ORIGINAL

Thomas A. Loquvam
Raymond S. Heyman
Pinnacle West Capital Corporation
400 North 5th Street, MS 8695
Phoenix, Arizona 85004
Tel: (602) 250-3630
Fax: (602) 250-3393
E-Mail: Thomas.Loquvam@pinnaclewest.com
RHeyman@swlaw.com

Attorneys for Arizona Public Service Company

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023 **ARIZONA PUBLIC SERVICE COMPANY'S NOTICE OF FILING DIRECT TESTIMONY**

Arizona Public Service Company provides notice of filing Direct Testimony of Bradley J. Albert, Ashley C. Brown, Leland R. Snook, and John Sterling in the above-referenced matter.

In addition, APS attaches a matrix that identifies where in the filed Direct Testimony responses to the various Commissioner questions filed in this docket can be found.[1]

[1] *See* Letter from Chairman Little, dated December 22, 2015; Letter from Commissioner Forese, dated January 8, 2016; Letter from Commissioner Burns, dated February 8, 2016; and, Letter from Commissioner Stump, dated February 19, 2016

RESPECTFULLY SUBMITTED this 25th day of February 2016.

By: ______________________________

Thomas A. Loquvam
Pinnacle West Capital Corporation
400 North 5th Street, MS 8695
Phoenix, Arizona 85004

and

Raymond S. Heyman
Snell & Wilmer
One Arizona Center
400 East Van Buren Street
Suite 1900
Phoenix, AZ 85004

Attorneys for Arizona Public Service

ORIGINAL and thirteen (13) copies
of the foregoing filed this 25th day of
February 2016, with:

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

COPY of the foregoing mailed/delivered
this 25th day of February 2016 to:

____

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

Teena Jilibian, Associate Law Judge
Legal Division
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

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

Richard Adkerson, CEO
Ajo Improvement Company
333 N. Central Ave
Phoenix, AZ 85004-2189

Dwight Nodes
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

Roy Archer
Morenci Water and Electric Company and Ajo Improvement Company
PO Box 68
Morenci, AZ 85540

Michael Arnold, Director
Morenci Water & Electric Company
333 N. Central Ave
Phoenix, AZ 85004

Than Ashby, Office Manager
Graham County Electric Cooperative
9 W. Center St
PO Drawer B
Pima, AZ 85543

Nancy Baer
245 San Patricio Dr
Sedona AZ 86336

Patrick Black
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, AZ 85016

Jack Blair, CMSO
Sulphur Springs Valley Electric Cooperative
311 E. Wilcox
Sierra Vista, AZ 85650

Tyler Carlson, CEO
Mohave Electric Cooperative, Inc.
PO Box 1045
Bullhead City, AZ 86430

Bradley Carroll
Tucson Electric Power Company
88 E Broadway Blvd, MS HQE910
PO Box 711
Tucson, AZ 85701-0711

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

Jennifer Cranston
Gallagher & Kennedy, PA
Attorney for Dixie Escalante Rural Electric,
Grand Canyon,& AZ Electric Power Cooperative
2575 E. Camelback Rd, Suite 1100
Phoenix, AZ 85016

C. Webb Crockett
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, AZ 85016

Jeffrey W. Crockett
Crockett Law Group, PLLC
2198 E. Camelback Rd. Suite 305
Phoenix, AZ 85016

Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North Fourth Ave
Phoenix, AZ 85003

Patricia Ferré
PO Box 433
Payson, AZ 85547

Jason Gellman
Snell & Wilmer, LLP
One Arizona Center
400 E Van Buren St, Suite 1900
Phoenix AZ 85004

Peggy Gillman, Manager of Public Affairs
Mohave Electric Cooperative, Inc.
PO Box 1045
Bullhead City, AZ 86430

Meghan Grabel
Osborn Maledon, PA
2929 N. Central Ave, Suite 2100
Phoenix, AZ 85028

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

Michael Hiatt
Attorney for Vote Solar
633 17th St, Suite 1600
Denver CO 80202

Timothy Hogan
Arizona Center for Law in the Public Interest
Attorney for Vote Solar and WRA
514 W. Roosevelt St
Phoenix, AZ 85003

Dillon Holmes
Clean Power Arizona
9635 N. 7th Street No 47520
Phoenix, AZ 85068

Mark Holohan, Chairman
Arizona Solar Industries Associaltion
2122 W Lone Cactus Dr, Suite 2
Phoenix AZ 85027

David Hutchens, President
UNS Electric, Inc.
88 E. Broadway Blvd, MS HQE910
PO Box 711
Tucson, AZ 85701-0711

Charles Kretek, General Counsel
Columbus Electric Cooperative
PO Box 631
Deming, NM 88031

Kevin Larson, Director
UNS Electric, Inc.
88 E. Broadway Blvd, MS HQE910
PO Box 711
Tucson, AZ 85701-0711

LaDel Laub, President and CEO
Dixie Escalante Rural Electric Association
71 East Highway 56
Beryl, UT 84714

Lewis M. Levenson
1308 East Cedar Lane
Payson, AZ 85541

Marcus Lewis
Garkane Energy Cooperative
PO Box 65
Loa, UT 84747

Steven Lunt, CEO
Duncan Valley Electric Cooperative
379597 AZ Hwy 75
PO Box 440
Duncan, AZ 85534

Craig A. Marks, PLC
Attorney for AURA
10645 N Tatum Blvd, Suite 200-676
Phoenix, AZ 85028

Dan McClendon
Garkane Energy Cooperative
PO Box 65
Loa, UT 84747

Charles Moore
Navopache Electric Company
1878 West White Mountain Blvd.
Lakeside, AZ 85929

Vincent Nitido, CEO/ General Manager
Trico Electric Cooperative
8600 West Tangerine Rd
Marana, AZ 85658

Paul O'Dair
Navopache Electric Company
1878 West White Mountain Blvd.
Lakeside, AZ 85929

Michael Patten
Snell & Wilmer, LLP
One Arizona Center
400 E Van Buren St, Suite 1900
Phoenix AZ 85004

Greg Patterson
Munger Chadwick
Attorneys for Arizona Competitive Power Alliance
916 W. Adams Suite 3
Phoenix AZ 85007

Gary Pierson
Arizona Electric Power Cooperative
PO Box 670
1000 S. Highway 80
Benson, AZ 85602

Susan H Pitcarin, MS
Richard H Pitcarin, PhD, DVM
1865 Gun Fury Road
Sedona, AZ 86336

Daniel Pozefsky
RUCO
1110 W. Washington, Suite 220
Phoenix, AZ 85007

Court Rich
Rose Law Group, P.C.
7144 East Stetson Drive, Suite 300
Scottsdale, AZ 85251

Timothy Sabo
Snell & Wilmer, LLP
One Arizona Center
400 E Van Buren St, Suite 1900
Phoenix AZ 85004

William Sullivan
Curtis, Goodwin, Sullivan, Udall & Schwab, PLC
Attorney for Garkane, Navopache, Mohave Electric
501 E Thomas Rd
Phoenix, AZ 85012-3205

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Chairman Little Q.1	How was the value and cost of solar considered in the development of the current net metering tariffs?	See: Brown, p. 7 Snook, p. 32
Chairman Little Q.2	Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?	See: Brown, pp. 19-20, 59 Albert, p. 15
Chairman Little Q.3	Is it appropriate to factor the cost of the panels into the reimbursement rate for net metering? If so, how?	See: Albert, p.15
Chairman Little Q.4	Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?	See: Brown, p. 25 Snook, pp. 17-18
Chairman Little Q.5	How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?	See: Albert, p. 27-28 Snook, p. 27
Chairman Little Q.6	How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?	See: Brown, p. 29, footnote 32; p. 58
Chairman Little Q.7	How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?	See: Brown, p. 15-18, 60 Snook, p. 24-25, 29-31 Albert, p. 27
Chairman Little Q.8	How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?	See: Brown, pp. 27-32, 34-36 Albert, pp. 10-11
Chairman Little Q.9	To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?	See: Albert, Figure 3 p. 31 Brown, pp. 25-28, 27-31 Snook, Figures 1-4, pp. 4, 13, 26

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Chairman Little Q.10	Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?	See: Brown, pp. 27-31, 34-35 Albert, pp. 14-15
Chairman Little Q.11	Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How should the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?	See: Albert, pp. 11, 19, 26 Brown, pp. 35-36 Snook, p. 29
Chairman Little Q.12	How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how? a. Job impacts associated with DG solar installations; b. Job impacts associated with closure of fossil fuel plants (and mines) displaced by DG solar; c. Distribution of DG solar economic benefits between DG installers, customers who install DG solar, PV panel manufacturers and others; d. Impact of DG solar deployment on overall energy costs and those costs' impacts on economic activity; e. Effect of DG solar deployment on natural gas and coal prices; and f. Opportunity costs associated with incenting DG solar, e.g., funds spent on DG solar cannot be spent on other renewable energy resources or energy efficiency.	See: Brown, pp. 15-18, 30-37, 45-47; Attachment ACB-2DR
Chairman Little Q.13	How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?	See: Albert, pp. 7, 8, 11, 19 Snook, p. 29 Brown, pp. 33-36
Chairman Little Q.14	Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?	See: Brown, pp. 21-22 Albert, p. 16 Snook, p. 18

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Chairman Little Q.15	Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?	See: Albert, pp. 11-12 Brown, p. 33-36 Snook, p. 29
Chairman Little Q.16	Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?	See: Albert, pp. 7-8, 11, 19 Brown, pp. 27, 33-36 Snook, p. 29
Chairman Little Q.17	Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?	See: Brown, p. 15, 61 See also, APS Response to Staff Questions in this docket dated February 14, 2014
Chairman Little Q.18	Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?	See: Albert, p. 15
Chairman Little Q.19	Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?	See: Brown, p. 38-39
Chairman Little Q.20	What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?	See: Albert, p. 12 Brown, footnote 33, p. 29, 36
Commissioner Stump Q. 1	The Commission's May 7, 2014 Workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?	See: Albert, p. 27
Commissioner Stump Q.2	Why argue that a value-of –solar proceeding is important only for resource-planning purposes, given that discussions about cost-shifts are informed discussions on the value of DG?	See: Snook, p. 28

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Commissioner Stump Q. 3	In 2014, lost fixed costs associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per-customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.	See: Snook, p. 24; Figure 4 p.26
Commissioner Stump Q. 4	How do we calculate regressive social costs into the value of solar, given that non-solar utility customers subsidize solar customers?	See: Brown, pp. 24, 46-47
Commissioner Stump Q.5	Are solar DG users being overcompensated or undercompensated for remitting excess solar power to the utility at the retail rate?	See: Albert, p. 32
Commissioner Stump Q. 6	To what degree do intermittency and non-dispatchability affect the value of solar?	See: Brown, pp. 27-32, 36
Commissioner Stump Q. 7	How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U.S. installation costs into a value-of-solar determination?	See: Brown, pp. 59-62 Albert, p. 28
Commissioner Stump Q. 8	In value-of-solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words, are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower installation costs? How does the cost and value of DG compare with alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that of utility-scale and community-scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility-scale or community-scale solar?	See: Brown, pp. 15-18, 41-44, 60 Snook, p. 24 Albert, pp. 27-28

