 Q. WHY IS IT IMPORTANT TO DISTINGUISH BETWEEN THE FINANCIAL
12 INTERESTS OF SOLAR INSTALLATION COMPANIES AND THE
13 FINANCIAL INTERESTS OF SOLAR DG CUSTOMERS?

14 A. Advocates for large DG solar installation companies, such as Mr. Fulmer, simplistically
15 assume that the interests of solar customers and solar companies are aligned with one
16 another. For example, in his December testimony, Mr. Fulmer raises the issue of the
17 impact UNSE's proposed rate change will have on PV adoption. His testimony takes the
18 cost of solar DG installation as a given, and then asks what electricity price would be
19 needed to support investment in solar DG.⁸ The presumption is that if the end
20 customer's payback is not rapid and guaranteed, then the proposed electricity price is
21 not adequate to support solar DG.

22 His focus on recovery of customer investment obscures the tension between the interests
23 of solar DG customers and solar installers. Prospective solar customers are looking for
24 cost effective means of meeting their need for electricity. Many of them also are
25 motivated by a public-spirited desire to increase the efficiency and "greenness" of the
26 electricity system as a whole. These aims, however, are not at all technology specific, so
27 going solar is but one option, not the option, as Ms. Kobor and Mr. Fulmer seem to

28 ⁸ Fulmer Direct Testimony at p. 15.

1 assume. It may not even be the most desirable option, and, as shown in this testimony
2 and elsewhere, it is probably never the most cost effective option.

3 **Q. CAN YOU EXPLAIN WHERE THE INTERESTS OF LARGE ROOFTOP**
4 **SOLAR COMPANIES DIVERGE FROM CUSTOMER INTERESTS?**

5 A. The interests of large rooftop solar companies and utility customers diverge on several
6 levels. In regard to solar leases, the most cost effective installation for customers may be
7 quite different than what is most profitable to the lessor. Solar DG companies, perhaps
8 lessors even more than vendors, routinely make false sales representations about their
9 products and benefits they offer, often retain the RECs and SRECs for their own use, as
10 opposed to the use the customer may prefer, and offer lease agreements whose terms are
11 notoriously onerous for customers.⁹

12 However, the primary divergence of interests relates to the massive profits made by
13 these companies—profits that are effectively paid by utility customers. Solar DG profits
14 by using the highly inflated and heavily subsidized net meter prices to shield themselves
15 from market pressure and having to pass on the declining cost of solar panels, whereas
16 the consumer interest is better served by having solar DG vendors/lessors be subject to
17 the marketplace or regulatory disciplines to which all other players in the energy market
18 are subject. Simply stated, it would be better if solar DG developers had to compete with
19 other forms of energy, rather than chasing just subsidies for themselves.

20 Thus, the customers' energy efficiency objectives may require price signals and self-
21 generation options that conflict with the objectives of solar DG developers. As seen in
22 Ms. Kobor's and Mr. Fulmer's testimony, solar DG providers oppose demand charges
23 and other types of pricing that would enable new energy service providers and vendors
24 to offer consumers products to reduce their energy bills. They are committed to
25 maintaining barriers to new entrants who might offer valuable products and services that
26

27 ⁹ A number of these practices are under active investigation by consumer protection agencies in a variety
28 of jurisdictions across the U.S., including Arizona.

1 provide customers with more options, preferring to limit the diversity of products and
2 services found in a robust market, so as to even further reduce the competition for solar
3 DG. Solar DG interests also generally oppose pricing regimes that would make solar
4 DG units more flexible, more attuned to system requirements, and more efficient,
5 because they prefer the simplicity of selling primitive products without having to
6 respond to price signals for a better, more efficient product, something that would add
7 considerable value for customers, but require a more modern and sophisticated business
8 model than simply peddling simple installations at inflated prices. Finally, consumers
9 benefit from an efficient electricity market with competitive discipline, while solar DG
10 companies are self-interested in preserving artificially high prices for their products at
11 considerable cost to consumers, solar and non-solar alike.

12 **Q. IT IS NORMAL FOR COMPANIES TO MAKE PROFITS, SO WHY IS IT**
13 **APPROPRIATE TO SEPARATELY CONSIDER PROFITS MADE BY LARGE**
14 **ROOFTOP SOLAR COMPANIES?**

15 A. The problem is two-fold: how the profits are derived and the magnitude of the profits
16 made by large rooftop solar companies. If the profits were derived from being more
17 efficient, making productivity gains, and reducing costs, those profits would have been
18 earned and deserved. For solar DG companies, however, as revealed in SolarCity's most
19 recent 10K filing with the SEC¹⁰ (discussed below), the profits are derived by chasing
20 subsidies and cross subsidies, including having the price to beat, unlike every other
21 energy source, be retail rather wholesale. Beyond that, of course, since the price they
22 compete against is the bundled, monopoly retail rate,¹¹ they have the advantage of being
23 paid a monopoly price without being subject to the discipline of cost based regulatory
24 oversight.

25 ¹⁰ SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, (available at
26 [http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-
897/1408356/filing.pdf](http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf)).

27 ¹¹ The retail price, they "compete" against, of course, includes compensation for a host of goods and
28 services they do not provide, and reflects the benefits for them that are associated with reallocating
revenue responsibility of a significant share of system costs to non-solar customers.

1 The second issue is the magnitude of profits that, until now, have gone largely
2 unexamined. It seems that, so far, large solar DG companies have been quite effective in
3 preserving large margins for themselves when making solar DG installations. As shown
4 in the testimony of APS witness Cory Welch, filed concurrently with this testimony,
5 rooftop solar leasing companies obtain an average of 40% margins on each installation
6 in UNSE's service territory.¹² This is an astonishing return, particularly in the monopoly
7 context described above. Policy makers and regulators would be well advised to see the
8 issues of subsidies and cross subsidies in the context of such high profits provided to
9 rooftop solar companies. The UNSE proposal for pricing solar DG constitutes a very
10 reasonable way of restoring a marketplace discipline to the pricing and a fairer way of
11 allocating costs.

12 **Q. HAS THE ISSUE OF ROOFTOP SOLAR COMPANIES' PROFITS BEEN**
13 **STUDIED ELSEWHERE?**

14 A. A recent study by MIT, *The Future of Solar*, provides a comprehensive overview of the
15 state of solar technology and of the industry as a whole and is very revealing.¹³ While
16 the authors of the study do not look specifically at profit levels, they do examine how
17 prices that enable and encourage short term profit taking by solar DG companies have
18 an adverse impact on the long term economic viability of solar energy. As part of this
19 study, the MIT authors present a comparative analysis of the costs and prices associated
20 with solar installations, contrasting utility-scale and DG installations. MIT built up its
21 costs estimates from data on hardware costs, combined with surveys of installers and
22 data about wages, and included costs for customer acquisition, sales taxes, margin, and
23 general and administrative expenses—working to develop an estimate of costs that
24 would be sufficient to sustain the industry. Then they compared their bottom-up costs
25 estimates (per watt of installed capacity) with reported actual prices charged (per watt of

26 ¹² Surrebuttal Testimony of Cory Welch Attachment CJW – 2SR.

27 ¹³ See *The Future of Solar Energy: An Interdisciplinary MIT Study*. MIT (2015).
28 https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

1 installed capacity). An interesting pattern emerged—for utility-scale PV, MIT’s bottom-
2 up cost estimates were fairly closely matched to actual prices charged for the systems.

3 This was not the case for distributed generation installation of solar. As expected, due to
4 the loss of certain economies of scale, MIT’s bottom-up costs estimate was higher than
5 for utility-scale solar. This finding is unsurprising. The surprise here is that MIT found a
6 considerable gap between its bottom-up cost estimate and actual reported prices charged
7 for solar DG systems. Here, average reported prices charged exceeded MIT’s cost
8 estimate by an average of 50%—a considerable margin.¹⁴ The existing subsidy structure
9 (including net metering, as well as federal tax incentives) makes it possible for
10 homeowners to pay these prices while still coming out marginally ahead economically—
11 but the prices they are being charged do not reflect the best possible value for
12 consumers, and they provide no incentives for productivity and efficiency gains for solar
13 DG. Indeed, they discourage such efforts. It is also reflective of the fact that while the
14 costs of solar panels themselves have been in dramatic decline, the prices for installing
15 the units have been increasing, thereby enabling the solar DG developers to retain most,
16 if not all, of the benefits of declining panel costs for themselves rather than passing them
17 on to their customers. This is reflected in a recent study by Lawrence Berkeley National
18 Labs which found that out of six countries it compared to the U.S. (Germany, Japan,
19 Italy, China, France, and Australia), only France had higher costs for installed
20 residential PV systems.¹⁵

21
22 These developments may be in the short-term interests of residential PV system
23 developers, but it is not in the long-term interest of solar power, whose interests would
24 be better served by a pricing regime that encouraged increased productivity, better
25

26 ¹⁴ *Id.* p. 86.

27 ¹⁵ Barbose, Galen and Naim Darghouth. *Tracking the Sun VIII: The Installed Price of Residential and*
28 *Non-Residential Photovoltaic Systems in the United States*. Lawrence Berkeley National Laboratory
(August 2015).

1 compatibility with system requirements, and deployment of technology, such as storage
2 and smart inverters, that would better secure solar DG's place in Arizona's energy
3 resource portfolio.¹⁶ Moreover, it is rate design and retail net metering that enables solar
4 DG lessors to retain most of the margin, and essentially pass on pennies on the dollar to
5 solar DG customers, recovering the balance of their profits from taxpayer funded
6 subsidies plus cross-subsidies paid by non-solar customers. No competitive market or
7 properly regulated market would enable that to happen. Thus, UNSE's use of large scale
8 solar, procured in a competitive market, as the benchmark for pricing solar DG solves
9 the problems and allows for more of the benefits of declining cost to be passed on to
10 customers. It might also be noted that the UNSE proposal also has the very positive
11 effect of not diverting capital from the more efficient large scale wind and solar
12 renewable energy to the less efficient solar DG, a likely development if net metering is
13 not replaced by a more rational pricing regime.

14 SolarCity's 10K filing is also quite revealing about its motivations for opposing pricing
15 reforms:

16 **Modifications to the utilities' peak hour pricing policies or rate**
17 **design, such as to a flat rate, would require us to lower the price of**
18 **our solar energy systems to compete with the price of electricity**
19 **from the electric grid.**¹⁷ (emphasis added)

20 This is the acknowledgement by the leading player in the solar DG that its business
21 model is fully dependent on being shielded from competition, hardly a virtue from the
22 standpoint of either consumers or the public interest. The actual cost, or even market
23 valuation, to provide service is not mentioned—it is all about charging as much as
24 possible, depending on the utility rates and existing incentives that will leave no
25 incentive for productivity and will provide marginal benefits, at best, for solar DG

26 ¹⁶ See MIT Study.

27 ¹⁷ SolarCity Corp 10K, filed 2/24/15 for period ending 12/31/14, p. 11 (available at
28 <http://files.shareholder.com/downloads/AMDA-14LQRE/1445127011x0xS1564590-15-897/1408356/filing.pdf>).

1 consumers. In short, net metering enables arbitrarily high prices for consumers,
2 extraction of monopoly rents by solar DG vendors/lessors, and dim prospects for the
3 future of solar DG.

4 **Q. WHAT DO THESE LARGE PROFIT MARGINS, AND THE PRICING**
5 **STRUCTURE UNDERLYING ROOFTOP SOLAR LEASES, MEAN WHEN**
6 **ASSESSING UNSE'S PROPOSAL?**

7 A. It means that the subsidies supporting rooftop solar can be reduced. Indeed, with the
8 recent Congressional extension of the Investment Tax Credit for solar, cross subsidies
9 can be eliminated, without doing harm to increased market penetration by rooftop solar.
10 Indeed, with increased exposure to market risk, solar DG vendor/lessors would be
11 compelled to reduce their prices and improve their products, developments that would
12 make solar DG much more attractive to the public. This, of course, would require the
13 solar DG industry to alter its business model of simple rent seeking and subsidy chasing
14 to one of vigorous competition in the market place and to be willing to accept rates of
15 return commensurate with its performance in the marketplace.

16 Based on the discussions of undisciplined profit margins above, advocates of net
17 metering are presenting the wrong analysis when they argue that eliminating the retail
18 net metering subsidy would make solar DG economically infeasible for end use
19 customers. With the large surplus margins shown by Mr. Welch and the MIT study built
20 into these prices (on top of normal business margins), there is a strong case to be made
21 that the same DG installations could be provided at considerably lower cost—a cost
22 which might well be affordable within the context of a revised tariff for solar DG
23 customers—and still be profitable for DG vendors/lessors. Indeed, with the UNSE
24 proposed reference price, both vendors and customers would be incentivized to improve
25 both efficiency and productivity, as the savings would accrue to them, but would be
26 earned, as opposed to being the gifts of a severely flawed pricing methodology.

1 TASC claims to champion competition and oppose monopoly power, and thereby serve
2 as the consumer's champion in creating a competitive marketplace. In fact, the reality is
3 exactly the opposite. Their advocacy of net metering in this proceeding and others
4 around the country calls for perpetuation of an inefficient, highly inflated, price not
5 subject to any competitive or even cost based pressure, a price that can only survive in a
6 non-competitive environment. In effect, they are seeking a market where they are free to
7 sell their product to customers, but where those very same customers have little
8 opportunity to see competitive or cost based pressure on the prices they are compelled to
9 pay for either purchasing solar DG or having to pay the cross-subsidies inherent in net
10 metering.

11 Current rate design and retail net metering enables TASC members and other solar DG
12 vendors/lessors to charge monopoly rents, subject only to the potential of competition
13 from other DG vendors/lessors, who share the same self-interest of preserving arbitrarily
14 high margins. They seek to preserve a business model in which customers are deprived
15 of the pricing benefits associated with either competitive markets or cost based
16 regulation. This is not in the interest of any utility customer, and in particular, the
17 interests of UNSE's customers.

18 **Q. WHAT ABOUT THE FUTURE OF SOLAR ITSELF? DO THE INTERESTS OF**
19 **LARGE SOLAR DG INSTALLATION COMPANIES THREATEN THE**
20 **FUTURE OF DISTRIBUTED SOLAR AS A COMPETITIVE ENERGY**
21 **TECHNOLOGY?**

22 A. Yes, the short term rent seeking business model of most, if not all, of these companies
23 has created an unsustainable environment in which solar cannot flourish in the long run.
24 In the short term, as noted, the current rate benefits the solar industry, because of the
25 inherent wealth transfer from non-solar to solar customers, plus the wealth transfer from
26 all customers to solar DG vendors/lessors discussed above. That is not a sustainable
27 long-term strategy, particularly if significant expansions in solar DG adoption are hoped
28 for. There are two reasons for this. The first is simply that the public appetite for paying

1 higher than necessary prices for goods and services is very limited, and their patience
2 with that reality, once it becomes, as is inevitable, public, is not great.

3
4 Second, and perhaps even more important in the long term, is the fact that solar, like
5 every other form of energy, must constantly be improving its productivity and overall
6 performance to remain competitive. Thus, to align that reality with the incentives for the
7 solar DG industry, incentives for productivity and efficiency gains should be embedded
8 in rates.

9 Unfortunately, that is precisely the opposite of what occurs under current net metering
10 tariffs. Current tariffs provide absolutely no incentive to improve the performance of a
11 generating resource that already ranks last among renewables in efficiency and cost
12 effectiveness, both in terms of economic efficiency and as a tool for reducing carbon
13 emissions. Any money spent on improving the technology or on storage, under retail net
14 metering, goes to reduce profits, not enhance them. The arbitrarily high, flat prices
15 permitted by current rate design and retail net metering simply do not incentivize
16 investing in improvements. Indeed, it does exactly the opposite.

17 **Q. MS. KOBOR AND MR. FULMER CLAIM THAT ADOPTING UNSE'S**
18 **PROPOSAL WILL REDUCE THE NUMBER OF SOLAR JOBS. WHAT IS**
19 **YOUR RESPONSE?**

20 A. First, neither Ms. Kobor nor Mr. Fulmer offer any specific evidence or analysis
21 regarding UNSE's service territory, both in terms of the number of current solar jobs or
22 the precise effect of UNSE's proposal on those jobs. In fact, in a recent proceeding
23 before the Nevada Public Utilities Commission, TASC and others relied on the same
24 Solar Foundation National Solar Jobs Census attached to Mr. Fulmer's testimony to
25 similarly claim that demand charges proposed by NV Energy would cause a massive
26 reduction in solar jobs. Upon review by Nevada PUC Staff, however, the Nevada
27 Commission rejected the Solar Foundation National Solar Jobs Census, stating that "the
28

1 figures cannot be reasonably relied upon as an estimate of the number of solar jobs in
2 Nevada or the number of jobs that could potentially be impacted by this Order.”¹⁸

3
4 The Solar Foundation report should be rejected here for the same reason: there is no
5 Arizona, much less UNSE, specific data that can be relied upon in considering the
6 impact of UNSE’s proposal on solar-related jobs.

7 **Q. ARE THERE OTHER PROBLEMS WITH MR. FULMER’S AND MS.
8 KOBOR’S CLAIMS REGARDING SOLAR JOBS?**

9 Yes, both involve a very one-dimensional look at the economic impact of solar that is
10 severely flawed and ultimately misleading. Advocates of subsidies for distributed solar
11 generation often point to the supposed economic benefits—particularly job creation—of
12 rooftop solar installation.¹⁹ But claims about a positive impact on job creation are one-
13 sided—they only count new jobs created in solar. They do not even bother to claim that
14 net metering creates more jobs than competitively priced solar DG would. They simply
15 look at solar DG jobs in a compete vacuum and without a real context. Perhaps more
16 importantly, they fail to even consider the broader effect on the economy.

17 If the cost of electricity is higher, jobs are likely to be lost elsewhere in the economy—
18 there is no reason to assume that the net job impact of distributed solar power is
19 positive.²⁰ In fact, a recent study by Tim James, Anthony Evans and Lora Mwaniki-
20 Lyman of Arizona State University used an Arizona-specific regional economic model
21 (a REMI model), balancing the costs of installed DG capacity (and related financing
22

23 ¹⁸ Order, Application of Nevada Power Company d/b/a NV Energy for approval of a cost-of-service
24 study and net metering tariffs, Public Utilities Commission of Nevada Docket Nos. 15-07041 & 15-
07042 at paragraph 229 (December 23, 2015).

25 ¹⁹ There may be some question as to the quality of at least some of the jobs, the solar witnesses claim
26 will be gained. In its most recent 10K filing with the SEC, SolarCity, the largest vendor/lessor of solar
27 DG, disclosed that its employments practices are the subject of an active investigation by the U.S.
28 Department of Labor.

²⁰ The *National Solar Jobs Census 2014* attached to Mr. Fulmer’s testimony is a good example of the
one-sided solar jobs cheerleading genre. It touts solar employment in isolation from the rest of the
economy.

1 costs) against what APS estimates to be the related savings on generation purchases and
2 generation capacity investment over thirty years (and their related customer savings),
3 based on different levels of investment in solar DG that might be made in the APS
4 service territory.²¹ This study models the complexity of judging the economic and job
5 impacts of a particular policy or subsidy—of course, there is an immediate positive
6 impact on some jobs from additional solar employment, but, over time, taking into
7 account the effects of lost spending power by consumers who have to pay more for their
8 electricity, the projected impacts on jobs and on the gross state product of the Arizona
9 economy are decidedly negative (for example, the model shows cumulative losses in
10 gross state product, over time, in the multiple billions of dollars).²²

11 Before leaving the topic of jobs, it is worth remembering that most solar panels sold or
12 leased in the U.S. are manufactured in China. In all likelihood, more American jobs are
13 associated with other forms of generation.

14
15 **Q. IS THE NUMBER OF SOLAR INSTALLATIONS THE DETERMINATIVE
16 STANDARD AGAINST WHICH UNSE'S PROPOSAL SHOULD BE JUDGED?**

17 A. No, it is not. It is clear from their testimony that both Mr. Fulmer and Ms. Kobor believe
18 that there is only one dimension by which to judge public policy on solar DG pricing:
19 how much solar DG is sold or leased. The theory they seem to articulate is quite simple:
20 if a tariff provision results in more solar DG, that is good, and if there is any slowdown
21 in solar DG's rapid growth, that is bad as a matter of public policy.²³

22
23

²¹ As detailed above, I am skeptical about how many of these savings will materialize.

24 ²² Evans, Anthony, Tim James, and Lora Mwaniki-Lyman. "The Economic Impact of Distributed Solar
25 in the APS Service Territory, 2016-2035." Report, L. William Seidman Research Institute, W.P. Carey
26 School of Business, Arizona State University, February 16, 2016. (Attachment ACB-2SR).

27 ²³ See, e.g., Kobor Direct Testimony at p. 51. It is also curious that neither Ms. Kobor nor Mr. Fulmer
28 even bother to ask whether there might be a more efficient pricing methodology under which more solar
DG would enter the market. They appear to be wed to the outdated, rent seeking business model of the
interests for whom they are testifying to even contemplate new approaches that might advance solar DG
out of its niche on the margins into the mainstream of Arizona's energy resources.

1 Public policy and regulatory decision making cannot and must not be as one
2 dimensional as Ms. Kobor and Mr. Fulmer would urge. The point of an electricity rate is
3 to establish a just and reasonable rate, disciplined by the market and/or cost. Such a rate
4 should enable solar DG to compete as a mainstream energy source (even assuming it
5 retains the advantages of federal tax subsidies and renewable energy requirements). If a
6 short-term decline in the growth of solar DG results, that is not necessarily a bad
7 outcome for the world—especially if it means investment is instead being directed
8 towards more cost effective technologies, such as improved solar DG products, utility-
9 scale renewables, and/or innovations that allow for more efficient and more productive
10 means of providing solar DG.

11 **Q. HOW DO YOU RESPOND TO MS. KOBOR AND MR. FULMER'S CLAIMS**
12 **ABOUT SOLAR INSTALLATIONS PLUMMETING IN SALT RIVER**
13 **PROJECT'S TERRITORY AFTER DEMAND CHARGES WERE**
14 **IMPLEMENTED?**

15 A. I don't think the level of DG installations in SRP's service territory is at all indicative, or
16 even relevant, in considering the impact of demand charges on solar installation levels.
17 After SRP implemented a demand charge, Ms. Kobor reports that applications for the
18 DG program fell by 95%.²⁴ Mr. Fulmer makes the same point, and provides a chart
19 showing monthly solar DG applications in SRP for three years before and nine months
20 after the change.²⁵ The chart itself shows an interesting pattern not mentioned by Mr.
21 Fulmer or Ms. Kobor—there was a significant increase in applications in the
22 approximately nine months before the rate change, including a huge spike in the month
23 prior to the change. (A rough estimate based on eyeballing the graph provided by Mr.
24 Fulmer suggests that monthly applications were about ten times the monthly average of
25 the first two years shown.)

26
27 ²⁴ Kobor Direct Testimony at p. 39.

28 ²⁵ Fulmer Direct Testimony at p. 17.

1 A look at the whole picture suggests a more nuanced and complex story than the one
2 told by Mr. Fulmer and Ms. Kobor. As one would expect, the imminent change to a
3 different rate formulation prompted a significant spike in demand—presumably,
4 customers with some intention of installing solar DG in the next couple of years were
5 highly motivated to get their applications in before the rate change. After this spurt of
6 activity, as one would expect, with demand temporarily exhausted, applications dropped
7 significantly. It remains to be seen what will happen once the system has absorbed the
8 demand spike that occurred right before the rate change. It is also important to note that
9 SolarCity has filed an anti-trust suit against SRP for its tariff reforms, alleging that these
10 changes have made it impossible to compete in SRP territory. Thus, SolarCity and
11 others in the solar DG industry have a powerful incentive to essentially boycott SRP
12 customers. To do otherwise would undermine their anti-trust case, since doing business
13 in SRP territory would effectively disprove their allegations of being unable to compete.
14 Thus, the drop in solar DG installations in SRP territory, assuming it is true, could well
15 be a self-fulfilling prophecy by the solar DG industry.

16 Indeed, that self-serving boycotting behavior was also evidenced by Nevada's very
17 recent experience; namely, that large solar installers will attempt to pressure
18 Commissioners, and even the Governor, to restore net metering by suspending
19 operations in the state. Given the analysis of the large margins of profitability above, I
20 would suggest that such a move might simply open up the market to new, local
21 competitors.

22
23 Events in SRP's service territory offer little useful information for another reason: after
24 SRP implemented demand charges, solar installers could literally walk across the street
25 and sell rooftop solar at immense profit margins (60% per system, according to Mr.
26 Welch's study²⁶) in APS's service territory. It is not clear why rooftop solar companies

27 ²⁶ Welch Surrebuttal Testimony, Attachment CJW – 2SR.
28

1 would voluntarily accept lower profits by installing in SRP's territory when they could
2 continue receiving the (overly) rich subsidies available in APS's territory with no
3 incremental effort.

4 **Q. WHY DO CURRENT RATE DESIGN AND RETAIL NET METERING MAKE**
5 **THE FUTURE OF SOLAR UNSUSTAINABLE?**

6 In the long term, in order to be fully sustainable, solar energy needs to be fully
7 competitive on both a price and qualitative basis. That means both that solar should be
8 competitive on a price basis, independent of any subsidy, and that steps need to be taken
9 to reduce the intermittent and off peak production characteristics of solar (e.g. link it to
10 storage, or use western rather than southern exposure in order to better align production
11 with peak demand).

12 Current rate design and retail net metering is exactly the wrong incentive. They simply
13 throw utility customer money at distributed solar in its most inefficient and primitive
14 form. Retail net metering not only fails to incent increases in productivity, but actually
15 discourages them. It makes solar artificially *more* profitable when companies refrain
16 from investing in technological development or taking other steps to improve
17 productivity. Under markets driven by competitive forces, by contrast, investments in
18 technological innovation increase the ability of companies to compete, and thus offer a
19 positive rate of return that justifies that initial investment. What is critical to understand
20 is that net metering, regardless of its profitability for solar DG vendors/lessors, is a
21 subsidy so poorly designed that it actually runs contrary to the long run economic
22 viability of distributed solar energy.

23 **Q. HOW MIGHT UNSE'S PROPOSAL AFFECT THE FUTURE OF SOLAR**
24 **ENERGY IN ARIZONA?**

25 A. UNSE's proposal is an important, if not critical, first step to preserving the future of
26 solar in Arizona. It is true that the proposed rate reform is likely to compel solar
27 vendors/lessors to change their business model from chasing subsidies to competing
28

1 (something they are loathe to do because they are flourishing in a much too cozy
2 environment at present). These companies will have to decide whether to change their
3 model or not, and if not, some may well seek to move their model into other
4 jurisdictions that may continue to shield them from market and regulatory pressures that
5 provide greater opportunity for consumers. The world in which that is happening,
6 fortunately, is changing, and the rooftop solar industry, just as every other segment of
7 the energy sector, will have to become more competitive.

8
9 If some players refuse to adapt, new players will emerge who will see business
10 opportunities and thrive on the challenge of well-functioning markets as opposed to
11 extracting subsidies. In the long run, solar energy will have a much brighter future and
12 will be better assured of finding its place in the mainstream of energy resources. The
13 dire predictions of Ms. Kobor and Mr. Fulmer should be treated with a great deal of
14 skepticism.

15 **Q. CONTRARY TO THE TESTIMONY OF MS. KOBOR AND MR. FULMER,**
16 **HOW MIGHT DEMAND CHARGES ACTUALLY HELP THE FUTURE OF**
17 **SOLAR?**

18 A. The demand charges proposed by UNSE provide price signals that will inevitably
19 enhance the productivity and efficiency of solar DG. What the fixed charge proposal of
20 UNSE does do is to promote overall system efficiency by tying rates and cost causality
21 more closely together so that marginal rates better reflect actual marginal costs while the
22 fixed rates recover unavoidable fixed costs. This improves the price signals to
23 customers, reduces the degree to which cross subsidies are built into rates (including
24 those that flow from non-solar to solar customers), and makes the actual market value of
25 solar DG and energy efficiency more transparent. In short, the result of both the change
26 in fixed costs and the adoption of demand charges for solar DG customers is to insert the
27 disciplines of market and cost that have been lacking in the past. In specific regard to
28

1 solar DG, the UNSE proposals will provide price signals that will enable solar DG
2 installations to operate optimally for both the solar host and the system as a whole.

3
4 What is important is that customers cannot respond to signals to shape their load in more
5 efficient ways unless they are given price signals to do so. A recent study by the Rocky
6 Mountain Institute (RMI) urges that demand rates be part of residential bills because
7 they are inherent to the overall objective of energy efficiency.²⁷ Indeed, RMI coins a
8 phrase, “flexiwatts,” to describe the services and technology that exist to fill the business
9 space demand charges will offer. A recent RMI blog post hails demand charges as an
10 opportunity for new technologies, customer options, and reduced grid costs:

11 Demand charges are a promising step in the direction of more
12 sophisticated rate structures that incent optimal deployment and grid
13 integration of customer-sited DERs. A demand charge more equitably
14 charges customers for their impact on the grid, can reward DG
15 customers with bill savings, and opens up potential for an improved
16 customer experience using load management tools. It can also benefit
17 all customers through reduced infrastructure investment and better
18 integration of renewable, distributed generation.²⁸

19 Similarly, a joint statement by the National Resources Defense Council and the Edison
20 Electric Institute endorses the use of demand charges.²⁹

21 The Natural Resources Defense Council also supported demand charges in a recent
22 filing with the California Public Utilities Commission.³⁰ Those positions, as well as
23 those taken by UNSE and the ACC Staff in this proceeding, are an excellent indication
24 that there are a wide variety of parties and interests who see demand charges as an

25 ²⁷ Lehrman, Matt. “*Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?*”
26 Blog Post, RMI Outlet (May 21, 2015).

27 http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design

28 ²⁸ *Id.*

29 ²⁹ EEI and NRDC, “EEI/NRDC Joint Statement to State Utility Regulators,” February 12, 2014
(http://docs.nrdc.org/energy/files/ene_14021101a.pdf).

30 ³⁰ Proposal of the National Resources Defense Council (NRDC) in Determining a Net Energy Metering
Successor Standard Contract or Tariff, filed August 3, 2015 in Rulemaking 14-07-002 before the Public
Utilities Commission of California.

1 important element of the efficient pricing of electricity. Demand charges work to smooth
2 customer demand, reducing spikiness, and increasing the utility's ability to rely on more
3 efficient resources, rather than turning to its last-resort, less energy efficient sources of
4 generation.

5 One might expect that solar industry interests would see the value in price signals that
6 would enable customers to shape their load in a manner that is both economically
7 efficient and environmentally desirable. Instead of seeing the opportunities for solar
8 energy to help customers shape their loads in more beneficial ways, witnesses Mr.
9 Fulmer and Ms. Kobor oppose innovation and efficiency by defending and clinging to
10 an inefficient and outdated business model of chasing subsidies for the most primitive
11 and inefficient use of solar energy. Once again, it appears that Ms. Kobor and Mr.
12 Fulmer seek to protect the short term profitability of their clients instead of looking out
13 for the long term future of solar energy and for a more efficient and more
14 environmentally friendly electricity marketplace.

15
16 **Q. ARE THERE OTHER EXAMPLES OF HOW TASC AND VOTE SOLAR'S**
17 **POSITIONS WILL HARM THE FUTURE OF SOLAR?**

18 A. Mr. Fulmer and Ms. Kobor's apparent opposition to "enabling technologies" that could
19 help customers manage their demand is another example of how their position
20 disregards the long-term interests of solar energy. Ms. Kobor's argument is particularly
21 ironic. Her main objection is that such technologies are "uncommon, costly to
22 implement, and have not achieved widespread adoption."³¹ It is ironic that she raises this
23 as an objection to changing net metering rates, since it is exactly these kinds of archaic
24 rates that make it hard for smart enabling technologies to take hold. Current net metering
25 rates provide zero incentive for customers to invest in such technologies. It is hardly fair
26 to complain that they have not been widely adopted while defending a rate structure that

27

³¹ Kobor Direct Testimony at p. 35.

1 prevents customers from realizing any savings by using these technologies. One of the
2 important benefits of UNSE's proposed revision to rates for DG customers would be
3 that it should contribute to the development of these kinds of technologies.

4 Indeed, it is fair to say that not only is their position contrary to solar, but by opposing
5 tariff changes, such as demand charges, they are effectively precluding innovations that
6 would enable providers of sophisticated energy services to enter the market. That is
7 because such companies depend on price signals to optimize the use of "negawatts" and
8 "flexiwatts." Transparent and meaningful unbundled prices will enrich the marketplace,
9 provide more options for consumers, and help to optimize the role that solar DG can
10 play. It is ironic that, instead of seeing that as an opportunity for the solar DG industry,
11 or a benefit for customers, the two witnesses argue for a "dumbed down" marketplace,
12 the effect of which is to reduce the amount of goods and services, restrict market entry
13 for otherwise valuable market participants, and, ironically provide channels for
14 optimizing solar DG.

15
16 **IV. ARGUMENTS FOR DELAY AND INACTION SHOULD BE REJECTED**

17 **Q. HOW DO MR. FULMER AND MS. KOBOR ARGUE THAT THE**
18 **COMMISSION SHOULD DELAY OR TAKE NO ACTION REGARDING**
RETAIL NET METERING?

19 A. Mr. Fulmer and Ms. Kobor provide a variety of arguments that urge no action. These
20 include that (i) an unbiased "Value of Solar" study should be performed before any
21 action is taken; (ii) rooftop solar customers only account for 2% of cost shifting in
22 UNSE's service territory and that other, larger, cost shifts exist; (iii) UNSE has not
23 performed specific studies on certain topics; (iv) rooftop solar is needed for UNSE to
24 achieve compliance with the distributed generation component of Arizona's Renewable
25 Energy Standard; (v) UNSE's proposal would violate Arizona net metering rules; and
26 (vi) demand charges are not part of the modern trend in rate design. I address each in
27 turn.

1 **Q. IS AN UNBIASED “VALUE OF SOLAR” STUDY NEEDED TO ADEQUATELY**
2 **ASSESS UNSE’S PROPOSAL?**

3 A. No, it is not. Ms. Kobor argues that UNSE needs to conduct a “full benefit/cost
4 analysis” (presumably, a “Value of Solar” study), stating that without such an analysis,
5 there is “no way to determine the current relationship between the retail rate and the
6 value of NEM exports, and thus no way to determine the reasonableness of the
7 Renewable Credit Rate.” If a cost shift exists, Ms. Kobor says, there is no way to even
8 tell what direction it goes in!³² I beg to differ. This is like saying that unless I can give
9 the precise height of an elephant, I can’t say it is bigger than a horse.

10 The “value” of solar simply does not need to be assessed before UNSE’s proposal is
11 acted upon. Rates are based on either a market or cost base, not some theoretical and
12 highly subjective notion of value. There have been a number of such studies in recent
13 years, which come to quite diverse and often conflicting conclusions. I do not believe
14 such studies can accurately determine what the prices should be, and I certainly do not
15 see any basis for pricing all energy sources based on cost and market, while solar DG,
16 alone, of all resources, is priced based on some consultant’s subjective assessment of
17 value.

18 **Q. WHY DO YOU BELIEVE THAT THE VALUE OF SOLAR CANNOT BE**
19 **ACCURATELY DETERMINED THROUGH AN UNBIASED STUDY?**

20 A. Assessing the future value of solar necessarily involves making arbitrary and subjective
21 determinations based on speculation about future events as well as monetizing alleged
22 attributes of distributed solar, some of which may not, in fact, actually be attributes. It is
23 simply impossible for one to conduct such a study on an unbiased, much less accurate,
24 basis.

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³² Kobor Direct Testimony at p. 27.

1 Ms. Kobor herself recognizes the fundamental problem, acknowledging the existence of
2 competing 2013 APS studies finding drastically different values.³³ She seems confident,
3 however, that with Commission oversight, a cost/benefit analysis can be conducted that
4 will produce a “reliable result,” and suggests use of a guidebook prepared by the
5 Interstate Renewable Energy Council, citing the categories of benefits identified in the
6 IREC report:³⁴

- 7 a) avoided energy benefits
- 8 b) system losses
- 9 c) generation capacity
- 10 d) transmission and distribution capacity
- 11 e) grid support services
- 12 f) financial services
- 13 g) security services
- 14 h) environmental services
- 15 i) social services
- 16 j) customer costs
- 17 k) utility costs
- 18 l) decline in value for incremental solar additions at high market penetration
- 19 m) transmission and distribution (T&D) line loss reduction (avoided
20 transmission/distribution investment)
- 21 n) environmental benefits (emission mitigation costs)
- 22 o) avoided purchased power/risk
- 23 p) avoided grid support
- 24 q) economic development

25
26 ³³ See Kobor Direct Testimony at p. 27.

27 ³⁴ Ms. Kobor, pp. 27-28. Witness Mark Fulmer references many of these same elements in his Direct
28 Testimony.

1 That Ms. Kobor considers the IREC Report to be an unbiased starting point proves more
2 than she intended.

3 The IREC publication, rather than being a “best practices” guide, is an advocacy piece
4 that simply lays out an outline for ways of arguing for cross subsidization of solar DG—
5 without any developed evaluation methodology. Indeed, it is an attempt to find a
6 rationale for the prices derived from retail net metering, which was never a carefully
7 reasoned pricing regime, but was, rather, a default methodology that evolved for reasons
8 that are no longer relevant in today’s electricity market. Not only does IREC offer no
9 methodological assistance, it provides no basis whatsoever for monetizing the criteria
10 noted above. It is, in fact, little more than a laundry list of potential attributes solar
11 advocates can use to call for higher prices for solar DG, without ever offering a serious,
12 fact based rationale for the claims asserted. It suggests, for example, an examination of
13 the impact of solar DG on carbon reduction, but gives little guidance on how such an
14 effort should be undertaken, and, remarkably, never even suggests that one might
15 examine the cost effectiveness of solar DG in reducing carbon emissions compared to
16 such alternatives as energy efficiency, large scale solar, nuclear, and wind. Similarly, it
17 fails to even reference the fact that in order to assess the carbon effects of solar DG, one
18 needs to clearly identify what generating resources are being displaced (e.g. coal,
19 combined cycle) by solar DG when it is producing energy and what the impact of the
20 intermittent nature of solar DG is on dispatch, as well as the environmental impact, not
21 to mention economic efficiency, of ramping generation up and down to accommodate
22 the intermittent injection of solar DG energy into the system.

23
24 The point here is not that the IREC document, or any number of value of solar studies,
25 are incomplete and biased, although the IREC report clearly is, as are many value of
26 solar studies. Rather, it is that such studies are highly subjective, often quite arbitrary,
27 and, if reasonably complete, extraordinarily complex (if the authors are truly
28

1 disinterested analysts, as opposed to advocates with a point of view), and, to be done
2 correctly, these studies require a great deal of time and expense. Moreover, the results,
3 no matter how honestly derived, are always going to be highly subjective, full of
4 debatable assumptions, and subject to severe criticism by any number of interest groups
5 with an axe to grind or a point of view to advance. Perhaps most interesting is that such
6 studies rarely even reference the historic reference points used for pricing, markets and
7 costs.

8
9 There is a reason we rely on markets and market prices, and not “value analysis,”
10 whenever possible. When we do use value analyses, it is important to keep these
11 limitations in mind. Indeed, electricity pricing in the U.S. has always been based on one
12 of two highly disciplined foundations, cost (including avoided cost), and/or market.
13 Every energy source in the country is priced on one of those foundations. Pricing one
14 resource based on someone’s subjective view of “value,” while pricing every other
15 resource based on a disciplined and systematic approach, is simply indefensible as a
16 matter of public policy. The public deserves better than that.

17 **Q. DO YOU AGREE WITH MS. KOBOR THAT THE EXISTENCE OF OTHER**
18 **COST SHIFTS IS A REASON TO TAKE NO ACTION ON ROOFTOP SOLAR**
19 **SUBSIDIES?**

20 A. I do not agree with her at all. First, the fact that there may be other cross-subsidies in
21 rates is hardly a reason for refusing to remedy perhaps the most inefficient of cross
22 subsidies. This is particularly true where the remedy, as proposed by UNSE, is so simple
23 to put in place.

24 More importantly, Ms. Kobor misses the point almost completely. It may be true that
25 other factors contribute more to UNSE’s revenue deficiency. The much bigger issue,
26 and the one Ms. Kobor completely ignores, is that current rate design and retail net
27 metering causes shifts, socially regressive ones, in cost allocation among customers. If
28 solar DG customers are excused, as they are under current rate design, from having to

1 pay their fair share of the fixed and demand costs associated with the energy service
2 provided to them, those costs do not disappear. Regulators are then left with just two
3 options, either pass on those costs to non-DG customers, or, alternatively, force utilities
4 to absorb those lost revenues, an outcome that is very likely to result in underinvestment
5 in the grid (and may not be legally permissible or consistent with the regulatory
6 compact). Neither of those outcomes is acceptable in any event. The real issue is
7 avoiding that highly unfortunate choice, and the way to fix it is to require all customers,
8 including rooftop solar customers, to pay their fair share of the system's fixed and
9 demand costs.