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Commissioner Stump Q. 9	How should we go about attempting to quantify largely externalized and unmonetized factors, such as projected financial, energy security, social, and environmental benefits? How are long-term forecasts accurately incorporated into present value-of-solar calculations?	See: Brown, pp.21-22, 45-47; Attachment ACB-2DR Albert, p. 3, 22, 29
Commissioner Stump Q. 10	Despite recognized advantages, a number of states are reexamining their traditional net metering policies and underlying rate designs. The increasingly pervasive review of conventional net metering policies by states is attributable to a multitude of trends, including decreasing solar rebate incentives, rapid encroachment of renewable portfolio standards, the realization of net metering caps, as well as raised public awareness surrounding prospective cost-shift concerns. For instance, the Hawaii Public Utilities Commission brought an end to the state's net metering program when it cut payments to new solar customers by approximately half the going rate.[4] Nevada alternatively reduced payments to existing solar customers from the retail to the wholesale rate and raised customers' fixed charges to cover the cost of using the grid.[5] Moreover, the California Public Utilities Commission recently approved a NEM 2.0 successor tariff, which effectively preserves retail rate payments for residential DG systems while imposing new interconnection fees, non-bypassable charges, and a shift to time-of-use rates for DG customers.[6] a. Given this context, how did Hawaii, Nevada, and California value the costs and benefits of net-metered solar? b. What analysis on the cost of solar did these states use when they changed their net metering policies in light of an acknowledged cost-shift? Did such analyses adequately account for the costs associated with redesigning and maintaining the distribution system to accommodate DG? c. How would a value-of-solar methodology facilitate the successful implementation of similar updated policies in Arizona? 4 Decision No. 33258, Docket No. 2014-0192 (Haw. Pub. Utils. Comm'n Oct 12, 2015) 5 Document IDs 8412 & 8414, Docket Nos. 15-07041 & 15-07042 (Nev. Pub. Utils. Comm'n Dec 23, 2015) 6 Decision No. 16-01-044, Docket No. R.14-07-002 (Cal. Pub. Utils. Comm'n Jan. 28, 2016)	Not addressed in the Company's Direct Testimony. APS will be prepared to discuss this question during the course of the proceeding in this docket.

APS RESPONSES TO COMMISSIONER QUESTIONS

	QUESTION	CITATION TO RESPONSE
Commissioner Burns	I would like to see testimony from the parties regarding the impact of rooftop solar and other distributed generation on water use… For example, if a person installs rooftop solar on his home which results in a decreased need for fuel from traditional generators, what level of water savings could result?	See: Albert, p.15
Commissioner Forese	It is my understanding that there is a complexity to addressing potential cost shifts which may include geographic differentials depending on the specific distribution infrastructure. Perhaps further discovery on this topic will lead to identify solutions that could help result in a "win-win" scenario.	See: Brown, pp. 26-27 Snook, p. 17

DIRECT TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

February 25, 2016

Table of Contents

DIRECT TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

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

A. My name is Leland R. Snook. My business address is 400 North 5th Street, Phoenix, Arizona, 85004. I am Director of Rates and Rate Strategy for Arizona Public Service Company ("APS" or "Company"). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My background and experience are set forth in Attachment LRS-1 to this testimony.

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

A. In my direct testimony I provide:

1. A summary of APS's conclusions and recommendations in this docket;
2. An overview of the APS testimony and witnesses in this proceeding;
3. The cost of service study ("COSS") that APS filed in this docket, including the methods that APS used to create the COSS, the results of the COSS and the implications of those results; and,
4. Direct responses to a portion of Chairman Little's questions set forth in his December 22, 2015 letter related to my testimony.

II. SUMMARY OF RECOMMENDATIONS

Q. MR. SNOOK, PLEASE SUMMARIZE THE COMPANY'S CONCLUSIONS AND RECOMMENDATIONS IN THIS DOCKET.

A. First, because rates are based on historical test year data, the Commission should adopt the Company's COSS methodology as set forth in this docket. Further, the Commission should find and conclude as a policy matter that Value of Solar methodologies will not be used in setting rates.

Second, the methodology for determining Value of Solar established by the Commission as a result of this docket should be approved as an appropriate analysis tool for determining (i) the value of solar in the resource planning context; and (ii) calibrating the price paid for energy exported to the grid from rooftop solar arrays.

III. OVERVIEW OF APS TESTIMONY

Q. PLEASE PROVIDE AN OVERVIEW OF THE APS WITNESSES IN THIS PROCEEDING.

A. In this proceeding APS is presenting testimony from four witnesses in its Direct Testimony. In addition to my own testimony on the COSS, APS is presenting testimony from:

- Ashley C. Brown, Executive Director of the Harvard Energy Policy Group, who will provide a national and policy perspective on the value of solar and related studies.
- Bradley Albert, APS's General Manager of Resource Management, Power Marketing and Acquisitions, who will describe several methods for calculating the value of residential distributed solar photovoltaics, including the various

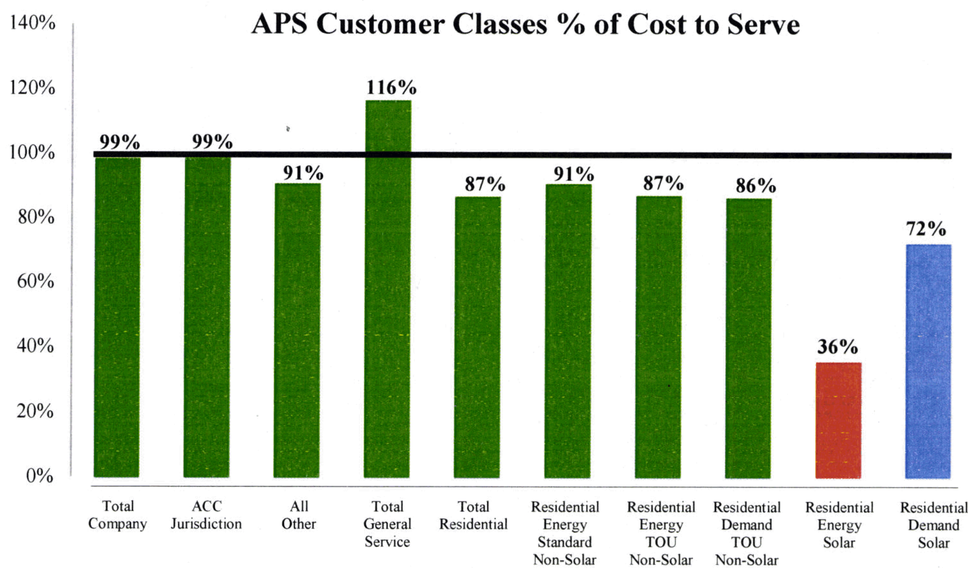
value attributes. Mr. Albert will also discuss various methodologies for arriving at the value of solar.

- John Sterling, Solar Electric Power Association's ("SEPA") Senior Director, Research & Advisory Services, who will provide an overview of SEPA's work with the Tennessee Valley Authority on their recent value of solar study and the results, which addressed many of the issues that are the subject of this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony first discusses the methods and results of the COSS that APS prepared in connection with this proceeding. The COSS demonstrates that residential rooftop solar customers, also referred to as Net Energy Metering ("NEM") customers, on energy-based rates pay only 36% of the cost to serve them, and that NEM customers on demand rates pay only approximately 72% of the cost to serve them. This is in contrast to residential customers without solar, who pay between 86% and 91% of the cost to provide them electric service. These COSS results demonstrate that the cost shift is real under APS's present rate design. If rate design is not modernized, approximately $67 per month in cost responsibility for solar customers on energy rates and $29 per month for solar customers on demand rates will be shifted to residential customers without solar — to the extent these fixed costs are not already being shifted through APS's Lost Fixed Cost Recovery Mechanism. Figure 1 below displays the percent of cost to serve results from the COSS, reflecting the amount that is being paid under current rate structures for all customer groups, in relation to the cost of providing service.

Figure 1.



Further, the COSS demonstrates that today, without the right price signals to incent behavior, the demand and energy usage of residential customers with rooftop solar differs significantly from residential customers without solar. These differences make it appropriate to evaluate, for ratemaking purposes, residential solar customers as a unique sub-class within the residential customer group.

Lastly, I discuss the implications of the COSS results. Relying on a kWh price for the bulk of cost recovery is no longer a workable solution. When customers reduce energy use only, and don't reduce fixed grid costs, current rate design shifts responsibility for fixed cost recovery to customers without rooftop solar. This cost shift will increase rates for those customers without solar, including the most vulnerable of our customers, the limited-income segment, without regard for cost causation. This is inequitable and must change for solar to be a sustainable technology for all customers over the long term. Further, volumetric rates pick which technologies win and which lose. Currently, only those technologies that reduce energy can permit customers to reduce their bills. Aligning costs with cost recovery, however, will permit different technology types to compete based on how effectively they reduce costs. The result will provide customers with more and more choices as technological innovation continues.

The COSS reflects what APS believes to be the appropriate method to use in rate case proceedings for the cost of service analysis for rooftop solar customers. It also supports realigning rate design to better match the costs incurred to serve customers. Realigning rates will help ensure that:

- Customers have accurate price signals from which to make efficient energy technology decisions;
- Prices for services are equitable for all customers, including both those that adopt technology and those who do not; and,
- The pricing framework is financially sustainable for all customers over the long term.

If a customer no longer consumes significant amounts of energy but continues to use infrastructure assets, APS's pricing structure must appropriately measure and bill for this changed, but ongoing, use in a manner that is fair for all customers. The current method of collecting fixed and demand-related costs on a fluctuating kilowatt-hour ("kWh") energy basis will not achieve this critical goal.

Q. PLEASE DESCRIBE THE SUMMARY SCHEDULES THAT SUPPORT THE COSS THAT YOU ARE SPONSORING.

A. The Summary Schedules provide detailed information regarding the Company's COSS. These schedules illustrate the jurisdictional allocation of costs to both retail (Arizona Corporation Commission ["ACC" or "Commission"]) and non-retail (predominantly Federal Energy Regulatory Commission ["FERC"] regulated services which are designated as "All Other"). Further, the Summary Schedules functionalize costs to each broad customer class and specific customer sub-classes, ultimately deriving the percentage of cost to serve that is being recovered under current rates, based on original cost by class and sub-class. The Summary Schedules also contain all cost-allocation factors used in preparing the study.

The following is a summary of these Schedules:

- Summary Schedule 1 shows the rate-of-return at existing rates by customer class, based on the unadjusted 2014 Test Year COSS. (Attachment LRS-2DR)
- Summary Schedule 2 shows the functionalized dollar amount and percentage of rate base allocated to each retail customer class. (Attachment LRS-3DR)
- Summary Schedule 3 shows the functionalized amount of operating expenses allocated to each retail customer class. (Attachment LRS-4DR)
- Summary Schedule 4 shows the amount of functionalized rate base allocated to ACC jurisdictional customers. (Attachment LRS-5DR)
- Summary Schedule 5 shows the amount of functionalized operating expense allocated to ACC jurisdictional customers. (Attachment LRS-6DR)
- Summary Schedule 6 lists the allocation factors used in preparing the 2014 Test Year COSS. (Attachment LRS-7DR)

Q. DO YOU SPONSOR ANY ADDITIONAL SCHEDULES RELATED TO THE COST OF SERVICE?

A. Yes. Attachment LRS-8DR to my testimony is the COSS Schedule, which is a summary showing:

1. Jurisdictional separation of rate-base costs, revenues, and operating expenses between the ACC and All Other jurisdictions;
2. Further allocation by retail customer class, of total ACC allocated costs and the percentage of cost to serve paid by each major customer class;
3. The same information by each general service sub-class; and,

4. The same information by each residential service sub-class, including the NEM energy and demand rate sub-classes.

IV. COST OF SERVICE STUDY

Q. WHAT IS A COST OF SERVICE STUDY?

A. A COSS is the fundamental tool for allocating a utility's costs among its customers based upon their responsibility for incurring such costs. It is foundational in developing appropriate pricing structures that align the rates customers pay for the services received with the customers who are driving the costs. This is often described as the "cost causation principle."