10 Ms. Kobor's testimony draws the wrong conclusion in reasoning that there is no good
11 reason to single DG customers out as a class for special reformed rates. First, as noted
12 by several witnesses, now including myself, in this proceeding, there are many reasons
13 why UNSE is correct in making the tariff reforms it proposes. Revenue deficiency is
14 only one of them, and perhaps not even the most important one. In specific regard to
15 revenue deficiency, however, DG solar is expected to continue to grow in Arizona, and
16 the more it grows, the bigger a burden the cross-subsidy will represent. Eventually, it
17 will simply not be sustainable. Moreover, as can already be seen in this state and others,
18 the politics of getting the tariffs right becomes increasingly difficult when more and
19 more people are invested in a severely flawed tariff that skews the prices in costly and
20 economically perverse ways. It is best to get the prices right from the beginning so that
21 when customers make their decision about whether or not to go solar, the price signals
22 are correct and the costs and benefits to society are correctly aligned in the tariff
23 formulation. Failing to do so means that every new solar DG installation represents a
24 significant investment made based on expectations of continuing out-of-market and
25 above cost pricing, thereby increasing the difficulty of ever reforming the policy. In
26 fairness to both DG and non-DG customers alike, it is important to get rate signals
27 correct and sustainable as soon as possible.
28

1 **Q. MS. KOBOR ASSERTS THAT UNSE HAS FAILED TO ADEQUATELY PROVE**
2 **ITS CLAIMS. PLEASE RESPOND.**

3 A. Ms. Kobor challenges UNSE's proposal that distributed generation has the potential to
4 seriously impact the grid and UNSE's analysis of the incentive problems it creates for
5 customers, by complaining that UNSE has not provided detailed evidence that the
6 problems it fears are happening at scale today, complaining that "UNSE...relies on
7 broad national and regional studies, which may or may not apply to UNSE's grid and
8 service territory."³⁵ She herself, however, provides no actual evidence that the facts are
9 on her side. She does not even present a plausible theory that would suggest the facts
10 might be on her side or explain why she thinks Arizona's circumstances are not
11 adequately captured by regional or national studies. What, exactly, does she think is
12 different about Arizona? She never bothers to explain.

13 In doing this, she is failing to meet her client's burden of raising sufficient doubt as to
14 the applicant's proposal to shift the burden of proof back to the utility. I was a regulator
15 for ten years. I have taught regulation in more than two dozen countries, and at many
16 institutions within the United States, including all three NARUC-approved training
17 programs, at Michigan State University, the University of Florida, and New Mexico
18 State University, as well as here at Harvard. The process that should be followed in
19 cases like these is clear. The utility makes a proposal, and parties who wish to rebut the
20 proposal, whether the staff of the Commission or outside parties, have the opportunity to
21 do so. They do, however, also have a burden of providing evidence to support their
22 rebuttal, and if they don't meet that burden, there is nothing for the Commission to go
23 on. Witness Kobor has offered absolutely no probative evidence to meet that simple
24 burden.

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27

³⁵ Kobor Direct Testimony at pp. 16-17.
28

1 In fact, both Ms. Kobor and Mr. Fulmer complain that the extensive evidence and
2 analysis provided by UNSE is somehow inadequate but fail to offer any countervailing
3 evidence or even, in many cases, a strong theory suggesting why UNSE's analysis
4 requires further support. What witnesses Mr. Fulmer and Ms. Kobor have provided here
5 is testimony making broad assertions with no evidentiary basis. Consequently, they have
6 failed what the law terms their burden of going forward with credible evidence
7 supporting their assertions.

8
9 It is ironic that all this effort to undermine UNSE's analysis still fails to get to the heart
10 of the issue. Ms. Kobor devotes many pages to an argument that points to the
11 unsurprising fact that DG customers are still a relatively small part of the UNSE
12 customer base—therefore, the gross amount of cross subsidy they are receiving is
13 currently relatively small. It is not clear why Ms. Kobor chooses to focus on just one
14 motivation for the tariff reforms proposed by UNSE, but her largely exclusive focus on
15 it makes it appear that she has presented less than a complete understanding of all of the
16 issues at hand.

17 **Q. SHOULD UNSE CONSIDER THE DISTRIBUTED GENERATION**
18 **REQUIREMENT IN ARIZONA'S RENEWABLE ENERGY STANDARD (RES)**
19 **IN SETTING ITS RATE FOR SOLAR DG ENERGY?**

20 No. Although Ms. Kobor warns that a change in the net metering rate might result in
21 UNSE failing to meet its distributed generation requirement in upcoming years,³⁶ this is
22 not a consideration that it is appropriate to incorporate into rate design. Significantly,
23 she has also failed to make any showing that her assertion that implementing UNSE's
24 rate proposals would cause UNSE to be out of compliance with its required quota of
25 DG. In effect, she is pleading for distorted pricing and incentives over the long term in
26 order to head off a specific, short-term problem which indeed may not turn out to be a
27 problem at all. This is not good ratemaking as expounded by Professor Bonbright!

28

³⁶ Kobor Direct Testimony at p. 52.

1 Instead, if there is a need for additional solar DG to meet state requirements, that should
2 be handled separately, helping to keep costs transparent and efficiency incentives in
3 place. Moreover, the rule itself is absolutely within the discretion of the Commission to
4 modify, eliminate, or waive.

5 **Q. WHAT IS THE RELEVANCE OF MS. KOBOR'S ARGUMENT THAT THE**
6 **PROPOSED RENEWABLE CREDIT RATE WOULD VIOLATE THE**
7 **COMMISSION'S EXISTING NET ENERGY METERING RULES?**

8 A. Ms. Kobor makes this argument on pp 32-33 of her testimony. Without evaluating this
9 argument substantively (I have not examined the question of whether the proposed rate
10 violates the existing rule or not), it is improbable that this is an insurmountable obstacle,
11 should the Commission wish to approve the proposed rate. Whatever the existing rules
12 are, they were established by the Commission. When I sat on the Public Utilities
13 Commission of Ohio, we always had available the ability to repeal, modify, or waive
14 commission-created rules where we believed the circumstances were such that the
15 action(s) was (were) both warranted and reasonable.

16 **Q. IS THERE ANY BASIS FOR MS. KOBOR'S ASSERTION ON PAGE 37 THAT**
17 **"MOVEMENT TOWARDS MANDATORY DEMAND CHARGES FOR ALL**
18 **RESIDENTIAL CUSTOMERS IS IN NO WAY REFLECTIVE OF MODERN**
19 **TRENDS IN RATEMAKING?"**

20 A. None at all. I am Executive Director of a leading "think tank" on electricity policy, and
21 the potential role of demand charges in rate design is a frequent subject of discussion.
22 Recent proceedings in Ms. Kobor's home state of California included significant debate
23 over that issue. In fact, demand charges are a critical element in the movement in
24 ratemaking toward unbundling prices, making prices more transparent, and providing
25 customers with meaningful price signals in order to bring greater efficiency to the use of
26 electric energy. Indeed, the position of the ACC Staff in this matter is a classic example
27 of demand charges being at the center of regulatory thinking in the U.S. today. Suffice it
28 to say that Ms. Kobor's deeming the idea as not reflective of modern trends in
 ratemaking is both uninformed and profoundly mistaken.

1 Q. **WOULD YOU AGREE WITH MS. KOBOR'S ASSERTION THAT THE**
2 **PROPOSAL TO REDUCE THE NUMBER OF CUSTOMER TIERS IS ALSO**
3 **NOT REFLECTIVE OF "MODERN RATE DESIGN?"**

4 A. No. Ms. Kobor has a distorted view of "modernized rate design" if she believes that
5 reduction of the number of rate tiers is not compatible with it.³⁷ This issue has been
6 vigorously debated within her own state very recently, and is a topic of debate across the
7 country, indeed, around the world.

8 V. UNSE'S PROPOSAL FOR A RENEWABLE CREDIT RATE IS AN APPROPRIATE
9 WAY TO COMPENSATE CUSTOMERS FOR ENERGY EXPORTED TO THE
10 GRID.

11 Q. **TURNING TO THE THIRD ELEMENT OF UNSE'S PROPOSED RATE, IS THE**
12 **MOST RECENT RENEWABLE PPA A REASONABLE BENCHMARK FOR**
13 **SETTING THE RENEWABLE CREDIT RATE FOR COMPENSATING DG**
14 **SOLAR PRODUCTION?**

15 A. Yes, this approach is entirely reasonable. It uses a benchmark price established for
16 intermittent renewable energy by looking at the last arms-length transaction to purchase
17 intermittent renewable energy in the competitive bulk power market. By using the most
18 recently negotiated rate, the price recognizes that energy prices fluctuate and does not
19 lock in a higher than market standard offer for solar DG. It does not over-compensate
20 distributed generation beyond levels of compensation offered to grid-scale renewables,
21 thereby averting the potential for diverting capital from a more efficient generator to a
22 less efficient one. Indeed, by gearing the price paid for solar DG to that of a more
23 efficient resource, UNSE' proposal has the very positive effect of incentivizing solar DG
24 to become more efficient and improve productivity. That incentive is completely lacking
25 in the existing retail net metering pricing model, and that is one of the problems that
26 cries out for reform of the type being proposed by the applicant in this proceeding.
27 Nonetheless, UNSE's proposal is still generous in the sense that it is paying the same for
28 solar DG as it does for utility-scale solar, despite the fact that the latter is the more
efficient resource. Finally, the benchmark price is derived from transactions involving

³⁷ Kobor Direct Testimony at p. 55.

1 energy resources that are, like solar DG, intermittent. Thus, UNSE’s proposal avoids
2 having to compare apples with oranges. The price point is one that is subject to market
3 discipline, recognizes fluctuations in the wholesale market, and prevents a reallocation
4 of capital toward less efficient resources.

5 **Q. WHAT ABOUT MR. FULMER’S AND MS. KOBOR’S ARGUMENT THAT THE**
6 **PRICE OFFERED FOR DG SOLAR SHOULD BE HIGHER THAN THE PRICE**
7 **OF UTILITY-SCALE RENEWABLES, BECAUSE DG SOLAR OFFERS MORE**
8 **VALUE TO THE UTILITY?**

9 A. The argument has no merit. The argument they are making is a variation on the “value
10 of solar” theme discussed above. Ms. Fulmer and Ms. Kobor both suggest that rooftop
11 solar offers more value than utility-scale solar in their discussion of UNSE’s proposal to
12 compensate DG solar at the going wholesale market rate, as established by the latest
13 comparable PPA. The geographic diversity of solar DG systems is their main argument.
14 This, they suggest, will alleviate the intermittency of solar power. At the same time, Mr.
15 Fulmer argues, distributed solar systems do not have “the potential habitat, visual and
16 cultural impacts associated with utility-scale solar plants.”³⁸ However, neither of the two
17 makes any effort to quantify this additional “value.” They do not even try to show that
18 the so called “value” they reference is equal to the full retail price of delivered
19 electricity. Because they do, as noted, cite anecdotal examples of the added “value” they
20 claim, I will address each of them.

21 **Assessing the value of geographic diversity relative to intermittency.** This argument
22 is one dimensional thinking—Mr. Fulmer and Ms. Kobor highlight one or two small
23 possible benefits of DG solar compared to utility-scale solar, while ignoring the
24 overwhelming, evidence-based, consensus that grid-scale PV generation is more
25 efficient—not just for the obvious reasons of economies of scale, and the fact that grid-
26 scale plants are far more likely to have optimized panel placement and tracking, but also

27 ³⁸ Fulmer Direct Testimony at p. 4.

1 because a utility-scale solar plant, purpose-built to produce solar power, is more likely to
2 be optimally situated in areas of peak sunshine.³⁹

3 It is unlikely this argument about geographic diversity points to any significant
4 advantage of solar DG over grid-scale solar. For one thing, it is based on the false
5 assumption that grid-scale solar plants are limited to a single location. Utility-scale solar
6 plants can take advantage of geographic diversity as well—and the potential for
7 diversity is great, since utilities can purchase power from distant plants, as long as they
8 are connected to the transmission grid. Rooftop solar, of course, by its very nature is
9 entirely concentrated within the narrower confines of a distribution utility. Thus, the
10 claim of geographic diversity as a benefit of rooftop solar has no basis in fact.

11
12 Even if one accepts the dubious premise of greater geographic diversity in rooftop solar
13 systems, the claim that this outweighs the benefits of utility-scale solar does not hold
14 water. The previously cited Brattle Group study comparing grid-scale with rooftop solar
15 systems looks at this issue in the terms proposed by Mr. Fulmer and Ms. Kobor, pitting
16 the intermittency of a single utility-scale solar unit against an array of rooftop solar
17 units. While acknowledging the potential role geographic diversity could play in
18 reducing intermittency from the rooftop solar units, the Brattle analysis also looks at
19 other significant factors, noting that “Utility-scale systems that oversize the panel array
20 relative to inverter capacity will likely have a better profile (less variability) than any
21 given residential-scale system,” a factor that needs to be weighed against geographic
22 diversity, stating that the net impact on ancillary services needs is “difficult to
23 determine,” but noting grid-scale solar’s other advantages of “better location selection
24

25 ³⁹ Tsuchida, Bruce, Sanem Sergii, Bob Mudge, Will Gorman, Peter Fos-Penner, and Jens Schoene.
26 *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado’s*
27 *Service Area.* Brattle Group, 2015, p. 9. Available at
[http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Uti
28 lity-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf?1436797265.](http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf?1436797265)

1 (higher insolation), better controllability and visibility by the system operator, and being
2 able to provide downward ancillary services.” After reviewing other factors, such as the
3 higher capacity factor of utility-scale PV, the possible transmission loss reductions
4 associated with distributed PV, the Brattle study concludes that “[o]verall, inclusion of
5 these factors is likely to increase the cost difference between utility-scale and
6 residential-scale PV systems.”⁴⁰

7 **Assessing the value of “habitat, visual and cultural impacts.”** In his November, 2015,
8 testimony, Mr. Fulmer cites the discussion of these potential impacts in the DOE’s
9 *Sunshot Vision Study* as an argument for the greater value of solar DG as opposed to
10 utility-scale solar.⁴¹ However, his presentation of the issue is one-sided, neglecting the
11 issues faced by distributed solar, ironically raised by the same DOE study he cites only a
12 few pages beyond the information he presents in his testimony:

13 owners of existing systems face potential challenges when growing
14 trees or new structures on neighboring property shade their solar
15 collectors. Given that there is no common-law right to sunlight in the
16 United States, these issues present serious barriers to the adoption of
solar energy⁴²

17 The DOE report goes on to suggest some legal mechanisms that may allow neighbors to
18 navigate this issue through establishing “landowners’ rights to present and future
19 unobstructed direct sunlight” or through sale of easements, etc.—but they have
20 appropriately pointed out that the installation of rooftop solar is not without implications
21 to neighboring homes—particularly if it results in attempts to limit the growth of trees
22 on a neighbor’s property or their attempts to remodel or expand homes.⁴³ What DOE is

23
24 ⁴⁰ *Id.* at pp. 35-36.

25 ⁴¹ For those, like me, puzzled by the reference to “cultural impacts,” the DOE study writes that “conflicts
26 may arise if development impacts cultural sites or interferes with U.S. Department of Defense (DOD)
activities.” “The SunShot Vision Study,” Department of Energy, February 2012, at p. 171. These
potential “cultural impact” problems seem to be readily addressed through proper site selection.

27 ⁴² DOE SunShot Vision Study at 184.

28 ⁴³ For that matter, it may be worth considering the incentive solar panels might present to cut down
existing shade trees. When tree shade is an issue, certainly, the calculus about the environmental costs

1 discussing is selective destruction of other people’s trees to accommodate solar DG. In
2 short, we may often run the real risk of losing the aesthetic, shade, and carbon offset
3 benefits provided by trees in order to accommodate solar DG. Thus Mr. Fulmer’s claim
4 that solar DG provides greater habitat value is highly dubious at best. Similarly in regard
5 to the claim of “visual” value, another well-known source of neighborhood conflict
6 related to solar DG is the potential for glare from solar panels to adversely impact
7 neighbors. In short, visual and habitat impacts are not limited to utility-scale solar.

8 **Q. MR. FULMER CRITICIZES UNSE’S RENEWABLE ENERGY CREDIT**
9 **BECAUSE IT IS SET UP TO ADJUST EVERY YEAR. WHAT IS YOUR**
10 **EVALUATION OF THIS ARGUMENT?**

11 A. Mr. Fulmer raises a number of concerns about the proposed compensation methodology;
12 however, not all his concerns seem to be consistent with each other. In part, his concern
13 seems to be that the deal being offered to rooftop solar customers is not good enough.
14 The proposal here is to tie rooftop solar compensation to a measure of the actual price of
15 renewable energy in the open marketplace in a given year—instead, Mr. Fulmer
16 suggests that rooftop solar customers should be given a twenty year price guarantee. He
17 asserts, “the prudent utility will look at its needs in the future and consider all the
18 options for meeting those needs in a least-cost fashion....If you can take actions NOW
19 that can save ratepayers money (or reduce risk or meet some other planning goal) in the
20 future, at higher costs today, they are likely the correct actions to take.”⁴⁴

21 Mr. Fulmer’s stated concern for securing marginal efficiencies for ratepayers related to
22 getting the most bang for their bucks in the purchase of renewable power is inconsistent
23 with his main objection to the proposed pricing scheme: “Further, as proposed, Rider 11
24 will likely act more like a ratchet, ever going down. This obviously creates a problem
25

26 and benefits of solar panels becomes increasingly complex, expanding to include the question of how
27 much additional air conditioning power might be used to compensate for loss of shade.

28 ⁴⁴ Fulmer Direct Testimony at p. 9.

1 for someone considering an investment in a fixed asset.”⁴⁵ That is, Mr. Fulmer
2 (correctly, in my opinion) anticipates that grid-scale renewable energy will get cheaper
3 over time (keeping in mind that, as discussed above, that larger-scale renewables are
4 more cost effective today).⁴⁶ And, disturbingly, he views this as a problem, one that
5 should be solved by committing utility resources to overpaying for DG renewable
6 energy for decades into the future—when that same amount of money, if indexed to
7 declining renewables costs, could buy ratepayers far more renewable energy per dollar
8 under the UNSE proposal, and would at the same time provide rooftop solar providers
9 with an incentive to be more efficient.

10 **Q. WOULD THE RENEWABLE CREDIT RATE BE SUBJECT TO GAMING?**

11 A. Ms. Kobor raises the vulnerability of the proposed pricing system to gaming as a
12 concern,⁴⁷ suggesting that the utility could manipulate its PPAs to artificially deflate the
13 Renewable Credit Rate.
14

15 There is no system that is not at least theoretically vulnerable to some type of gaming.
16 Indeed, policing against gaming that is contrary to the public interest is an important part
17 of the *raison d’etre* of the ACC. Thus, the risk of gaming is simply not a sufficient
18 reason to retain the severely flawed system of retail net metering, which itself is already
19 being gamed by the solar DG industry.⁴⁸ What UNSE has proposed has the virtue of
20 transparency. Through annual public filings, the Commission and the public will be able
21 to review the Renewable Credit Rate and address any concerns about gaming that may

22 ⁴⁵ Fulmer Direct Testimony at p. 7.

23 ⁴⁶ Curiously, Mr. Fulmer does not object to the fact that utilities, under net metering buy excess solar DG
24 at the retail rate, something which also fluctuates over time, but, based on solar DG industry marketing
25 claims (and I received such a robo call very recently) that fluctuation is upward. Thus, Fulmer is
essentially arguing not against uncertainty, but rather calls for a completely asymmetrical arrangement
where solar DG gets the benefits of any upward price fluctuation, but has no risk of downward
fluctuation in the marketplace.

26 ⁴⁷ Kobor Direct Testimony at p. 31.

27 ⁴⁸ SolarCity’s recent 10K filing clearly describes that its business model is built on chasing subsidies, a
classic example of gaming, which is not in the public interest. *See* SolarCity Corp. 10K (2/24/15) at p.
28 38.

1 arise. Moreover, the Commission itself has the requisite skills and intelligence to
2 monitor, identify, analyze, and remedy any adverse gaming that may occur.

3 **Q. IS THE PROPOSAL MADE BY LON HUBER OF RUCO FOR THREE RATE**
4 **OPTIONS FOR SOLAR DG CUSTOMERS A GOOD ALTERNATIVE RATE**
5 **APPROACH?**

6 A. RUCO's aim here as explained by Mr. Huber is laudable:

7 RUCO would like to begin by ensuring that rooftop DG can be a neutral
8 cost proposition for ratepayers as soon as possible. Once that milestone
9 is reached RUCO would like to see DG be a net benefit to all
10 ratepayers. Finally, the third milestone, RUCO would like to see a
11 closer cost parity between wholesale grid-connected solar and rooftop
12 solar.

13 I agree with these goals. However, the rate structure RUCO proposes would not get
14 Arizona there "as soon as possible"—in fact, though it might progress slowly in that
15 direction, it would never actually arrive, even after twenty years. I think we can fix the
16 retail net metering rate problem faster than that!

17 Mr. Huber suggests three rate options, all of which, in my opinion, are inferior to the
18 UNS proposal. Among other issues, they don't seem to fit together in a way that
19 constitutes consistent public policy. Although it appears from his testimony that he
20 understands the issues, the RUCO proposals do not seem to have translated into a
21 proposal that resolves the issues before the Commission. Here are the major problems
22 with RUCO's proposal as I see them:

- 23 1. *The Non-Export Option.* With this option, solar DG customers could stay on
24 traditional rates—they would just have to agree not to export solar power to the
25 grid. To me, this does not address the issues. To the extent that customers choose
26 any of the current rates, in which fixed costs are recovered through variable
27 energy use charges, the cross subsidy issues above are not addressed at all.
28 Furthermore, the non-export provision is not the direction Arizona should go if it
wants to optimize the potential contributions of solar power—the aim, rather,

1 should be to optimize the benefit to the consumer and the grid of investments in
2 solar, by having fair rates that create proper incentives for efficient deployment
3 and use of solar DG—not to discourage customers from maximizing the benefits
4 of their investment in solar energy.

5
6 2. *The DG “TOU” Option.* This proposed rate weakens some elements of the UNS
7 proposal that is intended to correct inequities associated with solar DG’s
8 participation in retail net metering. The minimum bill (alternative to fixed
9 charge) increase is smaller (\$12); and the proposed payment for exported power
10 is higher. The proposal is to pay 8.5 cents/kWh for excess power exported to the
11 grid—considerably more than the going rate for utility-scale renewable energy.
12 This higher rate is based on some very rough calculations of capacity savings
13 undertaken by Mr. Huber. For the reasons of solar intermittency I discussed
14 above, in my opinion these capacity savings will not be realized by the utility or
15 its customers. At the same time, the proposal includes an aggressively high TOU
16 demand charge during summer peak hours (2pm-8pm)—at \$19.50/KW, the
17 charge is almost twice as high as the higher of the two demand charges proposed
18 by UNS for customers whose demand exceeds 7 kW. This does provide a strong
19 incentive to customers who choose this rate to minimize their consumption
20 during these summer peak hours—I would note, though, that (keeping in mind
21 the California duck curve chart discussed earlier) the long-run interest of the
22 utility and of the growth of solar in Arizona is to encourage solar DG customers
23 to use energy when the sun is shining, but consciously reduce their usage when
24 the weather is cloudy and when the sun declines and sets. The 2pm-8pm TOU
25 rate proposed is too blunt an instrument to promote this behavior. Overall, it is a
26 little hard to tell what the impact of this proposed option would be, in terms of
27 minimizing cross subsidies. The element of choice of rates endorsed by RUCO
28

1 would be the decisive factor in preserving cross-subsidies, since presumably only
2 customers who hope to benefit from such a rate would choose it.

3
4 3. *RPS Bill Credit Option*. This final (very generous) option addresses only the
5 export rate portion of the cross subsidy. Reforming the export rate is a step in the
6 right direction, but to be comprehensive, it must be coupled with rate design
7 reforms. Further, this RPS Bill Credit Option pursues this partial reform in a way
8 that would be better described as “glacial” than “gradual.” The renewable credit
9 rate would start at a generous 11 cents/kWh—a rate which customers could lock
10 in for twenty years. For new customers, the initial rate offer would slowly
11 decline as more solar capacity was added, reaching competitiveness with current
12 utility-scale renewable energy rates as late as 2025 (though potentially this could
13 happen earlier, depending on how fast growth in solar capacity occurs).
14 Throughout this period, customers could lock in these elevated per kWh
15 reimbursement rates for twenty years at a time. So it would be twenty to thirty
16 years before the utility was buying DG solar power at a competitive rate
17 (assuming, meanwhile, that utility-scale renewable costs do not decline
18 further)—and even then, cross-subsidies associated with the use of solar to offset
19 a customer’s own consumption would not be addressed at all. While this option
20 has some merit in its structure and intent, it takes gradualism far beyond what the
21 respected Professor Bonbright could have intended!

22 **Q. DO YOU HAVE ANY COMMENTS ON THE ISSUE OF RATE GRADUALISM**
23 **THAT THE RUCO PROPOSAL IS TRYING TO ADDRESS?**

24 A. Yes. On the issue of rate gradualism, I must disagree with Mr. Huber’s assertion that
25 UNSE’s proposal violates this principle. Increasing the fixed charge from \$10 to \$20
26 (and now, as revised by UNSE, \$15) is not “seriously adverse to existing customers”
27 and is well short of revolutionary. For most customers, this change will, if anything, be
28 accompanied by a slight reduction in the overall bill, as the burden of paying for cross

1 subsidies to other customers is eased. And the individual customers likely to experience
2 the largest bill increases, DG customers, could for the most part protected by
3 grandfathering. The major change here is to the rates prospective new DG customers
4 will face, as they receive a more accurate signal about the value of the solar DG in
5 which they are considering investing.

6 VI. CONCLUSION

7 Q. **DO YOU HAVE ANY CONCLUDING REMARKS?**

8 A. Yes. As I have explained in my testimony, the central issue for solar DG in this matter is
9 not a conflict between the utility and solar energy providers. Rather, UNSE's proposed
10 rate change for solar DG customers is an attempt to enable effective competition
11 between different energy resources, in which solar DG will enjoy the "mainstream"
12 energy role called for by Vote Solar witness Ms. Kobor. The new UNSE rate would
13 provide powerful incentives to increase the productivity and efficiency of distributive
14 solar generation, ones that envision long term financial sustainability for distributed
15 solar energy. This attempt is being strenuously opposed by a solar DG industry
16 dedicated to preserving its special status as the beneficiary of arbitrarily high, out of
17 market, non-cost based, heavily subsidized prices, resulting in higher profits for
18 themselves at the expense of consumers, solar and non-solar alike, to the long run
19 detriment of the viability of distributed solar generation.

20
21 UNSE's proposals before the Commission would not only remedy an urgent and
22 growing problem related to the subsidies of higher-income customers by lower-income
23 customers entailed by net energy metering, reduce the risk of depriving the grid of
24 needed investment, open opportunities for new service providers to enter the market to
25 provide services and products to enhance efficiency opportunities for customers, and
26 enhancing competitive markets forces in the power sector. Just as important, and most
27 ironically, it would also establish a pricing structure to enhance the long term prospects
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of distributed solar generation far beyond the dubious prospects offered by the “chasing subsidies” business model currently being used by most solar DG developers.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

ASHLEY C. BROWN

EXECUTIVE DIRECTOR
HARVARD ELECTRICITY POLICY GROUP

MOSSAVAR-RAHMANI CENTER FOR BUSINESS AND GOVERNMENT
JOHN F. KENNEDY SCHOOL OF GOVERNMENT
HARVARD UNIVERSITY
79 JOHN F. KENNEDY STREET
CAMBRIDGE, MA 02138
617-495-0959
ashley_brown@harvard.edu
<http://www.hks.harvard.edu/hepg/brown.html>

Ashley Brown is an attorney. He is the Executive Director of the Harvard Electricity Policy Group at Harvard University's John F. Kennedy School of Government. It is a leading "think tank" on matters related to electricity restructuring, regulation, and market formation. He has been an instructor in Harvard's Executive program on "Infrastructure in a Market Economy," at the World Bank Regulatory Training Program at the University of Florida, and at the European University's Florence School of Regulation. Mr. Brown has also served as an arbitrator in matters relating to the evolution of competition in infrastructure industries.

Before his current activities, Ashley Brown served as Commissioner of the Public Utilities Commission of Ohio, appointed twice by Governor Richard F. Celeste, first for a term from April 1983 to April 1988 and for a second term from April 1988 to April 1993. As Commissioner, he was of five members responsible for the regulation of the state's electricity, telecommunications, surface transport, water and sanitation, and natural gas sectors.

Prior to his appointment to the Commission, Mr. Brown was Coordinator and Counsel of the Montgomery County, Ohio, Fair Housing Center. From 1979-1981 he was Managing Attorney for the Legal Aid Society of Dayton, Inc. From 1977 to 1979 he was Legal Advisor of the Miami Valley Regional Planning Commission in Dayton. While practicing law, he specialized in litigation in federal and state courts, as well as before administrative bodies. He has served as an expert witness in litigation in the courts and administrative agencies. In addition, Mr. Brown has extensive teaching experience in public schools and universities.

EDUCATIONAL
BACKGROUND

1968	B.S.	Bowling Green State University, Bowling Green, Ohio
1971	M.A.	University of Cincinnati, Cincinnati, Ohio
1977	J.D.	University of Dayton School of Law, Dayton, Ohio
		Doctoral Studies (all but dissertation) New York University, New York, New York
1967		Attended Universidade do Parana; Curitiba, Parana, Brazil as an exchange student

FAMILY

Wife	Edith M. Netter
Daughter	Sara Mariasha Brown-Worsham
Daughter	Mariel Schaefer Brown

CURRENT
AFFILIATIONS

Member, Editorial Advisory Board of *The Electricity Journal*

Member, Editorial Board, *International Journal of Regulation and Governance*

Member, Board of Directors, e-Curve

Fellow, Centro de Estudios en Regulación e Infraestructura, Fundación Getulio Vargas, Rio de Janeiro, Brazil

Member, Policy Committee, David Rockefeller for Latin American Studies, Harvard University

Member, Brazilian Studies Committee, David Rockefeller Center for Latin American Studies, Harvard University

Member, Advisory Board of Development Gateway Site, The World Bank

Frequent speaker and lecturer on regulatory, infrastructure, and energy policy matters in North and South America, Europe, Africa and Asia.

PREVIOUS
AFFILIATIONS

Member, Board of Directors, Entegra Power

Chairman, Town of Belmont Municipal Light Advisory Board

Member, Board of Directors, Oglethorpe Power Corporation, Tucker, GA

Member, Editorial Advisory Board of *Electric Light and Power*

Vice-Chair, American Bar Association Committee on Energy, Section of Administrative Law and Regulatory Practice

Chair, American Bar Association Annual Conference on Electricity Law

Member, The Keystone Center Energy Advisory Committee

Member, National Association of Regulatory Utility Commissioners

Member, Executive Committee, National Association of Regulatory Utility Commissioners

Chair, Committee on Electricity, National Association of Regulatory Utility Commissioners

Chair, Subcommittee on Strategic Issues, National Association of Regulatory Utility Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners Executive Committee

Member, Mid-America Regulatory Conference

Member, Board of Directors, The National Regulatory Research Institute

Member, Advisory Council to the Board of Directors of the Electric Power Research Institute

Member, U.S. EPA Acid Rain Advisory Committee

Chair, Planning Section, National Governors' Association Task Force on Electric Transmission

Member, the Keystone Center Dialogue on Emissions Trading

Member, the Keystone Center Project on the Public Utility Holding Company Act of 1935

Member, The Keystone Center Project on State/Federal Regulatory Jurisdictional Issues Affecting Electricity Markets

Member, Policy Steering Group, The Keystone Center Project on Electricity Transmission

Member, Advisory Council of the Board of Directors of Nuclear Electric Insurance Limited

Member, Advisory Council of the Consumer Energy Council of America Project on Electricity

Member, Advisory Committee of the Consumer Energy Council of America Air Pollution Emissions Trading Project

Member, National Task Force on Low Income Energy Utilization and Conservation

Member, Board of Directors, Center for Clean Air Policy

Member, National Blue Ribbon Task Force on Allocating the Cost of New Transmission

Of Counsel, Dewey & LeBoeuf

Of Counsel, Greenberg Tauris

INTERNATIONAL EXPERIENCE

Member, Board of Director, Entegra Power Group

Member, U.S. Delegation of State Government Officials in the Center for Clean Air Policy/ German Marshall Fund Sponsored Exchange on Clean Air Issues to Germany, 1989

Member, U.S. Delegation to International Electric Research Exchange (IERE), Rio de Janeiro, Brazil, 1991

Consultant, Hungarian Ministry of Industry and Trade on Gas and Electric Regulatory policy, 1991-1992

Advisor to Ministry of Trade and Industry on Writing New Laws Governing Electricity, Natural Gas, and Regulation

Consultant, SNE, Costa Rican Regulatory Agency, on Transmission Access Issues, 1992

Advisor on Development of Independent Power Producers and Transmission Access

Consultant, World Bank Mission to Hungary Investigating the Financing of New Power Plants for MVM (Hungarian Electric Co.), 1992

Preparation of Background Materials in Preparation of a World Bank loan to the Hungarian Power Sector

Member, U.S. Delegation, in Conjunction with the U.S. Department of Energy, to the Argentina and United States Natural Gas and Electricity Regulatory Meetings, 1992

Consultant, ENARGAS, the Argentine gas regulatory agency, 1992
Providing Training for ENARGAS Commissioners and Staff

Consultant, USAID India Private Power Initiative Program on the Introduction of Private Generation and Competition into the Public Sector, 1993
Preparation of a Report on Introducing and Promoting Private Investment in the Indian Power Sector

Instructor, Regulatory Training Program of the National Regulatory Research Institute at Ohio State University and the Institute of Public Utilities at Michigan State University, Buenos Aires, Argentina, 1993
Providing Training to Commissioners and Staff of ENARGAS

Consultant, The Province of Salta, Argentina on infrastructure regulation, 1996
Providing Training to Commissioners and Staff of the Regulatory Agency of the Province of Salta

Consultant, USAID, Philippines Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Philippine Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Consultant, USAID, Russian Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Russian Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Participant, Harvard University's East Asian Electricity Restructuring Forum, 1994-1995
Delivering a Series of Lectures in China, Indonesia, and Thailand on Reforming the Power Sector

Consultant, Government of Ukraine on Electricity regulatory policy and industry restructuring, 1994-1995
Advisor to the National Energy Regulatory Commission on the Structure, Processes and Substance of Electricity Regulation

Consultant, Government of Brazil on Electric Sector Restructuring, 1995-1996
Adviser to the Ministry of Mines and Energy on Various Issues Related to Privatization and Introduction of Competition in the Power Sector

Consultant, Energy Regulatory Board of Zambia, 1997- 2001
Advisor to the Energy Regulatory Board on the Structure, Processes and Substance of Electricity Regulation

Member, Brazil-U.S. Energy Summit, 1995-1996
Preparation of a Report and Lecture on the Options for the Regulation of a Restructured Brazilian Power Sector

Consultant, Nam Power, the electric utility in Namibia, 1998-1999
Advisor on Development of Independent Power Project and on Restructuring of the Electric Distribution Sector

- Consultant, Government of Indonesia on electricity regulation, 1999
Training Government and Industry Personnel on Electricity Regulation
- Consultant, Government of Mozambique on reform of the commercial code, 2000
Advisor on Reformation and Rewriting of the Commercial Code
- Instructor, South Asia Forum for Infrastructure Regulation, 1999-present
Annual Training Regulatory Personnel from Five South Asian Countries
- Consultant, Government of Tanzania on electricity regulation, 2002
Advisor of Rewriting the Laws Governing Energy and Transport Regulation
- Consultant to Inter-American Development Bank on Sustainability of Sector Reform in Latin American energy markets, 2001-2002
Preparation of a report and Analysis on the Sustainability of Power Sector and Regulatory Reform in Latin America, with Specific Focus on Colombia, Honduras, and Guatemala
- Consultant to Inter-American Development Bank, Brazilian Electric Restructuring, 2002
Preparation of A Report and Analysis on Problems in the Privatization and Market Reform on the Brazilian Power Sector
- Consultant to World Bank on Brazilian energy regulation, 2002-2004
Preparation of A Report and Analysis of Means for Improving Regulation of the Brazilian Power Sector.
- Consultant to the Brazilian Government on Redesign of Electricity Market, 2003-2004
Advisor to Ministry of Mines and Energy on Electricity Market Design
- Consultant to Government of Dominican Republic on Electricity Regulation, 2004
Delivery of a Series of Lectures on Problems in Restructuring and Privatization in Dominican Power Sector
- Consultant to Eskom, South Africa, 2004-2005
Advisor on to Eskom on Restructuring of South African Electric Distribution Sector
- Consultant to World Bank on Regulation and Market Reform in Russian Power Sector, 2004-2005
Preparation of Report and Lecture on Regulatory Issues in proposed New Market Design of Russian Power Sector, and Attraction of Private Capital
- Consultant to Government of Guinea-Bissau on Infrastructure Regulation, 2005
Training Government and Industry Personnel on Infrastructure Regulation
- Consultant to the Government of Mozambique on Electricity Regulation, 2006-2007
Assisting in the Re-Establishment of the Electricity Regulatory Agency
- Consultant to the Government of Equatorial Guinea, 2007
Assisting in writing the country's electricity law
- Consultant to the Public Utilities Commission of Anguilla, 2008
Report on Funding Regulatory Agencies
- Languages: English, Knowledge of Spanish and Portuguese

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THE ECONOMIC IMPACT OF DISTRIBUTED SOLAR IN THE APS SERVICE TERRITORY, 2016-2035

Dr. Tim James, Dr. Anthony Evans and Lora Mwaniki-Lyman

L. William Seidman Research Institute

W. P. Carey School of Business

Arizona State University

FINAL REPORT

February 16, 2016

L. WILLIAM SEIDMAN RESEARCH INSTITUTE

The L. William Seidman Research Institute serves as a link between the local, national, and international business communities and the W. P. Carey School of Business at Arizona State University (ASU).

First established in 1985 to serve as a center for applied business research alongside a consultancy resource for the Arizona business community, Seidman collects, analyzes and disseminates information about local economies, benchmarks industry practices, and identifies emerging business research issues that affect productivity and competitiveness.

Using tools that support sophisticated statistical modeling and planning, supplemented by an extensive understanding of the local, state and national economies, Seidman today offers a host of economic research and consulting services, including economic impact analyses, economic forecasting, general survey research, attitudinal and qualitative studies, and strategic analyses of economic development opportunities.

Working on behalf of government agencies, regulatory bodies, public or privately-owned firms, academic institutions, and non-profit organizations, Seidman specializes in studies at the city, county or state-wide level. Recent and current clients include:

- Arizona Commerce Authority (ACA)
- Arizona Corporation Commission (ACC)
- Arizona Department of Health Services (ADHS)
- Arizona Dept. Mines and Mineral Resources
- Arizona Hospital and Healthcare Association
- Arizona Investment Council (AIC)
- Arizona Mining Council
- Arizona Public Service Corporation (APS)
- Arizona School Boards Association
- Arizona Town Hall
- Arizona 2016 College Football Championship
- Banner Health
- BHP Billiton
- The Boeing Company
- The Boys & Girls Clubs of Metro Phoenix
- The Central Arizona Project (CAP)
- Chicanos Por La Causa
- The City of Phoenix Fire Department
- CopperPoint Mutual
- Curis Resources (Arizona)
- De Menna & Associates
- Dignity Health
- The Downtown Tempe Authority
- Environmental Defense Fund
- Epic Rides/The City of Prescott
- Excelsior Mining
- Executive Budget Office State of Arizona
- The Fiesta Bowl
- First Things First
- Freeport McMoRan
- Glendale Community College
- Greater Phoenix Economic Council
- HonorHealth
- Intel Corporation
- iState Inc.
- The McCain Institute
- Maricopa Community Colleges
- Maricopa Integrated Health System
- Navajo Nation Div. Economic Development
- The Pakis Foundation
- Phoenix Convention Center
- The Phoenix Philanthropy Group
- Phoenix Sky Harbor International Airport
- Protect the Flows
- Public Service New Mexico (PNM)
- Raytheon
- Republic Services, Inc.
- Rio Tinto
- Rosemont Copper Mine
- Salt River Project (SRP)
- Science Foundation Arizona (SFAZ)
- Tenet Healthcare
- The Tillman Foundation
- Turf Paradise
- Valley METRO Light Rail
- Tenet Healthcare
- Twisted Adventures Inc.
- Vote Solar Initiative
- Waste Management Inc.
- Yavapai County Jail District

Executive Summary

- This study examines the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of distributed solar systems.¹
- When considered in the round from a purely financial perspective, it concludes that all three potential distributed solar deployment scenarios will have a detrimental effect on the State of Arizona and Maricopa County economies, all other things being equal.
- Additional distributed solar is estimated to lower gross state product (GSP) by approximately \$4.8 billion to \$31.5 billion (2015 \$), dependent on the scenario.
- Additional distributed solar deployment is also estimated to result in the net loss of 16,595 to 116,558 job years' private non-farm employment over the entire study period, dependent on the scenario.
- Any benefits emanating from each scenario are at best temporary, only coincident with the timing of the solar installations, and quickly counteracted by their long-run/legacy effects.
- In all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers, 2016-2060, is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid.
- That is, in each distributed solar scenario, electricity consumers as a whole will pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

¹ The study assumes that the cost of a 2035 distributed solar installation will only be paid off in full in 2065, thereby accounting for legacy effects. If the economic life of an installation is less than 30 years, the negative economic consequences will be greater.

LITERATURE REVIEW

- The study begins with a comprehensive literature review to assess state-of-the-art methods in economic impact analysis.
- Seidman's methodological approach is initially positioned in a 3 x 2 matrix classification of economic impact studies, illustrated below.

Seidman's 3 x 2 Classification of Economic Impact Models

COUNT GROSS	PARTIAL GROSS	GENERAL GROSS
COUNT NET	PARTIAL NET	GENERAL NET

- **Gross** studies only consider the direct positive impacts of increased economic activity in a specific sector.
- **Net** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector.
- **Counts** are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within one specific sector.
- **Partial** models consider the wider effects of levels of activity in one specific sector, including the indirect and induced effects of the direct change, but do not consider the feedback effects of changed levels of activity in that sector – for example, the effect on wages in the labor market.
- **General** models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. They also yield the most significant **Gross** and **Net** impacts.

- A critique of fourteen contemporary solar economic impact studies identifies only one example of a general equilibrium analysis – that is, Cansino, Cardenete, Gonzalez and Pablo-Romero’s (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.
- Nine of the fourteen critiqued papers adopt the partial model approach, but six of these are gross, rather than net, studies.

Positioning Seidman’s Approach Relative to Fourteen Contemporary Economic Impact Studies

	Counts	Partial Models	General Models
Gross <i>Only positive or negative impacts</i>	<ul style="list-style-type: none"> • Pollin and Garrett-Peltier, 2009 • ETIC, 2016 	<ul style="list-style-type: none"> • AECOM, 2011 • Loomis, Jo & Alderman, 2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al., 2014 	<ul style="list-style-type: none"> • Cansino et al. 2013
Net <i>Both positive and negative impacts</i>	<ul style="list-style-type: none"> • Alvarez et al., 2009 • Frondel et al., 2009 	<ul style="list-style-type: none"> • NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al., 2014 • SEIDMAN 2016 	

- In the absence of an existing CGE model for the State of Arizona, and taking into account time and cost constraints, Seidman implements a **Partial Net** REMI analysis of solar deployment in the APS service territory, 2016-2035, as the next best alternative.

ECONOMIC IMPACT ANALYSIS

- The capital costs and financing implications of each distributed solar deployment scenario are first estimated by APS, validated by Seidman, and allocated by economic sector using NREL’s JEDI model for distributed solar installations throughout the supply chain in the State of Arizona.

- APS also supplied data describing the financial impact of each solar deployment scenario on its operating cash flow, future central station generation investments, and retail electricity rates.
- The changes in investment included in the economic impact model are:
 - The annual installed costs of distributed solar capacity, 2016-2035;² and
 - APS' deferred or avoided central station generation investments, 2016-2035.
- The long-term legacy costs of the investment included in the economic impact model are:
 - The customer financing costs of distributed solar installations, 2016-2060;³ and
 - Consumer electricity rate savings, due to the deferred or avoided central station generation, 2016-2060.
- The results for each scenario take into account the direct, indirect and induced economic impacts of the distributed solar deployment, and the 30-year legacy effects reflecting the economic life of the solar installations and deferred central station generation.
- Using an Arizona-specific REMI model, the economic impact of the low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:⁴

LOW CASE SCENARIO	Total Private Non-Farm Employment (Job Years) ⁵	Gross State Product (Millions 2015 \$)	Real Disposable Personal Income (Millions 2015 \$)
State of Arizona	-16,595	-\$4,806.6	-\$1,787.3
<i>Maricopa County</i>	-15,685	-\$4,491.8	-\$1,862.4

² APS assumes an initial \$2.50 a watt.

³ Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

⁴ Total effects for each economic measure may not tally due to rounding-up.

⁵ A job year is equivalent to one person having a full-time job for exactly one year.

- If the low case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 16,595 job years of employment, plus over \$4.8 billion gross state product, and \$1.8 billion real disposable personal income (both 2015 \$).
- The low case distributed solar scenario therefore estimates negative impacts for all three economic impact measures assessed for the study period, including legacy effects, in the State of Arizona and Maricopa County.
- The economic impact of the expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:⁶

EXPECTED CASE SCENARIO	Total Private Non-Farm Employment (Job Years) ⁷	Gross State Product (Millions 2015 \$)	Real Disposable Personal Income (Millions 2015 \$)
State of Arizona	-76,308	-\$21,613.3	-\$7,956.4
Maricopa County	-71,344	-\$20,149.9	-\$8,087.9

- If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 76,308 job years of employment, plus over \$21.6 billion gross state product, and approximately \$8 billion real disposable personal income (both 2015 \$).
- The expected or medium case distributed solar scenario's negative impacts for all three economic measures are approximately 4.5 times greater than the low case scenario's impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.
- The economic impact of the high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, is as follows:⁸

⁶ Total effects for each economic measure may not tally due to rounding-up.

⁷ A job year is equivalent to one person having a full-time job for exactly one year.

⁸ Total effects for each economic measure may not tally due to rounding-up.

HIGH CASE SCENARIO	Total Private Non-Farm Employment (Job Years) ⁹	Gross State Product (Millions 2015 \$)	Real Disposable Personal Income (Millions 2015 \$)
State of Arizona	-116,558	-\$31,454.4	-\$11,901.4
Maricopa County	-108,857	-\$29,346.7	-\$12,091.2

- If the high case distributed solar deployment scenario actually transpires, the State of Arizona is estimated to *lose* 116,558 job years of employment, plus \$31.5 billion gross state product, and \$11.9 billion real disposable personal income (both 2015 \$).
- The high case distributed solar scenario’s negative impacts for all three economic measures are 6.5 to 7 times greater than the low case scenario’s impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.
- The high case distributed solar scenario’s negative impacts for all three economic measures are also 46% to 53% greater than the expected or medium case scenario’s impacts in the State of Arizona for the 2016-2035 study period, including legacy effects.
- Seidman’s APS study therefore clearly demonstrates that increased adoption of distributed solar generation represents a loss to the Arizona economy in the low, expected and high distributed solar deployment scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.

⁹ A job year is equivalent to one person having a full-time job for exactly one year.

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1.0 Introduction

The purpose of this study is to calculate the total (net) economic impact of an APS distributed solar NEM program in Arizona up to and including 2035.

1.1. Net Metering

Net metering (NEM) encourages consumers to invest in renewable energy technologies by crediting them for distributed generation at the same tariff they pay for purchasing centrally-generated power.

Originating in Idaho and Arizona in the early 1980s, this utility resource usage and payment scheme allows customer meters to effectively run backwards whenever their own generation is in excess of their level of consumption.

Customers use their generation to offset their consumption over an entire billing period, and only pay for their net power purchase per month: that is, the amount of electricity consumed minus the amount of electricity generated. NEM credits are, de facto, based on current centrally-generated power tariffs.

Some suggest that NEM unfairly passes on the fixed costs of building and operating a transmission grid used by participants to non-participating customers. This is because residential and small business' utility rates volumetrically recover all costs, including those that are fixed. Advocates typically counter this criticism by arguing that NEM customers bring benefits to the grid that equal or exceed the fixed costs they avoid paying for through self-generation, including job creation and other economic impacts.

NEM is currently available in Arizona for a wide range of distributed generation renewables, including solar PV, solar thermal, wind, biomass, biogas, hydroelectric, geothermal, combined heat and power, and fuel cell technologies. The Arizona Corporation Commission (ACC) has not set a firm kilowatt-based limit on system size capacity. It simply stipulates that a system size cannot exceed 125% of a customer's total connected load or electric service drop capacity. There is also no aggregate capacity limit for net-metered systems in Arizona. However, each utility is obliged to file an annual report listing the net metered facilities and their installed capacity for the previous calendar year. Approximately 38,000 of APS' current 1.2 million customer base have distributed solar.

1.2. Economic Impact Analysis

An economic impact analysis measures the effect of a policy, program, project, activity or event on a national, state or local economy, with particular emphasis on three types of effects or impacts. These are the *direct*, *indirect* and *induced* impacts:

- **Direct** impacts include the initial capital investment when a business, policy or program is launched, and the people directly employed to manufacture a product, provide a service or deliver a program.
- **Indirect** impacts are the economic growth or decline resulting from inter-industry transactions or supplier purchases, such as a distributed solar installation company's purchase of solar modules.
- **Induced** impacts occur when the workers either directly or indirectly associated with an organization, policy or program spend their incomes in the local economy, when suppliers place upstream demands on other producers, and when state and local governments spend new tax revenues.

The indirect and induced economic impacts are second order expenditures and jobs created as a result of the initial "injection" of expenditure and direct jobs. For example, a utility employee hired to administer a NEM program would represent a *direct* job. Purchases made by a utility are *indirect* impacts; and the income that the utility or supplier companies' employees spend in the local economy will in turn create revenues/income for a variety of other businesses, generating *induced* effects.

The second and later rounds of indirect and induced expenditure are not self-perpetuating in equal measure. Through time, they become smaller as more of the income/expenditures "leak" out of the examined economy.¹⁰ The cumulative effect of the initial and latter rounds of expenditure is known as the multiplier effect. There is no one "magic" multiplier estimate for every conceivable scenario. Due to the inter-linked nature of the State of Arizona's economy and its links to the rest of the U.S. (and the world), the eventual ripple effects depend on numerous factors.¹¹

A full understanding of the total impact that a specific energy policy will have on an economy is therefore rather more complex than just an extrapolation of direct impacts.

¹⁰ For example, in the form of savings, or payments on goods and services produced outside of the state.

¹¹ In very simple terms, what matters is the size of the direct impact, where it occurs (that is, which county/state and which sector of the economy) and the duration of the impact.

1.3. Study Overview

To help position APS' service territory study and provide a context for its findings, Section 2 begins with an overview of economic impact modelling approaches to renewable energy, summarized in the form of a 3 x 2 matrix.

Fourteen published analyses drawn primarily, but not exclusively, from the U.S., and additional insights from Canada, Germany, and Spain (listed in Table 1) are reviewed by Seidman in Section 3, with a particular focus on assumptions, methods and conclusions.

Examining the varying magnitude of the employment and gross state product (GSP) impacts for each of the different types of study defined by the economic impact model matrix in Section 4, a clear rationale for Seidman's approach to assess the economic impact of distributed solar deployment in the APS service territory is also provided.

Sections 5 – 9 then examine the economic impact of three distributed (rooftop) solar deployment scenarios in the APS service territory for the study period 2016-2035 in the State of Arizona and Maricopa County. The analyses include the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.¹²

Section 5 introduces the 3 solar deployment scenarios assessed for APS. These are:

- A low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and

¹² Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- A high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

Table 1: Economic Impact Analyses Critiqued as Part of Current Study

Geography	Title & Author(s)
California	<i>AECOM (July 2011)</i> Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform
California	<i>Vote Solar Initiative (April 2013)</i> Economic and Job Creation Benefits of SB 43/AB 1014
Illinois	<i>Loomis, Jo and Alderman (December 2013)</i> Economic Impact Potential of Solar Photovoltaics in Illinois
Montana	<i>Comings, Fields, Takahashi and Keith (June 2014)</i> Employment Effects of Clean Energy Investment in Montana
Montana	<i>Energy and Telecommunications Interim Committee (January 2016)</i> Quantifying the Economic Impacts of Net Metering in Montana
Massachusetts	<i>Motamedi and Judson (March 2012)</i> Modeling the Economic Impacts of Solar PV Development in Massachusetts
Missouri & U.S.	<i>Treyz, Nystrom and Cui (October 2011)</i> A Multiregional Macroeconomic Framework for Analyzing Energy Policies
Nevada	<i>Vote Solar Initiative and Clean Energy Project (2011)</i> Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011
New York	<i>NYSERDA (January 2012)</i> New York Solar Study
Rhode Island	<i>Berkman, Lagos and Weiss (2014)</i> Distributed Generation Contracts Standard Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study
Andalusia	<i>Cansino, Cardenete, Gonzalez, and Pablo-Romero (2013)</i> Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach
Germany	<i>Fronzel, Ritter, Schmidt and Vance (2009)</i> Economic Impacts from the Promotion of Renewable Energy Technologies - The German Experience
Ontario	<i>Pollin and Garrett-Peltier (2009)</i> Building the Green Economy: Employment Effects of Green Energy Investments for Ontario
Spain	<i>Alvarez, Jara, Julian and Bielsa (March 2009)</i> Study of the Effects on Employment of Public Aid to Renewable Energy Sources

Section 6 describes the simulation results for the low distributed solar deployment scenario.

Section 7 presents the simulation results for the expected distributed solar deployment scenario.

Section 8 describes the simulation results for the high distributed solar deployment scenario.

Conclusions are offered in Section 9.

2.0 Economic Impact Assessment Methods

There are a number of different approaches to an economic impact assessment. These are codified in Figure 1 below.

Figure 1: Classification of Economic Impact Models

COUNT GROSS	PARTIAL GROSS	GENERAL GROSS
COUNT NET	PARTIAL NET	GENERAL NET

Figure 1 illustrates two key distinctions among economic impact studies.

The first distinction is between gross studies and net economic impact studies. Studies that are **Gross** in nature only consider the direct *positive* impacts of increased economic activity – in this case, solar generation. **Net** studies represent a more rounded form of economic assessment because they also account for the trade-offs in the economy which result from incentivizing one specific sector, such as the *negative* impacts on utilities and reduced spending and investment in other economic activities associated with increased solar activity.

For example, a gross study might consider the positive effects of the installation of 100MW utility-scale solar on the level of economic activity alone, while a net study of the same installation would additionally allow for the negative economic impacts such as the decreased use of conventional forms of generation if these were displaced, and the net changes in residential, commercial and industrial energy bills. Consider also the installation of a distributed solar system by a homeowner. To meet a \$30,000 cost of installation, the homeowner will forego spending the same \$30,000 on something else, such as perhaps a new or refurbished swimming pool at their property. There are obviously positive economic effects associated with the homeowner's investment in a distributed solar system, which would be captured in a gross economic study. However, in this example, there are also negative effects associated with the loss

of investment in the swimming pool, which are only ever considered alongside the positive benefits of the solar installation as part of a *net* study.

Nine gross and five net studies are examined in Section 3. The gross studies are:

- California: AECOM, 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- Montana: ETIC, (2016)
- Nevada: Vote Solar Initiative, 2011
- Andalusia: Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013
- Ontario: Pollin and Garrett-Peltier, 2009

The net studies are:

- Missouri & U.S.: Treyz, Nystrom and Cui, 2011
- New York: NYSERDA, 2012
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

The second key distinction is between simple counts, partial (equilibrium) modeling, and macroeconomic (or general equilibrium) modeling.

Counts are typically tallies of direct measures of economic activities, such as jobs, investments, or sales, without any attempt to capture the impacts of the inter-relationships with other economic sectors. As a result, counts can be more or less extensive in terms of their reach. Some just concentrate on counting the number of direct employees or assessing the level of sales within a specific economic sector, while others seek information about a sector's entire supply chain. Counts can be made by surveys or by assessing theoretically the required inputs for the installation of defined amounts of solar capacity – for

example, the first part of a JEDI model which estimates the number of jobs created in the solar sector in a linear fashion based on the MW capacity of the solar installations. Studies examined in this report that use the counts method are:

- Montana: ETIC, 2016
- Germany: Frondel, Ritter, Schmidt and Vance, 2009
- Ontario: Pollin and Garrett-Peltier, 2009
- Spain: Alvarez, Jara, Julian and Bielsa, 2009

Partial models consider the wider effects of levels of activity in a specific economic sector, and are one of the most common commercial approaches in economic impact modeling. In contrast to counts, which generally assess the direct impacts of a change in the economy, partial models also consider the indirect and induced effects of the direct changes within a particular geography. The one drawback with partial models is that they do not consider the feedback effects of changed levels of an investment or economic activity such as, for example, the effect of large solar projects on wages in the labor market. Studies examined in this report that use the partial model method are:

- California: AECOM 2011
- California: Vote Solar Initiative, 2013
- Illinois: Loomis, Jo & Alderman, 2013
- Massachusetts: Motamedi & Judson, 2012
- Missouri & U.S.: Treyz, Nystrom and Cui,, 2011
- Montana: Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
- New York: NYSERDA, 2012
- Nevada: Vote Solar Initiative and Clean Energy Project Nevada, 2011
- Rhode Island: Berkman, Lagos and Weiss (the Bratton Group), 2014

General models consider the effects of levels of solar activity in an economy-wide context with reference to every economic interconnection and feedback effect. An example is computable general equilibrium (CGE) models. These model the entire economy and attempt to account for all of the impacts associated with a specific level of solar activity. Only one study examined in this report uses a general model to assess

impacts, due to the cost prohibitive nature of producing a CGE model for a state or a region. This is Cansino, Cardenete, Gonzalez and Pablo-Romero's (2013) study of Andalusia.

Figure 2 summarizes the studies examined in this report in terms of the method employed, and whether they consider positive impacts alone, or both positive and negative impacts.

Figure 2: Classification of Studies Examined by Method

	Counts	Partial Models	General Models
Gross <i>Only positive <u>or</u> negative impacts</i>	<ul style="list-style-type: none"> • Pollin and Garrett-Peltier, 2009 • ETIC, 2016 	<ul style="list-style-type: none"> • AECOM, 2011 • Loomis, Jo & Alderman, 2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al., 2014 	<ul style="list-style-type: none"> • Cansino et al. 2013
Net <i>Both positive <u>and</u> negative impacts</i>	<ul style="list-style-type: none"> • Alvarez et al., 2009 • Frondel et al., 2009 	<ul style="list-style-type: none"> • NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al., 2014 	

3.0 Evaluation Framework and Review of Fourteen Economic Impact Analyses

To objectively critique fourteen contemporary analyses of the economic impact of solar PV/renewables, Seidman uses the following questions as an evaluation framework:

- (a) What is the context for a study?
- (b) What are the study's objectives?
- (c) Which geography is being studied?
- (d) What is the time-horizon of the study?
- (e) Which economic modeling tool is used?
- (f) What types of effects are modeled, with reference to Seidman's 3 x 2 classification of economic impact models?
- (g) What are the key inputs and assumptions used in the modeling process, including the solar growth projection assumptions?
- (h) What are the key findings?

The following tables in this Section provides Seidman's assessment of each of the fourteen contemporary studies.

Reference will also be made, where appropriate, when a particular study method is replicated in multiple geographies by the same authors.

Title	Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform
Author(s)	AECOM, July 2011
Background	Considers the impact of a 76% reduction in homeowner permitting costs for solar PV when scaled to the regional and state level, taking into account the projected growth in the industry through 2020.
Objective(s)	<ul style="list-style-type: none"> Evaluate the economic and fiscal implications of a streamlined local government permitting system for installing residential solar PV.
Geography	California
Time Period	2012-2020
Modeling Tool	IMPLAN
Type of Effects Examined	<ul style="list-style-type: none"> This is a Partial Gross analysis, as it lacks detail on negative impacts considered. Considers a few more factors than the VSI reports, such as the initial down payment for a solar system which is positioned as a loss to homeowner savings and a gain to the solar industry. It is at best a weak, borderline example of a net partial study as it does not: <ul style="list-style-type: none"> Explicitly consider non-solar energy sector losses; Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications; Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation; Remove the rebate dollars paid to homeowners and installers from the IMPLAN inputs; and Consider the administrative costs associated with changing permitting rules. Also questionably assumes that increased homeowner savings from reduced electricity bills will be spent in full in-state.
Model Assumptions	<ul style="list-style-type: none"> Base case scenario uses California Solar Initiative's 2011 residential installation costs of \$6.97 per watt decreasing to \$3.63 per watt by 2020. Streamlined permitting would reduce annual costs by \$0.38 per watt in 2020 (i.e. from \$6.10 per watt in 2011 to \$3.25 per watt in 2020). Investment Tax Credit of 30% is assumed to continue through 2020. Average size of residential solar systems was 5.6 kW, 2012-2020. All solar systems will be purchased in California, albeit region unknown. Assumes solar in both cases will appeal to homeowners whose annual electricity bills would be reduced by at least 5% post-installation. Value of residential solar only impacts property taxes when the home is sold. Buyers will pay on average 3.6% more for solar PV homes.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> Projects 1,006,500 installations at 5 utilities' service areas for current permitting, 2012-2020; or an additional 131,500 installations for streamlined permitting. 332 MW installed 2007-2011; 2,668 MW installed 2012-2020 without streamlined permitting (BAU case).
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> Current permitting scenario assumes: <ul style="list-style-type: none"> 73.5 job years created per total MW installed, amounting to 196,020 job years in total for the entire 2012-2020 period; \$1.24 million GSP per MW per year (2015 \$); and \$69.70 per MW per year increase in additional sales tax, property tax, and payroll tax (2015 \$).

Title	Economic and Job Creation Benefits of SB 43/AB 1014
Author(s)	The Vote Solar Initiative, April 2013
Background	SB43 and AB 1014 are two shared renewable pilot programs to enable residential renters and commercial customers to subscribe via PG&E, SCE, and SDGE to an offsite renewable energy project and receive a utility bill credit in return.
Similar Studies	<ul style="list-style-type: none"> • VSI (2010) Colorado; • VSI (2011) Nevada; • VSI (2011) Iowa; and • The Solar Foundation (2013) Colorado.
Objective(s)	<ul style="list-style-type: none"> • Estimate the number of jobs created under SB 43/AB 1014, and the increased dollars that will subsequently circulate throughout the California economy.
Geography	California
Time Period	2014-2016 construction; 25 year lifetime O&M
Modeling Tool	JEDI (based on IMPLAN I-O) version January 3, 2013
Type of Effects Examined	<ul style="list-style-type: none"> • This is a Partial Gross analysis of two shared renewable programs. • Study does not consider net job creation. It simply details the cumulative employment benefits of both proposed shared renewable programs, without taking into account the potential loss of jobs in other energy sectors. • State sales tax revenue and instate economic activity results are also exclusively considered from a shared renewable program perspective. • Authors ignore the net changes that will in reality occur due to changes in other sectors of the state economy prompted by both programs, including the potential for higher energy bills.
Model Assumptions	<ul style="list-style-type: none"> • Crystalline Silicon – fixed mount commercial; single axis tracking utility scale. • For both pilots, study assumes the following local purchases: <ul style="list-style-type: none"> ○ 100% of components for solar installations < 100 kW; ○ 50% of components for 100 kW to 1 MW installations; and ○ 30% of components for installations > 1 MW. • For both pilots, it also assumes the following local manufacturing: <ul style="list-style-type: none"> ○ 10%-20% of components for installations < 1 MW; and ○ 5-10% of components for installations > 1 MW. • This amounts to 546 MW local total purchases for the implementation of both pilot schemes, and 91.5 MW to 183 MW local manufacturing. • 2014-2016 construction period. • 25 year operational phase.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • For SB 43, 53 MW installed in 2014, 161 MW installed in 2015, and 286 MW installed in 2016, resulting in a 500 MW pilot. • For AB 1014, 65 MW installed in 2014, 285 MW installed in 2015, and 650 MW installed in 2016, resulting in a 1,000 MW pilot.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> • SB 43 is estimated to have a gross jobs impact of 26.7 job years/MW, \$179,000 GSP per MW per year, and \$5,291 sales tax revenue per MW per year (2015 \$). • AB 1014 is estimated to have a gross jobs impact of 24.0 job years/MW, \$175,000 GSP per MW per year, and \$5,331 sales tax revenue per MW per year (2015 \$).

Title	Economic Impact Potential of Solar Photovoltaics in Illinois
Author(s)	Loomis, Jo and Alderman, December 2013
Background	Center for Renewable Energy (Illinois State University) study, supported by an Illinois Department of Commerce and Economic grant.
Objective(s)	Considers employment and output impacts for the construction and operations phases of 3 solar deployment scenarios, with 3 levels of in-state manufacturing.
Geography	Illinois
Time Period	2014-2030
Modeling Tool	JEDI PV Model (PVS4.5.13)
Type of Effects Examined	<ul style="list-style-type: none"> • This is a Partial Gross analysis. • It exclusively considers renewable (solar) sector impacts, including supply chain. • It does not consider corresponding impacts in other parts of the energy sector, or other economic sectors.
Model Assumptions	<ul style="list-style-type: none"> • Installations profile: <ul style="list-style-type: none"> ○ 10% residential (80% retrofits, 20% new construction); ○ 10% small commercial; ○ 20% large commercial; ○ 60% utility-scale. • 100% local purchases: <ul style="list-style-type: none"> ○ Labor and soft costs (permitting and business overhead); and ○ Residential and small commercial materials and equipment. • All materials and equipment for large commercial and utility-scale installations are purchased 100% out-of-state. • Three levels of in-state manufacturing per scenario – 0%, 5%, and 10%.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • 2,292 MW, 2714 MW, or 11,265 MW by 2030.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> • For all 3 scenarios at 10% in-state manufacture: <ul style="list-style-type: none"> ○ 12.2 gross job years per MW installed; ○ Approximately \$107,000 GSP per MW per year (2015 \$); and ○ Approximately \$45,600 labor income per MW per year (2015 \$).

Title	Modeling the Economic Impacts of Solar PV Development in Massachusetts
Author(s)	Motamedi and Judson, March 28, 2012 (Unpublished PowerPoint)
Background	REMI. commission for the New England Energy and Commerce Association Renewables and Distributed Generation Committee.
Objective(s)	<ul style="list-style-type: none"> • Assess the economic impact of the <ul style="list-style-type: none"> ○ Construction of 305 MW of solar PV, 2012-2018; and ○ Operation of solar PV installations, 2012-2025.
Geography	Massachusetts
Time Period	<ul style="list-style-type: none"> • 2012-2018 construction; and • 2012-2025 operations.
Modeling Tool	REMI
Type of Effects Examined	<ul style="list-style-type: none"> • Partial Gross study, which generically describes, but does not state, the value of inputs used.¹³ • Energy cost savings are only considered from a solar savings perspective.
Model Assumptions	<ul style="list-style-type: none"> • Combination of residential, commercial, and utility-scale solar installations, with regional purchase coefficients of 0.629, 0.564, and 0.580 respectively. • Construction phase uses total investment after federal and state tax credit cost reduction, including some consumer consumption reallocation and production costs, along with consumer electricity price, and business electricity fuel cost changes. • Models locally supplied inputs as total construction spending. • Consumer price of electricity, electricity fuel costs for businesses, and production cost to utilities are used to represent the energy cost savings; and analysis assumes no change to SREC market.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • Additional 305 MW of PV, 2012-2018, taking total installation to 400 MW. • Does not state the split between residential, commercial and utility-scale solar.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> • 20.1 job years created per MW installed. • Approximately \$122,000 GSP per MW per year (2015 \$). • Approximately \$155,000 personal income per MW per year (2015 \$).

¹³ Motamedi and Judson mention energy cost savings, implying some consideration of the negative economic impacts of solar deployment. However, their PowerPoint presentation does not include any obvious assessment of negative impacts, and the REMI output is not suggestive of their inclusion. As a result, Seidman has classified their approach as **Partial Gross**.

Title	A Multiregional Macroeconomic Framework for Analyzing Energy Policies
Author(s)	Treyz, Nystrom and Cui, October 2011
Background	REMI-authored study considering the local, regional and national economic impacts of Missouri's RPS, excluding environmental and social impacts.
Objective(s)	Compares effects of electricity price-cap mandate (Scenarios 1 and 2) and an alternative bond-funded cost-recovery strategy (Scenarios 3 and 4) to finance the subbing of wind and solar for coal.
Geography	Missouri and the U.S.
Time Period	<ul style="list-style-type: none"> Construction impacts (RPS implementation), 2011-2021. Operational impacts, 2011-2035.
Modeling Tool	REMI
Type of Effects Examined	<ul style="list-style-type: none"> Partial Net study.
Model Assumptions	<ul style="list-style-type: none"> Baseline: No RPS implemented in Missouri. Scenario 1 = IOUs raise prices to statutory cap of 1% to recover low cost of subbing wind and solar for coal (cost fully recovered by 2023). Scenario 2 = IOUs raise prices to statutory cap of 1% to recover high cost of subbing wind and solar for coal (cost fully recovered by 2025). Scenario 3 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for low cost infrastructure. Scenario 4 = IOUs issue bonds with maturity of 15 years at 3.25% interest rates to raise funding needed for high-cost infrastructure. In Scenarios 1 and 2: <ul style="list-style-type: none"> 1% compound increase in commercial and industrial electricity prices; 1% compound increase in residential electricity prices, with lower disposable income corresponding consumption reallocation. In Scenarios 3 and 4: <ul style="list-style-type: none"> Utilities issue bonds at bank prime rate of 3.25% per year for 15 years; Impacts greater in the 2020s when consumers have to pay higher prices to pay off bonds, compared to 2010s when consumers pay the costs up front in Scenarios 1 and 2. In Scenarios 1-4: <ul style="list-style-type: none"> Solar panel purchase and O&M are treated as semiconductor manufacture exogenous final demand with corresponding consumption reallocation IOU rebates accounted for in production cost and transfer payments; Partial substitution of conventional electricity for solar electricity allows households to reduce conventional electricity consumption and expense, captured in consumption reallocation; and Creation of a custom industry for commercial wind generation, to account for different intermediate demands.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> RPS: Coal = 66%, Wind 14.7%, Solar 0.3% and Other 20% from 2021 onwards. Coal declines from 81% of electric production in 2010 to 66% by 2021; wind and solar from 0% to 15%.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> Graphs rather than data tables are provided, creating difficulties for interpretation. A state RPS is assumed to cause a short-term decrease in local employment, real GDP and personal real disposable income per capita. Raising electricity prices is estimated to result in the loss of 4,000 to 5,000 job years by 2021 or 2025, before recovering to the same level as the 2010 baseline in 2031. A bond scheme is estimated to create an initial short term annual employment increase of up to 1,000 jobs, but the trend reverses upon completion of the RPS in 2021,

decreasing by 2,000 to 3,000 jobs per year up until 2027, before recovering to a net decrease of 600-800 jobs by 2035.

- Real GDP would steadily decrease under the price-cap scenario, hitting a low of \$350-\$458 million loss in 2021 and 2025, before regaining some ground to a \$102 million loss in 2035 (2015 \$).
- The utility bond approach would have expand real GDP until 2021, peaking at \$153-\$204 million in 2019, fading to a decrease of \$306-\$408 million in 2027, before picking up to a loss of \$153-244 million by 2035 (2015 \$).

Title	Employment Effects of Clean Energy Investment in Montana
Author(s)	Comings, Fields, Takahashi and Keith (Synapse Energy Economics), 2014
Background	Examines the employment impacts of hypothetical additions to Montana's renewable energy portfolio.
Objective(s)	<ul style="list-style-type: none"> • Estimate employment impacts of construction and O&M activities associated: <ul style="list-style-type: none"> ○ Large-scale wind; ○ Large-scale solar PV; ○ Small-scale solar PV (rooftop), and ○ Energy efficiency.
Geography	Montana
Time Period	<ul style="list-style-type: none"> • Installation of systems is assumed to take place in 2016-2017. • Assumes 20 years of system operation.
Modeling Tool	IMPLAN in conjunction with capacity data from NREL's JEDI model.
Type of Effects Examined	<ul style="list-style-type: none"> • Partial Gross study of direct, indirect and induced employment impacts. • Makes no attempt to consider net effects. Focused entirely on job impacts of solar installation and O&M spending and considers no other benefits of solar deployment.
Model Assumptions	<ul style="list-style-type: none"> • Develops solar spending patterns associated with rooftop and utility-scale installations using NREL's JEDI model with adjustments for local conditions. • Estimates construction jobs in short-run and allocates them over 20 years together with O&M to obtain a 20 year cumulative job impact per average MW deployed.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • No actual projections. • Uses NREL's (2012) maximum hypothetical potential of 4,409 GW utility-scale and 2 GW rooftop solar PV for Montana.
Effects Scaled per Year	<ul style="list-style-type: none"> • Small PV – 9.2 job years per MW. • Large PV – 5.0 job years per MW.

Title	Quantifying the Economic Impacts of Net Metering in Montana
Author(s)	Energy and Telecommunications Interim Committee (ETIC), January 2016
Background	Examines the historical economic development impact of net metering installations in 2014 and 2000-14 in Montana.
Objective(s)	<ul style="list-style-type: none"> • Evaluate economic development impacts of the installation of net metering systems in terms of the following benefits and costs: <ul style="list-style-type: none"> ○ Bill savings of net metering customers; ○ Residential property value increases; ○ Revenue generated by installations; ○ Employment from installations; ○ Value of avoided carbon emissions; ○ Costs of income tax credits; and ○ Universal System Benefits (USB) renewable energy and Research & Development (R&D) allocations.
Geography	Montana
Time Period	2000-2014
Modeling Tool	Counts based on survey/modeling estimates from other states.
Type of Effects Examined	<ul style="list-style-type: none"> • This is in fact not an economic impact study or a normal assessment of economic development impacts. • It's a partial Count Gross analysis that considers a limited set of costs and benefits associated with net metering system deployments. • The tax revenue estimates are unclear, incomplete and based on very general assumptions.
Model Assumptions	<ul style="list-style-type: none"> • Based mostly on Montana Renewable Energy Association (MREA) survey data. • Uses NREL models to assess installation sales revenue based total installations each year but no specifics of the nature of the system(s) installed are given. • Employment outcomes are also based on survey work done by the Montana Environmental Information Center, Synapse Energy and the Sierra Club. • It is lacking in a number of aspects. It needs to: <ul style="list-style-type: none"> ○ Consider <i>full</i> indirect and the induced impacts of net metering; ○ Use appropriate bespoke models for Montana reflective of local economic circumstances; and ○ Not rely on very general rule of thumb estimates for jobs, revenues and taxes generated as base data. • It double-counts historical property value and homeowner energy savings as separate benefits.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • The extent of net metering systems installed in 2014 is stated as \$4M (2014 \$) but there is no statement of the extent of system additions or their capacity between 2010 and 2014.
Effects Scaled per Year	<ul style="list-style-type: none"> • There is no statement of installed capacity during the study period. There is also no statement of GSP, employment or tax revenue. It is thus impossible to calculate a jobs impact per MW, GSP per MW per year, or sales tax revenue per MW.

Title	Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011
Author(s)	Vote Solar Initiative and Clean Energy Project Nevada
Background	Considers the economic impact of expanding Nevada's DG solar market from 35 MW to 400 MW between 2011 and 2020.
Similar Studies	<ul style="list-style-type: none"> • VSI (2010) Colorado; • VSI (2011) Iowa; • VSI (2013) California; and • The Solar Foundation (2013) Colorado.
Objective(s)	<ul style="list-style-type: none"> • Evaluate the economic, job benefits and tax impacts of expansion of and changes to the incentive structure of Nevada's Solar Jobs Now proposal of 2011.
Geography	Nevada
Time Period	2011-2020
Modeling Tool	NREL's Jobs and Economic Impacts (JEDI) model.
Type of Effects Examined	<ul style="list-style-type: none"> • This is a very simplistic and rather opaque Partial Gross analysis since it lacks <i>any</i> consideration of the negative impacts of expansion. • It is biased in terms of its assessment of economic impacts since it does not: <ul style="list-style-type: none"> ○ Consider any non-solar energy sector losses; ○ Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications; ○ Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation; ○ Consider the economic impacts of rebate dollars paid to DG homeowners and installers; ○ Examine the economic impacts of reduced spending on other categories of expenditure throughout the expansion phase from capital expenditures on DG solar systems; and ○ Consider the administrative costs associated with changing permitting rules.
Model Assumptions	<ul style="list-style-type: none"> • Base assumptions are drawn from a JEDI model specific to Nevada. • Basic premise is a growth of 365 MW in residential and commercial DG solar. • No specifics about system characteristics used in the JEDI model are outlined in the paper.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • 365 MW installed 2011-2020.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> • Over the period 2011-2020, The Solar Jobs Now Proposal is estimated to have: <ul style="list-style-type: none"> ○ A gross jobs impact of 28.5 job years/MW; ○ \$443,400 GSP per MW per year (2015 \$); and ○ \$22,500 sales tax revenue per MW (2015 \$).

Title	New York Solar Study
Author(s)	New York State Energy Research & Development Authority (NYSERDA), January 2012
Background	Study required by The Power New York Act of 2011.
Objective(s)	Evaluate the cost-benefits of increasing solar PV in NY to 5,000 MW by 2025.
Geography	New York State
Time Period	2013-2049
Modeling Tool	REMI
Type of Effects Examined	<ul style="list-style-type: none"> • Partial Net study. • Quantifies direct PV job impacts of each scenario, economy-wide net impacts, gross state product, retail rate impacts, and environmental impacts. • Economy-wide net job analysis includes: <ul style="list-style-type: none"> ○ Positive impacts such as the creation of new PV jobs, and ratepayer savings when electricity prices are suppressed by PV output; and ○ Negative impacts, such as the cancellation of new power plants that are made unnecessary by the added PV capacity, or the additional costs of PV incentives, which reduce personal disposable income. • Net retail impact of PV deployment includes: <ul style="list-style-type: none"> ○ The above-market costs of PV; ○ Net metering costs; and ○ Savings generated by the suppression of wholesale electricity prices. • Net environmental impacts include: <ul style="list-style-type: none"> ○ Lower emissions via a reduction in the need for fossil fuel plants; and ○ Land use changes from rooftop to ground-mounted over time.
Model Assumptions	<ul style="list-style-type: none"> • Three scenarios: <ul style="list-style-type: none"> ○ Low Cost Scenario, using DOE SunShot goal for PV cost reduction, assuming extension of the federal tax credit (FTC) through 2025; ○ Base Case Scenario, using a DOE survey and moderate reduction of FTC beyond 2016, plus costs of \$2.5 million/MW for large-scale and \$3.1 million/MW for small-scale installations; and ○ High Case Scenario, based on the national average annual PV system price decline over the past decade, with FTC reverting to a pre-federal stimulus level in 2016. • 5% of solar components are manufactured in NY; the rest are imported. • Incentive costs are recovered from ratepayers through their electricity bills. • Quantified benefits of the 5000 MW by 2025 goal include a wholesale price suppression assumption, a reduction in energy lost to transmission and distribution inefficiencies, a reduction or deferral of the need to upgrade the utility distribution system, avoided RPS compliance costs, and a monetized carbon value of \$15 per ton.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • Achieve 5,000 MW solar PV deployment by 2025. • Four policy options are analyzed to stimulate demand: <ul style="list-style-type: none"> ○ Utilities obliged to purchase tradable solar renewable energy credits (SRECs) from spot market, supported by a price floor mechanism to provide greater degree of revenue certainty; ○ Utilities manage a competitive procurement similar to CA in which they award long-term contracts to purchase renewable energy; ○ Residential and commercial small PV system rebates, and larger systems incentives, provided centrally via competitive bidding; and ○ Utilities incentives for larger projects through competitive long-term contracts, and a cents per kWh produced for smaller projects.

Effects per Year (2015 \$)	Scaled	
		<ul style="list-style-type: none">• 4.7-6.3 gross job years created per MW installed, dependent on scenario, 2013-2025.• 700 economy-wide jobs net gain (low) or 750 to 2,500 economy-wide jobs net loss (base and high), 2013-2049.• \$15,760 GSP per MW per year gain (low), or \$16,930 to \$58,386 GSP per MW per year loss (base and high), 2013-2049 (2015 \$).

Title	Distributed Generation Standard Contracts Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study
Author(s)	Berkman, Lagos and Weiss (The Brattle Group), 2014
Background	<ul style="list-style-type: none"> Prepared for the Rhode Island Office of Energy Resources and Commerce as stipulated by the July 2013 Distributed Generation Standard Contracts (DGSC) Law.
Objective(s)	<ul style="list-style-type: none"> Examine the potential economic, fiscal and environmental impacts of the Distributed generation Standard Contract (DGSC) and Renewable Energy Fund (REF) 20134-2038.
Geography	Rhode Island
Time Period	2014-2038
Modeling Tool	IMPLAN in conjunction with energy capacity planning and energy dispatch models
Type of Effects Examined	<ul style="list-style-type: none"> A Partial Net study in terms of its economic impact assessment. Includes spending on installations as a gross addition to final demand. Does not net out the associated purchase/leasing costs which would likely swamp installation spending. Includes payments to DGSC/REF participants but no allows no countervailing reduction in non-DGC ratepayers' spending. Costs to ratepayers are assessed but not included in the economic impact assessment. Assess central generation capacity and operating costs with a capacity planning and economic dispatch model.
Model Assumptions	<ul style="list-style-type: none"> Includes both wind and solar renewable energy. Operational life span of renewable resources assumed to be 25 years. Source metrics for with and without DGC and REF scenarios obtained from past studies. Use secondary sources to assess central generation and capacity costs using approximations rather than primary modeling. It is unclear how DGSC/REF capacity deletions/additions are assessed to affect central generation costs.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> Three (assumed not forecast) scenarios above 2013 40 MW are assessed: <ul style="list-style-type: none"> 160 MW (by 2019) with REF of \$800,000 in solar installations; 200 MW (by 2019) with REF of \$800,000 in solar installations; and 1,000 MW (by 2024) with REF of \$1,600,000 in solar installations.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> Average annual GSP per MW: <ul style="list-style-type: none"> 160 MW DGC: \$191,790 GSP per MW (2015 \$); 200 MW DGC: \$182,216 GSP per MW (2015 \$); and 1,000 MW DGC: \$135,290 GSP per MW (2015 \$). Average annual job years per MW: <ul style="list-style-type: none"> 160 MW DGC: 1.53 jobs; 200 MW DGC: 1.465 jobs; and 1,000 MW DGC: 1.095 jobs.