A COSS is a detailed analysis of audited financial information and actual customer load data that assesses the responsibility of each customer group for the costs incurred to provide service during the relevant time period. The COSS functionalizes, classifies, and then allocates costs and revenues, beginning with wholesale and retail customers, then continuing the process with various broad classes of retail service and finally to sub-classes within each retail class.

The cost-allocation study enables APS to determine its unit costs, by function, incurred to provide energy, demand, and customer services to each customer class and sub-class, as well as the support to those costs that each customer group presently contributes through their rates.

The ACC, and public utility commissions across the country, use cost-of-service studies developed in this manner to set rates for most public utilities, including water, electric, and gas utilities.

Q. WHAT TIMEFRAME DID THE COMPANY USE FOR THE COST OF SERVICE STUDY THAT IT FILED IN THIS DOCKET?

A. APS conducted an embedded COSS using data from the most-recent calendar year available — the twelve-month period ending December 31, 2014 — as the test period ("Test Year").[1] The Company analyzed its costs, customer class sales and load characteristics during this period — the number of customers and their demand and energy usage is commonly referred to as "Billing Determinants" — and used those results to allocate the various plant and operating expenses to each customer class through a rigorous process of functionalization, classification, and allocation of costs. The study results allow APS to derive the percentage of cost to serve that is being recovered under current rates, based on original cost, by class and sub-class.

Q. WHAT DO YOU MEAN BY EMBEDDED COSS?

A. An embedded COSS is based on the historical costs and operating experience of the utility during the selected Test Year. Rate-making in Arizona is based on this historical Test Year and embedded cost approach. Under this method, rates are based on actual incurred costs as verified through audited financial data.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE EMBEDDED COST ALLOCATION STUDY.

A. This study was prepared using industry-accepted Cost of Service Functionalization, Classification, and Allocation principles, and is consistent with Commission-approved methods.

Functionalization refers to the process of attributing each rate base or expense item to a particular function — namely Production (generation of electricity), Transmission,

[1] Note that APS will use the next year, ending December 31, 2015, for the COSS in the rate case that APS will file in June 2016. As the year immediately preceding APS's rate case filing, 2015 is the most recent full calendar year upon which to base rates and will be the test year for the rate case.

Distribution or Customer Service (e.g., metering and billing) — in the provision of electric service. An example is assigning the costs of building and operating the Company's generation power plants to the Production function.

Classification refers to the process of determining the factor or factors that drive the magnitude of the cost. For example:

- If a cost to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as Energy.
- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as Demand.
- If a cost is driven by the number of customers taking service on the APS system irrespective of either the kW demand or kWh energy, it is classified as Customer.

Allocation occurs after a cost has been functionalized and classified. This is the process in which allocation factors — such as class coincident peak demand contribution at the time of system peak, non-coincident class peak ("NCP") or the sum of individual peaks, energy or number of customers — are applied to allocate the costs to particular jurisdictions, customer classes, and rate schedules or sub-classes. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

In summary, in the COSS the expense and rate-base items that comprise all of APS's costs were grouped into major categories, such as Plant in Service or Operating & Maintenance ("O&M") Expense. Each of these categories was first functionalized into Production, Transmission, Distribution or Customer related costs, then classified as Demand, Energy, or Customer-related. Allocation factors based on kW, kWh and number of customers were then developed so that the functionalized and classified costs could be allocated to the ACC retail jurisdiction and to the various retail customer classes and sub-classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the four summer months of June, July, August, and September (referred to as "4CP") to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before FERC, and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs, due to differences in allocation methods, cannot be recovered from either jurisdiction. It has also been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC-jurisdictional customer classes, production costs were allocated based on the Average and Excess Demand ("AED") method. This is a method required by the Commission in Decision No. 69663 (June 28, 2007). AED uses the sum of two demand allocators:

1. **NCP Average Demand allocator**, which uses each class's NCP demand weighted by the class load factor calculated using the class energy and the NCP demand.

2. **System Peak Excess Demand allocator**, which is determined by first calculating the NCP Excess Demand, which is the difference between each class's NCP and that class's average demand. Second, the sum of NCP Average

Demands is subtracted from the single system peak demand to derive the System Peak Excess Demand, which is then allocated to each class based on the proportionate share of the sum of NCP Excess Demands.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the Cost of Service Study. A portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff ("OATT") revenues to ensure there is no double-counting of transmission costs between the ACC and non-ACC jurisdictions. This also effectively assumes that each customer class pays the cost of transmission service even though this is demonstrably not the case for solar customers.

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not be coincident with the system peak load. Thus, allocation of costs related to distribution substations and primary distribution lines are made based on NCP loads. Allocation of costs related to distribution transformers and secondary distribution lines are made based on the summation of the individual peak loads or demands of all customers within a particular customer class ("Sum of Individual Max"). Each of these allocation methods has traditionally been used by APS and accepted by the Commission for many years.

Q. HOW DID YOU DETERMINE IT WAS APPROPRIATE TO CREATE A SEPARATE RESIDENTIAL SUB-CLASS FOR NEM ENERGY AND NEM DEMAND CUSTOMERS WITHIN THE RESIDENTIAL CUSTOMER CLASS?

A. It can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer sub-group in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, I determined that sufficient differences exist for at least separately studying this sub-class of residential customers in a COSS.

When evaluating the load characteristics of residential customers with and without rooftop solar, the peak demand — CP, NCP and Sum of Individual Max — and energy characteristics are very different for solar customers. The typical residential solar customer still needs about 81% of the capacity they used before they adopted solar and 30% of the energy. This is a significantly different profile than residential customers without solar, regardless of size.

Second, in the 2014 Test-Year, APS had more than 27,000 solar customers on an energy rate and almost 1,200 solar customers on a demand rate by year's end. The size of this residential solar customer sub-group, combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class. See Figures 2 and 3 for a comparison of typical solar and non-solar customer daily load shapes for a summer and winter day.

Figure 2.

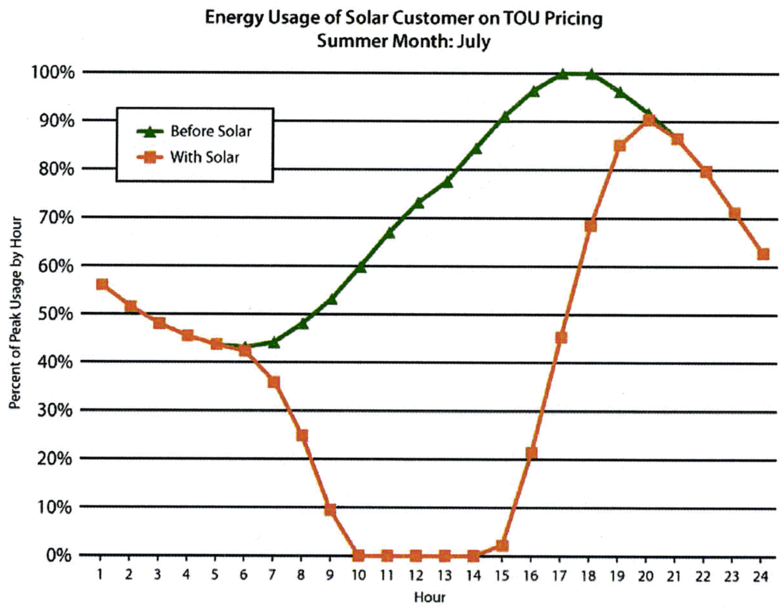
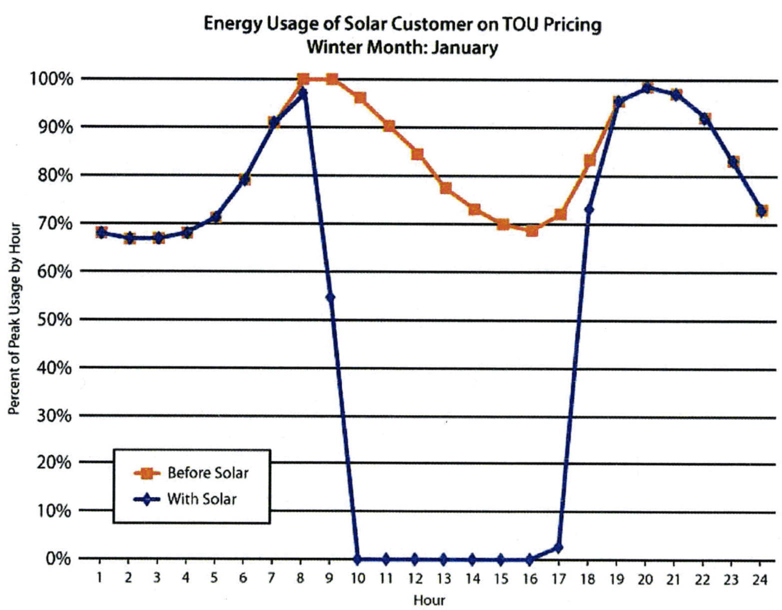


Figure 3.



Also, the Public Utilities Commission of Nevada ("PUCN") found that it is appropriate to evaluate NEM customers as a separate sub-class based on significant cost and load differences:

> It is just and reasonable and in the public interest to establish separate rate classes for *all* NEM ratepayers based on both the cost differentiation and load (usage) differentiation between NEM ratepayers and non-NEM ratepayers. Different services have different costs and thus require different rate classes. NEM ratepayers are partial-requirements service ratepayers. The Commission has historically established separate, optional rate schedules for ratepayers who self-select to become partial-requirements ratepayers. Partial-requirements service ratepayers are ratepayers whose electric requirements are partially or totally provided by non-utility generation. There is a significant difference in the load (usage) profiles between partial-requirements NEM ratepayers and full-requirement ratepayers. NEM ratepayers can rapidly go from exporting unused electricity to importing needed electricity from the local grid. As a result, NV Energy provides a distinct service to partial-requirements ratepayers who choose to purchase some, but not all, of their energy needs from the utilities.[2]

The PUCN also found that the load levels and hourly usage differences of NEM customers alone justified a separate rate class:

> Besides the partial-requirements nature of NEM ratepayers' service, the load levels and hourly usage differences between NEM and non-NEM ratepayers are sufficient (alone) to justify separate ratepayer classes for NEM ratepayers. There is a significant difference between the load shapes (usage profiles) of NEM and non-NEM ratepayers, thus supporting the establishment of new NEM ratepayer classes. The total load and delivered load of the NEM ratepayer is distinct and varies from the shape of non-NEM ratepayers on an hourly basis.[3]

I agree with the Nevada Commission. It is true that some differences exist between NV Energy's system and APS's system. However, those differences are limited, and only concern quantifying the objective magnitude of these differences, not the relative significance or whether these differences exist in the first place. The physics underlying

[2] Modified Final Order in Docket Nos. 15-07041 and 15-07042, at Paragraph 91 (February 17, 2016) (emphasis in original).
[3] *Id.*, at Paragraph 92.

electrical service are the same in Arizona as they are in Nevada. And the service, load, and cost differences regarding NEM customers found by the Nevada Commission are the same differences experienced by APS in relation to APS's solar customers.