Title	Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach
Author(s)	Cansino, Cardenete, Gonzalez and Pablo-Romero, 2013
Background	Annals of Regional Science published paper estimating the impact on productive activities of increasing the production capacity of two types of solar thermal plant in Andalusia.
Objective(s)	<ul style="list-style-type: none"> To quantify the gross direct and induced productivity impacts of a single parabolic trough solar collector power plant and a single solar tower plant for the Andalusian economy. To also quantify the gross direct and induced productivity impacts of both types of solar thermal technology based on the addition of 789 MW installed capacity by 2013 to comply with the Sustainable Energy Plan for Andalusia (PASENER).
Geography	Andalusia (Spain)
Time Period	<ul style="list-style-type: none"> 2008-2013 installation; and 30 year estimated lifetime for each plant.
Modeling Tool	Static computable general equilibrium (CGE) model, consisting of 27 productive activities in the Andalusian economy.
Type of Effects Examined	<ul style="list-style-type: none"> General Gross study.¹⁴ Describes gross economic impacts by sector, based on an enlarged electricity sector which combines renewables and non-renewables and prevents any substitution.
Model Assumptions	<ul style="list-style-type: none"> Walrasian notion of competitive equilibrium, extended to include producers, households, government, and foreign sectors. The single representative consumer maximizes a Cobb-Douglas utility function. Government maximizes a Leontief utility function. Foreign sector is modeled as a single sector that includes the rest of Spain, the European Union, and the rest of the world. Benchmark equilibrium scenario includes a perfect inelastic supply of capital and positive unemployment rate, and a fixed level of government and foreign sector activities which allows relative prices, activity levels, public deficit and foreign trade deficit to work as exogenous variables. Equilibrium is defined as an economic state in which the representative consumer maximizes his utility, the 27-sector productive activities maximize their profits after taxes, and public revenue is equal to the payments to the different economic agents. Does not consider if Andalusia's gross output gains are at the expense of other states' output – e.g. from the crowding-out effect of power generation.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> For the single plant analysis: <ul style="list-style-type: none"> 50 MW parabolic trough plant with 624 collectors; and 17 MW solar tower plant with 2,750 heliostats. Estimated lifetime of each plant is 30 years. For the PASANER scenario, to meet the 800 MW target by 2013 (789 MW additions), the model assumes 80% parabolic trough and 20% solar tower.
Effects Scaled per Year	<ul style="list-style-type: none"> Scenario 1 (single plant additions) is estimated to result in an economy-wide gross productivity increase of 0.75% for the parabolic trough plant, or a 0.68% economy-wide gross productivity increase for the solar tower plant. Scenario 2 (PASANER) is estimated to result in an economy-wide gross productivity increase of 35.37% over the 30-year lifetime of the parabolic trough and solar tower plant additions (30.81% parabolic trough; 4.57% solar tower).

¹⁴ Cansino et al. use a 27-sector CGE model that is a general modeling representation of the Spanish economy, allowing for both positive and negative feedback effects of increased levels of solar penetration in Andalusia. However, they model renewables and non-renewables as a single sector that does not allow for substitution between forms of generation, which means that they are effectively only allowing for positive direct demand shocks in their modeling. This is why Seidman classifies their approach as a *General Gross* model.

Title	Economic Impacts from the Promotion of Renewable Energy Technologies – The German Experience
Author(s)	Frondel, Ritter, Schmidt and Vance, 2009
Background	Critically reviews cost and job implications of the Renewable Energy Sources Act (EEG) – the centerpiece of the German promotion of renewable energy. This guaranteed stable feed-in-tariffs (FITs) for up to 20 years, and also favorable conditions for investments in green electricity production for the long-term.
Objective(s)	To demonstrate the impact of government-backed renewable incentives for stimulating the economy
Geography	Germany
Time Period	2000-2020
Modeling Tool	Non-Applicable
Type of Effects Examined	<ul style="list-style-type: none"> • Count Net study which balances gross renewable sector gains with: <ul style="list-style-type: none"> ○ The losses that result from the crowding out of cheaper forms of conventional energy generation; and ○ The drain on economic activity precipitated by higher electricity prices, including a loss of consumer spending power, and lower total investments of industrial energy consumers. • Also notes that: <ul style="list-style-type: none"> ○ New green jobs are often filled by workers who were previously employed, leading to a further overestimate of gross jobs effects; ○ Energy security benefits of solar PV are undermined by reliance of imported fossil fuel sources to meet technological demand; and ○ Technological innovation is stifled via a subsidy that compensates an energy technology for its lack of competitiveness. • Assesses real net present cost of solar subsidies, based on the volume of solar generation, the FIT, and conventional electricity prices. • Specific net cost per kWh = difference between solar FIT and market prices at the power exchange.
Model Assumptions	<ul style="list-style-type: none"> • Utility central station generation costs of 2-7 cents/kWh • Utilities obliged to accept delivery of power into their own grids from independent renewable producers • Solar-specific FIT of 50.62 cents/kWh paid by utilities in 2000 falling to 43.01 cents/kWh in 2009. • If solar subsidization ended in 2009, electricity consumers would still face charges until 2029. • Assumes 2% annual inflation. • Cost estimates for PV modules installed 2000-2008 are based on an overall solar electricity production of 96 billion kWh during 20 years of subsidization.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • Germany had 5,311 MW installed PV capacity in 2008.
Effects Scaled per Year (2015 \$)	<ul style="list-style-type: none"> • Net cost promoting Solar PV per MW installed: \$3.18 million, 2000-2008 (2015 \$).¹⁵

¹⁵ €2.2 million (2007 €) converted to US\$ at a rate of US\$1: €0.7687.

Title	Building the Green Economy: Employment Effects of Green Energy Investments for Ontario
Author(s)	Pollin & Garrett-Peltier, 2009
Background	University of Massachusetts-Amherst study sponsored by the Green Energy Act Alliance, Blue Green Canada, and World Wildlife Fund (Canada).
Objective(s)	<ul style="list-style-type: none"> • Considers the employment benefits of two Ontario green investment agendas: <ul style="list-style-type: none"> ○ Baseline Integrated Power System Plan (IPSP): \$18.6 BN investment over 10 years in conservation and demand management, hydroelectric, on-shore wind, bioenergy, waste energy recycling and solar power; and ○ Expanded Green Energy Act Alliance (GEAA): \$47.1 BN investment over 10 years in IPSP's 6 areas plus off-shore wind and smart grid electrical transmission system.
Geography	Ontario, Canada
Time Period	10 years
Modeling Tool	<ul style="list-style-type: none"> • Author-modified provincial I-O tables for Ontario, combined with national I-O tables for Canada to construct wind, solar, biomass and building retrofitting as industries in their own right. • Also uses U.S. data (BLS 2007 Occupational Employment Survey) to determine which occupations are likely to be in high demand for each of the 8 renewable energy areas considered.
Type of Effects Examined	<ul style="list-style-type: none"> • Count Gross study, addressing employment. • No comparison is made with alternative, non-green investments. • Neither do they consider if a green investment program is the most effective way to generate jobs in the region.
Model Assumptions	<ul style="list-style-type: none"> • Uses three factors to establish relative employment effects of alternative green investments: <ul style="list-style-type: none"> ○ Labor intensity of spending – that is amount spent on workers rather than land, energy, or materials; ○ Local content of spending; and ○ Wage rates. • 3% of baseline IPSP spending is allocated on an annual basis to solar. • 16% of expanded GEAA spending is allocated on an annual basis to solar.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • 88 MW of solar energy supplied over 10 years for baseline IPSP. • 1,738 MW of solar energy supplied over 10 years for expanded GEAA.
Effects Scaled per Year	<ul style="list-style-type: none"> • IPSP: 89.7 gross job years per MW installed. • GEAA: 68.7 gross job years per MW installed.

Title	Study of the Effects on Employment of Public Aid to Renewable Energy Sources
Author(s)	Alvarez, Jara, Julian and Bielsa, March 2009
Background	Universidad Rey Juan Carlos study part-funded by DG TREN (Energy & Transport) of the European Commission.
Objective(s)	To demonstrate the extent to which government support for green jobs in Europe has been economically counterproductive.
Geography	Spain
Time Period	2000-2008
Modeling Tool	Non-Applicable
Type of Effects Examined	<ul style="list-style-type: none"> • Count Net study. • Compares average amount of subsidized investment needed to create a solar job with the average amount of capital needed for a job in the private sector. • Also compares the average annual productivity that the solar job subsidy would have contributed to the economy had it not been consumed in public financing, with the average productivity of labor in the private sector that allows them to keep their job.
Model Assumptions	<ul style="list-style-type: none"> • The total subsidy to PV, wind, and hydro since 2000 is \$36 billion. • No additional solar plants have been constructed since December 2008. • \$12.1 billion has been committed for PV generation, 2000-2008.
Solar Growth Projection Assumptions	<ul style="list-style-type: none"> • Assumes that Spain has installed 2,934 MW solar PV by 2008.
Effects Scaled per Year	<ul style="list-style-type: none"> • For every renewable energy job financed by government, on average 2.2 jobs will be lost in the private sector. • However, for every solar MW installed, 8.99 private jobs are destroyed as a result of "green jobs" mandates, subsidies and related regimes.

4.0 Economic Impact Analyses – Magnitudes & Preferred Modeling Methods

Gross (positive impact only) studies clearly produce higher estimates of the economic impacts of solar enhancements than net studies, as demonstrated by the studies reviewed in Section 3. It is also important to note that gross studies are uniformly positive, while net studies are generally negative in terms of divined economic impact.

The principal effect of using a partial model approach rather than a count approach, or using a general (macroeconomic) modeling approach rather than a partial approach, is to reinforce the magnitude of the divined economic impacts. Thus, using a general (macroeconomic) model approach yields the most significant gross and negative studies.

Figure 3 summarizes the magnitude of impacts by type of economic impact study, based on the studies critiqued in Section 3.

Counts usually quantify the number of jobs. The Ontario **Count Gross** analysis reviewed in Section 3 estimated 68.7 to 89.7 gross (direct) job years are generated for every MW of wind and solar energy installed, which averages out at 69.74 for both renewable programs.

The Spanish **Count Net** analysis reviewed in Section 3 estimates that 8.99 private jobs are lost through “green jobs” mandates, subsidies and related regimes, for every 1 MW of solar installed.

Frondel et al. do not provide actual job counts for their German **Count Net** analysis. They simply conclude that “...any result other than a negative net balance of the German PV promotion would be surprising” (p. 17), based on a per capita subsidy of \$257,400 in 2008, the EEG’s crowding out effects, negative income effects and the unprecedented competition from cheaper Asian imports.¹⁶

Partial model estimates extend beyond a count to additionally estimate Gross State Product (GSP). The **Partial Gross** models reviewed in Section 3 estimated 5 to 73.5 gross job year gains per MW installed, and

¹⁶ Frondel et al. report that in 2006 and 2007, almost half of Germany’s PV demand was covered by imports, most notably from Japan and China.

a GSP gain of \$106,800 to \$1.24 million per MW installed per year (2015 \$). The AECOM study appears to be something of an outlier, as the gross job year estimate for the three other studies ranges from 5 to 24.9 job years per solar MW installed. Four of the studies in this section estimate GSP contributions of \$106,800 to \$176,354 GSP per MW per year (all 2015 \$). The two exceptions, estimating significantly higher GSP contributions per MW per year are VSI (2011) in Nevada, and the AECOM study.

NYSERDA's **Partial Net** model estimates a 700 economy-wide net gain in job years for their low case scenario, but a 750-2,500 economy-wide net loss for job years for their base and high case scenarios. Similarly NYSERDA estimate a \$15,760 GSP net gain per MW installed per year for their low case scenarios, compared to net losses of \$16,930 to \$58,386 per MW installed per year for their base and high case scenarios (all 2015 \$). Treyz et al. only present graphs, rather than actual data, which appear to show a net negative loss in both job years and GDP, 2011-2035.

Figure 3: Magnitude of Economic Impacts

	Counts	Partial Models	General Models
<p>Gross <i>Only positive or negative impacts</i></p>	<ul style="list-style-type: none"> 70 gross job years per MW 	<ul style="list-style-type: none"> Range of 5 to 73.5 gross job years per MW. Range of \$106,830 to \$1.24 million GSP per MW per year. 	<ul style="list-style-type: none"> \$7,198 total production per MW installed per year for parabolic trough installations.¹⁷ \$4,265 total production per MW installed per year for solar tower installations.¹⁸
<p>Net <i>Both positive and negative impacts</i></p>	<ul style="list-style-type: none"> -8.99 private jobs per MW per year 	<ul style="list-style-type: none"> Range of +750 to -2,500 net job years per MW, dependent on the scenario. Range of +\$15,862 to -\$58,386 GSP per MW installed per year, dependent on the scenario. 	

¹⁷ This is based on the PASENER target, 80% of which would be met by parabolic trough.

¹⁸ This is based on the PASENER target, 20% of which would be met by solar tower.

The **General Gross** model reviewed in Section 3 offers two solar-technology dependent estimates. These are a total gross productive increase of \$7,075 per MW installed per year for parabolic trough; and \$4,192 per MW installed per year for solar tower.¹⁹

Based on the 6-way matrix of economic impact studies initially presented in Section 2, the implementation of a **General Net** analysis of solar deployment in the APS service territory, 2016-2035 is the best methodological approach for the current study. However, to the research team's knowledge, a CGE model of this nature currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame. As a result, the current study implements a **Partial Net** analysis of solar deployment in the APS service territory, 2016-2035, presented in Sections 5 - 8. Seidman expects the results presented in the subsequent Sections to be directionally correct, but possibly understated, compared to a **General Net** (CGE) approach.

¹⁹ This uses an IRS 2013 dollar-euro annual currency exchange rate of US\$1: €0.783. Source: IRS (2014), downloaded at www.irs.gov/Individuals/International-Taxpayers/Yearly-Average-Currency-Exchange-Rates. Value is then converted into 2015 \$ using the Bureau of Labor Statistics CPI Inflation Calculator.

5.0 Economic Impact of Net Metering – Scenarios, Assumptions and Method

5.1. Scenarios and Assumptions

Three distributed (rooftop) solar deployment scenarios in the APS service territory are assessed for the study period 2016-2035, including the legacy effects of each scenario throughout the (assumed) 30 year economic life of the solar systems.²⁰ The solar deployment scenarios assessed for APS are:

- A low case scenario, which assumes 1,300 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 150,000 accounts;
- An expected or medium case scenario, which assumes 5,000 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 690,000 accounts; and
- A high case scenario, which assumes 7,600 MW_{dc} of nameplate distributed solar PV installations by 2035 in the APS service territory, which will increase APS' total number of distributed solar customers to approximately 1,050,000 accounts.

Distributed solar deployment is assumed to take place throughout the period of study in each scenario – that is, up to and including 2035.

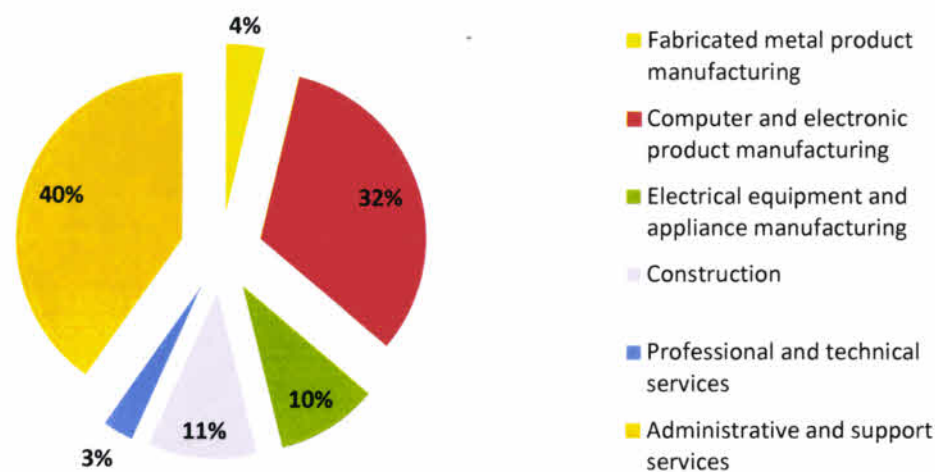
Approximately 86% of the solar installations are assumed to occur in Maricopa County, 5% in Pinal County, and 9% in Yuma County in each scenario.

The capital costs and financing implications of each solar deployment scenario is determined by examining the level of distributed generation as forecast by APS using generic assumptions about the costs of standard DG solar systems and financing parameters. NREL's JEDI model for solar installations is used to

²⁰ Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

distribute the capital costs of the solar installations throughout the supply chain in the State of Arizona.²¹ Figure 4 summarizes the breakdown of the JEDI model's solar system costs used in this analysis. This is based on national industry averages, and may not match Arizona's experience exactly, but is nevertheless widely accepted as a reasonable approximation. Administrative and support services account for an estimated 40% of solar system costs. This probably includes general administrative costs associated with state government permitting and federal rebates, and also local administrative costs in the solar industry.

Figure 4: JEDI Model Exogenous Final Demand Categories



Source: Authors' Calculations

APS has also supplied Seidman with an estimate of the financial impact of each solar deployment scenario on the utility's operating cash flow, future central station generation investments, and electricity retail rates. Approximately 70% of the deferred or cancelled central station generation investments occurring under the three distributed solar scenarios are assumed to occur in Maricopa County, with the balance in Pinal County.

The investment changes included in the economic impact model are:

- The annual installed costs of distributed solar capacity, 2016-2035; and

²¹ NREL's JEDI models are an open-source, Excel-based, user-friendly tools that estimate the economic impacts of constructing and operating power generation and biofuel plants at the local and state levels. To find out more about the JEDI models, see http://www.nrel.gov/analysis/jedi/about_jedi.html

- APS' deferred or avoided central station generation investments, 2016-2035.

The long-term legacy costs included in the economic impact model are:

- The customer leasing costs of distributed solar installations, 2016-2060;²² and
- Consumer electricity rate savings, 2016-2060, from the study period's deferred or avoided central station generation.

The timeframe of three of these elements extends beyond the last year of deployment (2035). This is because there are legacy effects associated with the deployment of distributed solar. For example, any customer installing a distributed solar PV system will have to meet the financial costs of that system for up to 30 years after the system has been installed on their roof. A utility is also required to recoup any investment in central station generation investments via retail electricity rates over the lifetime of that investment – again, usually 30 years. The legacy effects are therefore accounted for in the analysis.

The modelling elements are discussed in more detail in Section 5.2.

5.2. Study Method

Given the absence of a CGE model for the State of Arizona, Section 4 recommended the implementation of a **Partial Net** analysis of solar deployment in the APS service territory, 2016-2035. As a result, this study makes use of an Arizona-specific version of the REMI regional forecasting model, updated at the Seidman Research Institute, to produce partial net estimates of the impact on the Arizona economy of changes in the economic environment in the state.

REMI is especially useful when examining the economic impact associated with the launch or expansion of a new program, such as NEM, in a particular region, state or country. Through its dynamic modeling, REMI takes account of variations in the economic impact of a program as it moves from the establishment

²² Based on the assumed 30 year economic life of the distributed system, the customer financing costs of solar installations, 2016-2035, will not be completed until 2065. The REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

to operations phase, and also shows how estimates can vary through time. These estimated impacts are the difference between the baseline economy and the baseline economy augmented with the level of solar deployment assumed under each scenario. As a result, the analysis measures the Arizona economy up to 2035 *with* and *without* the existence of the new solar rooftop program.

The use of a county level model also enables a more detailed disaggregation of results to occur, estimating the “leakage” of economic impacts into other counties in Arizona.

Due to its overall flexibility, REMI allows for the examination of a whole host of different scenarios – different businesses and/or different construction and operations phases – while simultaneously providing estimates that are consistent across projects.

The method for estimating the economic impact involves four fundamental steps:

- 1. Prepare a baseline forecast for the state and county economies:** This Business As Usual (BAU) case forecasts the future path of state and county economies based on a combination of an extrapolation of historic economic conditions and an exogenous forecast of relevant national economic variables.
- 2. Develop a program or policy scenario:** This scenario describes the *direct* impacts that each distributed solar deployment scenario could generate in APS’ service territory.
- 3. Compare the baseline and policy scenario forecasts.**
- 4. Produce the “delta” results:** Differences between the future values of each variable in the forecast results estimate the magnitude that each distributed solar deployment scenario could have on the state or county economies, relative to the baseline.

The baseline or counterfactual scenario employed in this study assumes that there are no additions to the current stock of distributed solar installations over the period 2016-2035 in APS’ service territory. One consequence of this counterfactual scenario is that APS would need to add to both its central generation and transmission capacity, to cope with the increased load within its territory over the period. To cover the capital costs of the enhanced capacity and all subsequent operations and maintenance costs, APS would typically need to increase utility revenues over a 30-year period from the date of each investment. In isolation, this would manifest as a reduction in consumer spending, because utility customers would

collectively need to pay more for these new investments, and is also accounted for in the current study, up to and including 2060. In reality, some of this increased revenue will be provided by population growth which is creating the additional demand for new generation, and some will be offset by lower revenues for depreciating existing investments over time.

5.3. Solar Deployment Scenarios

Three distributed solar deployment scenarios are analyzed in this study. To represent the effects of increased penetrations of distributed solar, three key changes are included in the current study for the 2016-2035 time horizon. These are:

- The capital costs expended on rooftop solar systems purchased or leased by distributed generation customers, which are assumed to yield 20 years of construction-based benefits on the Arizona economy;
- The financial payments made by utility customers for leased solar systems for the economic life of their assets. This represents a reduction in spending on other goods and services and, as such, a likely reduction in economic activity in Arizona; and
- The reduction in revenue requirement for APS as a result of decreased net investment in centrally generated power. This represents a loss to the Arizona economy due to the reduction in central station generation construction and employment, offset by savings on fuel, O&M and financing costs over time.

Each scenario is modeled over a 20-year timeframe, starting in 2016 and ending in 2035, to estimate the employment, gross state product (GSP), and real disposable personal income (RDPI) for the State of Arizona and Maricopa County. However, there are also legacy effects associated with solar deployment and the deferral or cancellation of central station generation investments, which occur in the years immediately following an installation and last for the economic life of the solar installations. These legacy effects are therefore also included in the cumulative 2016-2035 estimate provided for each assessed economic measure, expressed in 2015 dollars (2015 \$).²³

²³ The legacy effects for any 2035 distributed solar installations should last until 2065, to reflect the economic life of the system. The current REMI model is unable to provide estimates after 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

6.0 Simulation Results: Low Distributed Solar Deployment Scenario

The low case scenario assumes that over \$1.5 billion is invested in new distributed solar installations by 112,000 customers between 2016 and 2035, and the net deferral or cancellation of \$85.5 million central station generation investments up to and including 2065 (all nominal \$).²⁴

Table 2 estimates the total employment impacts of the low case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers. They include employees, sole proprietors and active partners, but exclude unpaid family workers and volunteers. The data is expressed in job years. The label “job year” is important and should not be simplified or abbreviated to “job”. A “job year” is defined as one person having a full-time job for exactly one year. This means, for example, that one employee holding the same position at the same organization throughout 2016-2035 will account for 20 job years, but also only represent 1 job.

Table 2: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years ²⁵
State of Arizona	-16,595
Maricopa County	-15,685

Source: Authors' Calculations

Table 2 suggests that the low case distributed solar scenario could have a negative employment impact of 16,595 full-time (or equivalent) job years in the State of Arizona throughout the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.²⁶

In Maricopa County, there is a negative employment impact of 15,685 job years for the study period as a whole (including subsequent legacy effects).

²⁴ This simply reflects a deferral from the base case.

²⁵ A job year is equivalent to one person having a full-time job for exactly one year.

²⁶ The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 3 summarizes the industry sectors impacted the most by the low case distributed solar scenario.

Table 3: Statewide Employment Impacts by Industry Sector (Job Years)²⁷

Sector	Total Job Years, 2016-2060 ²⁸
Forestry, Fishing, and Related Activities	-2
Mining	-639
Utilities	-2,025
Construction	-2,549
Manufacturing	-385
Wholesale Trade	-548
Retail Trade	-3,102
Transportation and Warehousing	-514
Information	-203
Finance and Insurance	-845
Real Estate and Rental and Leasing	-998
Professional and Technical Services	-3,505
Management of Companies and Enterprises	-89
Administrative and Support Services	5,447
Educational Services	-440
Health Care and Social Assistance	-3,210
Arts, Entertainment, and Recreation	-406
Accommodation and Food Services	-1,348
Other Services, except Public Administration	-1,237
Total Net Change in Job Years	-16,595
Total Number of Job Years Lost in Non-Solar Industry Sectors²⁹	22,042

Source: Authors' Calculations

The table suggests that administrative and support services could benefit from the low case distributed solar scenario in terms of employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 16,595 job years lost statewide. The administrative gain probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed

²⁷ A job year is equivalent to one person having a full-time job for exactly one year.

²⁸ Total job years may not tally due to rounding-up.

²⁹ This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

in cumulative job years) during the study period in rank order are professional; scientific and technical services; health care and social assistance; retail trade; the construction industry; and utilities.

Table 4 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the low case distributed solar scenario for the period 2016-2035.

Table 4: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 \$)	Real Disposable Personal Income Millions (2015 \$)
State of Arizona	-\$4,806.6	-\$1,787.3
Maricopa County	-\$4,491.8	-\$1,862.4

Source: Authors' Calculations

Table 4 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over \$4.8 billion (2015 \$) in the State of Arizona. This includes an estimated \$4.5 billion GSP lost in Maricopa County (2015 \$).

Table 4 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by almost \$1.8 billion (2015 \$) in the State of Arizona. This includes an estimated fall in RDPI of over \$1.86 billion in Maricopa County (2015 \$).³⁰

The employment, GSP, and RDPI losses associated with the low distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (which extends beyond 2035) is greater than the amount which would have been paid had they all instead continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the low distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

³⁰ Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

7.0 Simulation Results: Expected Distributed Solar Deployment Scenario

The expected or medium case scenario assumes that approximately \$8.9 billion in total is invested by 650,000 customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of \$194 million central station generation investments (all nominal \$).³¹

Table 5 estimates the total employment impacts of the expected or medium case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

Table 5: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years ³²
State of Arizona	-76,308
Maricopa County	-71,344

Source: Authors' Calculations

Table 5 suggests that the expected or medium case distributed solar scenario would have a negative employment impact of 76,308 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.³³

In Maricopa County, there is a negative employment impact of 71,344 job years throughout the study period (including subsequent legacy effects).

Table 6 summarizes the industry sectors impacted the most by the expected or medium case distributed solar scenario.

³¹ This simply reflects a deferral from the base case.

³² A job year is equivalent to one person having a full-time job for exactly one year.

³³ The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 6: Statewide Employment Impacts by Industry Sector (Job Years)³⁴

Sector	Total Job Years, 2016-2060 ³⁵
Forestry, Fishing, and Related Activities	-18
Mining	-2,563
Utilities	-7,709
Construction	-11,098
Manufacturing	-1,504
Wholesale Trade	-2,691
Retail Trade	-15,762
Transportation and Warehousing	-2,472
Information	-943
Finance and Insurance	-4,558
Real Estate and Rental and Leasing	-4,948
Professional and Technical Services	-14,366
Management of Companies and Enterprises	-361
Administrative and Support Services	29,025
Educational Services	-2,336
Health Care and Social Assistance	-18,026
Arts, Entertainment, and Recreation	-2,231
Accommodation and Food Services	-6,886
Other Services, except Public Administration	-6,860
Total Net Change in Job Years	-76,308
Total Number of Job Years Lost in Non-Solar Industry Sectors³⁶	105,333

Source: Authors' Calculations

The table again suggests that administrative and support services alone could benefit from the expected or medium case distributed solar scenario in terms of job years' employment created. However, all other sectors are estimated to experience job losses, resulting in the total net estimate of 76,308 job years lost statewide. The administrative gain again probably originates to a large extent from the permitting of solar installations and business functions within the solar industry. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and utilities.

³⁴ A job year is equivalent to one person having a full-time job for exactly one year.

³⁵ Total job years may not tally due to rounding-up.

³⁶ This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 7 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the expected or medium case distributed solar scenario for the period 2016-2035.

Table 7: Total Gross State Product (GSP) and Real Disposable Personal Income Impacts (RDPI) 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 \$)	Real Disposable Personal Income Millions (2015 \$)
State of Arizona	-\$21,613.3	-\$7,956.4
Maricopa County	-\$20,149.9	-\$8,087.9

Source: Authors' Calculations

Table 7 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by over \$21.6 billion (2015 \$) in the State of Arizona under the expected or medium case scenario. This includes an estimated \$20.1 billion GSP lost in Maricopa County (2015 \$).

Table 7 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by approximately \$8 billion (2015 \$) in the State of Arizona. This includes an estimated fall in RDPI of almost \$8.1 billion in Maricopa County (2015 \$).³⁷

The employment, GSP, and RDPI losses associated with the expected distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the expected distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

³⁷ Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

8.0 Simulation Results: High Distributed Solar Deployment Scenario

The high case scenario assumes that approximately \$13.4 billion is invested by approximately 1 million customers in distributed solar installations between 2016 and 2035, and the deferral or cancellation of \$194 million central station generation investments (both nominal \$).³⁸

Table 8 estimates the total employment impacts of the high case distributed solar scenario for the period 2016-2035. These are full-time (or equivalent) annual employment changes, applicable to all sectors and industries apart from government and farm workers; and the data is again expressed in job years.

Table 8: Total Private Non-Farm Employment Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Job Years ³⁹
State of Arizona	-116,558
Maricopa County	-108,857

Source: Authors' Calculations

Table 8 suggests that the high case distributed solar scenario could have a negative employment impact of 116,558 full-time (or equivalent) job years in the State of Arizona for the 2016-2035 period of study, including any legacy impacts up to 2060. This legacy effect accounts for the fact that the true effects of the distributed solar deployment are only experienced in full after the period of study (2016-2035), consistent with the economic life of each solar installation.⁴⁰

In Maricopa County, there is a negative employment impact of 108,857 job years throughout the study period (including subsequent legacy effects).

Table 9 summarizes the industry sectors impacted the most by the high case distributed solar scenario.

³⁸ This simply reflects a deferral from the base case.

³⁹ A job year is equivalent to one person having a full-time job for exactly one year.

⁴⁰ The legacy effect should continue up to and including 2065. However, REMI currently does not allow for any analysis beyond 2060. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

Table 9: Statewide Employment Impacts by Industry Sector (Job Years)⁴¹

Sector	Total Job Years, 2016-2060 ⁴²
Forestry, Fishing, and Related Activities	-30
Mining	-3,496
Utilities	-10,632
Construction	-14,220
Manufacturing	-2,074
Wholesale Trade	-4,318
Retail Trade	-25,645
Transportation and Warehousing	-3,847
Information	-1,505
Finance and Insurance	-7,489
Real Estate and Rental and Leasing	-7,892
Professional and Technical Services	-20,701
Management of Companies and Enterprises	-538
Administrative and Support Services	45,650
Educational Services	-3,898
Health Care and Social Assistance	-29,486
Arts, Entertainment, and Recreation	-3,668
Accommodation and Food Services	-11,364
Other Services, except Public Administration	-11,405
Total Net Change in Job Years	-116,558
Total Number of Job Years Lost in Non-Solar Industry Sectors⁴³	162,208

Source: Authors' Calculations

Consistent with the previous two scenarios, the table suggests that administrative and support services could benefit alone from the high case distributed solar scenario in terms of job years employment created. The administrative gain again probably originates to a large extent from the permitting of solar installations, and also business support functions within the solar industry. All other sectors are estimated to experience job losses, resulting in the total net estimate of 116,558 job years lost statewide. The sectors estimated to experience the biggest job losses (expressed in cumulative job years) during the study period in rank order are health care and social assistance; retail trade; professional; scientific and technical services; the construction industry; and other services (excluding public administration).

⁴¹ A job year is equivalent to one person having a full-time job for exactly one year.

⁴² Total job years may not tally due to rounding-up.

⁴³ This is a summation of the job years lost in non-solar industry sectors negatively impacted by the deployment of new distributed solar, 2016-2035.

Table 10 estimates the cumulative gross state product (GSP) and real disposable personal income impacts (RDPI) associated with the high case distributed solar scenario for the period 2016-2035.

Table 10: Total Gross State Product (GSP) Impacts 2016-2035 (including Legacy Effects to 2060)

Geography	Gross State Product Millions (2015 \$)	Real Disposable Personal Income Millions (2015 \$)
State of Arizona	-\$31,454.4	-\$11,901.4
Maricopa County	-\$29,346.7	-\$12,091.2

Source: Authors' Calculations

Table 10 shows that in aggregate terms during the study period 2016-2035, and including legacy effects, total GSP could be cumulatively lower by \$31.5 billion (2015 \$) in the State of Arizona under the high case scenario. This includes an estimated \$29.3 billion GSP lost in Maricopa County (all 2015 \$).

Table 10 also shows that in aggregate terms during the study period 2016-2035, and including legacy effects, RDPI is estimated to be cumulatively lower by \$11.9 billion (2015 \$) in the State of Arizona. This includes an estimated fall in RDPI of almost \$12.1 billion in Maricopa County (2015 \$).⁴⁴

The employment, GSP, and RDPI losses associated with the high distributed solar deployment scenario are valid, because the total amount of money paid by distributed generation and central station generation electricity consumers over the 2016-2060 time horizon is greater than the amount which would have been paid had they all continued to draw electricity from the utility's central grid. In short, electricity consumers are paying more for the same amount of electricity consumed under the high distributed solar deployment scenario, and therefore have less money to spend in other parts of the economy.

⁴⁴ Some of Maricopa County's estimated losses in RDPI will be offset by minor gains in other counties, thereby resulting in a negligibly smaller loss for the State as a whole.

9.0 Conclusions

The goal of this study is to assess the impact of three distributed solar deployment scenarios in the APS service territory on economic activity in the State of Arizona and Maricopa County. The results of the analysis are influenced to an extent by the choice of economic impact model implemented.

Economic impact analyses can generally be classified in one of 6 ways, represented in Figure 5.

Figure 5: Seidman’s 3 x 2 Classification of Economic Impact Models

COUNT GROSS	PARTIAL GROSS	GENERAL GROSS
COUNT NET	PARTIAL NET	GENERAL NET

Gross studies only consider the direct positive impacts of increased economic activity in a specific sector, whereas **Net** studies represent a more thorough form of economic modeling as they also account for the trade-offs in the economy which result from incentivizing one specific sector,

Counts are usually survey-based or theoretical capacity installation quantifications of the number of direct employees within a specific economic sector, which can extend to that sector’s entire supply chain.

Partial models consider the wider effects of levels of activity in a specific economic sector, including the indirect and induced effects of the direct sectoral change. Frequently assessed via input-output models such as IMPLAN and REMI, partial models do not consider the feedback effects of changed levels of activity in a specific sector, such as the effect of large solar projects on wages in the labor market.

General models offer the most comprehensive economy-wide analysis, taking into account all of the economic interconnections and feedback effects. Of the fourteen contemporary solar economic impact studies critiqued by Seidman, only one uses a general equilibrium model. This is Cansino, Cardenete, Gonzalez and Pablo-Romero’s (2013) study of Andalusia. However, this is a gross, rather than net analysis, because the authors combine renewables and non-renewables as a single sector, thereby preventing any

substitution between conventional and renewable forms of generation, and effectively only allowing for positive direct demand shocks in their modeling.

The principal effect of using a *Partial* model approach rather than a *Count* approach, or using a *General* modeling approach rather than a *Partial* approach, is *generally* to reinforce the magnitude of the divined economic impacts. Thus, using a *General* model approach yields the most significant *Gross* and *Net* impacts.

However, to the research team’s knowledge, a CGE model currently does not exist for the State of Arizona; and it would be cost prohibitive to test and develop a CGE model for the State of Arizona in a short time frame.

Seidman has therefore implemented a *Partial Net* REMI analysis of solar deployment in the APS service territory, 2016-2035, for the current study. This is the next best alternative from a methodological standpoint; and it is consistent, for example, with the approach taken by Berkman, Lagos and Weiss (2014), NYSERDA (2012), and Treyz et al. (2011), critiqued in Section 3. Figure 6 positions Seidman’s approach relative to the fourteen critiqued studies

Figure 6: Classification of Seidman’s 2016 Approach for APS Relative to Fourteen Contemporary Economic Impact of Solar/Renewables Studies

	Counts	Partial Models	General Models
Gross <i>Only positive or negative impacts</i>	<ul style="list-style-type: none"> • Pollin and Garrett-Peltier, 2009 • ETIC, 2016 	<ul style="list-style-type: none"> • AECOM, 2011 • Loomis, Jo & Alderman, 2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al., 2014 	<ul style="list-style-type: none"> • Cansino et al. 2013
Net <i>Both positive and negative impacts</i>	<ul style="list-style-type: none"> • Alvarez et al., 2009 • Frondel et al., 2009 	<ul style="list-style-type: none"> • NYSERDA, 2012 • Treyz et al., 2011 • Berkman et al., 2014 • SEIDMAN 2016 	

The economic impacts of all three distributed solar deployment scenarios are assessed in terms of private non-farm employment, gross state product, and real disposable personal income.

The study clearly demonstrates that increased adoption of distributed solar generation represents a *loss* to the Arizona economy as a whole in all three scenarios. This is because the overall cost of provision of electricity to the State of Arizona will rise when referenced against a base case where electricity continues to be provided by central station generation.

If the low case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 16,595 job years private non-farm employment;
- Over \$4.8 billion gross state product (2015 \$); and
- \$1.8 billion real disposable personal income (2015 \$).

This takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.⁴⁵

If the expected or medium case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

- 76,308 job years private non-farm employment;
- Over \$21.6 billion gross state product (2015 \$); and
- Almost \$8 billion real disposable personal income (2015 \$).

This also takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

If the high case distributed solar deployment scenario actually transpires, the State of Arizona is cumulatively estimated to lose:

⁴⁵ The legacy effects of any 2035 distributed solar installation or deferred central station generation will continue until 2065. However, the REMI model used currently only provides economic impact estimates up to and including 2060, but Seidman does not believe that this will materially affect the conclusions in the analysis. If the economic life of an installation is less than 30 years, the negative economic consequences are in all probability greater than the estimates presented in this study.

- 116,558 job years private non-farm employment;
- Approximately \$31.5 billion gross state product (2015 \$); and
- \$11.9 billion real disposable personal income (2015 \$).

This again takes into account both the solar installation study period (2016-2035) and the legacy effects of those installations, to reflect the estimated 30 year economic life of the solar systems and deferred central station generation.

The implications of these findings are potentially far-reaching, as they challenge a sometimes expressed claim that an aggressive distributed solar initiative will have a significant positive impact on the state and county economies in the State of Arizona.

In short, and wholly based on the financial implications of solar installations from a customer, utility and supplier perspective, this study estimates that any benefits emanating from the three distributed solar deployment scenarios are at best temporary and only coincident with the timing of those solar installations. This is because the lasting legacy effects of each distributed solar scenario, which reflect the economic life of the installed systems and deferred central station generation, are negative. That is, in all three scenarios, the total amount of money paid by distributed generation and central station generation electricity consumers over the relevant time period (2016-2060) is greater than the amount which would have been paid had they all alternatively continued to draw electricity from the utility's central grid. In each distributed solar scenario, electricity consumers as a whole are being asked to pay more for the same amount of electricity consumed, and therefore have less money to spend in other parts of the economy.

Thus, when considered in the round from a purely financial perspective, the economic impact of all three potential solar deployed scenarios in the APS service territory are estimated to have a detrimental effect on both the State of Arizona and Maricopa County economies, all other things being equal.

Appendix

A.1. The REMI Model

REMI is an economic-demographic forecasting and simulation model developed by Regional Economic Models, Inc. REMI is designed to forecast the impact of public policies and external events on an economy and its population. The REMI model is recognized by the business and academic community as the leading regional forecast/simulation tool available.

Unlike most other regional economic impact models, REMI is a dynamic model that produces integrated multiyear forecasts and accounts for dynamic feedbacks among its economic and demographic variables. The REMI model is also an "open" model in that it explicitly accounts for trade and migration flows in and out of the state. A complete explanation of the model and discussion of the empirical estimation of the parameters/equations can be found at www.remi.com.

The operation of the REMI model has been developed to facilitate the simulation of policy changes, such as a tax increase for example, or many other types of events – anything from the opening of a new business to closure of a military base to a natural disaster. The model's construction includes a large set of policy variables that are under the control of the model's operators. To simulate the impact of a policy change or other event, a change in one or more of the policy variables is entered into the model and a new forecast is generated. The REMI model then automatically produces a detailed set of simulation results showing the differences in the values of each economic variable between the control and the alternative forecast.

The specific REMI model used for this analysis was Policy Insight Model Version PI+ version 1.7.2 of the Arizona economy (at the county level) leased from Regional Economic Models Inc. by a consortium of State agencies, including Arizona State University, for economic forecasting and policy analysis.

A.2. Effects Not Incorporated into the Analysis

No major financial impacts were left out.

Glossary

Gross State Product (GSP): The dollar value of all goods and services produced in Arizona for final demand/consumption.

Job Year: A job year is equivalent to one person having a full-time job for exactly one year.

Real Disposable Personal Income: The household income that is available to be spent after tax payments. Technically speaking, real disposable personal income is the sum of wage and salary disbursements, supplements to wages and salaries, proprietors' income, rental income of persons, personal dividend income, personal interest income, and personal current transfer receipts, less personal taxes and contributions for government social insurance.



L. WILLIAM SEIDMAN RESEARCH INSTITUTE

660 S MILL AVENUE, SUITE 300

TEMPE

AZ 85281-4011

Tel: (480) 965 5362

Fax: (480) 965 5458

www.seidmaninstitute.com

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SURREBUTTAL TESTIMONY OF AHMAD FARUQUI
On Behalf of Arizona Public Service Company
Docket No. E-04204A-15-0142

February 23, 2016

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1 **SURREBUTTAL TESTIMONY OF AHMAD FARUQUI**
2 **ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
3 **(Docket No. E-04204A-15-0142)**

4 I. INTRODUCTION

5 **Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND**
6 **PARTY FOR WHOM YOU ARE FILING TESTIMONY.**

7 A. My name is Ahmad Faruqui. I am a Principal with The Brattle Group. My business
8 address is 201 Mission Street, Suite 2800, San Francisco, California 94105. I am filing
9 testimony on behalf of Arizona Public Service Company.