Q. PLEASE EXPLAIN THE PROCESS THAT APS USED TO CREATE A UNIQUE RESIDENTIAL SUB-CLASS FOR NEM CUSTOMERS.

A. Consistent with the methodology I previously discussed:

1. APS grouped NEM customers currently on energy-based rate schedules, which includes customers both on inclining block and time-of-use rate schedules.

2. APS separately grouped NEM customers on demand-based time-of-use rate schedules.

3. APS used the data for the NEM customer's entire load at the home — load served both by APS and the customer's rooftop solar system — as the starting point for cost allocation to develop the CP, NCP and Sum of Individual Max demand allocations, as well as the energy allocations.

4. APS then explicitly credited the customer for:

    - All their self-provided capacity based on a comparison to the APS-delivered customer load; and,

    - Their entire energy production, including both what the customer consumes on site and what is delivered from the NEM customer to the grid.

This approach fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to NEM customers based on what APS has to provide.[4]

Q. PLEASE EXPLAIN FURTHER HOW THIS APPROACH COMPENSATES NEM CUSTOMERS FULLY FOR THE BENEFITS THEY PROVIDE TO APS.

A. By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure which no longer needs to be provided by APS as a result of the solar system. While a solar installation will have a certain maximum-production capability, that capability will only be realized at mid-day and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time. The alignment between when a residential customer needs power and when the solar system operates is not significant in APS's service territory. APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than mid-day.

The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the NEM customer's solar system is at offsetting APS's peak loads. For example, the COSS indicates the appropriate level of production demand credit is no more than approximately 19% — when considering the class peak coincident with system peak and class NCP data — which are both relevant to and consistent with the production-cost-allocation method of AED.

[4] This addresses Question 14 from Chairman Little's December 2015 Letter regarding the consideration of fuel cost savings. In its COSS, APS directly credited DG customers for the fuel and energy value at APS's filed avoided cost. A detailed analysis that assesses the value at the time of production would yield lower results. In a resource planning context, the fuel savings will vary over the study period, however, in a COSS, the fuel savings is based on the test-year results.

Likewise, the energy compensation in a COSS should reflect the actual fuel costs that APS avoids when a solar customer consumes less energy. The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system, which is a conservative proxy for the actual cost saved by APS.[5]

Q. HOW DID THE COSS METHODOLOGY CONSIDER THE SEVEN CORE COST AND BENEFIT CATEGORIES IDENTIFIED BY CHAIRMAN LITTLE IN HIS DECEMBER 22, 2015 LETTER?

A. As Chairman Little's letter articulated in its suggested outcomes from this proceeding, APS reviewed the categories of cost and benefits in the process of developing this COSS methodology. The COSS methodology includes two of the three categories of cost articulated in Outcomes 4; it does not include system-integration costs. APS considered all of the benefits articulated in Outcomes 4, and recognized generation capacity and energy savings as described above. The COSS methodology did not include savings for transmission or distribution costs, nor did it include environmental or economic development benefits.

Q. DOES THE COSS METHODOLOGY INCLUDE VARIATIONS BASED ON SPECIFIC CUSTOMER LOCATION?

A. No. At present, there is no demonstrable effect on cost of service based on the location of a rooftop solar system. APS is presently studying the effect of rooftop solar on feeders in targeted locations as a part of its Solar Partners Program.[6]

---

[5] APS Witness Albert describes a detailed methodology for establishing a value of solar that compares the market value of the energy at the time it is produced. Such an analysis would likely produce a different value of energy based on market prices than the filed APS avoided cost.

[6] Decision No. 74878 (December 23, 2014).

Q. DOES THE COSS METHODOLOGY INCLUDE TRANSMISSION OR DISTRIBUTION SAVINGS?

A. No. Although some have speculated on this topic, the 2014 data make clear that customers with rooftop solar which was installed without regard to location did not cause any transmission or distribution savings.

Q. DOES THE COSS METHODOLOGY INCORPORATE ENVIRONMENTAL AND ECONOMIC DEVELOPMENT BENEFITS?

The COSS methodology does not consider environmental or economic development benefits because they are not part of the cost to serve customers. They are intangible and unquantifiable values. If they are to be considered at all, they are more appropriately considered in a resource planning context when comparing resource alternatives. There, one can assess which resource provides the most environmental and economic benefit and use that assessment in resource planning decisions as appropriate. But with regard to developing a COSS methodology — in which the actual costs incurred to provide electric service are allocated to customers on the basis of cost causation — intangible and unquantifiable values should not be included.

Q. DOES THE 19% DEMAND CREDIT PROVIDED TO DISTRIBUTED SOLAR IN YOUR COSS MEAN THAT RESIDENTIAL ROOFTOP SOLAR INSTALLATIONS HELP DEFER FUTURE APS POWER PLANT ADDITIONS?

A. The production-demand infrastructure credit today is at most 19%, which is the appropriate level of credit that results from the COSS. In the future, APS's peak demand will slowly move later in the day. 2014 was the first year APS saw summer peak demands occur in the hour ending at 6:00 p.m. As the peak continues to shift to a later time, the production-demand infrastructure credit value will further decrease. APS witness Brad Albert discusses this topic in detail.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS makes sales to parties that are not traditional APS retail customers such as sales to Rate Schedule E-36 customers for station service power to large generation plants owned by other parties. To be certain that all the benefits of such transactions flow through to retail customers, the revenues derived from these transactions, which more than cover the incremental costs associated with producing or acquiring the required energy, are allocated to all customers. Thus, the entire margin or profit that APS realizes from these non-retail transactions is attributed to each class through the revenue credit, which benefits all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions and a number of other small items, such as Rent from Electric Property, Forfeited Discounts, Miscellaneous Service Revenues, and Other Electric Revenues, as revenue credits.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES?

A. Yes. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates. The COSS only addresses the base rate portion of the cost to serve. The revenues from adjustors are a revenue credit to the COSS revenue requirement. When the revenue from adjustors is included in the overall calculation, an additional shortfall from solar customers is included in cost recovery. For a full determination of costs that will otherwise be shifted to customers without solar, this shortfall should be added to the COSS results.

Q. HAVE YOU CALCULATED THE COSTS, RATE BASE, AND PERCENT OF COST TO SERVE BASED ON THE 2014 TEST YEAR?

A. Yes. In addition to establishing the Production, Transmission, and Distribution functional allocations and the Demand, Energy, and Customer classifications for each class of retail customers, the percentage of cost to serve for each class under Test Year rates appears in the Summary Schedules.

Q. BASED ON THE RESULTS OF YOUR 2014 TEST YEAR COST OF SERVICE STUDY, WHAT CONCLUSIONS HAVE YOU MADE?

A. The Summary and COSS Schedules plainly show disparities in the ratio of the allocated cost for APS to actually provide service and what customer classes and sub-classes pay for the services APS provides. The residential class contributes less toward the cost to serve than does the general service class. Specifically, under current rates, the revenue from the residential class covers approximately 87% of the cost to serve while the general service class covers 116% of the cost to serve. This difference has been recognized in, and results from, past decisions in APS rate cases, and is true for many utilities in this country.

Within the residential class, there is further disparity within the sub-classes:

- NEM customers on energy-based rates cover only approximately 36% of the cost to serve;
- NEM customers on demand rates cover around 72% of the cost to serve; and,
- Other non-solar residential customer sub-classes cover a range from 86% to 91% of the cost to serve.

Unlike the differences between residential and general service classes, the difference in cost-of-service contributions by residential customers with and without solar does not stem from express Commission direction.

Q. BASED ON THE PERCENTAGE OF COST TO SERVE RESULTS, WHAT IS THE COST SHIFT THAT WILL OCCUR UNDER CURRENT RATE STRUCTURES?

A. Absent affirmative action by the Commission, responsibility to pay the cost of service not paid by residential customers with solar will be shifted to residential customers without solar in APS's next rate case. This is commonly referred to as the "cost shift," and was recognized by the Commission in Paragraph 49 of Decision No. 74202 (2013). In fact, utility commissions across the country are beginning to explicitly recognize and acknowledge the need to address the cost shift. Most recently, the PUCN found that NEM customers do shift costs and quantified that cost shift for NV Energy customers:

> On average, the resulting shift in cost responsibility is approximately $623 and $471 for each single family residential NEM ratepayer annually for NPC and SPPC, respectively. The magnitude of this cost shift is unreasonable.[7]

In APS's territory, the magnitude of the cost shift is even higher. By paying 36% of the cost to serve instead of the residential average of 87%, each NEM customer on an energy-based rate avoids $67 per month and each NEM customer on a demand-based rate avoids $29 per month.

Whereas the annual cost shift for the two utilities in Nevada is approximately $471 and $623 for solar customers on energy-based rates, the annual cost shift in APS's territory is approximately $804. This represents the total amount shifted, which includes both the

[7] Modified Final Order at Paragraph 88. In the Order, NPC refers to Nevada Power Company and SPPC refers to Sierra Pacific Power Company.

amount in base rates determined by the COSS and the amount from APS's adjustor mechanisms.

Q. BASED ON THE COST SHIFT OF $804 ANNUALLY PER SOLAR CUSTOMER, WHAT IS THE TOTAL COST SHIFT OVER THE LIFE OF THE ROOFTOP SOLAR SYSTEMS?

A. Assuming the cost shift is grandfathered, the 27,078 NEM customers on an energy rate and the 1,176 NEM customers on a demand rate at the end of 2014 will increase the revenue to be collected from all other residential customers by approximately $22 million per year. Over the typical 20 year life of a rooftop solar system, the total amount shifted to customers without rooftop solar will be approximately $440 million. In addition, APS added 9,044 new residential rooftop solar customers in 2015. For each year that this pace continues, the annual cost shift will grow by more than $7 million and the 20-year cost shift will grow by more than $144 million. In other words, assuming all DG systems installed through 2015 are grandfathered, the annual cost shift is $29 million, and the 20-year cost shift will be over $580 million.[8]

Q. IS THE COST-SHIFT CAUSED BY THE PREDOMINANT VARIABLE KWH PRICE SIGNALS IN EXISTING RATE DESIGN?

A. Yes. In the COSS, costs are allocated based on the true-cost drivers. APS's infrastructure costs are predominantly driven by capacity needs — which do not vary with kWh consumption. As previously shown in Figures 1 and 2, the residential NEM customer significantly changes their energy profile by taking less energy during the day. This customer does not, however, significantly change their demand profile; APS must still meet the customer's demand later after the sun has set, but when the customer is

[8] In APS's application for the Grid Access Charge filed on April 2, 2015 in Docket No. E-01345A-13-0248, APS indicated a cost shift of over $800M over 20 years if all systems installed through mid-2017 were grandfathered. Using this same approach and with updated data the number would be approximately $804 million.

still significantly relying on the grid. As a result, APS must still incur the capacity-related production, transmission and distribution costs needed to provide service to the NEM customer. The mismatch in the most-common residential rates used by NEM customers results from the fact the price to the customer is overwhelmingly based on kWh energy, rather than capacity, which is offset to a much smaller degree. Said another way, infrastructure, and the related costs are a function of demand, rather than energy.

Q. ARE THERE OTHER POTENTIAL COST SHIFTS IN RESIDENTIAL RATES?

A. Yes. As discussed previously, APS's residential rates in total are lower today than the COSS's calculated cost to serve, and commercial rates are correspondingly higher. This difference has been in existence in APS's service territory for a long time and is not uncommon within the electric utility industry. Limited-income discounts are another specific cost shift that have been purposefully established.

Q. HAVE OTHER POTENTIAL COST SHIFTS BEEN DISCUSSED IN OTHER DOCKETS RELATED TO NET METERING?

A. Yes. Some have suggested there is a subsidy related to coal or nuclear generation resulting from historical tax treatment or, for example, the Price-Anderson Act that benefitted the nuclear generation industry. However, any cost advantage APS's generation fleet enjoys inures to the benefit of all APS customers; there is no cost shift from one customer group to another. In addition, some have alleged:

1. Customers who engage in energy efficiency are no different than customers who adopt solar generation;

2. Subsidies exist when a small apartment pays less than the average monthly customer cost for service;

3. Seasonal customers do not pay their fair share of grid support costs;

4. Customers with gas appliances in their homes do not pay their fair share of costs; and,

5. Empty nesters, customers who travel, or homes with no one at home during the day all contribute less to the residential cost of service than they should.

Q. IS THERE ANY FACTUAL BASIS TO THESE ASSERTIONS?

A. No. These assertions are unsupported by the facts. Most of the assertions merely reflect the normal variations in energy usage that occur within a rate sub-class, where the variations are not significant enough to merit separate sub-class analysis. For example, the empty nesters, customers who travel, and homes with no one home during the day would fall into this group. Typical residential rooftop solar adoption stands in deep contrast. The typical solar customer will reduce their energy purchases by 70% or more, but will only reduce their kW demand during peak periods by 19% — meaning they will have a monthly energy consumption from APS equal to a small apartment, but with an infrastructure service requirement of a medium to large house.

Q. HOW IS ENERGY EFFICIENCY DIFFERENT THAN ROOFTOP SOLAR?

The customer who engages in multiple energy-efficiency programs retains a load shape that is very similar to the average APS residential customer. The solar customer does not. The rooftop solar customers' energy profile is not the same as a customer who aggressively pursues energy efficiency. While energy-efficiency measures under energy-only rate designs can shift costs too, the cost shift is significantly different from solar.

Energy efficiency typically reduces energy consumption by 5% to 10%, compared with a 70% reduction with rooftop solar. Under an energy-based rate, where the amount of energy consumed determines the amount contributed to grid costs, the difference is dramatic. In addition, energy-efficiency measures do not require APS to provide backup generation. If an efficient air conditioner does not turn on, the customer's load goes away — the air conditioner is not working. If a solar system suddenly stops producing energy, however, the customer's load must just as suddenly be served by utility generation.

Finally, virtually everyone can participate in energy efficiency, not just the owners of single-family residences with particular roof characteristics. Although energy efficiency shifts costs to other customers, those other customers can also participate in energy efficiency, mitigating any resulting inequity.

Q. DOES APS HAVE ANY INFORMATION ON THE COST TO SERVE SMALL APARTMENT CUSTOMERS?

A. Yes. While APS does not create a separate sub-class for apartments, APS has conducted a review of whether customers living in apartments are paying an appropriate share of the cost to serve. Based on this analysis, customers who live in apartments are paying about 88% of the cost to serve. This results from a lower capacity requirement in addition to the lower energy use.

For example, a typical residential rooftop solar customer has a demand above 7 kW during peak periods. By contrast, a typical apartment customer uses the same energy as that 7 kW solar customer, but only has a peak demand of approximately 4 kW.

Q. HAS APS REVIEWED THE COST TO SERVE SEASONAL CUSTOMERS?

A. Yes. For APS, seasonal customers are largely winter visitors that are residents in Arizona during the milder winter season and reside elsewhere during the summer months. Because winter visitors are not in Arizona in the summer, the time of year that drives APS's system costs, winter visitors have a relatively low bill, but still pay over 100% of the cost to serve, in contrast to the typical residential customer that pays 87% of the cost to serve.

Q. DOES APS HAVE ANY INFORMATION ON THE COST TO SERVE CUSTOMERS THAT ALSO HAVE NATURAL GAS APPLIANCES?

A. Yes. APS has a sample of customers that have gas appliances and performed an analysis of the cost to serve these customers. This customer group pays 82% of the cost to serve. While this is a lower percentage of the cost to serve than the typical APS residential customer who pays 87%, it is still higher than even the residential solar customers on APS's existing residential demand rates that pay 72%. See Figures 4 and 5 for a comparison of typical solar and non-solar customer's daily load shapes for a summer and winter day, contrasted with the load shapes for customers that 1) adopt energy efficiency; 2) live in an apartment; 3) a winter visitor; and 4) live in a dual fuel home.

Figure 4.

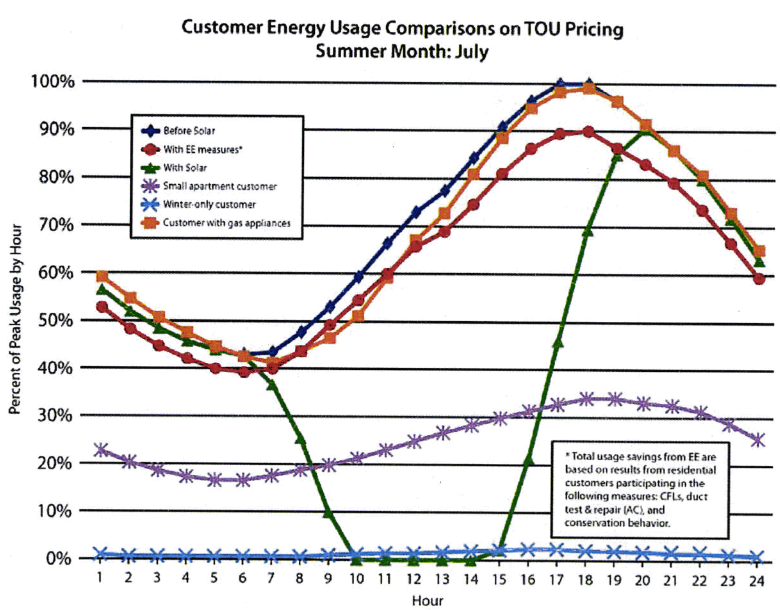
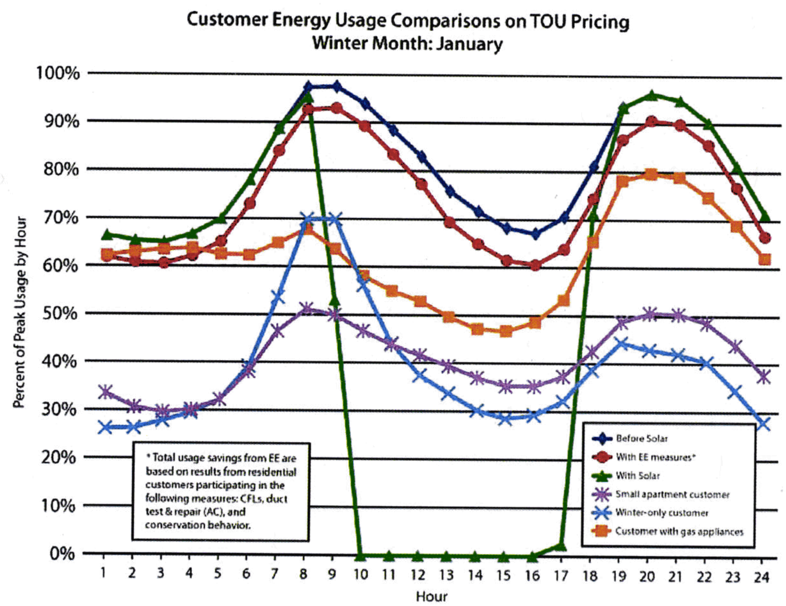


Figure 5.



Q. ARE THERE RESIDENTIAL RATE DESIGN ALTERNATIVES THAT COULD ADDRESS THE FACT THAT SOLAR CUSTOMERS ARE PAYING A MUCH LOWER PORTION OF THE COST TO PROVIDE SERVICE THAN NON-SOLAR RESIDENTIAL CUSTOMERS?

A. Yes. Rate designs that are better aligned with cost drivers will do a better job of recovering the cost of providing electric service from the customers driving the cost. For example, a residential demand rate would provide better price information to the customer to manage demand in addition to their energy consumption. A demand rate that focuses on the on-peak time period further enhances this price information.

A demand-rate approach sends price information that will assist a customer in determining system orientation that is superior to a kWh price alone. For example, if the customer orients their system to the west, the system will produce later in the day, helping to offset the customer's load later into the on-peak period. Orienting the system to the south will maximize energy production, but most of the production will occur at mid-day. A demand rate structure would provide price information that properly values both capacity and energy. Today's current rate design does not.[9]

V. RESPONSE TO CHAIRMAN LITTLE'S LETTER

Q. CHAIRMAN LITTLE REQUESTED PARTIES' INPUT ON THE APPROPRIATE METHODOLOGY TO USE IN FUTURE RATE CASE PROCEEDINGS. GIVEN THIS CONTRAST BETWEEN A COST OF SERVICE STUDY AND A VALUE OF SOLAR STUDY, PLEASE PROVIDE APS'S PERSPECTIVE ON THIS.

A. APS firmly believes the COSS should be used in the rate-setting process and a value of solar analysis is appropriate to consider in a resource planning context. The two analyses are fundamentally different for the reasons stated above.

APS further believes its cost allocation methods in the COSS in this docket, where solar customers have been modeled as a separate customer rate class, should be the method adopted by the Commission with respect to future rate-case proceedings. This method provides definitive results relying on actual data, and removes the current ambiguity regarding the degree to which customers with solar contribute to the cost to provide them electrical service.

I note, however, that in addition to resource planning, a value of solar study can still inform policies regarding distributed solar. For instance, compensation to a solar customer for net energy exported to the grid is distinct from the design of that customer's rate as established through a COSS. The cost of service should determine the manner in which a customer contributes to the grid's fixed, variable, and demand-related costs. But the Commission may determine that it is appropriate to establish a value for solar, and that non-solar customers should pay solar customers that value for solar

[9] See Chairman Little's Question 5.

energy supplied to the grid from rooftop solar systems. And it is within the Commission's purview to decide that non-solar customers should pay more than cost for this solar energy (in other words, subsidize solar). APS witness Albert discusses this issue in more detail, and provides a range of methodologies that the Commission could use to develop a value of solar.