10 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?**

11 A. Yes, I filed Direct Testimony on December 9, 2015.

12 II. SUMMARY AND ORGANIZATION OF SURREBUTTAL TESTIMONY

13 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS**
14 **PROCEEDING?**

15 A. The purpose of my Surrebuttal Testimony is to rebut some of the points made in the
16 direct testimony of several intervenors in this proceeding, including, TASC witness
17 Fulmer, Vote Solar witness Kobor, WRA witness Wilson, and RUCO witness Huber. In
18 addition, I will comment on some of the points raised by Staff witness Solganick.

19 **Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

20 A. Several intervenors have mischaracterized demand charges and three-part rates in
21 general. Demand charges are an appropriate price signal that closely relates the design
22 of the rate to the costs it is recovering. Through this close alignment with costs, in
23 addition to improving economic efficiency and equity/fairness, three-part rates will
24 provide an incentive for customers to adopt emerging energy management technologies
25 that reduce power system costs for all customers. Customers are likely to be able to
26 understand the concept of demand and respond to a demand charge by reducing their
27 maximum demand through behavioral changes or adoption of the aforementioned
28 technologies. In fact, while some customers' bills will go down and others will go up

1 with the new rate design, demand charges will provide all customers - including those
2 with limited income - with three opportunities to reduce their electricity bill: First, by
3 managing their demand, second by conserving energy, and third by shifting usage to off-
4 peak periods. In my Surrebuttal Testimony, I elaborate on these points.

5
6 **Q. HOW IS YOUR SURREBUTTAL TESTIMONY ORGANIZED?**

7 A. My Surrebuttal Testimony is organized around the following issues: the appropriateness
8 of demand charges as a price signal; the role of demand charges in promoting advanced
9 energy technologies; customer understanding and acceptance of demand charges; the
10 impact of demand charges on bills and electricity consumption; the impact of three-part
11 rates on customer bills; and how to make the transition to demand charges.

12 **Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR SURREBUTTAL
13 TESTIMONY?**

14 A. No.

15 **III. THE APPROPRIATENESS OF DEMAND CHARGES AS A PRICE SIGNAL**

16 **Q. DO YOU AGREE WITH THE ASSERTION THAT DEMAND CHARGES ARE
17 NOT AN APPROPRIATE PRICE SIGNAL?**

18 A. No. As I indicated throughout my Direct Testimony, three-part rates, which include a
19 demand charge as well as a fixed charge and an energy charge, do a much better job of
20 reflecting the cost structure of generating and delivering electricity than two-part rates,
21 which recover costs almost entirely through a volumetric charge.¹ Two-part rates over-
22 collect costs from larger-than-average customers and under-recover costs from smaller-
23 than-average customers. Not only do three-part rates improve equity in rate design; they
24 also encourage technological innovation by incentivizing the adoption of newly
25 emerging energy technologies and by bringing about changes in energy consumption
26 behavior that lead to more efficient use of power grid infrastructure and resources.

27 _____
28 ¹ See Decision No. 51472 (Oct. 21, 1980).

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Q. WHY ARE THREE-PART RATES AN IMPROVEMENT OVER TWO-PART RATES?

A. Some intervenors have argued that while three-part rates may do a better job of reflecting costs in the short run, they do not do so in the long run.² They argue that two-part rates send a better price signal than three part rates.³ Precisely the opposite is true. In the long run, transmission, distribution, and generation capacity costs are directly driven by peak demand. Thus, increases in demand translate into a need for more capacity in the long run. Reductions in demand reduce the need for new capacity. By virtue of being tied specifically to a measure of a customer's maximum demand, demand charges capture this relationship between demand and infrastructure investment requirements.

The view that three-part rates are an improvement in rate design is supported by the testimony of ACC Staff. Staff witness Solganick, for instance, indicates that rate design should recognize the concepts of customer, demand, and energy costs, and the time-and season-differentiated nature of these costs.⁴ Staff witness Solganick further notes that three-part rates are the norm for medium and large commercial and industrial (C&I) customers, and thus set a precedent in Arizona.⁵ Indeed, in much of the country, three-part rates are the norm for commercial and industrial customers and have been the norm for the better part of the past century.

Q. SOME INTERVENORS WHO OPPOSE THE INTRODUCTION OF A DEMAND CHARGE HAVE PROPOSED ALTERNATIVE RATE DESIGNS. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THOSE PROPOSED DESIGNS.

A. Two alternative rate designs are mentioned in intervenor testimony. One is a minimum bill, in which each customer would pay a fixed minimum amount for electricity each

² Direct Testimony of Mark Fulmer, p. 19.
³ Direct Testimony of Briana Kobor, p. 34-35.
⁴ Direct Testimony of Howard Solganick, p. 10.
⁵ *Id.*, p. 13.

1 month, even if their net consumption (net of any self-generation) was very low.⁶ The
2 second is a time-of-use (TOU) rate in which the volumetric charge varies by time of
3 day, with a higher price during peak hours of the day and a lower price during off-peak
4 hours.⁷

5 **Q. DO YOU AGREE WITH EITHER OF THESE ALTERNATIVE DESIGNS?**

6 A. No, I do not believe either of these is a suitable replacement for the three-part rate that
7 has been proposed by UNSE. These alternatives will not solve the cost-shift issue that is
8 attendant to the two-part design that is currently in place. Neither will they adequately
9 reflect cost of service or incent adoption of new technology. I expand on these points
10 below.

11
12 **Q. WHY IS A MINIMUM BILL NOT A SUITABLE ALTERNATIVE TO A
13 THREE-PART RATE WITH A DEMAND CHARGE?**

14 A. There are two reasons why it is not a suitable alternative.

15 First, minimum bills must be set at a very high level in order to sufficiently recover
16 capacity costs from rooftop solar customers. Second, minimum bills by themselves do
17 not reward reductions in demand or improvements in load factor. Thus, there is no
18 incentive to do either.

19
20 **Q. WHY IS A TOU RATE NOT A SUITABLE ALTERNATIVE TO A THREE-
21 PART RATE WITH A DEMAND CHARGE?**

22 A. Since infrastructure costs do not vary with electricity consumption, they cannot be
23 recovered adequately through a volumetric (kWh) rate, TOU or otherwise. From a cost-
24 causation standpoint, the most efficient way to represent kilowatt-based costs is through
25 a kilowatt-based charge, i.e., through a demand charge. That is why demand charges are
26 part of the standard tariff for most commercial and industrial customers.

27 ⁶ Direct Testimony of Kenneth Wilson, p. 11-12.

28 ⁷ *Id.*, p. 13, Fulmer Direct, p. 23.

1 TOU rates are an appropriate method for recovering energy costs if they vary by time-
2 of-use but not for recovering capacity costs. Thus, they are a good complement to a
3 demand charge; not a substitute. Offering a rate with both a demand charge and a time-
4 varying energy charge may be the best option.

5
6 **IV. THE ROLE OF DEMAND CHARGES IN PROMOTING ADVANCED ENERGY TECHNOLOGIES**

7 **Q. WOULD THE INTRODUCTION OF DEMAND CHARGES IMPACT ADOPTION OF DISTRIBUTED ENERGY RESOURCES (DER)?**

8
9 A. A change in rate design will affect the economics of DER. Adoption of the technologies
10 is driven in part by their economic attractiveness,⁸ thus the inclusion of demand charges
11 in rate design should affect their adoption levels. Some intervenors have suggested that
12 demand charges would curtail the adoption of distributed generation (DG), rooftop solar
13 in particular.⁹ However, this technology-specific perspective takes too narrow a view on
14 the impacts of demand charges on energy technology adoption.

15 **Q. WHY IS A FOCUS ON THE IMPACT OF DEMAND CHARGES ON ROOFTOP SOLAR PV TOO NARROW OF A PERSPECTIVE?**

16
17 A. A three-part rate will foster technological innovation by encouraging customers to adopt
18 technologies that enable peak demand reductions and also reduce their energy
19 consumption. Examples of such technologies include battery storage, smart thermostats,
20 demand controllers, and energy information displays. The use of these technologies to
21 reduce demand will not only reduce customer bills but will also reduce the utility's
22 costs, thus benefitting all customers.

23 In the same vein, introducing a demand charge and reducing the volumetric charge
24 would decrease the economic attractiveness of energy technologies that cannot provide
25

26
27 ⁸ Other factors beyond economics also drive consumer buying decisions, such as a desire to be "green"
or to have more control over energy consumption or simply to buy the newest technologies.

28 ⁹ Kobor Direct, p. 4, Fulmer Direct, p. 17.

1 energy savings during those peak hours when the energy reductions are most valuable to
2 the system. This simply means that the three-part rate structure is encouraging adoption
3 of those technologies that are most beneficial to the power grid and to customers. It is
4 important to take this broader view of energy technologies to avoid overstating the
5 importance of one particular option that may not be the most beneficial.

6
7 **Q. HOW WILL DEMAND CHARGES IMPACT OWNERS OF ELECTRIC VEHICLES?**

8 A. WRA witness Wilson has suggested that ownership of an electric vehicle (EV) would
9 lead to a “peakier” consumption profile, resulting in an increase in the cost of charging
10 the vehicle with a demand charge.¹⁰ This is not necessarily correct. If the vehicle is
11 charged during nighttime hours when the household is otherwise using relatively little
12 electricity, then charging the electric vehicle would not necessarily create a new peak.
13 Additionally, smart charging equipment would allow the EV owner to manage his or her
14 charging to reduce the possibility of setting a new peak.

15
16 It is also important to note that, while off-peak load building is beneficial to the power
17 system by reducing average costs, the simultaneous charging of several EVs on a
18 capacity constrained feeder could lead to a need for distribution system upgrades.
19 Demand charges should help to send a price signal that encourages flatter load profiles
20 throughout the day and reduces this possibility.

21 **V. CUSTOMER UNDERSTANDING AND ACCEPTANCE OF DEMAND CHARGES**

22 **Q. DO YOU AGREE WITH THOSE INTERVENORS WHO HAVE SUGGESTED THAT CUSTOMERS WILL NOT UNDERSTAND DEMAND CHARGES?**

23
24 A. No, I don’t agree with TASC witness Fulmer and WRA witness Wilson, for example,
25 who have suggested that residential customers will not be able to understand demand
26

27
28

¹⁰ Wilson Direct, p. 10.

1 charges.^{11,12} I believe there are several reasons why customers will be able to
2 understand demand charges, if they are explained properly to them.

3
4 **Q. WHY DO YOU BELIEVE THAT CUSTOMERS CAN UNDERSTAND A DEMAND CHARGE?**

5 A. First, 117,000 customers of Arizona Public Service (“APS”) have elected to take service
6 on voluntary demand charges. APS has been offering these rates to its residential
7 customers since the very early 1980s. In other words, long before the advent of
8 advanced metering infrastructure (“AMI”), there is evidence that customers were able to
9 comprehend the notion of demand and recognize the benefits of being on such a rate.

10 Second, just about every customer has encountered the concept of electricity demand in
11 daily life, perhaps without knowing what demand was. It would be hard to find a
12 residential customer who is not familiar with a light bulb. When buying or installing a
13 light bulb, the customer had to choose a bulb that would project a certain amount of
14 light. It was then that the customer would have encountered the power of the bulb
15 expressed in watts.¹³ The wattage would have been expressed as 40 watts, 60 watts, 75
16 watts or 100 watts (or their equivalent, if the bulb was a compact fluorescent or LED
17 bulb). Some wattages would have been higher, for three-way bulbs, such as 50, 100,
18 and 150; or 100, 200 and 250. Thus, it would be difficult to find a customer who has not
19 encountered the concept of watts. Further, if the customer had purchased a high wattage
20 hair dryer and a high wattage electric iron, and decided to run both at the same time,
21 they may have tripped the circuit breaker, requiring a trip to the garage or basement to
22 reset it after one of the two devices had been unplugged. That is yet another way
23 through which customers would have become familiar by experience with the concept of
24 demand or capacity.

25
26 _____
27 ¹¹ Fulmer Direct, p. 18.

28 ¹² Wilson Direct, p. 5.

¹³ Watts is the industry-accepted unit of power or demand.

1 Third, customers do not need to know the precise definition of a kilowatt in order to be
2 able to respond to a demand rate. Simple messages encouraging customers to avoid the
3 simultaneous use of electricity-intensive appliances can convey this concept in easy-to-
4 understand terms without even using the word “kilowatt.”

5 Fourth, all of this would apply even with greater force to customers with rooftop solar.
6 They would have encountered the concept of watts (or kilowatts) once again when they
7 purchased or leased their solar panels since that is the measure in which the size and cost
8 of the panels are expressed. Demand rates for rooftop PV customers, therefore, would
9 convey prices in terms in units that they are already familiar with.
10

11 **Q. DO YOU AGREE THAT A DEMAND CHARGE WILL FUNCTION AS AN**
12 **ADDITIONAL FIXED CHARGE FOR MOST CUSTOMERS?**

13 A. No, I do not agree with Vote Solar witness Kobor who states that a demand charge will
14 “likely function as an additional fixed charge for most residential and small commercial
15 customers because they lack the tools and understanding to effectively respond to the
16 demand charge price signal.”¹⁴ Demand charges are significantly different than fixed
17 charges in that customers can, and are likely to, reduce their demand charge by lowering
18 their demand. Conversely, customers are not able to take any behavioral actions to
19 reduce their fixed charges.

20 **Q. HOW ARE DEMAND CHARGES DIFFERENT THAN FIXED CHARGES?**

21 A. Importantly, demand charges vary with a customer’s demand for electricity. Customers
22 with high maximum demand will be charged more than customers with low maximum
23 demand. The result is that customers are charged in a manner that is proportional to
24 their use of the power grid. Fixed charges, on the other hand, charge each customer the
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¹⁴ Kobor Direct, p. 36

1 same amount regardless of their use of the power grid. Referring to a demand charge as
2 a fixed charge ignores this important distinguishing feature of demand charges.

3
4 Additionally, with a demand charge, customers have the ability to reduce their bill by
5 changing the way they consume electricity. Fixed charges, on the other hand, are not
6 under the customer's control. In my Direct Testimony, I cited four studies that found
7 that customers respond to demand charges by reducing their maximum demand.
8 Additionally, the Direct Testimony of APS witness Miessner stated that 60% of a
9 sample of APS's customers on a three-part rate reduced their demand after switching to
10 the three-part rate, with those who actively manage their demand achieving demand
11 savings of 10% to 20% or more.¹⁵

12 **Q. DO THE INTERVENORS OFFER ANY EVIDENCE THAT CUSTOMERS**
13 **CANNOT UNDERSTAND A DEMAND CHARGE?**

14 A. TASC witness Fulmer and Vote Solar witness Kobor cite a study in California by Hiner
15 and Partners ("Hiner") to suggest that customers could not understand a demand
16 charge.¹⁶ However, for several reasons this study does not support the conclusion that
17 customers cannot understand a demand charge.

18 **Q. WHY IS IT INCORRECT TO USE THE HINER STUDY TO SUPPORT A**
19 **CONCLUSION THAT CUSTOMERS CANNOT UNDERSTAND A DEMAND**
20 **CHARGE?**

21 A. There are several problems with Mr. Fulmer's and Mr. Kobor's use of the Hiner study in
22 their testimony. In his testimony, Mr. Fulmer states the following in support of his
23 claim that customers will not understand demand charges: "The survey found 'Possible
24 that concept was confusing and respondents did not understand that it varies based on
25
26

27 ¹⁵ Direct Testimony of Charles Miessner, p. 7.

28 ¹⁶ Fulmer Direct, p. 18, Kobor Direct, p. 36.

1 kW demand levels, which made demand charges appear low relative to monthly service
2 fee.”¹⁷

3
4 Based on careful inspection of the study, at no stage was customer understanding of
5 demand charges even investigated. Mr. Fulmer selectively quotes extracts from
6 commentary by the study authors and presents this information as a finding of the
7 survey. The reality is that in a conjoint analysis, investigating relative preferences for
8 various rates, the study found that the existence of demand charges was relatively
9 unimportant in rate plan selection. Rather the presence of a “monthly service fee had
10 more influence on rate choice than any other attribute,” followed by “the price per kWh
11 associated with different rate structures rather than by the rate structure itself.”¹⁸ To
12 explain this result, the study authors speculated, “[It is] possible that [the] concept [of
13 demand charges] was confusing and respondents did not understand that it varies based
14 on kW demand levels, which made demand charges appear low relative to [a] monthly
15 service fee.”¹⁹ This is speculative commentary, not fact, and only one possible
16 explanation of many for why demand charges seemed to have little impact on rate plan
17 selection.

18 Additionally, Mr. Fulmer indicates that the survey identified the following as surveyed
19 customers’ preferred features in a solar rate: “57% stated save money, 39% said simple,
20 and 34% said ‘fits my habits and lifestyle.’”²⁰ Mr. Fulmer fails to mention, however,
21 that the same study says that the advantages of demand charges are that they can, “save
22 money (through changing behavior), gives control over the bill.”²¹ Moreover the study
23 listed “confusing” as a negative attribute of all four of the rates examined in the study--a
24

25
26 ¹⁷ Fulmer Direct, p. 18.

¹⁸ Hiner & Partners, Inc. “RROIR Customer Survey – Key Finding,” April (2013), slide 18.

¹⁹ *Id.*, slide 22.

²⁰ Fulmer Direct, p. 19.

²¹ Hiner & Partners, “Final Report: Solar (NEM) Rate Preferences Survey Results” (June 2015), slide 8.

1 feed in tariff; a demand charge, a solar capacity charge and a panel rate (where you are
2 billed by the size of circuit panel for delivery).²² In fact when one looks at how
3 customers rated the four plans on simplicity (“Does not require a lot of effort to
4 understand how my energy use will affect my bill.”), there is very little variation in the
5 results.²³ Twenty-eight percent of customers found the feed in tariff plan (which
6 involves only kWh) to be simple, 26% found the installed capacity charge and the panel
7 rate to be simple and 24% found the demand charge to be simple.²⁴ In sum, the Hiner
8 study does not prove that customers would not understand or not be interested in a rate
9 with a demand charge. The assertion by the intervenors that it does is an unsupported
10 generalization.

11 **Q. IS ANY OTHER EVIDENCE OFFERED TO SUGGEST THAT CUSTOMERS**
12 **WOULD NOT WANT OR UNDERSTAND A DEMAND CHARGE?**

13 A. Vote Solar witness Kobor claims that APS’s 10% enrollment level in its voluntary three-
14 part rate is evidence that customers do not want three-part rates.²⁵ It is inherently
15 difficult to get customers to voluntarily sign up for new energy programs. Many
16 demand response programs have participation of around 10%. When new rate designs
17 are introduced on a voluntary basis they rarely achieve enrollment levels in excess of
18 20% to 30%.²⁶ This has been the experience with time-varying rates. New rates
19 typically must be offered on a mandatory or default basis to achieve significantly higher
20 enrollment levels.²⁷

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23

²² *Id.*

24 ²³ *Id.*, slides 22, 26, 30, 34.

25 ²⁴ *Id.*

26 ²⁵ Kobor Direct, p. 38

27 ²⁶ For information on residential demand response program participation, see FERC reports on advanced
28 metering and demand response: [http://www.ferc.gov/industries/electric/indus-act/demand-
response/dem-res-adv-metering.asp](http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp)

²⁷ Ahmad Faruqui, Ryan Hledik, and Neil Lessem, “Smart by Default,” *Public Utilities Fortnightly*, August 2014.

1 **Q. IS CUSTOMER ACCEPTANCE THE ONLY CRITERION THAT SHOULD BE**
2 **CONSIDERED WHEN EVALUATING THE MERITS OF A THREE-PART**
3 **RATE?**

4 A. While customer acceptance of and satisfaction with the new rate design is certainly a
5 consideration, it is not the only criterion that should be taken into account. It is only one
6 of the ten Bonbright criteria. In fact, if customer acceptance were the only principle that
7 mattered, one could argue that customers should simply be given free electricity, as they
8 would certainly be more satisfied with free electricity than with paying for it. Rather, as
9 I discussed throughout my direct testimony, a demand rate which more closely aligns
10 the structure of the rate with underlying costs improves fairness in rate design and can
11 have significant benefits for customers. Factors such as cost causation, equity/fairness,
12 and the impact of the rate on emerging energy technology adoption are all critical
13 considerations beyond a having only narrow focus on customer acceptance.

14 **Q. REGARDING THE ISSUE OF EQUITY, DO YOU AGREE WITH THOSE**
15 **INTERVENORS WHO HAVE SUGGESTED THAT MANY CROSS-SUBSIDIES**
16 **ARE EMBEDDED IN CURRENT RATES AND THAT WE THEREFORE**
17 **SHOULD NOT FOCUS ON JUST ADDRESSING A CROSS-SUBSIDY**
18 **RELATED TO THE ADOPTION OF DISTRIBUTED GENERATION?**

19 A. No, I do not agree with the argument made by AURA witness Alston that it is
20 inappropriate to address DG-related cross-subsidies without addressing all subsidies
21 embedded in today's rates.²⁸ First, demand charges better align rates with costs.
22 Therefore, the introduction of a demand charge does more than just address the DG-
23 related cross subsidy. It also addresses the subsidization of customers with peak (i.e.,
24 costly) consumption patterns by those with flat (i.e., beneficial) consumption patterns.
25 If deployed to all customers, this amounts to the removal of a significant cross-subsidy
26 and one not just limited to DG-related issues.

27 _____
28 ²⁸ Direct Testimony of Thomas Alston, p. 3

1 Second, while DG market penetration may be relatively low today, it is the trajectory of
2 adoption that matters. PV costs continue to decline rapidly, and Congress just extended
3 the income tax credit by five years. It is better to get in front of this issue now, before it
4 becomes a bigger problem and while grandfathering of current rooftop solar customers
5 under the current rate is still a feasible policy option.

6
7 VI. THE IMPACT OF DEMAND CHARGES ON BILLS AND ELECTRICITY CONSUMPTION

8 **Q. SOME INTERVENORS SUGGEST THAT DEMAND CHARGES WILL INCREASE BILLS FOR LIMITED INCOME CUSTOMERS. IS THERE ANY EVIDENCE TO SUPPORT THIS CLAIM?**

9
10 A. I have not come across any empirical evidence from the intervenors which shows that
11 limited income customers will be made worse off overall with a three-part rate.
12 Whether or not a three-part rate will cause a customer's bill to increase or decrease is
13 not determined by the customer's income or even their monthly consumption. The bill
14 impact is driven by the customer's load factor. If the customer has a high load factor
15 (i.e., a relatively flat electricity consumption profile), then his or her bill is likely to
16 decrease. If the customer has a low load factor (i.e., a "peaky" consumption profile), the
17 bill is likely to increase. A common mistake is to equate the impact of a demand charge
18 on a customer's bill with the customer's total monthly consumption. Demand charges
19 do not automatically increase bills for small users, because a small user could have a
20 higher load factor than the class average.

21 **Q. COULD DEMAND CHARGES PROVIDE LIMITED INCOME CUSTOMERS WITH AN OPPORTUNITY TO REDUCE THEIR ELECTRICITY BILL?**

22
23 A. Yes, demand charges could provide limited income customers with a new opportunity to
24 save money on their electricity bills. Whereas the existing two-part rate provides only
25 one opportunity to save money - by reducing one's total consumption - the three-part
26 rate also provides an opportunity to save through both reductions in total consumption
27 and reductions in maximum demand. Certain actions which would not provide material
28

1 bill savings under the two-part rate, such as staggering the use of electricity intensive
2 appliances, would yield a bill reduction under the three-part rate.

3
4 **Q. WILL DEMAND CHARGES REDUCE THE INCENTIVE TO CONSERVE ENERGY?**

5 A. I don't agree with WRA witness Wilson's and TASC witness Fulmer's suggestion that
6 the lowering of the volumetric rate will reduce the incentive to conserve.²⁹ As I
7 indicated earlier in my Surrebuttal Testimony, a three-part rate gives customers an
8 additional option for reducing their electricity bill - they can reduce total consumption
9 and/or maximum demand. Rather than removing a customer's incentive to conserve,
10 demand charges encourage a different and/or more efficient type of conservation - that
11 is, conservation at peak times when it is most valuable to the power system. In his
12 Direct Testimony, APS witness Miessner indicates that customers on APS's demand
13 rate have not only reduced their demand but their total electricity consumption as well.³⁰
14 Demand charges are therefore not implicitly going to impair energy efficiency efforts;
15 they will simply guide those efforts toward the most beneficial efficiency initiatives.

16 VII. TRANSITIONING TO DEMAND CHARGES

17 **Q. DO YOU AGREE WITH STAFF, WHO HAS SUGGESTED THAT CUSTOMERS NEED EDUCATION AND INFORMATION IN THE
18 TRANSITION TO A THREE-PART RATE?**

19 A. Yes. Staff witness Solganick indicates throughout his testimony that customers will need
20 education and information about demand charges in order to successfully make the
21 transition to a three-part rate. I agree with this and believe that a transition plan should
22 be developed when making significant changes to rate design in order to facilitate a
23 smooth introduction of the new rate.

24
25 **Q. WHAT DO YOU CONSIDER TO BE IMPORTANT ELEMENTS OF A RATE
26 TRANSITION PLAN?**

27 ²⁹ Wilson Direct, p. 9, Fulmer Direct, pp. 21 and 24

28 ³⁰ Miessner Direct, pp. 7-8.

1 A. The transition plan should be tailored to the specific needs of the utility and its
2 customers. As such, it will vary from one jurisdiction to the next. In other words, there
3 is not a “one size fits all” approach to the rate transition. Still, there are several
4 examples of elements that I would consider to be useful options to consider in the plan.
5 As I described above, one is a customer education plan that includes the provision of
6 general information about the new rate and opportunities to mitigate potential bill
7 impacts, as well as targeted outreach and education for those customers who are most
8 likely to experience bill changes under the new rate.

9
10 VIII. CONCLUSION

11 **Q. WHAT DO YOU CONCLUDE, BASED ON YOUR REVIEW OF THE
INTERVENOR TESTIMONY?**

12 A. The intervenors’ objections to the three-part rate are not supported by evidence. For
13 several reasons, I believe that a three-part rate would be a significant improvement over
14 the current two-part rate. It would do a much better job of reflecting the cost structure
15 of generating and delivering electricity. The rate would simultaneously improve
16 economic efficiency while promoting equity and fairness in rate design -arguably the
17 two most important principles in rate design. It would provide customers with new
18 opportunities to save money on their electricity bills. Finally, it would foster innovation
19 by improving the economics of a range of emerging energy technologies that can reduce
20 demand and, as a result, infrastructure costs.

21 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

22 A. Yes, it does.
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SURREBUTTAL TESTIMONY OF CHARLES A. MIESSNER
On Behalf of Arizona Public Service Company
Docket No. E-04204A-15-0142

February 23, 2016

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1 **SURREBUTTAL TESTIMONY OF CHARLES A. MIESSNER**
2 **ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY**
 (Docket No. E-04204A-15-0142)

3 I. INTRODUCTION

4 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

5 A. Charles A. Miessner, 400 North Fifth Street, Phoenix, Arizona 85004.

6 **Q. DID YOU PROVIDE TESTIMONY EARLIER IN THIS DOCKET?**

7 A. Yes, I provided Direct Testimony on behalf of Arizona Public Service Company (APS).
8

9 **Q. DID YOU REVIEW THE REBUTTAL TESTIMONY OF UNSE AND THE**
10 **DIRECT TESTIMONY OF STAFF AND OTHER INTERVENORS?**

11 A. Yes, I did.

12 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

13 A. The purpose of my Surrebuttal Testimony is to respond to certain assertions and claims
14 made by other intervenors that relate to my Direct Testimony and to assess their
15 recommendations made in this proceeding. I will also address UNSE's proposal for a
16 buy-back rate for customers with rooftop solar and Staff's proposal for a transition
17 period to three-part rates.
18

19 II. SUMMARY

20 **Q. WILL YOU PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY?**

21 A. In my Surrebuttal Testimony, I respond to the objections to three-part demand rates
22 made by various intervenors. Specifically, I address five key points:

- 23 • Demand charges;
 - 24 • Minimum bills;
 - 25 • Time of use (TOU) rates;
 - 26 • Complexity for residential customers; and
 - 27 • Impacts on energy efficiency.
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Demand charges. Contrary to the objections made by TASC and Vote Solar, APS believes demand charges appropriately reflect the cost of service and recover the right amount of revenue.

Minimum bills. Minimum bills are not a viable alternative to three-part demand rates as asserted by TASC, WRA, and other intervenors. Minimum bills would have to be both very large and tiered for small, medium, and large homes to have any beneficial effect. Specifically, the minimum bill would have to be significantly larger than the amounts typically discussed by these parties, \$10 to \$25, to address the cost recovery issue for any but the smallest energy users. For example, minimum bills for medium-sized and large-sized homes would likely need to be in the range of \$70 to \$150 per month.

Time-of-Use (TOU) rates. Two-part time-of-use (“TOU”) energy rates are not a viable alternative to three-part demand rates as asserted by TASC, WRA, and other intervenors. TOU kWh rates, while having advantages over other two-part kWh rate designs, still do not and cannot adequately reflect cost of service because they inherently recover infrastructure costs through variable kWh charges. What’s more, neither minimum bills nor TOU kWh rates incent customers to invest in home technologies that actually reduce the utility’s infrastructure costs. While TOU kWh rates provide a higher incentive to reduce energy during the on-peak hours, if this response is not consistent throughout the entire month, these rates will have either a limited impact or no impact at all on the demand-related infrastructure costs.

Complexity for residential customers. I rebut the contention made by TASC, WRA, and Vote Solar that residential customers will not be able to understand or manage demand. As discussed extensively in my Direct Testimony, APS’s existing three-part demand rate has shown just the opposite; a significant number of APS customers have already accepted the demand-rate concept and can and do manage their demand.

1 **Impacts on energy efficiency.** I also respond to claims made by TASC, WRA, and
2 other intervenors that three-part demand rates will hurt energy efficiency. These parties
3 claims are wrong. A demand rate will incent energy efficiency programs that are
4 refocused on opportunities that can reduce both energy and demand, which would be
5 much more valuable to the electrical system and other customers because they could
6 result in both savings in future fuel costs and savings from avoiding or deferring the
7 need to build additional power plants.

8
9 In addition, APS supports the general direction proposed by UNSE to replace net
10 metering with a solar purchase rate arrangement for the excess power. While the best
11 rate is avoided cost, the purchase rates proposed by UNSE could provide a reasonable
12 method to value excess energy exported to the grid. Certainly, the purchase rate should
13 be no higher than the purchase price for grid-scale PV solar power.

14 For these reasons, APS recommends that the Commission approve three-part demand
15 rates for UNSE residential customers. This is consistent with the proposals made by
16 Staff and agreed to by UNSE in their rebuttal testimony. In that respect, APS also
17 supports Staff's recommendation for a transition period combined with customer
18 education. APS further supports adoption of UNSE's net metering proposal.

19
20 III. MISSTATEMENTS ABOUT APS DEMAND RATES

21 **Q. DOES APS HAVE EXTENSIVE EXPERIENCE WITH THREE-PART DEMAND
22 RATES FOR RESIDENTIAL CUSTOMERS?**

23 A. Yes. As detailed in my Direct Testimony APS has several decades of experience with
24 residential demand rates. We currently have more than 117,000 residential customers
25 on a demand rate, which is approximately 11% of our total residential customer base. In
26 addition, all of our business customers served under our small to extra-large rates are
27 billed with a demand charge.

1 **Q. HAVE APS'S RESIDENTIAL DEMAND RATES BEEN SUCCESSFUL?**

2 A. Yes. While Vote Solar witness Kobor considers an 11% adoption rate to be low and
3 indicates that not many customers desire a demand rate, it is actually quite impressive
4 for a rate that is voluntary and competed with as many as four residential two-part TOU
5 rates (now just two). In fact, APS has the highest participation in residential demand
6 rates in the country. Vote Solar claims that APS's current three-part demand rate does
7 not produce any demand reduction – the participants are only high-use customers who
8 naturally save on the rate. Both parts of this assertion are untrue. I have provided
9 substantial information in my Direct Testimony concerning the demand and energy
10 reductions achieved by customers currently on the demand rate, which are significant.
11 *See also* APS's response to RUCO Data Request 1.6, which is attached as Attachment
12 CAM-ISR and incorporated into my Surrebuttal Testimony by this reference.

13
14 **IV. INTERVENORS' OBJECTIONS TO DEMAND RATES ARE UNFOUNDED**

15 **Q. WHAT OBJECTIONS DO SOME INTERVENORS HAVE TO THREE-PART
16 DEMAND RATES?**

17 A. Certain intervenors testified that they object to three-part rates for residential customers
18 because they have asserted:

- 19 • Demand charges do not reflect long-run cost of service;
- 20 • Demand charges will somehow recover too much revenue because of customer
21 diversity;
- 22 • Minimum bills and TOU rates are better alternatives;
- 23 • Customers won't understand or manage demand; and
- 24 • Demand charges will disincent energy efficiency.

25 **Q. DO DEMAND CHARGES REFLECT COST OF SERVICE?**

26 A. Yes. In fact, demand charges correct the misalignment between a customer's cost of
27 service and their bill inherent in two-part energy rates that rely on a monthly service
28

1 charge and kWh energy charges to recover the utility's infrastructure investment
2 necessary to serve the home. I included a detailed explanation of this issue in my Direct
3 Testimony in this proceeding and therefore will refer the reader to that testimony rather
4 than repeating that information here. However, the highlights are:

- 5 • A significant portion of the cost to serve residential customers is comprised of
6 infrastructure investments;
- 7 • These costs are indisputably driven by the kW demand of the home, not the
8 monthly kWh consumption; and
- 9 • A kW demand charge is the most appropriate and accurate way of recovering
10 these costs.

11 **Q. BUT AREN'T ALL COSTS VARIABLE IN THE LONG RUN?**

12 A. Not in the sense that some intervenors are referring. Utilities typically face higher fuel
13 costs, higher customer-related costs like meters and billing systems, and higher
14 infrastructure costs as they build new power plants, transmission lines, and distribution
15 facilities over time. However, once an infrastructure investment is made it is not
16 variable over its useful life, which can be several decades. Therefore, this notion of
17 fluctuating costs over time can lead to a somewhat common misconception about fixed
18 versus variable costs articulated by TASC witness Fulmer in his direct testimony.
19 Fulmer claims that kWh charges, which he correctly characterizes as a variable charge,
20 are a better reflection of cost of service because all costs are variable in the long run.
21 Hence variable charges for variable costs.

22
23 The problem with this reasoning is that the increases in customer-related costs and
24 infrastructure investment are not driven by increased kWh consumption, but rather the
25 increased number of customers and increased kW demand, respectively, over time. All
26 costs and charges can and do change over time, but that doesn't change the fundamental
27 need for a direct nexus between rate design and cost of service. Increased fuel and
28

1 variable operating and maintenance costs (“O&M”), which vary with kWh production,
2 should be recovered through higher kWh charges; increased customer-related costs
3 should be recovered through higher monthly service charges; and increased
4 infrastructure costs should be recovered through higher demand charges.

5 **Q. WILL DEMAND CHARGES OVERRECOVER INFRASTRUCTURE COSTS**
6 **DUE TO CUSTOMER DIVERSITY AS CLAIMED BY WRA?**

7 A. No. That’s not how the rate making process works. APS has been billing residential
8 and business customers on demand rates for decades and has established those charges
9 in numerous rate cases. The diversity issue was appropriately reflected and adjusted for
10 as a part of this process. There simply is no double counting.

11 Let me explain with an example. The monthly demand for APS’s residential customers,
12 i.e., the hour when the electrical load in each home is at its peak, typically occurs
13 between 5 p.m. and 9 p.m. in both summer and winter months, although there are always
14 exceptions to this usual pattern. However, the precise hour of this demand will vary for
15 each home – some will peak at 6 p.m., others at 7 p.m. and so on. That is what is called
16 diversity.

17
18 Consider a simple example with 5 residential customers, each with an individual
19 monthly peak demand of 6 kW for their home and lower kW loads in other hours. The
20 sum of the individual demands for the 5 homes would be 30 kW (6 kW times 5
21 customers). As illustrated in Table 1 below, in this example the combined load of all 5
22 homes, taken as a group, peaks at 7 p.m., which only adds up to 26 kW because not all
23 of the homes are that their maximum load at that time. This combined maximum hourly
24 load for the group is referred to as the class peak. In addition, suppose the utility also
25 serves some business customers and the combined peak for all customer classes occurs
26 at 6 p.m., which is referred to as the system peak. The residential load in this example is
27 23 kW at the system peak hour.

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Table 1.
Illustrative Hourly kW loads for 5 Customers

Customer	5:00 PM kW	System Peak 6:00 PM kW	Class Peak 7:00 PM kW	8:00 PM kW	Individual Demand kW
1	4	4	6	4	6
2	4	4	6	4	6
3	4	5	6	4	6
4	6	5	4	4	6
5	4	5	4	6	6
Total	22	23	26	22	30

So what's the issue? There's a mistaken notion that because the utility bills each of the 5 customers according to their individual demand, the 6 kW, even though the infrastructure costs are driven by the combined peak of all the homes at the time of the system peak, the 23 kW, they will over recover these costs – they will charge for an aggregate of 30 kW, but only incur costs for 23 kW.

Q. IS THIS NOTION CORRECT?

A. No, it's not, and for two reasons. First of all, not all of the utility's infrastructure costs are driven by the system peak. For example, the costs for some equipment like the pad mounted transformer in front of the home are driven by the diversified peak of the homes served off of that transformer (5 homes, and 26 kW in this illustrative example), not the system peak. Similarly, the cost for the local substation that serves the home is driven by the neighborhood or class peak, not the system peak. Infrastructure costs that are farther "upstream" from the home and serve a much wider group of customers, such as power plant costs, are primarily driven by the system peak.

1 Second and more importantly, irrespective of the cost drivers, diversity does not result in
2 any double counting or over recovery. This is because of the way the demand charge is
3 derived in the rate-making process.

4 **Q. PLEASE EXPLAIN.**

5 A. In the rate-making process the demand charge is calculated in two steps: (1) the
6 allocation of demand-related costs to a specific customer class and (2) the derivation of
7 the monthly demand charge using the allocated costs and the class billing determinants
8 (i.e. the total customer kW that will be billed each month).

9
10 In the first step, the utility's infrastructure costs are allocated or assigned to each
11 customer class based on the cost drivers discussed above. This step establishes the total
12 infrastructure cost to be recovered through rates from the specific class. Continuing
13 with the same example of 5 residential customers, assume that the various infrastructure
14 costs associated with the three cost drivers (individual demand, class peak, and system
15 peak) are as shown in Table 2 below. These costs are allocated to the residential class
16 according to the kW specific to each driver: the cost related to the kW of the individual
17 homes is allocated at 30 kW (5 homes at 6 kW peak demand per home); the cost related
18 to the class peak kW is allocated at 26 kW; and the costs related to the system peak are
19 allocated at 23 kW. This allocation process results in \$3,780 per year of total
20 infrastructure costs to be recovered in rates from residential customers. Importantly, this
21 allocated cost fully reflects the appropriate level of diversity for each type of cost.
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Table 2.
Illustrative Cost Allocation and Demand Charge Derivation

Step 1. Cost Allocation

Cost Driver	Unit Cost \$-kW	Units kW	Allocated Cost
Individual Demand	30	30	\$ 900
Class Peak	40	26	\$ 1,040
System Peak	80	23	<u>\$ 1,840</u>
Total			\$ 3,780

Step 2. Derivation of Demand Charge

Total Allocated Cost	\$	3,780	
Total Billed kW (12 months of kW)		360	(30 kW X 12 months)
Monthly Demand Charge (\$-kW)	\$	10.50	(\$3,780 / 360 kW)
Revenue from Demand Charge	\$	3,780	(\$10.50 X 360 kW)

In the second step of the process, the monthly demand charge is derived by dividing the \$3,780 annual cost by the total kW that will be billed for all 5 customers, which in this case is 360 kW (5 customers times 6 kW per month times 12 months). The resulting demand charge is \$10.50 per kW. This step also ensures that there is no double counting or overrecovery of costs because the kW used to derive the charge (30 kW per month, 360 kW per year) are the same kW that will be billed customers. In other words, the utility's annual revenue from the demand charge in this example is \$3,750 (\$10.50 per kW times 30 kW per month times 12 months), which is exactly the same as the infrastructure costs allocated to the residential class.

In recap, the cost allocation process ensures that the right amount of costs are recovered in rates by appropriately reflecting the customer load diversity in the allocated costs for each customer class. The rate derivation process ensures that the demand charge will be designed to recover this allocated cost by calculating the charge using the same

1 “undiversified” kW that customers will be billed on – and that the utility must have the
2 local infrastructure in place to support. Expanding the example from five customers to a
3 million complicates the math a bit, but would not change the result.

4 **Q. WHY IS A MINIMUM BILL NOT A VIABLE ALTERNATIVE TO A THREE-**
5 **PART DEMAND RATE?**

6 A. A minimum bill is not a viable alternative to a three-part demand rate both from a cost-
7 of-service perspective and a practical standpoint. Conceptually, a minimum bill would
8 have to address two potential situations - a customer whose kWh and kW drop
9 significantly in a particular month, e.g., the customer is absent from the house for two
10 weeks out of the month, and a situation where a customer’s kWh drops significantly, but
11 their kW remains at or near the normal level for the home.

12 A sufficiently sized minimum bill could be somewhat useful for the first situation where
13 both the kWh and kW usage drop significantly. In this case the minimum bill could help
14 recover infrastructure costs that are: (1) sized for and reserved for a home’s electrical
15 service; (2) are not recovered through the monthly service charge; (3) are not used by
16 the customer or otherwise paid for in the absent month; and (4) cannot be used to
17 temporarily serve other customers, and charged to them.