Q. PLEASE EXPLAIN FURTHER WHY RATES SHOULD NOT BE SET BASED ON POTENTIAL FUTURE BENEFITS OR "VALUE OF SOLAR"?

A. Rates have been and are based on cost, not on potential future benefits. A COSS, using actual, verifiable data, is used to set rates. Using a COSS to set rates protects customers by ensuring that customers pay only for actual costs that they cause. In a COSS, the tangible benefits in the study period of rooftop solar are included.

A value of solar analysis does not look at actual costs, and is fundamentally different than a COSS. It involves predicting the marginal benefits of solar over the next 20 or 25 years, and often includes both operational and societal benefits These analyses then attempt to monetize the hypothetical values to arrive at a "value of solar," and then net those future unknown benefits against actual costs established in a COSS. I note that the adjusted cost of grid-scale solar method to determine the value of solar, as discussed by APS witness Albert, does not share these same drawbacks.

The structure of a value of solar analysis is similar to the long-run marginal cost analyses traditionally used by resource planners in deciding the amount and type of resource to procure in light of predicted resource needs. There are important differences, however, including:

- Resource planners focus on estimating impacts to future operating and capital costs of the utility, not societal benefits; and,
- Resource plans are continually updated so that by the time a decision must be made about procuring resources, the relevant time period for the estimates is only a few years in the future and the best available information is available.

Long-run marginal cost studies are not COSS and are not used to establish rates — not in Arizona, nor in any other retail jurisdiction of which I am aware. A small handful of states, such as Nevada, use marginal cost studies to determine allocation factors, which are then applied to embedded costs in the rate making process. States with future test periods project costs into the future, but only as far as the future test period to set rates, and have carefully crafted procedures to ensure that the resulting rates reflect actual costs.

A COSS determines how to recover the cost of providing service today based on costs actually incurred. Although rate making and resource planning are related activities, they are two separate analyses used specifically for different purposes. A valid Value of Solar study is a resource planning exercise and should not be conflated with a cost of service analysis used for ratemaking.

As stated above, a COSS includes the tangible benefits. Indeed, netting the hypothetical benefits of solar against known and established costs and benefits can create significant problems for customers. The result of this netting is that customers without solar pay more — customers with solar contribute less to fixed costs than they should, as established by a COSS, under the assumption that the hypothetical benefits will equitably resolve cost responsibility at some point in the future. The problem arises because these unpaid fixed costs are shifted to customers without rooftop solar, who pay higher rates as a result. But what if those customers without rooftop solar move before the projected cost savings occur? Or what happens if the hypothetical benefits do not materialize? In those circumstances, those customers without rooftop solar will have been paying higher rates in anticipation of future cost savings that they never benefit from, or never even occur in the first place.

In Nevada, the PUCN recently opined on this very topic and rejected the rooftop solar industry's argument that speculative value should offset rates based on a historical test year:

> Parties' proposals to weigh speculative, unquantified future benefits/values of NEM to offset current, known costs are rejected. These proposals conflate two separate and distinct regulatory processes: (1) the rate setting process, and (2) the resource planning process. When determining the rates that ratepayers pay for electric service, the revenue requirement is allocated to ratepayer classes based on the actual, measureable costs of providing service. Future benefits/values of NEM should be evaluated in the resource planning process. Rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any ratepayer class. External societal costs and benefits are not included in the cost recovery that NV Energy's rates provide for any class. No exception should be made for NEM ratepayers.[10]

The Public Service Commission of Utah arrived at the same conclusion, rejecting the rooftop solar industry's proposal to:

> . . . adopt a framework that treats customer-owned and controlled equipment as a system resource, requiring speculation about the cost impacts of these customer owned and controlled assets decades into the future and assigning a present value to impacts that, even if they come to fruition, are not projected to materialize for many years.[11]

[10] Modified Final Order at Paragraph 85.

[11] Order (November 10, 2015) in Public Service Commission of Utah Docket No. 14-035-114 at p. 14.

Q. ARE THERE ANY OTHER ITEMS RAISED BY CHAIRMAN LITTLE'S LETTER THAT YOU WANT TO ADDRESS?

A. Yes. Chairman Little's Question 1 asks whether the value and cost of solar was considered in the development of the current net metering tariffs. In adopting the revised 2005 federal PURPA standards, the Commission did identify potential benefits that DG might provide.[12] The Commission also references concerned expressed by APS and other utilities that "customers taking service under net metering rates do not pay the full cost of the transmission and distribution system."[13] The Commission decision, however, did not resolve either the benefits or costs of net metering.

A year later, the Commission created the net metering rules in Decision No. 70567. Similar to the 2007 decision adopting the 2005 PURPA standards, the Commission decision adopting the net metering rules did not resolve the issue of benefits and costs in relation to net metering. In fact, Decision No. 70567 does not appear to address benefits and costs at all.[14]

VI. <u>CONCLUSION</u>

Q. WOULD YOU STATE YOUR GENERAL CONCLUSIONS AS TO COST OF SERVICE MATTERS IN THIS PROCEEDING?

A. The 2014 test year COSS demonstrates that it is appropriate to consider NEM customers as a unique customer sub-class, given their unique load characteristics and their class size. With NEM customers segmented into unique energy- and demand-rate sub-classes within the residential class of service, the COSS reveals that NEM customers on an energy-based rate only pay about 36% of the cost to serve and NEM customers on a

---

[12] Decision No. 69877 at paragraphs 7-8 (August 28, 2007).
[13] Decision No. 69877 at paragraph 11.
[14] Decision No. 70567 (October 28, 2008).

demand rate only pay approximately 72% of the cost to serve. Non-solar residential customers pay between 86% and 91% of the cost to serve. Further, the COSS effectively illustrates that the base rate cost shift from residential NEM customers to non-solar residential customers is real and significant, equal to $67 per customer per month on an energy rate and $29 on a demand rate. This affirms the Commission's finding that the cost shift resulting from NEM under current APS residential rate design exists.

Because rates are based on historical test year data, the Commission should adopt the Company's COSS methodology as set forth in this docket. Further, the Commission should find and conclude as a policy matter that Value of Solar methodologies will not be used in setting rates. Finally, it would be appropriate for the Commission to treat residential rooftop solar customers as a unique sub-class in cost of service studies and in the design of residential rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Attachment LRS-1DR

Statement of Qualifications

Leland R. Snook

Leland R. Snook is Arizona Public Service Company's Director, Rates and Rate Strategy. Mr. Snook's areas of expertise include development and analysis of electric utility revenue requirements, modeling of cost of service, rate schedule design, embedded and marginal cost analysis and formulation of utility service policies. Mr. Snook has previously testified before the Arizona Corporation Commission on customer contracts, cost recovery mechanisms, fair value of utility property, rate schedules and pricing. Mr. Snook holds a Bachelor of Science Degree in Electrical Engineering from Texas Tech University and is a registered professional electrical engineer in the state of Arizona.

Mr. Snook has held his current position at Arizona Public Service Company for approximately seven years. Prior to assuming that position, he served as the Director of Federal Regulation for APS. Before joining APS, Mr. Snook had a 22-year career with Tucson Electric Power Company, where he served in various professional and leadership roles.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *Present Rates*
Rates of Return by Customer Classification
Test Year Ending December 31, 2014
($000)

					Total ACC Jurisdiction				
		Total Company	Total ACC Jurisdiction	All Other	Residential	General Service	Water Pumping	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	2,896,934	2,828,140	68,794	1,437,422	1,332,635	29,641	19,973	8,469
1.b.	Other Revenues	592,011	565,177	26,834	311,955	242,388	7,668	2,475	691
2.	Expenses	2,669,476	2,702,420 (a)	(32,944)	1,506,611 (a)	1,142,678 (a)	31,168 (a)	16,621 (a)	5,342 (a)
3.	Operating Income Before Income Taxes	819,469	690,897	128,572	242,766	432,345	6141	5,827	3,818
4.	Income Taxes	249,269	210,201	39,068	56,372	149,039	1,960	1,618	1,212
5.	Net Operating Income	570,200	480,696	89,504	186,394	283,306	4,181	4,209	2,606
6.	Rate Base	7,378,528	6,216,598 (b)	1,161,930	3,979,550 (b)	2,093,716 (b)	45,844 (b)	68,320 (b)	29,169 (b)
7.	Rate of Return	7.73%	7.73%	7.70%	4.68%	13.53%	9.12%	6.15%	8.93%

Supporting Schedules:
(a) Schedule 3
(b) Schedule 2

Recap Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Allocation to Classes of Service
Total Rate Base
Test Year Ending December 31, 2014
($000)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(a)	(a)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	1,771,780	0	0	212,713	236,772	128,701	818,738	319,305	3,488,009	63.68%	47,999	50.70%
2.	General Service	1,109,199	0	0	130,125	144,842	0	415,181	118,813	1,918,160	35.02%	44,804	47.33%
3.	Water Pumping	31,708	0	0	3,644	4,057	0	0	1,187	40,596	0.74%	1,256	1.33%
4.	Street Lighting	14,358	0	0	1,670	1,859	615	5,999	1,525	26,027	0.48%	523	0.55%
5.	Dusk to Dawn	2,393	0	0	268	299	99	963	245	4,267	0.08%	84	0.09%
6.	Total	2,929,438 (a)	0	0	348,421 (a)	387,829 (a)	129,414 (a)	1,240,882 (a)	441,075 (a)	5,477,059	100.00%	94,666	100.00%

Line No.	Class of Service	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(a)	(a)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
7.	Residential	(101,117)	45,335	105,238	186,778	78,093	0	0	6,894	15,504	336,723	77.55%
8.	General Service	(72,604)	6,250	42,614	42,534	9,521	0	0	841	1,890	31,047	7.15%
9.	Water Pumping	(893)	586	0	1,362	110	0	0	10	22	1,197	0.28%
10.	Street Lighting	(674)	0	0	0	76	0	41,180	7	15	40,605	9.35%
11.	Dusk to Dawn	(212)	0	0	0	622	24,042	0	55	123	24,630	5.67%
12.	Total	(175,500) (a)	52,171 (a)	147,852 (a)	230,674 (a)	88,422 (a)	24,042 (a)	41,180 (a)	7,806 (a)	17,555 (a)	434,201	100.00%

Line No.	Class of Service	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)	TOTAL ACC JURIS. %
		(a)	(D)	(E)	(F)
13.	Residential	106,817	50.70%	3,979,550	64.01%
14.	General Service	99,708	47.33%	2,093,716	33.68%
15.	Water Pumping	2,795	1.33%	45,844	0.74%
16.	Street Lighting	1,165	0.55%	68,320	1.10%
17.	Dusk to Dawn	188	0.09%	29,169	0.47%
18.		210,672 (a)	100.00%	6,216,598	100.00%

Supporting Schedules
(a Schedule 4

Recap Schedules:
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
Expense Allocation to Classes of Service
Operating Expenses Excluding Income Taxes
Test Year Ending December 31, 2014
($000)

Line No.	Class of Service	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %	Total Energy	Total Energy %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1.	Residential	360,390	0	154,275	(11,756)	35,312	18,595	72,604	25,487	654,908	60.24%	624,968	48.64%
2.	General Service	241,798	0	90,363	14,155	21,602	0	36,818	9,507	414,243	38.10%	636,159	49.51%
3.	Water Pumping	6,952	0	3,825	396	605	0	0	91	11,870	1.09%	16,488	1.28%
4.	Street Lighting	2,926	0	1,052	182	277	89	532	122	5,180	0.48%	6,267	0.49%
5.	Dusk to Dawn	581	0	168	29	45	14	85	20	942	0.09%	1,087	0.08%
6.	Total	612,647 (a)	0 (a)	249,684 (a)	3,007 (a)	57,841 (a)	18,698 (a)	110,039 (a)	35,227 (a)	1,087,143	100.00%	1,284,970	100.00%

Line No.	Class of Service	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
7.	Residential	6,575	9,379	51,616	75,400	0	0	26,437	14,566	183,974	74.79%
8.	General Service	907	3,798	11,754	9,193	0	0	24,934	1,776	52,361	21.29%
9.	Water Pumping	85	0	376	106	0	0	1,103	20	1,691	0.69%
10.	Street Lighting	0	0	0	74	0	4,384	236	14	4,707	1.91%
11.	Dusk to Dawn	0	0	0	600	2,453	0	70	116	3,239	1.32%
12.	Total	7,567 (a)	13,177 (a)	63,747 (a)	85,373 (a)	2,453 (a)	4,384 (a)	52,780 (a)	16,493 (a)	245,972	100.00%

Line No.	Class of Service	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (c)	TOTAL ACC JURIS. %
		(C)	(D)	(E)	(F)
13.	Residential	42,761	50.70%	1,506,611	55.75%
14.	General Service	39,915	47.33%	1,142,678	42.28%
15.	Water Pumping	1,119	1.33%	31,168	1.15%
16.	Street Lighting	466	0.55%	16,621	0.62%
17.	Dusk to Dawn	75	0.09%	5,342	0.20%
18.	Total	84,335 (a)	100.00%	2,702,420	100.00%

Supporting Schedules:
(a) Schedule 5

Recap Schedules:
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Rate Base by Function
Total Rate Base
Test Year Ending December 31, 2014
($000)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	2,929,438	0	0	0	0	0	0	0	2,929,438	53.49%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	0	0	0	0	0	0	0	0.00%
4.	Distribution Substation	0	0	0	348,421	0	0	0	0	348,421	6.36%
5.	Distribution OH Primary	0	0	0	0	387,829	0	0	0	387,829	7.08%
6.	Distribution OH Secondary	0	0	0	0	0	129,414	0	0	129,414	2.36%
7.	Distribution UG Lines	0	0	0	0	0	0	1,240,882	0	1,240,882	22.66%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	441,075	441,075	8.05%
9.	Total	2,929,438	0	0	348,421	387,829	129,414	1,240,882	441,075	5,477,059	100.00%

Line No.	Plant Classification	Cust. Advances & Deposits	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
10.	Cust. Advances & Deposit	(175,500)	0	0	0	0	0	0	0	0	(175,500)	-40.42%
11.	Distribution OH Services	0	52,171	0	0	0	0	0	0	0	52,171	12.02%
12.	Distribution UG Services	0	0	147,852	0	0	0	0	0	0	147,852	34.05%
13.	Distribution Meters	0	0	0	230,674	0	0	0	0	0	230,674	53.13%
14.	Customer Accounts	0	0	0	0	88,422	0	0	0	0	88,422	20.36%
15.	Dusk to Dawn	0	0	0	0	0	24,042	0	0	0	24,042	5.54%
16.	Street Lighting	0	0	0	0	0	0	41,180	0	0	41,180	9.48%
17.	Customer Service & Info	0	0	0	0	0	0	0	7,806	0	7,806	1.80%
18.	Sales	0	0	0	0	0	0	0	0	17,555	17,555	4.04%
19.	Total	(175,500)	52,171	147,852	230,674	88,422	24,042	41,180	7,806	17,555	434,201	100.00%

Line No.	Plant Classification	Total Energy	Total Energy %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(E)	(F)	(G)
20.	Production - Energy	94,666	100.00%			
21.	Regulatory Assets					
22.	System Benefits			210,672	100.00%	
23.	TOTAL ACC					6,216,598

Supporting Schedules:
N/A

Recap Schedules:
(a) Schedule 2

Attachment LRS-5DR
Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY
Distribution of Expenses by Function
Operating Expenses Excluding Income Taxes
Test Year Ending December 31, 2014
($000)

Line No.	Plant Classification	Production - Demand	Transmission Substation	Transmission Lines	Distribution Substation	Distribution OH Primary	Distribution OH Secondary	Distribution UG Lines	Distribution Line TXFs	Total Demand	Total Demand %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
1.	Production - Demand	612,647	0	0	0	0	0	0	0	612,647	56.35%
2.	Transmission Substation	0	0	0	0	0	0	0	0	0	0.00%
3.	Transmission Lines	0	0	249,684	0	0	0	0	0	249,684	22.97%
4.	Distribution Substation	0	0	0	3,007	0	0	0	0	3,007	0.28%
5.	Distribution OH Primary	0	0	0	0	57,841	0	0	0	57,841	5.32%
6.	Distribution OH Secondary	0	0	0	0	0	18,698	0	0	18,698	1.72%
7.	Distribution UG Lines	0	0	0	0	0	0	110,039	0	110,039	10.12%
8.	Distribution Line TXFs	0	0	0	0	0	0	0	35,227	35,227	3.24%
9.	Total	612,647	0	249,684	3,007	57,841	18,698	110,039	35,227	1,087,143	100.00%

Line No.	Plant Classification	Distribution OH Services	Distribution UG Services	Distribution Meters	Customer Accounts	Dusk to Dawn	Street Lighting	Customer Service & Info	Sales	Total Customer	Total Customer %
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
10.	Distribution OH Services	7,567	0	0	0	0	0	0	0	7,567	3.08%
11.	Distribution UG Services	0	13,177	0	0	0	0	0	0	13,177	5.36%
12.	Distribution Meters	0	0	63,747	0	0	0	0	0	63,747	25.92%
13.	Customer Accounts	0	0	0	85,373	0	0	0	0	85,373	34.71%
14.	Dusk to Dawn	0	0	0	0	2,453	0	0	0	2,453	1.00%
15.	Street Lighting	0	0	0	0	0	4,384	0	0	4,384	1.78%
16.	Customer Service & Info	0	0	0	0	0	0	52,780	0	52,780	21.46%
17.	Sales	0	0	0	0	0	0	0	16,493	16,493	6.71%
18.	Total	7,567	13,177	63,747	85,373	2,453	4,384	52,780	16,493	245,972	100.00%

Line No.	Plant Classification	Total Production - Energy	Total Energy %	Total System Benefits	Total System Benefits %	TOTAL ACC JURIS. (a)
		(A)	(B)	(E)	(F)	(G)
19.	Production - Energy	1,284,970	100.00%			
20.	Regulatory Assets					
21.	System Benefits			84,335	100.00%	
22.	TOTAL ACC					2,702,420