18
19 In this case the customer isn’t paying for or using the demand-related facilities in the
20 vacation month. Nonetheless, the unused facilities may not be available to serve another
21 customer because they are not suitably fungible, or the facilities are needed to serve the
22 customer in a subsequent month and therefore cannot be shifted to someone else, or the
23 absence occurs in a month with low system loads. Therefore, the facilities are not
24 needed to serve anyone else.

25 In this case, where a customer significantly, but temporarily, reduces their kW demand,
26 a large minimum bill could help pay for these infrastructure facilities, e.g. substations,
27 wires, poles, transformers, and power plants. However, the minimum charge couldn’t
28

1 be one-size-fits-all. Undoubtedly, the dedicated but unused facilities will be much
2 higher for a large home versus a small apartment. For example, a large home with a
3 monthly bill of \$500 may have \$350 of infrastructure costs per month (e.g. 70%), while
4 a small apartment with a \$60 bill may have \$40 of monthly infrastructure costs. A
5 minimum facilities charge of \$30, the \$20 service charge, plus \$10 for the dedicated
6 demand-related facilities may be reasonable for the small apartment, but it does not
7 come close to recovering any reasonable portion of the \$350 infrastructure cost for the
8 large home.

9
10 Therefore, any minimum bill would have to be tiered to the normal kW demand for the
11 home – a higher minimum bill for the higher kW needed to serve the larger home and a
12 lower minimum for the lower kW needed to serve the small apartment. In addition, the
13 levels of minimum bills would have to be significantly higher than the amounts
14 currently proposed by solar companies, residential advocates, or other proponents of this
15 concept. Finally, because the minimum bill would need to be tiered by the home's kW,
16 the minimum bill concept provides little to no advantage over a demand charge with a
17 minimum billed kW.

18 **Q. WHAT IF A CUSTOMER REDUCES THEIR MONTHLY KWH, BUT NOT**
19 **THEIR KW DEMAND?**

20 A. The minimum bill concept is even more troubling when the customer significantly
21 reduces the kWh energy but not the kW demand for their home. In this case the
22 customer continues to consume the monthly kW, but not pay for it if they are served
23 under a two-part rate. Thus, there are no unused facilities that could theoretically be
24 used to serve another home. As a result, no realistic minimum bill concept could
25 adequately replace a demand charge for recovering these infrastructure costs.
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27
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1 This point is demonstrated through the following example, which is typical for
 2 customers with solar generation. The assumptions and results are provided below in
 3 Table 3.

4
 5 Table 3.
 6 Minimum Bill Example for Typical Residential Customer

7 Medium Size Home

	kW <u>Used</u>	kWh <u>Used</u>	Service <u>Charge</u>	Demand <u>Charge</u>	Energy <u>Charge</u>	Total <u>Bill</u>
9 <u>Typical Monthly Electrical Load</u>						
10 Cost of Service	6	1200	20	\$36	\$72	\$128
11 Bill 2-part rate	6	1200	20	0	\$108	\$128
12 Bill 3-part rate	6	1200	20	\$36	\$72	\$128
13 Minimum Bill						\$25
14 <u>Same Demand, 75% Lower Energy</u>						
15 Cost of Service	6	300	\$20	\$36	\$18	\$74
16 Bill 2-part rate	6	300	\$20	0	\$27	\$47
17 Bill 3-part rate	6	300	\$20	\$36	\$18	\$74
18 Minimum Bill						\$25

19 This home consumes 6.0 kW demand and 1,200 kWh of energy per month. The
 20 customer's monthly bill is \$128 per month without taxes or adjustor rates. This is based
 21 on a \$20 service charge, \$6 per kW demand charge and \$0.06 per kWh energy charge
 22 for the demand rate and \$20 service charge and \$0.09 per kWh for the two-part rate,
 23 which are similar to the charges proposed by UNSE. The \$128 bill is the same whether
 24 it's computed under a two-part energy rate or a three-part demand rate, and the cost to
 25 provide service is also \$128 per month.

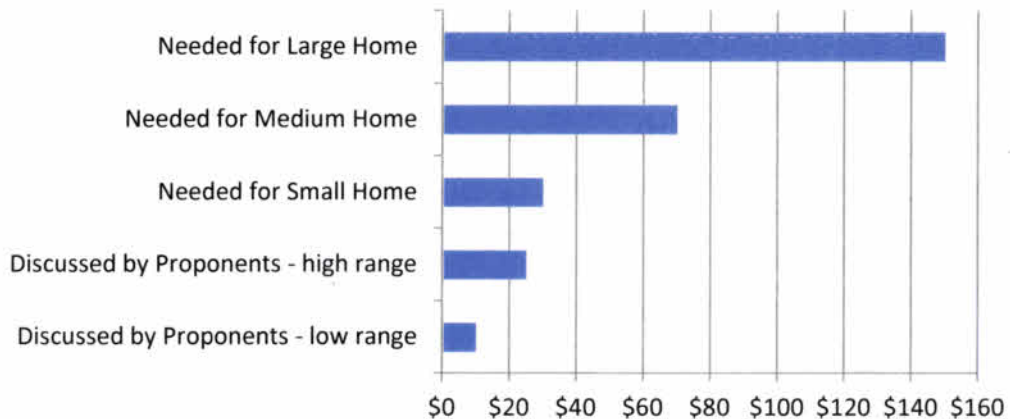
26 But what happens when the customer reduces their monthly kWh energy consumption
 27 by 75%, from 1,200 to 300 kWh, and their monthly demand usage remains at 6.0 kW.

1 The cost of service is assumed to be reduced from \$128 to \$74, if the \$0.06 kWh rate
2 truly reflected variable energy costs, because the utility avoided \$54 in variable costs
3 (\$0.06 * 900 kWh) such as fuel and variable O&M. For APS's residential customers
4 this variable cost of energy service would be closer to \$0.04 per kWh, not \$0.06. But
5 because UNSE provides most of its generation through power purchases rather than
6 their own power plants, the higher variable cost number might not be unreasonable. The
7 bill under the three-part demand rate is also reduced to \$74. Thus, the rate structure is
8 aligned with the cost of service, and the UNS customer received the right price signal
9 for reducing the kWh energy, namely, the variable cost of energy service. However, the
10 bill under the two-part energy rate is reduced to \$47, which is significantly less than the
11 cost of service. The two part rate is not aligned with cost of service because the
12 customer received \$0.09 per kWh to reduce their energy consumption when the variable
13 cost was only \$0.06 per kWh; while the customer still "demanded" (i.e. needed) 6.0 kW
14 of capacity at some point during the billing month, and the utility needed to have the
15 infrastructure in place to meet that demand, irrespective of the overall reduction in kWh.

16 What does a minimum bill do to correct the deficiency in this scenario? The answer –
17 nothing. A minimum bill of \$25, which is around the high range proponents are
18 discussing, has absolutely no effect at all. In fact, even for this medium size home the
19 minimum bill would have to be at least \$47 a month - the \$20 service charge plus the
20 \$27 variable cost for the kWh still consumed by the home - to make any contribution
21 towards the infrastructure costs that are still used, but not paid for. In this case, the
22 correct minimum bill for a medium-size home would be \$74, the amount resulting from
23 a three-part demand rate. The minimum amount would include \$20 for the monthly
24 service costs, \$36 for the demand-related infrastructure costs, and \$18 for the fuel costs
25 associated with the 300 kWh of usage, which would be included in the minimum. As in
26 the first case, the minimum bill would have to be tiered to the home's kW load, and
27
28

1 would have to be at a level that is significantly higher than that proposed by proponents
2 of the concept, to be effective at all in recovering infrastructure costs.

3
4 **Figure 1.**
5 **Minimum Bills Likely Needed for Small, Medium and Large Homes**
6 **Versus Levels Proposed by Proponents**



14
15 In summary, a minimum bill, as proposed by various intervenors is not a viable
16 alternative to a three-part demand rate to recover infrastructure costs. To be effective
17 and fair, the minimum bill could not be one-size-fits-all – it would have to be tiered to
18 the usual demand needed to serve each home. It would also have to be much higher
19 than the service charge and the variable costs for any kWh consumed in the month to
20 have any contribution towards fixed cost recovery. The minimum bill would also have
21 to distinguish between customers that have both low kWh and low kW usage in a given
22 month from those that reduce their kWh energy consumption but not their kW demand.
23 In either case, the levels of minimum bill amount would have to be much higher than
24 even the highest range discussed or proposed by proponents of the concept. Minimum
25 bills of \$30 for small homes, \$70 for medium-size homes, and \$150 for large homes
26 would be the range of possibilities for a minimum bill to be a viable alternative to a
27 three-part demand rate.

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Q. UNDER A MINIMUM BILL, DOES A CUSTOMER HAVE AN OPPORTUNITY TO REDUCE THEIR BILL BELOW THE MINIMUM AMOUNT?

A. No. A minimum bill acts like an “adder” to the basic service charge. A customer would not have any opportunity to reduce their bill below this amount. In this example, if the minimum bill was \$74 per month for a medium-size home, which includes 300 kWh of consumption, the customer would have no opportunity to reduce the bill below the \$74 minimum. In contrast, under a three-part rate the customer would have an opportunity to substantially reduce the bill, in that a demand rate affords a customer who does in fact reduce their demand to reduce their bill – the very alignment and price signal that is desired and not attainable with a minimum bill. It is also worth noting that a minimum bill does not send any effective price signal for customers to invest in home energy technologies

Q. ARE TOU ENERGY RATES A BETTER ALTERNATIVE THAN THREE-PART DEMAND RATES?

A. No. WRA, and TASC assert that two-part TOU energy rates are a better alternative to three-part demand rates. They assert that the TOU rates are easier for customers to understand and are as effective in recovering infrastructure costs as the demand rates. But this is incorrect.

Q. PLEASE EXPLAIN.

A. TOU rates can have an important role in aligning rates with costs, but by themselves they are not a viable alternative to a three-part demand rate, which can also have a time-of-use structure. While TOU kWh rates have advantages over other two-part kWh rate structures, they still do not and cannot adequately reflect cost of service because they inherently recover infrastructure costs through variable kWh charges. Even though TOU kWh rates provide an incentive to reduce energy during the on-peak hours, which is helpful from a resource perspective, if this response is not consistent throughout the

1 entire month, it will have minimal impact on the demand-related infrastructure costs
2 necessary to serve the home.

3
4 For example, if a customer reduces their kWh energy usage during half of the on-peak
5 hours in a month, let's say every other day, the utility would not likely be able to reduce
6 the infrastructure investment needed for the home very much, if at all – certainly not
7 anywhere near 50%. Just because the customer reduces their electrical demand on
8 Monday, but requires the usual electrical demand on Tuesday, doesn't mean the utility
9 can permanently downsize the grid infrastructure, such as transformers, poles, wires, and
10 other equipment needed to serve their home. In this example, the utility would not be
11 able to downsize the grid at all. However, the customer would be overcompensated
12 through the avoided higher on-peak energy charges.

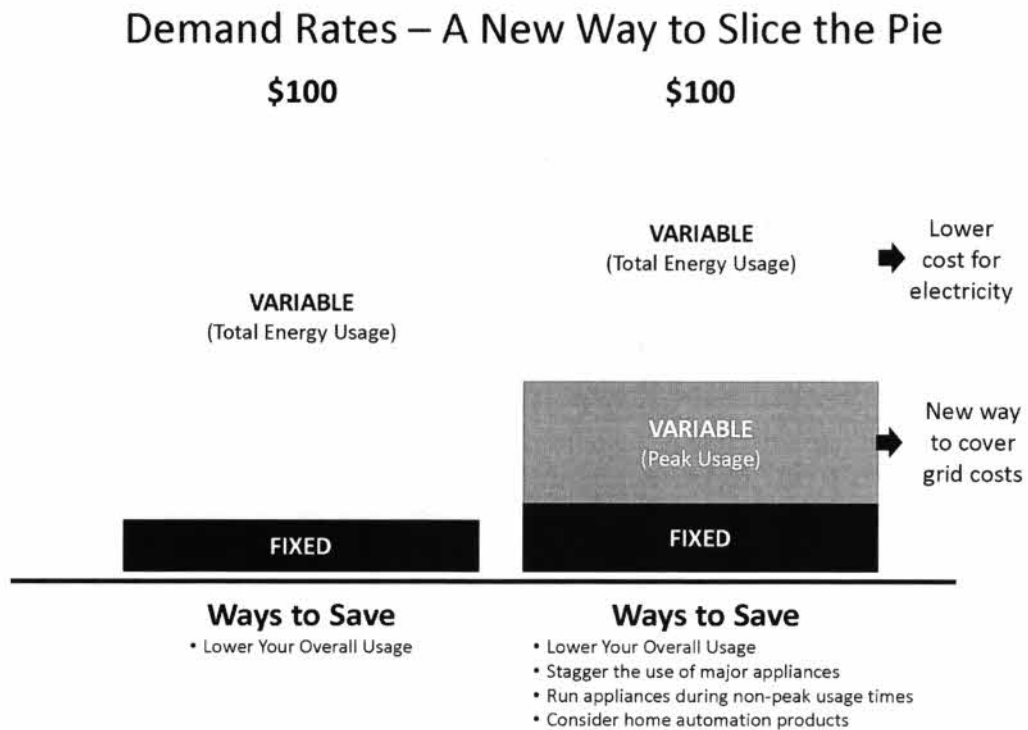
13 Theoretically, these sporadic energy reductions could have some beneficial impacts at
14 the system peak level, which in turn drives utility's power plant capacity costs. But this
15 would require enough participants in the TOU rate with a sufficient diversity of sporadic
16 energy reductions at different times of the day, and days of the year, to provide a
17 combined energy reduction that is somewhat more consistent across the utility's critical
18 peak hours. However, even in this hypothetical case, the combined diversified impact
19 on system peak would almost certainly be far less than the sum of the impacts for the
20 individual homes.

21 In any event, a two-part TOU energy rate would not be likely to incent the type of
22 technology or electrical appliance choices that are focused on reducing the home's
23 electrical infrastructure requirements. For example, some electrical appliance choices,
24 such as instantaneous water heaters, may use a high level of demand, but lower kWh's
25 during the month, compared to alternatives. These devices can reduce the utility's fuel
26 costs to serve the home, but also require significantly more infrastructure investment
27 from the utility. Two-part kWh rates, including TOU rates, would incent the customer to
28

1 invest in the latter choice, with the higher demand but lower energy requirements. Other
2 home energy technologies would also be incented to focus on, and be rewarded for,
3 reducing on-peak energy but not necessarily demand, under a two-part TOU rate.

4 From a customer's perspective, a three-part TOU rate provides three ways to save on
5 their bill – shifting kWh energy usage to off-peak hours, reducing overall kWh energy
6 usage, and reducing the on-peak demand, while a two-part TOU rate only provides the
7 first two ways to save, as illustrated in Figure 2 below. In addition, these three ways to
8 save are much better aligned with the utility's cost of service, which creates a win-win
9 situation where the customer's bill savings result in similar utility cost savings.
10

11 Figure 2.



25 **Q. WHAT ABOUT APPLYING THE DEMAND ONLY TO ON-PEAK HOURS?**

26 A. Some parties including Staff, RUCO, and WRA have proposed that demand charges
27 should only apply to on-peak hours for residential customers. APS believes this
28

1 argument involves the inherent tension between theoretical precision and practical
2 application. In general, APS supports applying the demand charge to the on-peak hours
3 for residential customers, but only under certain circumstances. And this opinion is
4 driven more by practical considerations than by theoretical precision.

5 **Q. PLEASE EXPLAIN.**

6 A. All utility charges are a mix of theoretical precision and practical application. The
7 perfect charges, whether they are demand charges, energy charges or something else,
8 would likely be too complex and expensive to implement. For example, the best
9 demand charge would likely be two demand charges – an untimed (non-time-of-use)
10 demand charge to recover distribution costs that vary with the size of the home and are
11 driven by the neighborhood peak, rather than the system peak, and an on-peak demand
12 charge to recover power plant infrastructure costs that are driven by system peak hours.
13 This could also be accomplished through separate on-peak and off-peak demand charges
14 that would differ by the power plant capacity costs.

15
16 However, APS believes that this structure would be complex, at least initially, and
17 therefore more appropriate for business customers than residential customers.
18 Therefore, APS believes that an on-peak demand charge is a viable option for
19 recovering the costs of both power lines and power plants if the following conditions
20 are met: (1) the monthly service charge recovers the grid costs from the meter, point of
21 delivery, service drop to the home, and the distribution transformer (along with the other
22 customer-related costs such as meter reading, billing, and customer care); and (2) the on-
23 peak period is defined to include the hours that typically drive the design peaks for
24 residential feeders and substations as well as the system-peak hours that drive power
25 plant costs.

26
27 As a practical matter, a uniform un-timed demand charge could work because residential
28 customers largely peak on the system peak. Under this scenario an un-timed demand

1 charge would reasonably reflect the infrastructure costs for each home, without unduly
2 complicating the bill.

3
4 **Q. SHOULD THE DEMAND CHARGE ONLY BE APPLIED TO SUMMER MONTHS?**

5 A. No. The demand charges could be somewhat higher in the summer months compared
6 with the winter, but APS does not recommend only applying the demand charge to one
7 month or one season. From a theoretic standpoint, as discussed above, not all
8 infrastructure costs are driven by system peak months or hours. For example, the
9 distribution grid, while typically sized for summer load, is needed to serve homes
10 throughout the year. And while it may be cost justified to apply a significant portion of
11 power plant costs only to the core summer months, from a practical standpoint
12 residential customers already face high summer bills, and this option would exacerbate
13 that issue.

14 **Q. WILL THREE-PART DEMAND RATES HURT ENERGY EFFICIENCY?**

15 A. No, it will refocus energy efficiency and turn it into a better resource for the utility and
16 provide means by which customers can exercise greater control over their utility bill
17 through demand management.

18
19 **Q. PLEASE EXPLAIN.**

20 A. As discussed in my Direct Testimony, APS believes that home technology investments
21 can be an important resource for meeting future power needs – if the investments are
22 properly incented and focused on reducing the costs for both building and running
23 power plants in the future. Currently, the two-part kWh rates focus energy efficiency
24 programs on investments that reduce operating costs, such as fuel and variable O&M,
25 but not the costs of the power plants themselves, which are more significant. A three-
26 part demand rate incents home technologies and energy efficiency investments that can
27 reduce both of these costs.

1 Concerning the customer's potential bill savings, a three-part demand rate will have a
2 lower kWh charge compared with a two-part kWh rate. But, under the three-part
3 demand rate, the demand charge will provide the customer an additional incentive and
4 opportunity to save on their bill. Therefore, APS believes that three-part demand rates
5 can result in viable opportunities for energy efficiency programs, and those programs
6 will have a much higher value to the electric system because of the potential increased
7 utility cost savings compared with those that are primarily focused on energy savings.

8 **Q. WHAT WERE VOTE SOLAR'S REMARKS CONCERNING ENERGY EFFICIENCY AT MINGUS HIGH SCHOOL?**

9
10 A. Vote Solar witness Kobor testified that Mingus Union High School District ("Mingus")
11 was harmed because APS implemented a demand charge to their bill after the customer
12 invested more than \$1 million in energy efficiency. Because the estimated bill savings
13 from the energy efficiency project was apparently targeted at reducing kWh energy and
14 not kW demand, the actual bill savings were much lower than expected, which reduced
15 the investment's net benefits.

16 **Q. DO YOU AGREE WITH VOTE SOLAR'S TESTIMONY REGARDING THE ENERGY EFFICIENCY INVESTMENTS MADE BY MINGUS?**

17
18 A. No.

19 **Q. PLEASE EXPLAIN.**

20 A. In 2013 and 2014, Mingus implemented energy efficiency projects apparently targeted
21 at reducing kWh energy and not kW demand. As a result, the actual bill savings were
22 much lower than expected, which reduced the investment's net benefits. Mingus –
23 along with all business customers with loads greater than 20 kW – has been subject to a
24 three-part demand rate for decades. Therefore, contrary to Vote Solar's testimony the
25 demand charge was in place many years before the energy efficiency investment took
26 place. An adjustment to how the demand charge is calculated during a low-load month
27 was approved in our last general rate case and effective in July 2012, which was also
28

1 well before the energy efficiency measures were installed. Unfortunately, it appears that
2 either Mingus or their third-party vendor may have miscalculated the anticipated savings
3 from its investment in energy efficiency.

4 APS is sympathetic to our customer for this situation. We know that utility bills are
5 especially important to our schools because of relatively tight overall funding and
6 limited control over significant portions of their operating budgets such as teacher's
7 salaries. As such, we also know it is critical that the investments they make in energy
8 efficiency, solar and other technologies produce sufficient savings in utility bills or other
9 operating costs to justify their cost.

10
11 While APS does not know precisely how the savings miscalculation occurred for the
12 project, a plausible reason is that Mingus (or their third-party vendor) may have
13 overestimated the savings by dividing the total bill by the monthly kWh to get an
14 average savings per kWh, rather than calculating specific expected savings for the
15 demand and energy components of the bill, as they should have. Had the estimated bill
16 savings included both the demand and energy components, the actual bill savings would
17 have been more in line with or even surpassed their expectations. As a result, the
18 estimated bill savings from the reduction in monthly kWh were overstated compared to
19 the actual bill reduction.

20
21 V. STAFF'S RECOMMENDATION FOR CUSTOMER EDUCATION ON THREE-
22 PART RATES

23 Q. **DO YOU AGREE WITH STAFF THAT CUSTOMER EDUCATION IS AN
24 IMPORTANT PART OF IMPLEMENTING THREE-PART RATES?**

25 A. Yes. APS believes that it is important to educate customers about all components of
26 their bill, how the bill is calculated and the actions they can take to save and mitigate
27 potential impacts from rate changes. This education can emphasize that under a three-
28 part time-of-use rate, for example, the customer would have three ways to save on their

1 bill – lower their overall monthly energy use (or kWh), shift energy to the off-peak
2 hours, and lower their monthly peak usage (kW demand) during a specific on-peak
3 period.

4 Customer education would also focus on the use of modern technologies such as home
5 energy monitors and controls, smart thermostats, advanced air-conditioners, battery
6 storage, and smart inverters. These devices help manage and reduce peak usage, thus
7 allowing customers to better manage and reduce their bills.
8

9 **Q. DOES THIS EDUCATION HAVE TO BE HIGHLY COMPLICATED AS**
10 **SUGGESTED BY TASC?**

11 A. No. Not at all. We have found that the demand charge concept and strategies to save
12 can be, and should be, explained very simply for the general customer group.
13 Customers don't need an energy engineer in their home, as suggested by TASC in a Salt
14 River Project proceeding, to understand either. Additional detailed information can be
15 made available on the utility's website, or through other education channels, for the
16 customers that are interested in learning about further specific details.

17 **Q. DOES APS HAVE ANY EXAMPLES OF THIS EDUCATION MATERIAL?**

18 A. Yes. Attachment CAM-2SR is a sample draft customer education piece we are currently
19 developing as we contemplate proposing an expansion of our three-part rate program.
20 The piece is not yet complete. However, APS thought it could be helpful to provide
21 examples of education concepts. *See also* APS's response to RUCO Data Request 1.6,
22 which is attached as Attachment CAM-3SR and incorporated into my Surrebuttal
23 Testimony by this reference. This material includes information used for our current
24 three-part rate program.
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1 VI. UNSE'S PROPOSAL FOR A SOLAR PURCHASE RATE

2 **Q. WHAT DOES UNSE PROPOSE CONCERNING A SOLAR PURCHASE RATE?**

3 UNSE proposes that excess power from rooftop solar that flows back to the grid be
4 purchased by the utility at a solar purchase rate and credited on the bill each month.
5 Their proposed solar purchase rate reflects the purchase price from a large grid-scale
6 solar plant, which would be revised from time to time.

7 **Q. WHAT IS APS'S POSITION?**

8 A. APS believes that the best rate for excess power would be an avoided cost rate.
9 UNSE's proposed purchase price from a grid-scale solar plant could be reasonable, but
10 should be the maximum considered for purchase of excess generation from rooftop
11 solar.

12
13 VII. CONCLUSION

14 **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.**

15 A. APS recommends that the Commission approve three-part demand rates for UNSE
16 residential customers. This is consistent with the proposals made by Staff and UNSE in
17 their Rebuttal Testimony. APS also recommends that the Commission adopt Staff's
18 recommendation for a transition period combined with customer education. APS further
19 recommends adoption of UNSE's net metering proposal.

20 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

21 A. Yes.
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RESIDENTIAL UTILITY CONSUMER OFFICE'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
DECEMBER 22, 2015

RUCO 1.2: APS'S Residential Three-Part Demand Charge Based Rates - On page 7, line 22 of APS witness Charles A. Miessner's rate design direct testimony he states that "We looked at a sample of customers that switched from an energy-only time-of-use rate to the three-part demand rate and found that about 60% of those customers saved on their demand and energy. We also found that those who actively manage their demand have achieved demand savings of 10% - 20% or more. On average, customers on the three-part rate reduce their monthly demand by 3% to 4% depending on the season. These customers also tend to save on their on-peak and monthly kWh usage after switching to the three-part rate." Based on that statement please answer the following questions:

- a. Please state the methodology that APS employed to select its sample.
- b. Please specify the number of residential customers under this plan that were used in APS's sample?
- c. Please provide the worksheet and criteria used to justify the statement that "60% of residential customers that switched from a time of use plan to the APS residential three-part demand rates saved."
- d. Please identify the 40 percent of the sample that did not save, and reasons why they did not save given APS's criteria.
- e. Please provide your calculations, criteria, and supporting documentation to support the statement "We also found that those who actively manage their demand have achieved demand savings of 10% - 20% or more."
- f. Please provide your calculations, criteria, and supporting documentation to support the statement "On average, customers on the three-part rate reduce their monthly demand by 3% to 4% depending on the season. These customers also tend to save on their on-peak and monthly kWh usage after switching to the three-part rate."

Response:

- a. Information about the sample and the selection method is provided in the first page/tab of Attachment APS15766.

RESIDENTIAL UTILITY CONSUMER OFFICE'S
FIRST SET OF DATA REQUESTS TO
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Response to
RUCO 1.2
(continued):

- b. The total study size was 977 customers, which constituted all customers meeting the criteria.
- c. The summary information is provided in APS15766.
- d. The summary information for the customers that did not save under a demand rate is included in APS15766. Typically these customers did not save under a demand rate because their on-peak demand was relatively high in relation to their overall energy consumption and it appears they did little or nothing additional to manage their electrical usage patterns.
- e. As shown in the attachment, the top 20% (most successful) savers reduced their bills by 10% to 20% or more under the demand rate.
- f. As provided in the attachment, the average demand reduction for the sample was 3% to 4% while the top 20% reduced their monthly demand by roughly 24% on average.

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

Background:

Analysis performed in 2015

The purpose of the study was to assess the impact of a three-part demand rate on demand, energy, and monthly bills for residential customers.

The study isolated the demand change impact by comparing the same customer before and after switching to a three-part rate.

Since the three-part rate was a time-of-use rate, APS compared customers moving from a two-part TOU rate with similar on-peak hours.

The study specifically compared the two-part Rate ET-2 with the three-part Rate ECT-2, both having on-peak hours of 12 noon to 7 pm weekdays.

Sampling Frame:

Phoenix Metro customers

Switched from ET-2 to ECT-2 in 2013

Had 12 months billing data in 2012 and 2014

Resided in same home for the three year period

Total sample size = 977 customers

Adjustments:

Load data was normalized for temperature and humidity for summer months.

Winter months were not adjusted because correlation factors between load and weather were very low.

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

The change in kW, kWh, and monthly bill resulting from switching from a two-part rate to a three-part rate

% Customers	Summer Load Change (Weather Normalized - temp, humidity)						Summer Bill ¹			
	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	\$ Change	% Change
5%	(617)	(234)	(383)	(3.0)	-27%	-40%	-22%	-39%	\$ (93.94)	-35%
10%	(444)	(134)	(310)	(1.8)	-19%	-24%	-17%	-24%	\$ (66.07)	-25%
15%	(386)	(139)	(247)	(1.6)	-15%	-21%	-13%	-19%	\$ (64.35)	-22%
20%	(364)	(117)	(246)	(1.3)	-14%	-17%	-13%	-16%	\$ (62.67)	-21%
25%	(358)	(89)	(269)	(1.1)	-14%	-14%	-14%	-13%	\$ (58.15)	-20%
30%	(196)	(76)	(120)	(0.9)	-8%	-11%	-7%	-11%	\$ (45.61)	-16%
35%	(99)	(48)	(51)	(0.7)	-4%	-8%	-3%	-9%	\$ (37.68)	-14%
40%	(162)	(66)	(96)	(0.7)	-6%	-9%	-5%	-8%	\$ (45.06)	-14%
45%	(40)	(29)	(11)	(0.5)	-2%	-5%	-1%	-6%	\$ (29.43)	-11%
50%	(78)	(41)	(38)	(0.4)	-3%	-6%	-2%	-4%	\$ (30.38)	-10%
55%	(31)	(25)	(6)	(0.2)	-1%	-4%	0%	-2%	\$ (29.28)	-10%
60%	7	(12)	19	(0.1)	0%	-2%	1%	-1%	\$ (22.88)	-9%
65%	2	(4)	6	0.1	0%	-1%	0%	1%	\$ (17.45)	-6%
70%	68	8	60	0.2	3%	1%	4%	3%	\$ (14.64)	-5%
75%	3	7	(4)	0.3	0%	1%	0%	4%	\$ (17.65)	-6%
80%	181	25	156	0.5	8%	4%	9%	6%	\$ (7.49)	-3%
85%	200	45	155	0.7	8%	7%	8%	9%	\$ (1.01)	0%
90%	144	52	92	0.9	6%	9%	5%	12%	\$ (3.11)	-1%
95%	256	63	193	1.2	11%	10%	11%	16%	\$ 7.82	3%
100%	519	166	353	2.1	25%	34%	22%	33%	\$ 41.43	18%
Average	(70)	(32)	(37)	(0.31)	-2.9%	-5.2%	-2.1%	-3.9%	\$ (29.88)	-11%

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

stratified by % kW change during summer months

Winter Load Change (No Weather Normalization)

% Customers	Winter Load Change (No Weather Normalization)				Winter Bill ¹					
	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kWh	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kWh	% Change	
5%	(242)	(61)	(182)	(1.2)	-21%	-29%	-19%	-26%	\$ (27.63)	-23%
10%	(159)	(45)	(115)	(0.9)	-12%	-18%	-11%	-18%	\$ (25.31)	-19%
15%	(88)	(23)	(66)	(0.3)	-7%	-10%	-6%	-7%	\$ (13.58)	-11%
20%	(140)	(32)	(108)	(0.5)	-10%	-13%	-10%	-10%	\$ (18.44)	-14%
25%	(147)	(22)	(125)	(0.4)	-12%	-9%	-12%	-9%	\$ (16.23)	-13%
30%	(52)	(5)	(46)	(0.3)	-4%	-2%	-5%	-6%	\$ (10.51)	-8%
35%	(94)	(3)	(92)	(0.1)	-8%	-1%	-9%	-3%	\$ (10.56)	-9%
40%	(63)	(9)	(54)	(0.3)	-4%	-3%	-5%	-5%	\$ (13.28)	-9%
45%	(5)	1	(6)	(0.3)	0%	0%	-1%	-5%	\$ (6.04)	-5%
50%	(22)	3	(24)	0.1	-2%	1%	-2%	2%	\$ (7.40)	-6%
55%	(1)	11	(12)	(0.1)	0%	5%	-1%	-1%	\$ (5.18)	-4%
60%	(18)	(0)	(17)	(0.2)	-2%	0%	-2%	-4%	\$ (7.61)	-7%
65%	12	17	(5)	0.0	1%	8%	-1%	0%	\$ (3.20)	-3%
70%	45	20	25	0.1	4%	10%	3%	2%	\$ 0.77	1%
75%	23	16	7	0.1	2%	8%	1%	3%	\$ (4.20)	-4%
80%	137	33	104	0.2	12%	16%	11%	4%	\$ 5.20	4%
85%	53	26	27	0.2	4%	10%	2%	4%	\$ (1.60)	-1%
90%	58	29	30	0.3	5%	14%	3%	6%	\$ (0.26)	0%
95%	151	53	98	0.6	13%	26%	10%	13%	\$ 9.10	8%
100%	231	68	163	0.8	19%	32%	17%	17%	\$ 13.41	11%
Average	(16)	4	(20)	(0.11)	-1.3%	1.7%	-2.0%	-2.2%	\$ (7.13)	-6%

**ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis**

stratified by % kW change during summer months

% Customers	Annual Load Change						Annual Bill ¹				
	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kWh	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kWh	% Change	\$ Change	% Change
5%	(430)	(147)	(282)	(2.1)	-25%	-37%	-21%	-34%		\$ (60.78)	-32%
10%	(302)	(89)	(213)	(1.3)	-16%	-22%	-15%	-21%		\$ (45.69)	-23%
15%	(237)	(81)	(156)	(1.0)	-12%	-18%	-11%	-14%		\$ (38.96)	-18%
20%	(252)	(75)	(177)	(0.9)	-13%	-16%	-12%	-13%		\$ (40.56)	-18%
25%	(252)	(55)	(197)	(0.8)	-13%	-12%	-14%	-11%		\$ (37.19)	-18%
30%	(124)	(41)	(83)	(0.6)	-7%	-9%	-6%	-9%		\$ (28.06)	-14%
35%	(97)	(26)	(71)	(0.4)	-5%	-6%	-5%	-7%		\$ (24.12)	-12%
40%	(113)	(37)	(75)	(0.5)	-5%	-8%	-5%	-6%		\$ (29.17)	-13%
45%	(23)	(14)	(8)	(0.4)	-1%	-3%	-1%	-6%		\$ (17.73)	-9%
50%	(50)	(19)	(31)	(0.1)	-3%	-4%	-2%	-2%		\$ (18.89)	-9%
55%	(16)	(7)	(9)	(0.1)	-1%	-2%	-1%	-2%		\$ (17.23)	-8%
60%	(5)	(6)	1	(0.1)	0%	-2%	0%	-2%		\$ (15.25)	-8%
65%	7	7	0	0.1	0%	2%	0%	1%		\$ (10.33)	-5%
70%	56	14	43	0.1	3%	3%	3%	2%		\$ (6.93)	-4%
75%	13	12	1	0.2	1%	3%	0%	4%		\$ (10.92)	-6%
80%	159	29	130	0.3	9%	7%	10%	5%		\$ (1.15)	-1%
85%	127	36	91	0.5	7%	8%	6%	7%		\$ (1.30)	-1%
90%	101	40	61	0.6	6%	10%	4%	10%		\$ (1.68)	-1%
95%	204	58	146	0.9	12%	14%	11%	15%		\$ 8.46	4%
100%	375	117	258	1.5	23%	33%	20%	26%		\$ 27.42	16%
Average	(43)	(14)	(29)	(0.21)	-2.4%	-3.4%	-2.0%	-3.3%		\$ (18.50)	-9%

Notes:

1. Excluding adjustors and taxes.

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)
ECT-2 Load (calendar year 2014)

% Customers	Summer Monthly Avg (May-Oct)			Winter Monthly Avg (Nov-April)			Annual			Avg Monthly Load Factor		
	Total kWh	On-Pk kWh	Off-Pk kWh	Total kWh	On-Pk kWh	Off-Pk kWh	Total kWh	On-Pk kWh	Off-Pk kWh	Summer	Winter	Annual
5%	1,700	345	1,355	937	149	788	1,319	247	1,071	49%	37%	43%
10%	1,898	432	1,465	1,162	199	963	1,530	316	1,214	45%	39%	42%
15%	2,156	526	1,630	1,209	206	1,003	1,683	366	1,316	42%	35%	38%
20%	2,272	566	1,705	1,222	221	1,001	1,747	394	1,353	42%	34%	38%
25%	2,195	572	1,623	1,098	217	881	1,647	394	1,252	41%	32%	37%
30%	2,252	587	1,665	1,173	234	939	1,713	410	1,302	41%	33%	37%
35%	2,254	581	1,673	1,137	215	921	1,695	398	1,297	43%	33%	38%
40%	2,563	637	1,926	1,379	254	1,124	1,971	446	1,525	43%	35%	39%
45%	2,329	602	1,727	1,211	217	994	1,770	410	1,360	42%	35%	38%
50%	2,454	638	1,816	1,304	255	1,049	1,879	447	1,433	40%	33%	37%
55%	2,421	620	1,801	1,248	233	1,015	1,834	426	1,408	42%	34%	38%
60%	2,240	571	1,668	1,081	196	885	1,660	384	1,277	43%	36%	39%
65%	2,410	624	1,786	1,234	236	998	1,822	430	1,392	40%	34%	37%
70%	2,388	631	1,757	1,182	224	958	1,785	428	1,357	40%	33%	37%
75%	2,428	616	1,812	1,201	231	970	1,815	424	1,391	41%	35%	38%
80%	2,540	646	1,894	1,301	240	1,061	1,920	443	1,478	42%	35%	39%
85%	2,685	693	1,992	1,419	274	1,145	2,052	484	1,568	41%	34%	38%
90%	2,515	649	1,866	1,228	235	993	1,871	442	1,430	41%	35%	38%
95%	2,569	671	1,897	1,312	260	1,052	1,940	466	1,475	40%	33%	37%
100%	2,606	654	1,952	1,424	282	1,142	2,015	468	1,547	42%	35%	38%
Average	2,344	593	1,751	1,223	229	994	1,783	411	1,372	42%	35%	38%

ARIZONA PUBLIC SERVICE COMPANY

Residential Demand Rate Analysis

stratified by % kW change during summer months

Two-part Energy Rate (Time-of-use)

ET-2 Load (calendar year 2012)

% Customers	Summer Monthly Avg (May-Oct)				Winter Monthly Avg (Nov-April)				Annual				Load Factor		
	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	Summer	Winter	Annual
5%	2,317	579	1,738	7.7	1,179	210	969	4.7	1,748	394	1,354	6.2	41%	35%	38%
10%	2,342	566	1,776	7.6	1,321	244	1,078	5.0	1,832	405	1,427	6.3	42%	37%	39%
15%	2,542	665	1,877	8.6	1,297	229	1,068	5.1	1,920	447	1,473	6.8	40%	35%	38%
20%	2,635	683	1,952	8.6	1,362	254	1,108	5.5	1,999	469	1,530	7.1	41%	34%	38%
25%	2,553	661	1,892	8.3	1,245	238	1,007	5.2	1,899	450	1,449	6.7	42%	33%	38%
30%	2,448	663	1,785	8.4	1,225	239	986	5.2	1,837	451	1,385	6.8	40%	33%	36%
35%	2,353	630	1,724	7.9	1,231	218	1,013	4.9	1,792	424	1,368	6.4	41%	35%	38%
40%	2,725	703	2,023	8.7	1,442	263	1,179	5.7	2,084	483	1,601	7.2	42%	35%	39%
45%	2,369	632	1,737	8.0	1,217	217	1,000	5.1	1,793	424	1,369	6.5	40%	33%	37%
50%	2,533	679	1,854	8.7	1,326	252	1,074	5.3	1,929	466	1,464	7.0	40%	34%	37%
55%	2,452	645	1,808	7.9	1,249	222	1,026	5.1	1,851	434	1,417	6.5	42%	34%	38%
60%	2,232	583	1,650	7.2	1,099	196	902	4.3	1,666	390	1,276	5.8	42%	35%	39%
65%	2,409	629	1,780	8.1	1,221	218	1,003	5.0	1,815	423	1,392	6.6	40%	34%	37%
70%	2,320	623	1,697	7.8	1,137	204	933	4.9	1,729	414	1,315	6.3	40%	32%	36%
75%	2,426	609	1,816	7.7	1,178	215	963	4.6	1,802	412	1,390	6.2	43%	35%	39%
80%	2,359	621	1,738	7.7	1,164	207	957	4.9	1,761	414	1,348	6.3	42%	33%	37%
85%	2,485	648	1,837	8.2	1,366	248	1,118	5.5	1,925	448	1,477	6.9	41%	34%	38%
90%	2,371	597	1,774	7.4	1,170	206	964	4.6	1,770	402	1,369	6.0	44%	35%	39%
95%	2,312	608	1,704	7.5	1,161	207	954	4.8	1,736	408	1,329	6.1	42%	34%	38%
100%	2,087	488	1,600	6.4	1,193	214	979	4.9	1,640	351	1,290	5.6	45%	34%	39%
Average	2,414	625	1,788	7.9	1,239	225	1,014	5.0	1,826	425	1,401	6.5	41%	34%	38%

ARIZONA PUBLIC SERVICE COMPANY
Residential Demand Rate Analysis

stratified by % kW change during summer months

Three-part Demand Rate (Time-of-use)				Two-part Energy Rate (Time-of-use)			
ECT-2 Average Monthly Bill ¹				ET-2 Average Monthly Bill ¹			
% Customers	Summer	Winter	Annual	% Customers	Summer	Winter	Annual
5%	\$ 171.15	\$ 90.08	\$ 130.61	5%	\$ 265.09	\$ 117.71	\$ 191.40
10%	\$ 198.22	\$ 105.72	\$ 151.97	10%	\$ 264.30	\$ 131.03	\$ 197.66
15%	\$ 230.36	\$ 113.95	\$ 172.16	15%	\$ 294.71	\$ 127.53	\$ 211.12
20%	\$ 241.06	\$ 116.50	\$ 178.78	20%	\$ 303.73	\$ 134.94	\$ 219.34
25%	\$ 236.56	\$ 109.36	\$ 172.96	25%	\$ 294.71	\$ 125.59	\$ 210.15
30%	\$ 242.96	\$ 114.00	\$ 178.48	30%	\$ 288.58	\$ 124.51	\$ 206.54
35%	\$ 238.98	\$ 111.42	\$ 175.20	35%	\$ 276.66	\$ 121.98	\$ 199.32
40%	\$ 267.80	\$ 127.85	\$ 197.82	40%	\$ 312.86	\$ 141.13	\$ 226.99
45%	\$ 248.55	\$ 114.87	\$ 181.71	45%	\$ 277.98	\$ 120.91	\$ 199.44
50%	\$ 266.28	\$ 125.11	\$ 195.69	50%	\$ 296.66	\$ 132.50	\$ 214.58
55%	\$ 256.19	\$ 118.49	\$ 187.34	55%	\$ 285.47	\$ 123.67	\$ 204.57
60%	\$ 237.77	\$ 103.32	\$ 170.54	60%	\$ 260.65	\$ 110.93	\$ 185.79
65%	\$ 262.34	\$ 118.24	\$ 190.29	65%	\$ 279.79	\$ 121.45	\$ 200.62
70%	\$ 258.80	\$ 115.16	\$ 186.98	70%	\$ 273.44	\$ 114.39	\$ 193.91
75%	\$ 259.67	\$ 114.06	\$ 186.86	75%	\$ 277.31	\$ 118.26	\$ 197.79
80%	\$ 267.91	\$ 121.54	\$ 194.72	80%	\$ 275.40	\$ 116.34	\$ 195.87
85%	\$ 287.12	\$ 132.75	\$ 209.93	85%	\$ 288.13	\$ 134.35	\$ 211.24
90%	\$ 268.61	\$ 116.33	\$ 192.47	90%	\$ 271.72	\$ 116.58	\$ 194.15
95%	\$ 277.96	\$ 125.27	\$ 201.62	95%	\$ 270.15	\$ 116.17	\$ 193.16
100%	\$ 275.72	\$ 132.57	\$ 204.14	100%	\$ 234.29	\$ 119.17	\$ 176.73
Average	\$ 249.70	\$ 116.33	\$ 183.01	Average	\$ 279.58	\$ 123.46	\$ 201.52

Notes:

1. Excluding adjustors and taxes.

How to Manage Your Peak Usage and Save

If you're able to make slight changes to when and how you use energy, you can lower your energy bill and save. Here are some simple suggestions.

- 1) Stagger the use of major appliances (AC, oven, dryer, electric water heater)**
When possible, wait to do laundry until later in the evening after you are done cooking dinner.
- 2) Run appliances during non-peak usage times**
Set your dishwasher to run on a delay cycle and put your pool pump on a timer.
- 3) Consider home automation products**
Programmable thermostats and load controllers are a great way to reduce your peak usage without giving it a second thought. Set your parameters, and the products do all the managing for you.
- 4) Lower your overall usage**
Take advantage of some basic energy-efficiency programs, tips and tools – turning off lights and fans when leaving a room, setting your thermostat a few degrees higher in the summer and lower in the winter, switching to LEDs, and taking our Energy Analyzer online survey, to name just a few.



Lower Your Peak Usage and Save Money



Understanding How Peak Usage Impacts Your Bill

Simply put, peak usage is your **highest one hour** of energy use during times when there is already a lot of demand for energy; Energy demand is at its greatest on weekdays when Arizonans are coming home from school or work. Your peak usage is averaged over an entire hour – a full 60 minutes – not just one moment in time. And since there's a direct tie between your peak usage and your bill amount, you can save money by managing your energy use.

Let's take a look at an example of two customers – with identical appliances – who have different peak usage numbers based on how many appliances they're using **at the same time**.



STEVE

Steve, who puts a priority on comfort and convenience, comes home from work and...

- Turns his AC down to **75°**
- Cooks dinner
- Starts a few loads of laundry
- Has the TV on

STEVE'S HOME

Air Conditioner	On	3.8 kW
Oven	On	1.3 kW
Washer	On	0.4 kW
Dryer	On	1.9 kW
Television	On	0.1 kW
Peak Usage		7.5 kW



JAMIE

Jamie, who is more concerned with cost-savings, comes home from work and...

- Turns her AC down to **79°**
- Cooks dinner
- Has the TV on

JAMIE'S HOME

Air Conditioner	On	2.5 kW
Oven	On	1.3 kW
Washer	Off	0.0 kW
Dryer	Off	0.0 kW
Television	On	0.1 kW
Peak Usage		3.9 kW

(Examples are based on 1,800 sq. ft. homes during a typical summer evening)

Who Will Save More Money?

It's no surprise that Jamie's peak usage is almost half that of Steve's since she is not running all her major appliances at once. So while Steve will pay his typical bill amount, **Jamie will save approximately \$20 on her bill.** Why? Because the lower your peak usage, the greater your savings.

RESIDENTIAL UTILITY CONSUMER OFFICE'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER
REGARDING UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
DECEMBER 22, 2015

RUCO 1.6: APS'S Residential Three-Part Demand Charge Based Rates – What programs, tools, or customer support does APS provide for customers on their demand charge based rates? Please explain how APS currently educates customers who switch to a demand charge based rate? Does APS see their education strategy changing over time?

Response: APS customers receive information on available rate plans, including the Company's three-part residential demand rate, in several ways.

Customers calling APS requesting to set up a new account are asked a set of questions about lifestyle choices and property characteristics designed to assist both the customer and the call center associate to determine which rate plan might be the most beneficial to the customer (for example: Do you have gas service at your home? Does your home have a pool? Are you at home during daytime hours?).

Call center associates also provide a description of how APS's three-part residential demand rate works when an existing customer contacts APS through the call center to inquire about changing rate plans. In addition, customers that request additional information will be directed to aps.com or, if the customer cannot access the website, a letter can be sent that explains each of the available residential rate plans (this letter is attached to this response as APS15759).

In each of the Company's customer service offices brochures are available to residential customers that discuss each of the available rate plans to assist customers in determining which plan might be appropriate for their circumstances. This brochure is attached as APS15760.

The above information is also available at aps.com for customers to review at any time. In addition, to assist customers in choosing an appropriate rate plan, the Company offers a rate comparison tool for existing customers that will use the customer's actual energy usage history to provide an overview of each available rate plan. This information is accessed through each customer's individual online account. Screenshots of this tool are attached as APS15761.

APS provides customers with information regarding rate plans and rate plan options on an ongoing basis and will continue to assess new education strategies.

January 6, 2016

JOE & MARY SMITH
400 N 5TH ST
PHOENIX AZ

Dear Joe & Mary Smith:

Thank you for contacting APS regarding our residential service plan options. We recognize that when it comes to energy usage, different people have different needs. That's why we offer several electric service plans - so you can find the one that is most convenient for your lifestyle and saves you the most money. Please see the detailed information that is included in this letter for more information.

Additionally, you can find complete information on our Web site at www.aps.com/rates, and can also perform a comparison and find out about other options such as Green Choice rates.

If you have any questions regarding this or need additional information, please feel free to contact our Customer Care Center at (602)371-7171 or (800)253-9405. Associates are available 24-hours-a-day. Or, visit us online at www.aps.com.

We appreciate your business and the opportunity to serve you.

Sincerely,

Bernard

Bernard
APS Customer Care Center

Standard

This plan helps those who use less energy save money. It doesn't make any difference what time of day electricity is used. This plan may be best for you if:

- You generally use 1,000 kWh or less each month due to the size of your home and type of appliances.
- You live in a home, mobile home, condominium or apartment that is 1,100 square feet or less.
- You do not have a swimming pool or spa that is electrically heated.

Here's how it works:

- In the summer (May-October) you are billed at different costs per kilowatt hour (kWh) depending on your energy usage;
 - The first 400 are billed at about 9.7¢
 - The next 400 are billed at about 13.7¢
 - The next 2,200 are billed at about 16.3¢
 - All remaining kWh are billed at about 17.4¢
- In the winter (November-April) the cost is about 9.4¢ per kWh used.

Time Advantage 7 p.m.-Noon

This plan is best for those who have minimal energy usage during on-peak periods (Noon-7 p.m., Monday-Friday), especially during the summer months. This plan may be best for you if:

- You generally use 1,000 kWh or more each month due to the size of your home and type of appliances.
- You are not home during the day or have low daytime energy use.
- You are able to use your dishwasher, dryer, washer and range more during off-peak hours.
- You are able to operate your major electric appliances such as the water heater, pool pump and spa heater during off-peak hours.
- You have a programmable thermostat or can set your air conditioning to a warmer temperature during on-peak hours.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis.
- Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*. Electricity used during off-peak hours is billed at a lower rate.
- On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
- In the summer (May-October) you are billed at about 24.4¢ per kWh used on-peak, and 6.1¢ per kWh used off-peak.
- In the winter (November-April) you are billed at about 19.8¢ per kWh used on-peak, and 6.1¢ per kWh used off-peak.
 - *Note: The APS meter readers must have safe, unassisted access to physically touch the meter each month.*

Combined Advantage 7 p.m.-Noon

This plan is best for those who have minimal energy usage during peak periods (Noon-7 p.m., Monday-Friday). You can save on your bill by adjusting when you use energy and how much you use at one time. This plan works just like the Time Advantage 7 p.m.-Noon plan, with one main difference:

- This plan has a Demand component, which is the largest portion of the bill and is billed in addition to the charge for on-peak and off-peak kilowatt hours used.
 - The Demand (kW) is the one on-peak 60-minute period of the billing cycle when you use the most electricity.

This plan may be best for you if:

- You are able to spread out your use of major appliances during on-peak hours, so you are not using them all at once.
- You are able to operate your major electric appliances such as the water heater, pool pump and spa heater during off-peak hours.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis, with an on-peak demand component.
 - Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*.
 - On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
 - The Demand is the one on-peak 60-minute period of the billing cycle when you use the most electricity. It is also the largest component of the bill.
- The chart below shows the costs for the different timeframes and components of the bill:

Summer (May-October billing cycle)	Cost
Demand charge (kW)	\$13.404 per kW
On-peak kWh used	8.845¢ per kWh
Off-peak kWh used	4.363¢ per kWh

Winter (November-April billing cycle)	Cost
Demand charge (kW)	\$9.203 per kW
On-peak kWh used	5.815¢ per kWh
Off-peak kWh used	4.273¢ per kWh

- To save money, it is important for you to use more energy on weekends and weekday mornings before Noon or evenings after 7 p.m., since electricity used during off-peak hours costs less. It is also important to limit the number of appliances that you use at one time during on-peak hours in order to minimize the demand charge.
 - *Note: The APS meter readers must have safe, unassisted access to physically touch the meter each month.*

Time Advantage Super Peak 7 p.m.-Noon

This plan is best for those who can significantly limit energy usage during peak (Noon-7 p.m., Monday-Friday) and Super Peak periods (3 p.m.-6 p.m. Monday-Friday, summer only). A smart meter must be installed at your home to select this rate. This plan works just like the Time Advantage 7p.m.-Noon plan, with one main difference:

- You are able to use more of your energy during off-peak hours, and can significantly limit your energy use during the summer between the hours of 3 p.m. and 6 p.m. Monday through Friday in the billing months of June through August.

Here's how it works:

- The plan is billed on an off-peak and on-peak basis, with a Super peak period in the summer billing months of June through August.
 - Off-peak hours are weekdays from 7 p.m. to Noon and all day Saturday and Sunday, as well as six major holidays*.
 - On-peak hours are Monday through Friday from Noon to 7 p.m. and are billed at a higher rate.
 - Super-peak hours are Monday through Friday from 3 p.m.-6 p.m. in the billing months of June through August and are billed at the most expensive cost per kWh on this plan.
- The chart below shows the costs per kWh for the different timeframes:

Off-peak	Nov-Apr Per kWh	May, Sep, Oct Per kWh	Jun-Aug Per kWh
7 p.m.-Noon, Mon-Fri	5.253¢	5.254¢	5.254¢
All day Sat-Sun and six holidays	5.253¢	5.254¢	5.254¢

On-peak (Mon-Fri)	Nov-Apr Per kWh	May, Sep, Oct Per kWh	Jun-Aug Per kWh
Noon-3 p.m.	19.825¢	24.445¢	24.445¢
3 p.m.-6 p.m.	19.825¢	24.445¢	49.445¢
6 p.m.-7 p.m.	19.825¢	24.445¢	24.445¢

- To save money, it is important for you to use more energy on weekends and weekday mornings before Noon or evenings after 7 p.m., since electricity used during off-peak hours costs less.

*Holidays for 7 p.m.-Noon Rate Plans:

- New Year's Day (January 1)
- Memorial Day (last Monday in May)
- Independence Day (July 4)
- Labor Day (first Monday in September)
- Thanksgiving Day (fourth Thursday in November)
- Christmas Day (December 25)

NOTE: If these holidays fall on a Saturday, the preceding Friday will be off-peak. If they fall on a Sunday, the following Monday will be off-peak.

Time Advantage 7 p.m. – Noon

This plan is best if you use more energy during off-peak times (7 p.m. to Noon Monday – Friday, weekends all day and select holidays). Consider this plan if you:

- Use 1,000 kWh or more each month and don't use much energy during on-peak periods (Noon to 7 p.m., Monday – Friday).
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use other major electric appliances such as water heater, pool pump and spa heater during off-peak hours.
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours.

Combined Advantage 7 p.m. – Noon

This plan is best if you use more energy during off-peak times (7 p.m. to Noon Monday – Friday, weekends all day and select holidays). Consider this plan if you:

- Use 1,000 kWh or more each month.
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use more energy during off-peak hours and use a timer to run major appliances (water heater, pool pump, spa heater).
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours.
- Can stagger your use of major appliances during on-peak hours so you're not using them simultaneously.

Time Advantage Super Peak 7 p.m. – Noon

If you can reduce your energy usage by 20% or more during super peak hours of 3 p.m. and 6 p.m. during weekdays, June through August, and use most of your energy during off-peak hours this plan may be best for you. Consider this plan if you:

- Use 1,000 kWh or more each month.
- Use your dishwasher, washing machine, dryer and range more during off-peak hours.
- Use your major appliances (water heater, pool pump, spa heater) during off-peak hours.
- Have a programmable thermostat or can set your AC to a warmer temperature during on-peak and super-peak hours.

APS Peak Time Rebate

Our Peak Time Rebate program is designed to help you save energy and money. By participating in this unique program, you can actually earn money by reducing your energy use during peak time events—times when energy demand is at its highest.

- We will designate from 6 to 18 peak time events from June through September.
- Events will not take place on weekends or holidays.
- Each event will last for five hours between 2 p.m. and 7 p.m.

For additional information about our Peak Time Rebate program, call us at (602) 371-3660 (metro-Phoenix) or (800) 659-8148 (other areas).

APS Service Plans to fit your lifestyle

aps.com/plans



APS15760
Page 1 of 2

Find the Service Plan that's right for you

Not everyone uses energy the same way. To help you manage your usage and save money on your energy bill, APS offers a variety of service plans. To find the plan that's right for your lifestyle, visit aps.com/compare and use the Rate Comparison tool. You'll see how energy costs on your current plan compare to estimated costs on other plans. Check it out today.

The Standard Plan

The Standard Plan helps you save if you have a small home and your energy use is low. And it doesn't make any difference what time of day you use the electricity. Your bill will simply depend on the total amount of electricity you used, not when you used it.

Consider this plan if you:

- Live in a home or apartment that is 1,100 square feet or less.
- Generally use 1,000 kilowatt-hours or less each month; and
- Do not have a swimming pool or electrically heated spa.

How the Standard Plan helps you save

Designed to encourage customers to conserve energy, the Standard Plan price goes up as your use increases—giving you an incentive to use less electricity per month.

- May through October – the cost per kWh increases after 400 kWhs and again after 800 kWhs.
- November through April – there is just one price per kWh.
- Learn more at aps.com/plans.

Time-of-Use (TOU) Service Plans

On a TOU plan, you pay a lower price for electricity during off-peak hours, but pay a higher price during on-peak hours. To save money, it is important to shift more of your energy use to off-peak hours. Learn more at aps.com/plans.

Off-Peak holidays for Time-of-Use Plans

The following six holidays are considered off-peak times all day long: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

If one of these holidays falls on a Saturday, the preceding Friday will be off-peak. If it falls on a Sunday, the following Monday will be off-peak.

What's a kilowatt hour (kWh)?

A kilowatt-hour (kWh) is a unit of measurement for electricity. Just as a gallon is a unit of measurement for gasoline or water, a kWh is 1,000 watts of electricity used for one hour. For example, the amount of electricity that ten 100-watt light bulbs use during one hour is one kWh (ten 100-watt bulbs X one hour equates to one kWh).

Login with username and password

residential business community & environment our company **my account** hello, [redacted] [logout](#)

aps [f](#) [in](#) search

my bill my energy my rebates & renewables my profile & preferences help & support

my account account [redacted] [3](#)

! your payment of \$100.00 is past due as of January 05, 2016 total amount due : \$100.00 [make a payment](#)

what do you want to do today?

[see more](#)
+-

summary of what you owe

for service at: [redacted]
plan: combined advantage 7pm - noon

bill date: december 24, 2015
[view bill](#) | [print page](#)

previous bill	last payment	balance forward	new charges	total amount due
\$403.39	(\$108.48) on dec 28, thank you	\$101.68	\$106.80	\$100.00 due date: jan 05
billing history	payment history	daily & hourly usage	usage history	

property details

[download property data](#)

address and plan type	total electricity used (kWh)	on-peak	off-peak	other peak	demand	total electric charges
[redacted] plan: combined advantage 7pm -	758 usage history	154	604		3.6	\$106.80 charge breakdown

Select my energy > compare service plans

residential business community & environment our company **my account** hello, [redacted] [logout](#)

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my ac [daily & hourly usage](#)
[usage history](#)
[custom usage download](#)
[compare service plans](#)
[energy challenge](#)
[energy analyzer](#)
[ways to save](#)

find out if your current plan is the most affordable for your energy usage

account [redacted] [3](#)

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summary of what you owe

for service at: [redacted]
plan: combined advantage 7pm - noon

bill date: december 24, 2015
[view bill](#) | [print page](#)

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aps search

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compare service plans

account home

last payment of \$160.82 received on december 21, 2016

equalizer payment due : \$0.00

make a payment

residential service plan compare

for service at [redacted]
plan: combined advantage 7pm - noon



The results of your service plan comparison are listed below. The rate comparison tool provides a forecast of your energy costs and usage for the next 12 months. This data is based on our current pricing and your usage history.

Based on your usage history, the Time Advantage 7pm-noon may be better suited to you. Projections are based on estimated on-peak usage. Your costs may vary depending on your ability to shift usage to off-peak hours.

If you feel another plan may better suit your lifestyle, you can request a service plan change

For additional information regarding our service plans please review our service plan pricing and details.

We encourage our customers to perform a comparison each year to ensure they are still on the best service plan. If you have decided you would like to change your rate plan, please proceed.

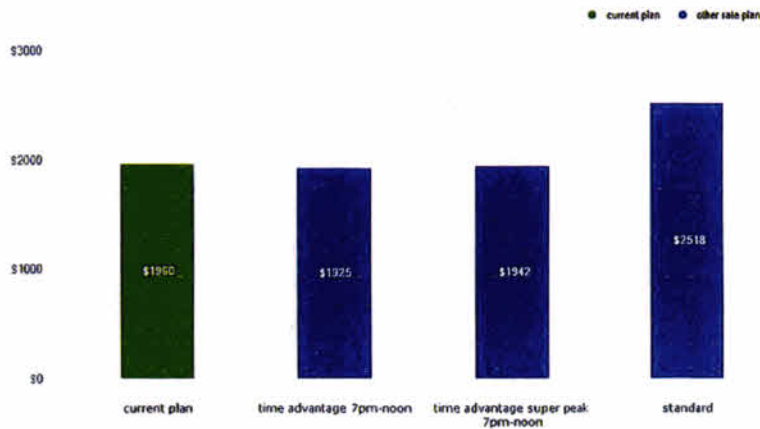
APS does not make adjustments or refunds based on this information.

Please take a moment to complete a brief survey about your recent visit to aps.com. We value your feedback.

change your plan

your cost summary forecast for the next 12 months

based on your energy usage, you may save money on another rate plan.



Recommended plan overview popup

plan: time advantage 7pm-noon

This plan is best if you don't use much energy during on-peak periods (noon - 7 pm, Monday - Friday).

best if you

- use 1,000 kWh or more each month
- aren't home during the day or don't use much energy during on-peak periods
- use your dishwasher, washing machine, dryer and range more during off-peak hours
- use your major electric appliances (water heater, pool pump, spa heater) during off-peak hours
- have a programmable thermostat or can set your AC to a warmer temperature during on-peak hours

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SURREBUTTAL TESTIMONY OF CORY WELCH
On Behalf of Arizona Public Service Company
Docket No. E-04204A-15-0142

February 23, 2016

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**SURREBUTTAL TESTIMONY OF CORY WELCH
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-04204A-15-0142)**

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, JOB TITLE, BUSINESS ADDRESS AND THE PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Cory Welch. I am a Director in the Energy Practice at Navigant Consulting, Inc. My business address is 1375 Walnut Street, Boulder, CO. Today, I will be filing testimony on behalf of Arizona Public Service Company.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have a Master of Science in Mechanical Engineering from Massachusetts Institute of Technology (MIT) and a Master of Business Administration (MBA) from MIT's Sloan School of Management, in addition to a BS in Mechanical Engineering from Cornell University. I have been working in the clean energy industry for the last 15 years, including a 4-year position at the National Renewable Energy Laboratory. For the last eight years I have worked in renewable energy and energy efficiency at Navigant. My clients include both utilities and utility regulatory agencies on issues related to modeling the economics and cost-effectiveness of energy efficiency and renewable energy, forecasting market adoption of efficient and renewable technologies, and quantifying the energy and peak demand impacts of efficient and renewable technologies. A copy of my curriculum vitae is attached as Attachment CJW-1SR.

Q. WHAT ARE YOUR RESPONSIBILITIES AT NAVIGANT?

A. I am currently a Director in Navigant's Energy Practice, focusing on quantitative modeling associated with renewable and energy efficient technologies. I have developed several of Navigant's proprietary financial and market adoption models for renewable energy and energy efficiency technologies, including Navigant's Renewable Energy

1 Market Simulator (RE-Sim™) model, which was used for the analysis I'll be discussing
2 today.

3
4 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?**

5 A. No, I have not.

6
7 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

8 A. The purpose of my testimony is to respond to portions of Direct Testimony submitted by
9 Briana Kobor on behalf of Vote Solar on December 9, 2015.

10 **II. SUMMARY OF TESTIMONY AND STUDY FINDINGS**

11 **Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

12 A. I am presenting analysis that suggests solar providers have headroom to respond to some
13 rate changes in Arizona, based on the results of a study recently conducted by Navigant
14 Consulting, Inc. for Arizona Public Service Company (APS). The Vote Solar testimony
15 to which I am responding suggests on page 51 that “growth of DG on the UNS system
16 would most certainly be reduced,” and on page 55 that rate changes could “destroy the
17 solar market.” I am calling into question the inevitability implied by these and similar
18 statements. Recent federal policy changes, combined with recently observed lease rate
19 increases by solar providers in Arizona, reveal that third-party-owned (TPO) solar
20 provider project returns on invested capital have increased relative to what they had
21 been throughout 2015. Navigant’s analysis suggests that it is not inevitable that any
22 adjustments to variable charges or fixed and demand related charges would necessarily
23 affect solar adoption. Depending on the magnitude of the ultimate rate changes, I
24 conclude it is also possible that rate changes would simply result in lowering solar TPO
25 provider project returns. In other words, the recently observed increased solar TPO
26 provider project returns could simply go back to levels prior to favorable federal policy
27 changes and solar TPO lease rate increases.

1 **Q. ARE YOU SPONSORING ANY ATTACHMENTS TO YOUR TESTIMONY?**

2 A. Yes. I am sponsoring an attachment entitled “Solar Project Return Analysis for Third
3 Party Owned Solar Systems,” dated February 19, 2016, which contains the findings and
4 results of the Navigant study, which I oversaw, and forms the basis for my opinions
5 here. The study is attached as Attachment CJW-2SR and incorporated into my testimony
6 by this reference.

7
8 **Q. BRIEFLY EXPLAIN THE FINDINGS AND CONCLUSIONS OF THE SOLAR
PROJECT RETURN ANALYSIS FOR THIRD PARTY OWNED SOLAR
SYSTEMS.**

9 A. Key findings of the analysis include the following:
10

11 • Navigant’s research indicates that solar providers who offer a TPO leasing model
12 (the dominant business model for residential systems in Arizona) tend to compete in
13 jurisdictions where they can maximize their return by undercutting utility offset
14 rates.^{1,2,3}

15 • Solar TPO providers appear to be tracking utility offset rates and pricing
16 accordingly, evidenced by higher observed lease prices in jurisdictions with higher
17 offset rates. These higher lease prices cannot be fully accounted for by variations in
18 system cost, solar production, and tax rates across service territories.

19
20 • Navigant’s analysis found that solar TPO providers’ project returns vary by
21 utility service territory, with higher project returns calculated in service territories
22 having higher utility offset rates.

23
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25

¹ Utility offset rates (\$/kWh) are defined as the dollar value of a customer’s bill reduction for each kWh
26 generated by the customer’s solar system. It is the amount of their bill that is “offset” for each kWh
generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

27 ² In Arizona, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly
dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an
“effective lease rate” (lease rate) on a \$/kWh basis.

28 ³ For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

1 • Federal incentives such as the Investment Tax Credit (ITC), accelerated
2 depreciation, and bonus depreciation have a significant impact on project return. The
3 solar TPO business model is able to maximize the benefits of these federal incentives,
4 which are amplified considerably by the TPO's ability to use a system "value", which is
5 higher than the system cost, as the basis for the tax credit and asset depreciation.

6 • Navigant's research found that despite continuing declines in solar system costs
7 and recent favorable policy decisions (e.g., re-introduction of bonus depreciation), solar
8 lease rates have recently *increased* in certain locations, including in UNS Electric, Inc.
9 (UNSE) service territory, where a 9% increase was observed in SolarCity's TPO lease
10 rates. In 2015, SolarCity in UNSE territory experienced an estimated 40 percent project
11 return to TPO providers, which is expected to increase to around 80 percent in 2016, due
12 to an observed lease rate increase from \$0.087/kWh to \$0.095/kWh between 2015 and
13 2016 and the re-introduction of the 50 percent bonus depreciation allowance, which
14 came into effect in December of 2015.

15
16 I conclude that solar TPO providers have headroom to adjust to some changes in rate
17 structures while maintaining project returns. The amount of the headroom relative to the
18 new offset rates that would result from proposed UNSE rates in the residential sector has
19 not been specifically analyzed.

20 III. METHODOLOGY AND ASSUMPTIONS

21 **Q. BRIEFLY DESCRIBE THE METHODOLOGY AND ASSUMPTIONS USED IN**
22 **THE STUDY.**

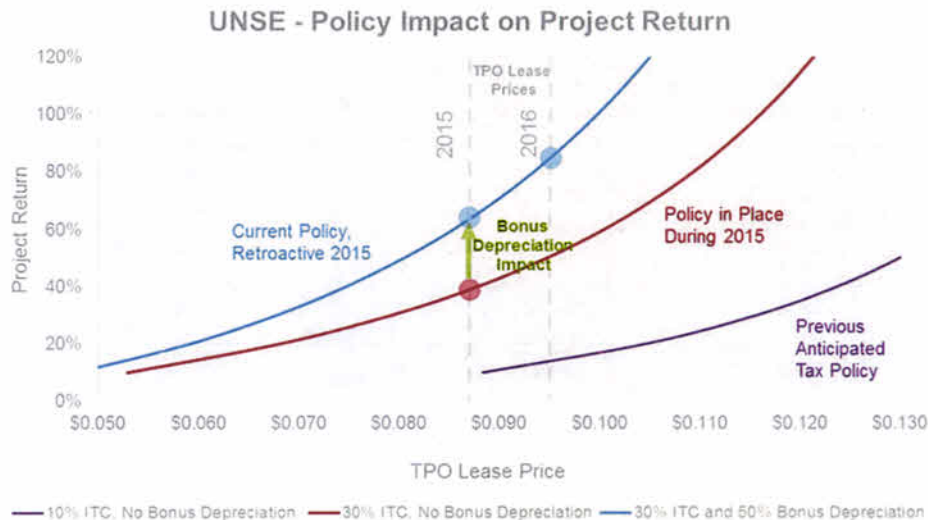
23 A. The analysis focused on solar systems installed using a third-party-ownership model,
24 which is the dominant residential sales model for solar in Arizona and throughout the
25 country. SolarCity is the dominant solar TPO provider in Arizona with around 51%
26 market share of residential installations in 2015. The study obtained lease price
27 estimates through their public website and focused on analysis of project returns
28

1 assuming lease prices offered by SolarCity are reasonably indicative of the Arizona
2 market.

3
4 We then conducted a discounted cash flow analysis of a typical residential solar PV
5 system installation, including all relevant project costs and other cash flow streams. As a
6 benchmark, we calculated project return on invested capital (project return) for systems
7 installed in UNSE territory in 2015. Our estimates indicated that project return was
8 around 40% at observed lease rates in UNSE territory of \$0.087/kWh. We then re-
9 calculated estimated project return in UNSE service territory after incorporating two
10 changes. First, we accounted for the reinstated bonus depreciation benefit of 50%
11 (which expired at the end of 2014, but was re-introduced in December of 2015 and
12 applies retroactively to 2015 projects). Second, we accounted for an observed lease rate
13 increase in UNSE service territory from \$0.087/kWh in December 2015 to \$0.095/kWh
14 in January 2016. As we note in our attached report, rate increases are consistent with
15 statements made by SolarCity to correspond with increases in utility rates and shift its
16 focus less on growth and more on near-term profitability. We also found that solar lease
17 rates increased in four out of the six service territories analyzed in our report.
18 Incorporating these two changes into the analysis resulted in increased project returns
19 from 40% to 80%. This result alone suggests that there is headroom for solar providers
20 in UNSE service territory to adjust to some rate changes through compression of project
21 return. We offer additional evidence in the attached report.

22 The figure below, which is excerpted from Figure 8 of the attached report, illustrates the
23 impact on project return of the re-introduction of bonus depreciation and the recently
24 observed lease rate increases by SolarCity in the UNSE service territory. During 2015,
25 estimated project return was 40% at a \$0.087/kWh lease rate (the red dot on the red line,
26 on which it is estimated SolarCity was operating). After re-introduction of 50% bonus
27 depreciation (which applies retroactively to 2015 installations) and after increasing lease
28

1 rates to \$0.095/kWh in UNSE service territory, SolarCity is estimated to achieve an 80%
 2 project return (the higher blue dot) and is estimated to be operating on the blue line. For
 3 context, we estimate that solar TPO providers would have been operating on the purple
 4 line as of January 1, 2017, prior to the extension of the Federal ITC and re-introduction
 5 of 50% bonus depreciation.



There are of course many assumptions underlying this analysis, all of which is detailed in the attached report in the interest of transparency. The assumptions draw upon publicly available and credible sources, including SolarCity's own website, cost roadmap, and public reports. The analysis also benchmarks the assumptions against statements from other publicly traded companies, third-party market reports, as well as reports from the Department of Energy and the National Renewable Energy Laboratory.

The analysis goes on to compare observed lease rates in other jurisdictions with those calculated to result in the same 40% project return as estimated in UNSE service territory, accounting for variations in factors such as labor costs, solar insolation, and tax rates, which can differ across jurisdictions. This comparative analysis illustrated that solar TPO provider lease rates and project returns tend to increase with higher utility

1 offset rates, without direct cost causation. In other words, solar TPO providers benefit
2 from higher project returns in jurisdictions with higher utility rates.

3 **Q. ARE THE ASSUMPTIONS USED IN THE STUDY CONSERVATIVE, AND IF**
4 **SO, HOW?**

5 A. The analysis uses several conservative assumptions that would actually tend to
6 understate, rather than overstate, true TPO solar project returns. These conservative
7 assumptions include:

- 8 • **Cost of debt:** The analysis uses a cost of debt of 6 percent throughout the
9 analysis. Some sources indicate that this cost of debt could be as low as 5
10 percent.⁴
- 11 • **Lease term and residual value:** The analysis uses a 20 year contract term with
12 no residual value for contract renewal and no residual value for the system at the
13 end of life. The typical system life is longer than 20 years and the system is
14 expected to have a residual value at the end of the lease term.
- 15 • **Markup assumed for the ITC and depreciation basis:** The analysis used a 35
16 percent markup on system cost for calculating the value of the ITC and system
17 depreciation. This would effectively result in a solar TPO developer reporting
18 system value of \$3.74-3.87/W-DC to the Internal Revenue Service, which is
19 lower than observed system sales prices typically ranging from 4.20-4.75.^{5,6,7,8}
20 The ability of PV providers to markup cost to something more akin to a price, or
21 system value, when calculating tax credits and depreciation is a key driver in the
22 favorable economics for solar TPO providers.

23
24
25

⁴ UBS Solar, US Alternative Energy & YieldCos, 4Q15 Playbook: Giving Solar 'Credit,' January 2014.

26 ⁵ Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.

27 ⁶ "A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax
Treatment in the Residential PV Sector," Lawrence Berkeley National Laboratory, June 2015.

28 ⁷ SolarCity Company Analyst Day, December 2015.

⁸ Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.

1 IV. CONCLUSIONS

2 **Q. WHAT KEY CONCLUSIONS DO YOU DRAW FROM YOUR ANALYSIS?**

3 A. The primary conclusion I draw from the analysis is that solar TPO providers likely have
4 headroom to adjust to some rate changes in Arizona, including in UNSE service
5 territory. Depending on the magnitude of the rate changes, it is possible that adequate
6 project returns could be maintained while incorporating a reduction in utility offset rates
7 due to adjustment of variable charges or introduction of fixed and demand related
8 charges.

9 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

10 A. Yes.
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Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

Professional Summary

Cory Welch is a Director in the Energy Practice of Navigant Consulting, Inc.. He has 20 years of complex system modeling, project management, and engineering experience in fields including fuel cell development, energy efficiency, renewable energy, energy R&D portfolio and policy analysis, and power plant engineering. Mr. Welch brings expertise in renewable energy economics and market adoption, financial analysis, efficiency portfolio evaluation, efficiency potential estimation, system dynamics, stochastic analysis, discrete choice analysis, optimization, and statistics, which he has applied to various analysis projects for utility clients, regulatory agencies, and the U.S. Department of Energy. Mr. Welch is the lead developer of many of Navigant's proprietary renewable energy and energy efficiency models. Mr. Welch holds an SM in Mechanical Engineering from Massachusetts Institute of Technology (MIT), an MBA from MIT's Sloan School of Management, and a BS in Mechanical Engineering from Cornell University. Additionally, he completed a rigorous 6-month graduate-level curriculum in mechanical and nuclear engineering while serving as an officer in the U.S. Navy.

Professional Experience

- Developed Navigant's Renewable Energy Market Simulator (RE-Sim™) model. Applied this model in strategic advisory engagements with six major electric utilities looking to better understand the economics, dynamics and drivers of adoption of distributed solar PV. This model includes a rigorous discounted cash flow optimization model, which is used to understand solar PV project economics. It fully accounts for the economics of third-party-ownership, a dominant business model in distributed PV. The RE-Sim model also forecasts market adoption of solar PV using an enhanced version of the Bass diffusion algorithm, implemented in a System Dynamics framework. Calibrated back-casting is used to develop diffusion coefficients. The model can forecast adoption under a wide variety of policy, costs, and rate regimes, providing a rigorous and robust platform for understanding likely dynamics of solar PV adoption.
- Developed a highly transparent, web-capable model for Pacific Gas & Electric to estimate the impact on customers and utility economics of changes to Net Energy Metering policies in California. The model analyzed probability distributions of historic payback times for solar PV installations under various NEM grandfathering and rate scenarios.



Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

Professional Experience (Continued)

- Developed Navigant Consulting's Demand Side Management Simulator (DSMSim™) to simulate the adoption of energy-efficient technologies in efficiency potential studies and program design. DSMSim™ is a bottom-up technology diffusion model grounded in the principles of System Dynamics (stock/flow modeling). Led projects estimating energy-efficiency potential analyses for ten electric/gas utilities. Acted as senior modeling advisor on potential studies for eleven additional utilities, including the four large IOUs in California.
- Led the re-development of a nonlinear stochastic optimization model for the Northwest Power and Conservation Council. This model calculates optimal electric generation and demand side management resource strategies with explicit consideration of uncertainty and risk. It is currently being used in the Council's creation of its seventh power plan for the NW region
- Managed a \$6M project to evaluate the energy efficiency savings achieved from five Maryland electric utilities.
- Developed the optimization portion of an energy-efficiency portfolio optimization tool for DTE Energy. The model used linear programming techniques to maximize energy savings for target cost levels under various constraints including low-income participation, low-income spending, maximum and minimum measure-level participation, sector spending targets, etc.
- Managed a \$4M portfolio impact evaluation for five Maryland utilities to estimate kW and kWh savings from their energy efficiency programs and to permit bidding peak demand reductions achieved through efficiency programs into the PJM forward capacity market.
- Acted as the deputy project manager for the evaluation of 56 Local Government Partnership energy efficiency programs for the California Public Utility Commission (CPUC), a multi-year, multi-million dollar portfolio impact evaluation.
- Developed a stochastic model estimating the probabilistic benefits and costs of Smart-Grid technologies for Bonneville Power Administration. This model is currently being used to shape Smart-Grid policy and strategy in the Northwest U.S.



Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

Professional Experience (Continued)

- Developed a nonlinear optimization model for NV Energy to optimize dispatch of Demand Response (DR) resources and to forecast DR savings. Provided model to the client with a user-friendly graphical user interface.
- Estimated the remaining useful life of residential appliances for a California utility using established Weibull regression methods as well as a novel method involving a stock/flow model using System Dynamics.
- Assessed the market potential for Demand Response in the Con Edison service territory (New York City). Developed Navigant Consulting's Demand Response Simulator (DRSim™) model to assist in evaluating DR market potential, including assessment of market risk using Monte Carlo techniques.
- Guided development of a smart-grid benefit/cost model for Tendril networks. Provided model to the client with a user-friendly graphical user interface and trained Tendril staff in its use.
- Developed a model evaluating the pricing of power purchase agreements for a large renewable installation in Southern California.
- Developed a model simulating the dispatch of a gas turbine for purposes of assessing the market value of improved startup times and reduced startup emissions.
- Developed a model simulating the supply/demand balance in the LA Basin load pocket for the California Energy Commission. This model considered environmental and transmission constraints and facilitated scenario analysis associated with shutting down once-through cooling plants due to environmental concerns.

Work History

- Navigant Consulting, Inc. – Director
- Navigant Consulting, Inc. – Associate Director
- Summit Blue Consulting – Managing Consultant



Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

- National Renewable Energy Laboratory – Senior Energy Analyst
- UTC Fuel Cells – Program Manager
- Lieutenant, United States Navy – Naval Nuclear Propulsion Headquarters

Certifications, Memberships, and Awards

- Association of Energy Service Professionals
- Systems Dynamics Society

Education

- MS, Mechanical Engineering, Massachusetts Institute of Technology
- MBA, Massachusetts Institute of Technology's Sloan School of Management
- BS, Mechanical Engineering, Cornell University (with distinction)

Publications

- Welch, C. and Richerson-Smith, D. "Incentive Scenarios in Potential Studies: A Smarter Approach" Peer reviewed paper presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2012. Pacific Grove, CA.
- Welch, C. and Rogers, B. "Estimating the Remaining Useful Life of Residential Appliances." Peer reviewed paper presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2010. Pacific Grove, CA.
- Welch, C. and Stern, F. "Simulation the Adoption of Energy Efficient Technologies." Poster presented at American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings. August, 2010. Pacific Grove, CA.



Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

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- Welch, C., Wipke, K., Gronich, S., and Garbak, J. "Hydrogen Fleet and Infrastructure Demonstration and Validation Project: Data Analysis Overview." Paper (<http://www.nrel.gov/hydrogen/pdfs/37845.pdf>) and presentation (<http://www.nrel.gov/hydrogen/pdfs/37811.pdf>) prepared for the National Hydrogen Association Conference, Washington, DC., March 2005.



Cory J. Welch

Director

cory.welch@navigant.com
Boulder, CO
Direct: 303.728.2528

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Solar Project Return Analysis for Third Party Owned Solar Systems

Submitted by:

Navigant Consulting, Inc.
One Market Street
Spear Street Tower, Suite 1200
San Francisco, CA 94105

415 356 7100
navigant.com

Reference No.: 183992
February 19, 2016

Prepared for:

Arizona Public Service



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Appendix A..... **16**

EXECUTIVE SUMMARY

1.1 UNDERSTANDING THE SITUATION

Navigant conducted an analysis to evaluate the Third-Party Owned (TPO) solar PV (solar) leasing business model, which has emerged as the dominant business model in Arizona (AZ) and throughout the country. Customers with solar TPO systems receive solar-generated power without the high up-front cost of purchasing a system or the responsibility of system monitoring or maintenance. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar TPO lease rate (lease rate)¹ for the term of the agreement.² The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate. Our analysis focuses on quantifying solar TPO providers' project returns in utility service territories across AZ and California (CA).

1.2 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.³
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from \$0.087/kWh to \$0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on page 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

¹ For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

² In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a \$/kWh basis.

³ Utility offset rates (\$/kWh) are defined as the dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. It is the amount of their bill that is "offset" for each kWh generated (hence the term). In other words, it is the amount a customer saves on their utility bill.

2. SOLAR PROJECT RETURN ANALYSIS

2.1 THIRD-PARTY OWNED SOLAR BUSINESS MODEL

Third-Party Owned solar systems, as compared with customer owned systems, has emerged as the dominant distributed solar business model throughout the country. Solar TPO providers offer customers the option to adopt solar power with no upfront costs. Customers sign a long term contract for solar electricity and the solar TPO provider owns and maintains the system. Solar electricity is delivered to the customer at a contracted fixed or escalating effective solar lease rate⁴ for the term of the agreement.⁵

The emergence of the solar TPO business model has allowed TPO providers to present customers with a comparison between two rates, the first-year solar lease rate and the customer's retail electricity rate.

2.2 ARIZONA SOLAR MARKET

Navigant obtained data from ArizonaGoesSolar.org⁶ and used those data to characterize the 2015 residential solar market. The data revealed that the solar TPO business model dominates the Arizona market with a handful of large national players comprising the majority of the solar market share. For UNSE, the market is dominated by one national player, SolarCity, and a handful of regional companies. Navigant observed the same trends in other service territories – dominance of the solar TPO business model and SolarCity followed by other national and regional players.

2.2.1 Arizona 2015 Solar Data

Since not all utilities report data to ArizonaGoesSolar.org denoting whether a system is solar TPO or a customer purchased system, Navigant looked at data from APS, the utility with the largest residential solar market, to quantify the market share of solar TPO systems in the overall residential market. In 2015, APS territory comprised 81 percent of the solar PV installations across the Arizona utility territories examined in this report (UNSE, Arizona Public Service (APS), Sulphur Springs Valley Electric Cooperative (SSVEC), and Tucson Electric Power (TEP)). Given the large percentage of solar PV installations in APS's service territory, relative to other Arizona utilities, Navigant assumed the ownership type split in APS's service territory reasonably represents the Arizona market. These data indicate that solar TPO is the dominant business model in the residential sector. Figure 1 shows that 72 percent of systems 10 kilowatts and smaller installed in the APS service territory in 2015 were TPO. This aligns with the U.S. Solar Market Insight Q3 2015 report, which reported that third party providers owned 77-80 percent of new residential installations in Arizona in 2015.⁷

⁴ For the purpose of this analysis, Navigant refers to all solar TPO rates as lease rates.

⁵ In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production (in kWh). One can therefore calculate an "effective lease rate" (lease rate) on a \$/kWh basis.

⁶ Arizonagoessolar.org, <http://arizonagoessolar.org/UtilityIncentives/ArizonaPublicService.aspx>, Accessed January 12, 2016.

⁷ GTM Research and Solar Energy Industries Association, U.S. Solar Market Insight, Q3 2015, December 2015.

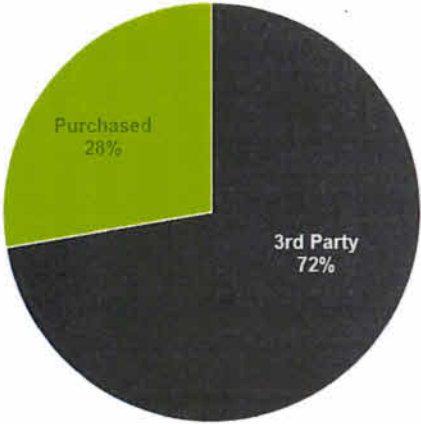
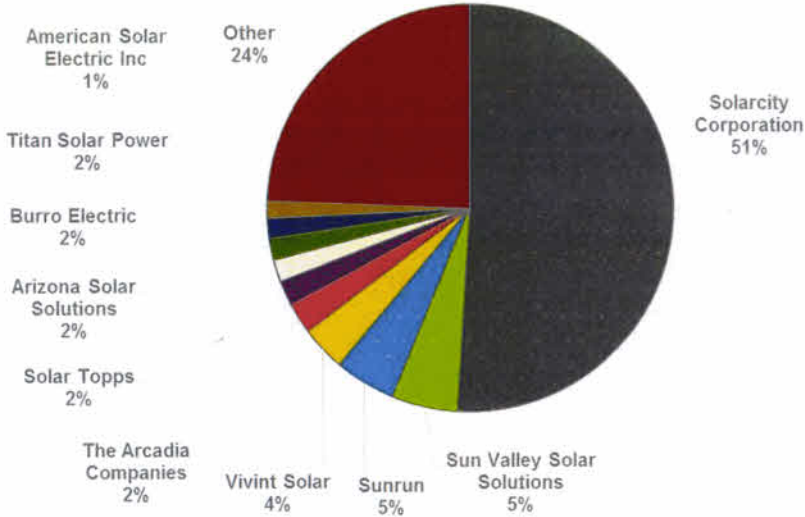


Figure 1. Arizona Residential Solar APS 2015 Ownership Type⁸

ArizonaGoesSolar.org data indicate that SolarCity is the dominant solar player across all Arizona utilities, comprising approximately 50 percent of the residential market in 2015, as shown in Figure 2. SolarCity is also the dominant player in UNSE territory with around 32 percent of total installed residential systems in 2015.



* Other includes all other installers in the Arizona examined service territories.

Figure 2. Arizona (APS, TEP, UNSE, and SSVEC) Residential Solar Market Share, Leading Installers⁹

Based on the dominance of solar TPO and SolarCity, Navigant used solar TPO and SolarCity data to represent the Arizona solar market.

⁸ APS market share installation data for systems <10kW in 2015, as other utilities do not report ownership type.
⁹ Installation data for systems <10kW in 2015.

2.3 LEASE PRICING VS. UTILITY OFFSET RATES

Navigant obtained lease data from leading solar TPO companies in states with high penetration of distributed solar PV, benchmarking this information through industry interviews and market research. Solar TPO providers reported that their residential lease rates are typically 5 to 20 percent below residential retail rates.¹⁰ Navigant’s research indicates that third party providers choose to operate in jurisdictions where they can undercut utility offset rates. Further, Navigant’s research found that the solar TPO pricing strategy is such that jurisdictions with higher offset rates are likely to see higher solar TPO lease prices without direct cost-causation. Table 1 lists the lease rates and utility offset rates used for this analysis.

Table 1. Lease Rates and Utility Offset Rates¹¹

State	APS	UNSE	TEP	SSVEC	PG&E	SMUD
Observed Lease Rate (Year-1) – Jan 2016 (\$/kWh)	0.105	0.095	0.093	0.110	0.162	0.109
Observed Lease Rate (Year-1) – Dec 2015 (\$/kWh)	0.105	0.087	0.090	0.105	0.150	0.109
Lease Rate Annual Escalation	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Utility Offset Rate (\$/kWh)	0.133	0.103	0.108	0.122	0.234	0.137

2.3.1 Lease Rate Pricing

In AZ, solar TPO leases are the dominant contract vehicle. Leases typically involve a monthly dollar payment for a minimum guaranteed solar production in kWhs. One can therefore calculate an “effective lease rate” (lease rate) on a \$/kWh basis. In other jurisdictions, the contract might entail a rate directly specified on a \$/kWh basis, often referred to as a power purchase agreement (PPA) rate. For simplicity, we refer throughout this document to the lease rate, as though it is analogous to a PPA rate. Residential customers usually enter 20-year lease agreements with the solar TPO provider that often include a year-one lease rate and an annual escalator.

Navigant accessed publicly available lease rate pricing data for the six utilities listed in Table 1 from SolarCity’s website and benchmarked them through interviews and market research. In some utilities, lease rates have increased from 2015 to 2016, consistent with public disclosures and comments from leading players such as SolarCity and SunRun.

- SolarCity reported on its Q3 2015 earnings call that in 2016 the company would focus on cost reduction and value, with less emphasis on growth. They reported that pricing would increase in Q1 of 2016 to correspond with escalation in utility rates.¹²

¹⁰ Navigant interviews with industry experts.

¹¹ Sources: Energy Information Administration Average Utility Rates, System Advisor Model – National Renewable Energy Laboratory, SolarCity website <https://go.solarcity.com/#/my-home/zip-nearme>, Navigant Modeling (Rates: APS: Residential TOU ET2; SSVEC: Residential Service; TEP: R-01; UNSE: Residential-RES-01; PG&E: E-6 TOU Region R; Residential TOU Option 1)

¹² SolarCity Corp (SCTY) Earnings Report: Q3 2015 Conference Call Transcript, <http://www.thestreet.com/story/13345540/1/solarcity-corp-scty-earnings-report-q3-2015-conference-call-transcript.html>, Accessed January 28, 2016.

- SunRun reported on its Q3 2015 call that cost structure improvements are a primary focus. For a significant portion of their current markets, SunRun is currently pricing on a per kilowatt hour basis at 25 percent or more below utility rates, even before anticipating future increases in utility rates. They reported that because of strong consumer demand, they have begun to and will selectively raise prices.¹³

2.3.2 Utility Offset Rates

Utility offset rates (\$/kWh) are defined as dollar value reduction to a customer's utility bill for each kWh generated by the customer's solar system. In other words, it is the amount of their utility bill that is "offset" for each kWh of solar generated. Navigant calculated the offset rate for each utility using residential tiered rates and time of use rates. Consistent with net metering rules, Navigant sized the system to meet 80 percent of customer load over the course of the year, such that the system never over generates on an annual basis and generation exported to the grid is credited to the customer at a retail rate rather than a wholesale rate.

Navigant benchmarked these offset rates using National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) and the average residential rates published by the Energy Information Administration (EIA). Both the Navigant and NREL SAM models rely on TMY3 weather data and OpenEI data for average hourly residential building load profiles.

2.3.3 Rate Comparison

Consistent with the findings from the 2015 Lawrence Berkeley National Laboratory (LBNL) Tracking the Sun VIII report, Navigant found that solar TPO vendors pursue value-based pricing strategies by undercutting the utility offset rate, which is evidenced by the positive correlation between lease pricing and the offset rate.¹⁴ Figure 3 shows that offset rate increases across utility territories correspond with lease rate increases.

¹³ Transcript of SunRun earnings conference call or presentation 12-Nov-15, <http://finance.yahoo.com/news/edited-transcript-run-earnings-conference-032845202.html>, Accessed January 28, 2016.

¹⁴ "Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," Lawrence Berkeley National Laboratory, 2015. https://emp.lbl.gov/sites/all/files/lbni-188238_1.pdf

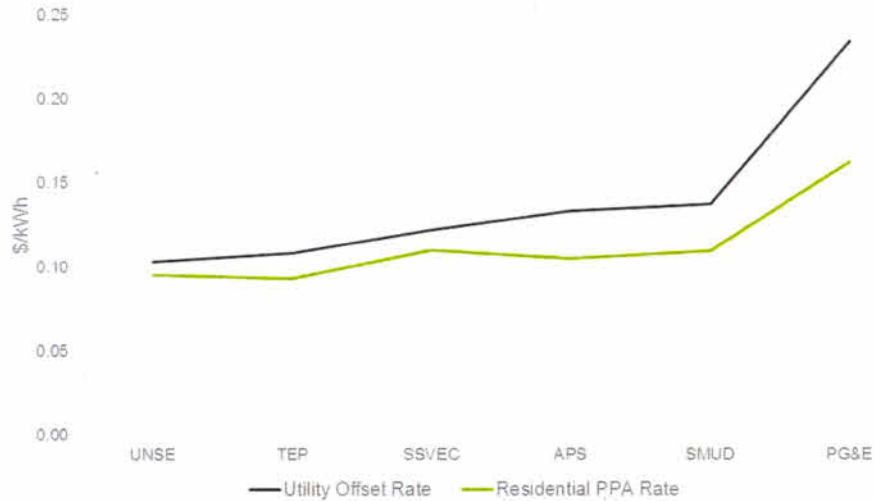


Figure 3. Utility Offset Rate vs. Lease Rate – Line Graph

In Figure 4, the dashed grey line represents the points at which the residential solar lease rate equals the utility offset rate. Along this line customers would be paying the same for grid and solar generated electricity. Points below the line indicate where lease rates are undercutting utility offset rates. However, while solar TPO providers are undercutting utility offset rates, the analysis needs to consider the impact of locational factors such as solar insolation, installed system cost, state income tax rates and state incentives to correctly compare lease rates across different service territories and locations. We will present these jurisdiction specific factors in the following section.

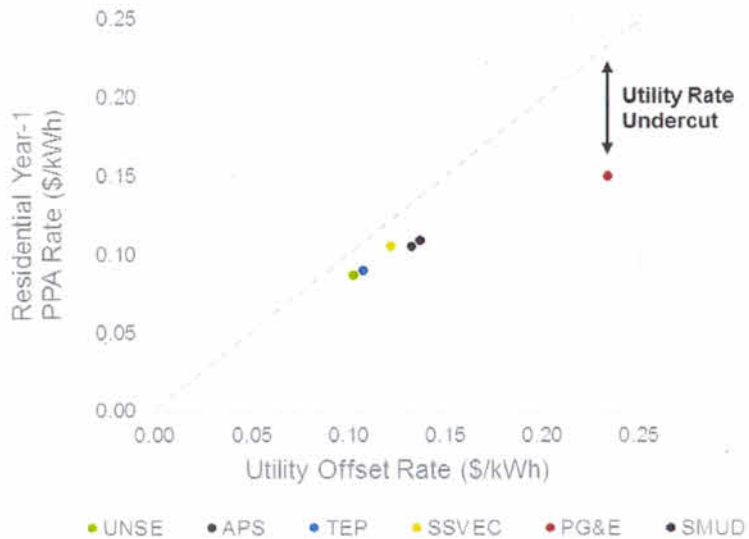


Figure 4. Utility Offset Rate vs. Lease Rate – Scatter Plot

2.4 PROJECT RETURN ANALYSIS

2.4.1 Project Return

This section presents Navigant's jurisdiction-specific analysis of solar TPO lease pricing. Navigant used its proprietary Renewable Energy Market Simulator (RE-Sim™) discounted cash-flow analysis model to calculate a leveraged project return on invested capital on a project-specific basis.

Consistent with standard economic practice, we define the project return on invested capital (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero. Navigant's analysis estimates the project return assuming a solar TPO provider both owns and installs the system, consistent with the dominant solar PV business model. We calculate total project return independent of the breakdown of possible recipients of the project return (i.e., whether an equity investor, a tax equity investor, or the third-party provider itself is the recipient of the project return on invested capital).

In this report, Navigant defines the project return on invested capital (project return), sometimes referred to as an internal rate of return or economic rate of return, as the discount rate at which the net present value of all cash flow streams is equal to zero.

The cash flow streams accounted for in this analysis include:

- Initial capital outlay, inclusive of all system component costs, installation costs, and an allocation of overhead costs
- Operation and maintenance (O&M) costs, inclusive of inverter replacement
- Debt-financing cash inflow and interest payments
- Federal Investment Tax Credit (ITC) benefits
- Incentives (where applicable)
- Accelerated depreciation for tax purposes (MACRS and Bonus Depreciation)
- Federal and State corporate income taxes
- Lease revenue, including lease rate escalation and accounting for system output degradation

Navigant's model is a discounted-cash-flow optimization model, whose objective function is to minimize the lease rate, a decision variable in the optimization, subject to constraints on the input project return and minimum debt service coverage ratio.¹⁵ Another decision variable in the optimization is the debt ratio, which is an output of the optimization rather than an assumed input, as with some more simplistic analyses. The reason we calculate the debt ratio rather than assume a debt ratio is that higher lease rates afford the opportunity for a provider to have greater leverage (i.e., a higher debt ratio), while still being able to service its debt. Having greater leverage offers the potential for higher project returns on invested capital, since for a given revenue stream the required capital outlay is lower. As such, a rigorous analysis must calculate the debt ratio rather than take it as an input.

¹⁵ Navigant's model can also calculate the effective project return given an input lease rate.

2.4.2 Financial Assumptions

As described above, Navigant conducted a discounted cash flow analysis to calculate the project return for projects across various service territories in AZ and CA. While several assumptions were fixed across utility territories, as detailed in the Appendix, locational assumptions varied by service territory where applicable. Locational assumptions that varied by service territory include: the installed system cost (\$/Watt), capacity factor, PV production, local taxes, and incentives. These locational assumptions are detailed in Table 1 and Table 2 and are explained in the following sections.

Table 2. Locational Financial Assumptions

	APS	UNSE	TEP	SSVEC	PG&E	SMUD
Installed Cost (\$/W-DC)	2.76	2.76	2.77	2.77	2.87	2.88
First Year PV Production (kWh/kW-DC)	1,684	1,718	1,718	1,692	1,591	1,469
State Income Tax Rate	6.00%	6.00%	6.00%	6.00%	8.84%	8.84%
Incentives	-	-	-	-	-	\$500/system

2.4.2.1 PV System Costs

Navigant developed detailed cost estimates for residential solar PV systems installed in 2015 based on a system size of 7.00 kW. As displayed in Figure 5, Navigant's bottom-up estimate for the national average installed system cost in 2015 is \$2.82/W. Navigant adjusted installed system costs for each utility service territory accounting for changes in key cost components such as direct labor and sales tax.

While some components of the installed system costs can vary significantly by location, the overall impact of locational cost differences is small. For example, direct labor is a leading cost component that changes by location. Navigant adjusted direct labor costs by utility service territory and, while costs may differ by as much as 30-35 percent between high cost locations in CA and low cost locations in AZ, the overall impact on the total installed system cost is relatively low, as direct labor costs only account for around 10-15 percent of the total installed system costs.^{16,17}

¹⁶ Quarterly Census of Employment and Wages - Bureau of Labor Statistics

¹⁷ Electrical Cost Data - RSMMeans

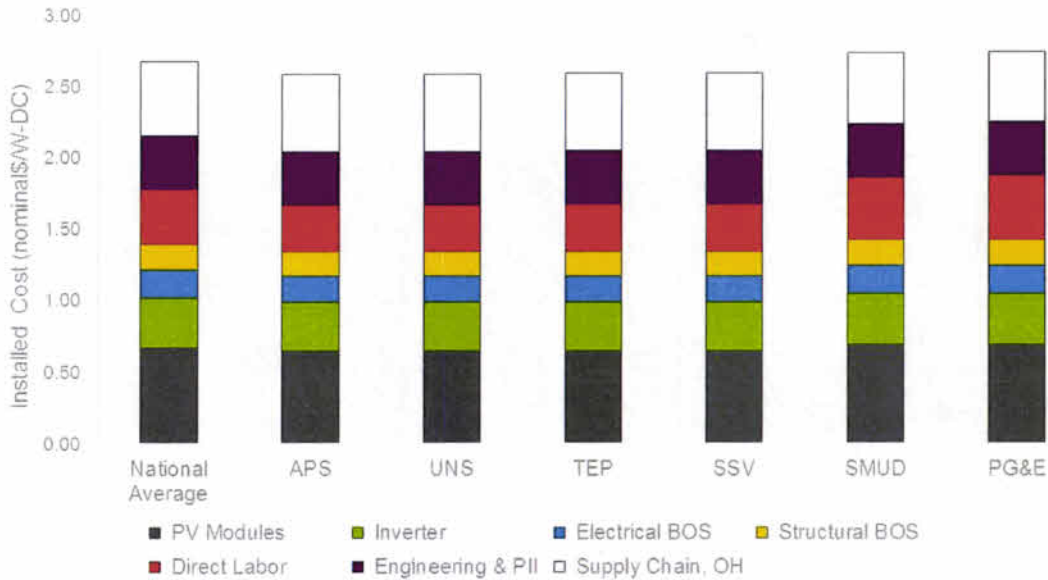


Figure 5. 2015 Installed System Costs, Residential

Over the coming years, system costs are expected to decline further as published in the solar market leaders' three-four year cost reduction roadmaps. In December 2015, SolarCity reiterated its cost goal of \$2.25/W by mid-2017 and \$2.00/W by 2019.¹⁸ This cost reduction roadmap is part of a broader initiative by SolarCity to improve profitability over focusing on pure growth. Key elements of the cost reduction roadmap include: the use of higher efficiency panels, hardware cost reductions and sales and operations cost reduction. Other industry leaders have also published cost reduction roadmaps. For example, SunRun is projecting 2016 cost declines to follow 2015 cost decline trends.¹⁹

2.4.2.2 Solar Resource

Navigant used NREL's SAM model to calculate system performance across all regions. System design assumptions were fixed, though the solar resource assumptions changed for each service territory. This methodology accounted for the variance in locational solar resource, and therefore capacity factor and system generation, while keeping system design constant.

2.4.3 Policy Adjustments

Solar project economics are currently driven by federal incentives including the investment tax credit (ITC), accelerated depreciation, and bonus depreciation. During 2015, federal incentives included the ITC and accelerated depreciation, as bonus depreciation had expired at the end of 2014. However, in December 2015, the ITC benefit was extended through 2022. Additionally, bonus depreciation was also extended

¹⁸ SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3_compressed-min.pdf

¹⁹ SunRun Q3 2015 Q3 Earnings Conference Call Presentation, November 12, 2015. <http://investors.sunrun.com/phoenix.zhtml?c=254007&p=irol-calendar>

through 2019, retroactively impacting 2015 project economics.^{20,21} Federal incentives currently driving the solar market include:

- **Investment Tax Credit:** The ITC has recently been extended allowing solar system owners to take advantage of this benefit until 2022. The revised policy allows for 30 percent ITC through 2019, 26 percent in 2020, 22 percent in 2021, and 10 percent in 2022, after which the ITC is set to remain at 10 percent.²⁰ The ITC benefits solar TPO providers by directly reducing providers' tax liability in the form of a tax credit, effectively reducing the cost of acquiring the asset.²²
- **Accelerated depreciation:** Qualifying solar energy equipment is eligible for an accelerated cost recovery period of five years.²³ This accelerated depreciation is a significant benefit to solar TPO providers compared with normal depreciation of a capital asset for tax purposes, which would require depreciating an asset over its useful lifetime (e.g., 20-30 years). Since depreciating an asset reduces a firm's tax liability, accelerating the depreciation improves a firm's after-tax income in the early years. Since a dollar today is worth more than a dollar tomorrow, due to the time value of money, this benefits solar TPO providers and/or investors.²⁴
- **Bonus depreciation:** The bonus depreciation benefit has been re-introduced and is currently 50 percent through 2017, after which it is reduced to 40 percent in 2018, 30 percent in 2019, and zero percent from 2020 onward.²¹ The benefits of bonus depreciation are similar to those described for accelerated depreciation, except that they result in even greater depreciation of an asset in the first year of a capital investment. For instance, with a 50 percent bonus depreciation, one can essentially depreciate an additional 50 percent of the asset's value in the first year.

2.4.4 Locational Adjustments

As described above, observed variations in residential solar lease rates alone do not determine project return, as factors such as PV production and systems costs, among others, also need to be considered in the calculation. In our analysis, Navigant used the lowest project return calculated as a comparative benchmark for project returns by solar TPO providers in other jurisdictions. For the six utilities analyzed in 2015, UNSE service territory had the lowest observed lease rate of \$0.087/kWh and a project return around 40 percent.

Navigant then made adjustments to account for key drivers such as solar production, system costs, incentives, and tax rates to calculate a lease rate required to achieve the same 40 percent return in other service territories, as presented in Figure 6.

In PG&E's service territory, a 40 percent project return would result in a calculated lease rate around \$0.10/kWh, which is about 33 percent lower than the observed \$0.15/kWh lease rate in PG&E territory in 2015. In APS's service territory, a 40 percent return would result in a calculated lease rate around

²⁰ HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 303

²¹ HOUSE AMENDMENT #1 TO THE SENATE AMENDMENT TO H.R. 2029, MILITARY CONSTRUCTION AND VETERANS AFFAIRS AND RELATED AGENCIES APPROPRIATIONS ACT, 2016; Sec 143

²² A tax credit is a dollar-for-dollar reduction in the income taxes that a solar TPO would otherwise have to pay the federal government.

²³ SEIA, Depreciation of Solar Energy Property in MACRS, <http://www.seia.org/policy/finance-tax/depreciation-solar-energy-property-macrs>, Accessed February 1, 2016.

²⁴ The significant tax benefits from the ITC, accelerated, and bonus depreciation require a "tax appetite" to monetize these benefits (i.e., one must have sufficient tax liability to take advantage of these tax breaks). Thus, it is not surprising that tax equity investors (which can provide the tax appetite required) constitute a substantial portion of solar TPO providers' financing.

\$0.090/kWh, yet observed lease rates in APS service territory in 2015 were around \$0.105 (Figure 6). This shows the calculated project return in one service territory vastly differs from the project return in other service territories.

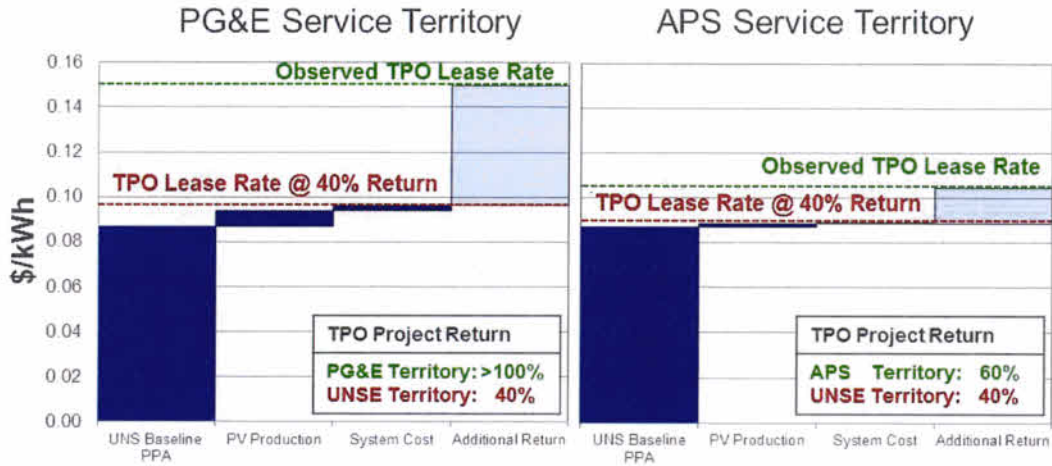


Figure 6. Impact of Locational Factors on Solar TPO Project Return, 2015²⁵

Figure 7 plots the observed solar TPO lease rates in each of six jurisdictions in AZ and CA (represented by the green dots) on the same graph as what lease rates would be if instead solar TPO providers achieved a benchmark 40 percent project return in those jurisdictions, accounting for locational differences (represented by the red dots). These red and green dots on Figure 7 correspond with the red and green dotted lines in Figure 6, respectively. The positive difference between the observed solar TPO lease rates and the TPO lease rates at 40 percent project return, shown as the green shaded area in Figure 7, represents an opportunity for solar TPO providers to achieve “additional return” in those service territories.

As is evident in Figure 7, solar TPO project returns increase with increasing utility rates, which cannot be accounted for by variations in locational factors. In other words, calculated project returns vary by utility and are positively correlated with the utility rates.

²⁵ Prior to retroactive bonus depreciation.

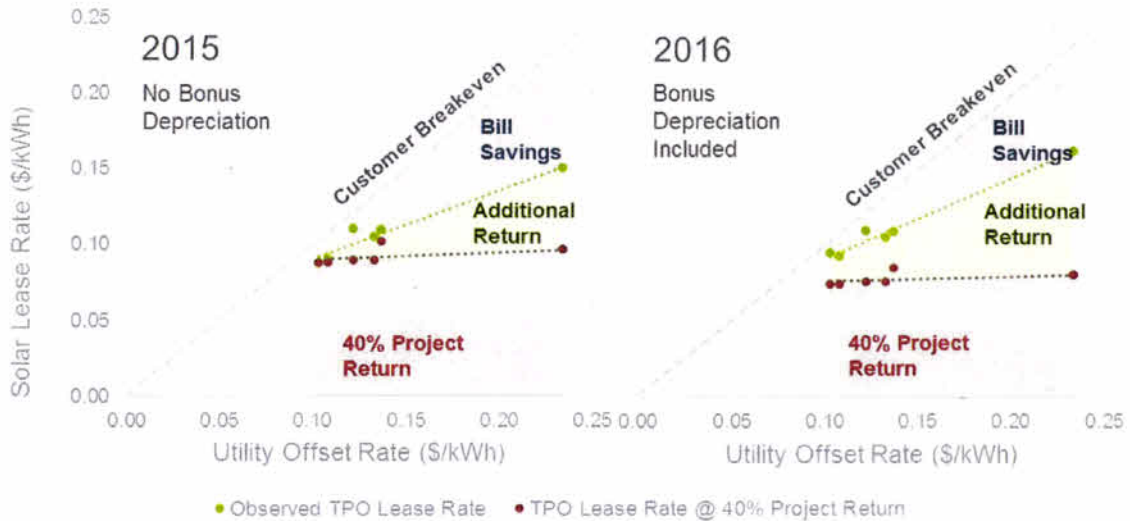


Figure 7. Project Value Analysis across six utility service territories in AZ and CA

Navigant conducted this analysis for lease rates in 2015 and 2016. We found that in four out of the six utility service territories analyzed, SolarCity, for example, increased their lease rates in 2016. This occurred despite declining system costs and favorable policy re-introducing the 50 percent bonus depreciation allowance. The chart above clearly illustrates that solar TPO providers have headroom in many jurisdictions, including UNSE’s service territory, to reduce solar TPO rates while still achieving project returns at or above those achieved in UNSE’s service territory in 2015 (when lease rates were lower, and when bonus depreciation had not yet been re-introduced, as is discussed in further detail in the next section).

2.4.5 Impact of Policy

Figure 8 shows how the ITC and bonus depreciation policy impact project returns in UNSE and APS territories for various solar TPO lease prices. Throughout 2015 bonus depreciation did not exist for solar systems. However, in December 2015, bonus depreciation was reintroduced and retroactively applies to all 2015 projects.²⁶ In Figure 8, the red line reflects policy in place during 2015, which has been replaced by current policy (blue line) as of December 2015 and applies retroactively to 2015 projects. Following the favorable bonus depreciation change, solar TPO project returns increased significantly. For example, if lease rates were held constant at \$0.087/kWh, project return in UNSE service territory for systems installed in 2015 would have retroactively increased from 40 percent to 60 percent. Similarly, solar TPO providers in APS’s service territory experienced project return increases from 60 to 110 percent for systems installed in 2015 due solely to the re-introduction of bonus depreciation.

Simultaneously, UNSE customers have seen increases in lease rates from 2015 to 2016. These lease rate increases are consistent with multiple residential solar players announcing plans to raise lease prices at the end of 2015.³¹ As shown in Figure 8, UNSE customers have seen a 9 percent increase in solar TPO lease rates, representing a further project return increase from 60 percent in 2015 to 80 percent in 2016.

²⁶ UBS, Global Research – “SolarCity Corp, Getting a Bigger Policy Boost”, 16 December, 2015

In contrast, the purple line reflects previously anticipated 2017 policy -- 10 percent ITC and no bonus depreciation. Before these recent policy changes, solar companies would have had to compete along the purple line as of Jan 1st, 2017, yet now they are operating along the blue line.

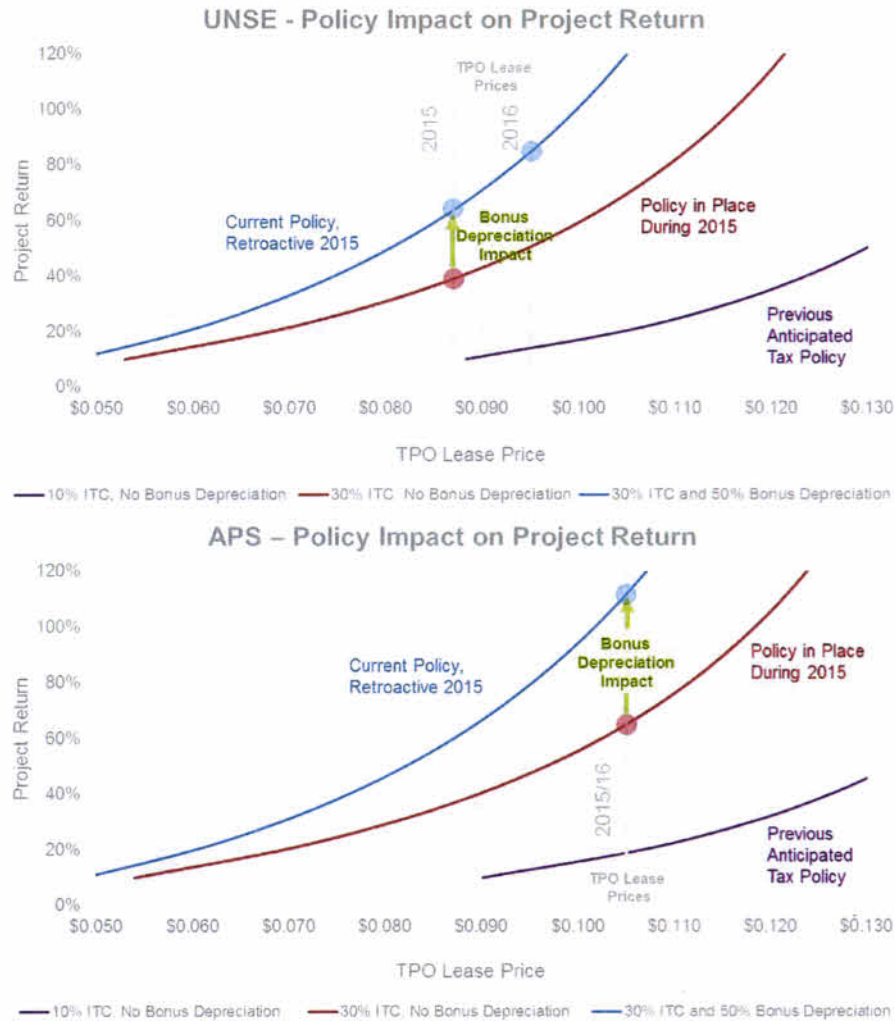


Figure 8. Incentive Impact on Project Return, APS and UNSE Service Territories

The analysis above suggests that the combined impacts of the re-introduction of bonus depreciation and the increase of lease rates from 2015 to 2016 offer headroom for solar TPO providers to reduce lease rates and adjust to changing rate structures while still enjoying the same project returns achieved in 2015. For instance, in 2015 in UNSE's territory, SolarCity, the leading solar TPO provider, could earn a project return of 40 percent with solar TPO prices set at \$0.087/kWh. With the re-introduction on bonus depreciation, this should permit SolarCity, the leading solar TPO provider in UNSE service territory, to earn 40 percent return with lease rates of about \$0.075/kWh, which differs substantially from current observed lease rates of \$0.095/kWh. The headroom available in other service territories appears to be even greater, based on our analysis indicating that service territories with higher offset rates tend to have larger project returns. The above analysis is presented in a slightly different format below in Table 3.

Table 3. Policy Impact of Project Returns, 2015 and 2016²⁷

	2015 policy		2015 retroactive change to bonus depreciation		2016 policy	
	in place through Dec 2015		in place after Dec 2015		in place after Dec 2015	
	2015 Solar Lease Rate (\$/kWh)	Project Return	2015 Solar Lease Rate (\$/kWh)	Project Return	2016 Solar Lease Rate (\$/kWh)	Project Return
UNSE	0.087	40%	0.087	60%	0.095	80%
APS	0.105	60%	0.105	110%	0.105	110%

Navigant notes that project return calculations can be sensitive to certain input assumptions. Since project returns grow exponentially as lease rates increase (see Figure 8), this sensitivity is most notable when lease rates and corresponding project returns are high. The robustness of this analysis is in its *comparative* nature, such that minor uncertainties in inputs are applied equally across all jurisdictions, and across comparative policy and lease price changes. As a result, the conclusions of this analysis are driven primarily by the relative values of the calculated project returns across service territories and over time. Furthermore, Navigant makes no assertions regarding whether any individual project return is deemed to be acceptable, too high, or too low.

Although these calculated project returns are high, we note that we have made several conservative assumptions in our analysis that would actually tend to understate, rather than overstate, true project returns. These conservative assumptions include:

- **Cost of debt:** Our analysis used a cost of debt of 6 percent throughout the analysis. Some sources indicate that this cost of debt could be as low as 5 percent.²⁸
- **Lease term and residual value:** The analysis uses a 20 year contract term with no residual value for contract renewal and no residual value for the system at the end of life. The typical system life is longer than 20 years and the system is expected to have a residual value at the end of the lease term.
- **Markup assumed for the ITC and depreciation basis:** We used a 35 percent markup on system cost to calculate the value of the system for the purpose of ITC and system depreciation benefits. This value is also known as the fair market value (FMV). Using FMV as the basis for tax credits and depreciation benefits would effectively result in a solar TPO developer reporting a system value of \$3.74-3.87/W-DC to the Internal Revenue Service, which is still lower than observed system sales prices that typically range from \$4.20-\$4.75.^{29,30,31} The ability of PV providers to

²⁷ Project returns are influenced by several key factors including: installed system cost, ITC, bonus depreciation, accelerated depreciation.

²⁸ UBS Solar, US Alternative Energy & YieldCos, 4Q15 Playbook: Giving Solar 'Credit,' January 2014.

²⁹ Deutsche Bank Market Research, SolarCity, Analyst Day Recap, December 15, 2015.

³⁰ "A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax Treatment in the Residential PV Sector", Lawrence Berkeley National Laboratory, June 2015

³¹ SolarCity 2015 Analyst Day, December 15 2015. http://files.shareholder.com/downloads/AMDA-14LQRE/1426590891x0x866739/D20C11BF-C791-4BCB-B49B-2F78B0A6FFB7/SCTY_Analyst_Day_FNL-12AM-3.compressed-min.pdf

markup cost to something more akin to a price, or system value, when calculating tax credits and depreciation is a key driver in the favorable economics for solar TPO providers.^{32, 33}

2.5 KEY FINDINGS

Key findings include the following:

- Navigant's research indicates that solar TPO providers choose to operate in jurisdictions where they can maximize their return by undercutting utility offset rates.³⁴
- Solar TPO providers appear to be tracking utility rates and pricing accordingly, evidenced by higher observed lease prices in jurisdictions with higher utility rates. These higher lease prices cannot be fully accounted for by variations in system cost, solar production, and tax rate (locational factors).
- Navigant's analysis found that solar TPO providers' project returns vary by utility service territory, with higher project returns calculated in service territories having higher utility offset rates.
- Federal incentives such as the Investment Tax Credit (ITC), accelerated depreciation, and bonus depreciation have a significant impact on project return. The solar TPO business model is able to maximize the benefits of these federal incentives, which are amplified considerably by the TPO's ability to use a system "value", which is higher than the system cost, as the basis for the tax credit and asset depreciation.
- Navigant's research found that despite continuing declines in solar system costs and favorable policy decisions (e.g., re-introduction of bonus depreciation), lease rates have recently increased in certain locations, consistent with public disclosures from leading solar players and indicating higher project returns for solar TPO providers. In 2015, UNS Electric, Inc. (UNSE) solar TPO providers experienced an estimated 40 percent project return, which is expected to increase to around 80 percent in 2016, due to the lease rate increase from \$0.087/kWh to \$0.095/kWh between 2015 and 2016 and the re-introduction of the 50 percent bonus depreciation allowance (see Figure 8 on 13).
- We conclude that solar TPO providers have headroom to adjust to some changes in rate structures while maintaining project returns.

³² "Evaluating Cost Basis for Solar Photovoltaic Properties", U.S. Treasury Department.

[https://www.treasury.gov/initiatives/recovery/Documents/N%20Evaluating Cost Basis for Solar PV Properties%20Final.pdf](https://www.treasury.gov/initiatives/recovery/Documents/N%20Evaluating%20Cost%20Basis%20for%20Solar%20PV%20Properties%20Final.pdf)

³³ "Valuation of Solar Generating Assets", Solar Energy Industries Association,

<http://www.seia.org/sites/default/files/Valuation-of-Solar-Generation-Assets.pdf>

³⁴ Utility offset rates (\$/kWh) are defined as dollar value of a customer's bill reduction for each kWh generated by the customer's solar system. In other words, it is the amount of their bill that is "offset" for each kWh generated (hence the term).

APPENDIX A.

Financial Assumptions		
System Specifications	Asset life/investment horizon (Years)	20
	Installed cost (\$/W-DC)	Varies by location
	Total asset size (kW)	7.00
	Annual capacity factor (%)	Varies by location
	Annual degradation (%/year)	0.50%/year
	Fixed O&M (\$/kW-year)* ^{35,36}	20.00
	Fixed O&M escalator	1.90%
Financing	Cost of equity	Model output
	Cost of debt	6.00%
	Percentage of cap structure – equity	Model output
	Percentage of cap structure – debt	Model output
	Debt amortization period (Years)	20
	Residual Value	\$0.00
	Target Debt Service Coverage Ratio	1.30
Taxes and Incentives	Federal income tax	35.00%
	State income tax	CA: 8.84%; AZ: 6.00%
	Investment Tax Credit	30.00%
	Depreciation type	MACRS, Bonus where applicable
	Discounting convention	Mid-year ³⁷
	System Cost Markup for Tax and Depreciation	35.00%
	State incentives	None
	Local incentives	None (SMUD: \$500/system)
Other	Lease rate	Varies by location
	Lease escalation rate	2.90%

*O&M costs include all O&M components as well as inverter replacement.

³⁵ National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014.

³⁶ National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html, Accessed February 1, 2016.

³⁷ A mid-year discounting convention is a standard assumption about when cash flows occur throughout the year for the purposes of a discounted cash flow analysis. The problem with an end-of-year discounting convention is that it discounts the future value too much. It assumes that the entire cash flow for a given year comes at the very end of that year, and therefore should be discounted accordingly. This is often inaccurate, since cash flows typically occur in each month of the year. The mid-year discounting convention better represents the time-value of these monthly cash flows than an end-of-year convention. The mid-year convention assumes that all the cash comes in halfway through the year, which averages out the time differences between the individual monthly cash flows.

<http://www.wallstreetoasis.com/finance-dictionary/what-is-mid-year-discount>