Supporting Schedules:
N/A

Recap Schedules:
(a) Schedule 3

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	E-38,221 (Water Pumping)	Street Lighting	Dusk to Dawn
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	100.00%	97.93%	2.07%	97.93%	59.23%	37.08%	1.06%	0.48%	0.08%
	Production Demand	100.00%	97.93%	2.07%	97.93%	59.23%	37.08%	1.06%	0.48%	0.08%
2. DEMPROD6	Specific Assignment	100	0	100	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Substation	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	100	0	100	0	0	0	0	0	0
	Transmission Lines	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	7,289,745	7,289,745	0	7,289,745	4,450,431	2,722,500	76,251	34,950	5,613
	Distribution Substation	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	7,105,017	7,105,017	0	7,105,017	4,337,653	2,653,510	74,319	34,064	5,471
	Distribution OH Primary Lines	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,946,854	6,946,854	0	6,946,854	6,908,554	0	0	33,000	5,300
	Distribution OH Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.44%	0.00%	0.00%	0.48%	0.08%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	7,030,698	7,030,698	0	7,030,698	4,337,653	2,653,510	0	34,064	5,471
	Distribution UG Primary Lines	99.97%	99.97%	0.00%	99.97%	61.66%	37.75%	0.00%	0.48%	0.08%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,946,854	6,946,854	0	6,946,854	6,908,554	0	0	33,000	5,300
	Distribution UG Secondary Lines	100.00%	100.00%	0.00%	100.00%	99.44%	0.00%	0.00%	0.48%	0.08%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,224,567	9,224,567	0	9,224,567	7,039,817	2,021,771	123,951	33,627	5,401
	Distribution OH Line Transformers	99.99%	99.99%	0.00%	99.99%	76.30%	21.93%	1.34%	0.36%	0.06%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	9,858,352	9,858,352	0	9,858,352	7,039,817	2,779,507	0	33,627	5,401
	Distribution UG Line Transformers	99.99%	99.99%	0.00%	99.99%	71.39%	28.21%	0.00%	0.34%	0.05%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	301,428	301,428	0	301,428	261,928	36,113	3,387	0	0
	Distribution OH Services	100.00%	100.00%	0.00%	100.00%	86.90%	11.98%	1.12%	0.00%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	1,099,867	1,099,867	0	1,099,867	782,860	317,007	0	0	0
	Distribution UG Services	100.00%	100.00%	0.00%	100.00%	71.16%	28.84%	0.00%	0.00%	0.00%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	7,105,017	7,105,017	0	7,105,017	4,337,653	2,653,510	74,319	34,064	5,471
	Distribution Rents	99.98%	99.98%	0.00%	99.98%	61.04%	37.33%	1.05%	0.48%	0.08%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	28,439,817	27,821,398	618,419	27,821,398	14,106,290	13,167,438	369,052	153,848	24,770
	Production - Energy	99.98%	97.81%	2.17%	97.81%	49.60%	46.28%	1.30%	0.54%	0.09%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Total Company	Total ACC Jurisdiction	All Other	Total Retail	Residential	General Service	E-38,221 (Water Pumping)	Street Lighting	Dusk to Dawn
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	100.00%	97.83%	2.17%	97.83%	49.85%	46.13%	1.28%	0.49%	0.08%
	Production - Energy (Fuel and Purchased Power)	100.00%	97.83%	2.17%	97.83%	49.85%	46.13%	1.28%	0.49%	0.08%
17. CUST370	Weighted Costs for Distribution Meters ($)	1,299,475	1,290,334	9,140	1,290,334	1,044,789	237,926	7,620	0	0
	Distribution Meters	100.00%	99.30%	0.70%	99.30%	80.40%	18.31%	0.59%	0.00%	0.00%
18. CUST371	Dusk to Dawn Customer Class Specific	1	1	0	1	0	0	0	0	1
	Dusk to Dawn	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	100.00%
19. CUST373	Street Lighting Customer Class Specific	1	1	0	1	0	0	0	1	0
	Street Lighting	100.00%	100.00%	0.00%	100.00%	0.00%	0.00%	0.00%	100.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	1,184,446	1,182,977	1,469	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Customer Accounts	100.00%	99.88%	0.12%	99.88%	88.21%	10.76%	0.12%	0.09%	0.70%
21. CUST910	Number of Customer Accounts	1,182,977	1,182,977	0	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Customer Service and Information	100.00%	100.00%	0.00%	100.00%	88.32%	10.77%	0.12%	0.09%	0.70%
22. CUST916	Number of Customer Accounts	1,184,446	1,182,977	1,469	1,182,977	1,044,789	127,379	1,467	1,023	8,319
	Sales Expense	100.00%	99.88%	0.12%	99.88%	88.21%	10.75%	0.12%	0.09%	0.70%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	28,439,817	27,821,398	618,419	27,821,398	14,106,290	13,167,438	369,052	153,848	24,770
	System Benefits - Energy Related	100.00%	97.83%	2.17%	97.83%	49.60%	46.30%	1.30%	0.54%	0.09%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	General Service	(Church Rate) General Service	E-32 TOU (0-100kW)	E-32 TOU (101-400kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	37.08%	0.30%	0.09%	0.18%	0.58%	0.51%	12.83%	9.14%	6.76%	2.24%	4.45%
	Production Demand	37.08%	0.30%	0.09%	0.18%	0.58%	0.51%	12.83%	9.14%	6.76%	2.24%	4.45%
2. DEMPROD6	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0	0	0	0	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	2,722,500	23,845	6,886	12,097	45,384	38,392	1,016,993	650,410	509,739	137,822	280,932
	Distribution Substation	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.99%	1.89%	3.85%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution OH Primary Lines	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.99%	1.89%	3.85%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0	0
	Distribution OH Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution UG Primary Lines	37.75%	0.33%	0.10%	0.17%	0.63%	0.53%	14.10%	9.02%	7.07%	1.91%	3.89%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	0	0	0	0	0	0	0	0	0	0	0
	Distribution UG Secondary Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,021,771	28,136	9,434	13,041	45,764	40,172	1,393,698	491,526	0	0	0
	Distribution OH Line Transformers	21.93%	0.31%	0.10%	0.14%	0.50%	0.44%	15.11%	5.33%	0.00%	0.00%	0.00%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	2,779,507	28,136	9,434	13,041	45,764	40,172	1,393,698	491,526	493,981	49,166	214,589
	Distribution UG Line Transformers	28.21%	0.29%	0.10%	0.13%	0.46%	0.41%	14.14%	4.99%	5.01%	0.50%	2.18%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	36,113	118	97	42	0	67	35,108	680	0	0	0
	Distribution OH Services	11.98%	0.04%	0.03%	0.01%	0.00%	0.02%	11.65%	0.23%	0.00%	0.00%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	317,007	885	725	388	873	616	262,281	22,565	21,815	2,616	4,243
	Distribution UG Services	28.84%	0.08%	0.07%	0.04%	0.08%	0.06%	23.85%	2.05%	1.98%	0.24%	0.39%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	2,653,510	23,241	6,711	11,791	44,234	37,419	991,221	633,928	496,822	134,330	273,813
	Distribution Rents	37.33%	0.33%	0.09%	0.17%	0.62%	0.53%	13.94%	8.92%	6.99%	1.89%	3.85%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	13,167,438	41,349	40,726	75,181	281,190	117,838	4,263,784	3,352,488	2,622,747	801,426	1,570,709
	Production - Energy	46.28%	0.15%	0.14%	0.26%	0.99%	0.41%	14.98%	11.79%	9.22%	2.82%	5.52%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	General Service	(Church Rate) General Service	E-32 TOU (0-100kW)	E-32 TOU (101-400kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0 - 100 kW)	E-32 (101 - 400 kW)	E-32 (401+ kW)	E-34	E-35
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	46.13%	0.15%	0.14%	0.26%	0.97%	0.41%	15.11%	11.78%	9.15%	2.78%	5.38%
	Production - Energy (Fuel and Purchased Power)	46.13%	0.15%	0.14%	0.26%	0.97%	0.41%	15.11%	11.78%	9.15%	2.78%	5.38%
17. CUST370	Weighted Costs for Distribution Meters ($)	237,926	2,600	1,172	404	780	755	193,237	25,147	10,581	1,529	1,720
	Distribution Meters	18.31%	0.20%	0.09%	0.03%	0.06%	0.06%	14.87%	1.94%	0.81%	0.12%	0.13%
18. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Customer Accounts	10.76%	0.03%	0.03%	0.01%	0.00%	0.01%	10.25%	0.36%	0.07%	0.00%	0.00%
21. CUST910	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Customer Service and Information	10.77%	0.03%	0.03%	0.01%	0.00%	0.01%	10.26%	0.36%	0.07%	0.00%	0.00%
22. CUST916	Number of Customer Accounts	127,379	409	336	73	57	116	121,274	4,252	795	30	37
	Sales Expense	10.75%	0.03%	0.03%	0.01%	0.00%	0.01%	10.24%	0.36%	0.07%	0.00%	0.00%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	13,167,438	41,349	40,726	75,181	281,190	117,838	4,263,784	3,352,488	2,622,747	801,426	1,570,709
	System Benefits - Energy Related	46.30%	0.15%	0.14%	0.26%	0.99%	0.41%	14.99%	11.79%	9.22%	2.82%	5.52%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Residential	Residential - Solar Demand Rates	Residential - Solar Energy Rates	E-12	ET-1 & ET-2	ECT-1 & ECT-2	
1. DEMPROD1	Average & Excess @ Generation - Retail [4CP Juris.]	59.23%	0.11%	1.72%	15.65%	30.11%	11.64%	0.00
	Production Demand	59.23%	0.11%	1.72%	15.65%	30.11%	11.64%	0.00%
2. DEMPROD6	Specific Assignment	0	0	0	0	0	0	0
	Ancillary Service - Scheduling & Dispatch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3. DEMTRAN1	Specific Assignment	0	0	0	0	0	0	0
	Transmission Substation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4. DEMTRAN3	Specific Assignment	0	0	0	0	0	0	0
	Transmission Lines	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5. DEMDIST1	NCP Demand @ Substation Level w/losses (KW)	4,450,431	8,015	130,073	1,171,727	2,271,340	869,276	0
	Distribution Substation	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
6. DEMDIST2	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution OH Primary Lines	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
7. DEMDIST3	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,908,554	11,693	198,649	2,137,411	3,344,350	1,216,451	0
	Distribution OH Secondary Lines	99.44%	0.17%	2.86%	30.77%	48.13%	17.51%	0.00%
8. DEMDIST4	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution UG Primary Lines	61.66%	0.11%	1.80%	16.23%	31.48%	12.04%	0.00%
9. DEMDIST5	Individual Maximum Demand @ Secondary Line Level w/losses (KW)	6,908,554	11,693	198,649	2,137,411	3,344,350	1,216,451	0
	Distribution UG Secondary Lines	99.44%	0.17%	2.86%	30.77%	48.13%	17.51%	0.00%
10. DEMDIST6	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,039,817	11,915	202,423	2,178,022	3,407,893	1,239,564	0
	Distribution OH Line Transformers	76.30%	0.13%	2.19%	23.61%	36.93%	13.44%	0.00%
11. DEMDIST7	Individual Maximum Demand @ Secondary TXF Level w/losses (KW)	7,039,817	11,915	202,423	2,178,022	3,407,893	1,239,564	0
	Distribution UG Line Transformers	71.39%	0.12%	2.05%	22.09%	34.56%	12.57%	0.00%
12. CUSTOH1	Weighted Customer Costs for Distribution Services ($)	261,928	295	6,788	117,421	107,657	29,767	0
	Distribution OH Services	86.90%	0.10%	2.25%	38.96%	35.71%	9.88%	0.00%
13. CUSTUG1	Weighted Customer Costs for Distribution Services ($)	782,860	881	20,290	350,951	321,770	88,969	0
	Distribution UG Services	71.16%	0.08%	1.84%	31.90%	29.25%	8.09%	0.00%
14. DEMDIST10	NCP Demand @ Primary Line Level w/losses (KW)	4,337,653	7,812	126,777	1,142,034	2,213,782	847,248	0
	Distribution Rents	61.04%	0.11%	1.78%	16.07%	31.16%	11.92%	0.00%
15. ENERGY1	Customer Class Energy @ Generation (MWH)	14,106,290	27,426	398,750	3,860,095	6,857,795	2,962,224	0
	Production - Energy	49.60%	0.10%	1.40%	13.57%	24.11%	10.42%	0.00%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDED DECEMBER 31, 2014

Factor	Definition and Application of Allocation Factor	Residential	Residential - Solar Demand Rates	Residential - Solar Energy Rates	E-12	ET-1 & ET-2	ECT-1 & ECT-2	
16. ENERGY2	Weighted Hourly Energy Allocator @ Generation	49.85%	0.10%	1.41%	13.68%	24.25%	10.41%	0.00
	Production - Energy (Fuel and Purchased Power)	49.85%	0.10%	1.41%	13.68%	24.25%	10.41%	0.00%
17. CUST370	Weighted Costs for Distribution Meters ($)	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Distribution Meters	80.40%	0.09%	2.08%	36.04%	33.05%	9.14%	0.00%
18. CUST371	Dusk to Dawn Customer Class Specific	0	0	0	0	0	0	0
	Dusk to Dawn	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19. CUST373	Street Lighting Customer Class Specific	0	0	0	0	0	0	0
	Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20. CUSTNUM	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Customer Accounts	88.21%	0.10%	2.29%	39.54%	36.26%	10.02%	0.00%
21. CUST910	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Customer Service and Information	88.32%	0.10%	2.29%	39.59%	36.30%	10.04%	0.00%
22. CUST916	Number of Customer Accounts	1,044,789	1,176	27,078	468,372	429,427	118,736	0
	Sales Expense	88.21%	0.10%	2.29%	39.54%	36.26%	10.02%	0.00%
23. ERGSYSBEN	Customer Class Energy @ Generation (MWH)	14,106,290	27,426	398,750	3,860,095	6,857,795	2,962,224	0
	System Benefits - Energy Related	49.60%	0.10%	1.40%	13.57%	24.11%	10.42%	0.00%

Supporting Schedules:
N/A

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	ELECTRIC TOTAL (1)	ACC JURISDICTION (2)	ALL OTHER (3)	TOTAL RETAIL (4)	RESIDENTIAL (5)	GENERAL SERVICE (6)	E-221 (Water Pumping) (7)	STREET LIGHTING (8)	DUSK TO DAWN (9)
1	**SUMMARY OF RESULTS**									
2										
3	**DEVELOPMENT OF RATE BASE**									
4	ELECTRIC PLANT IN SERVICE	$ 14,696,707,221	$ 12,461,310,312	$ 2,235,396,909	$ 12,461,310,312	$ 7,873,908,648	$ 4,310,123,653	$ 95,788,128	$ 129,497,556	$ 51,992,326
5	GENERAL & INTANGIBLE PLANT	1,399,767,310	1,293,230,475	106,536,835	1,293,230,475	852,085,017	417,906,299	11,173,933	8,027,437	4,037,789
6	LESS: RESERVE FOR DEPRECIATION	(6,173,357,275)	(5,390,237,335)	(783,119,940)	(5,390,237,335)	(3,400,040,425)	(1,880,485,209)	(45,796,324)	(46,224,142)	(17,691,235)
7	OTHER DEFERRED CREDITS	(1,225,088,587)	(1,169,199,077)	(55,889,510)	(1,169,199,077)	(707,151,484)	(441,199,733)	(12,223,376)	(6,625,086)	(1,999,398)
8	WORKING CASH	(101,350,672)	(84,517,428)	(16,833,244)	(84,517,428)	(54,258,104)	(28,376,526)	(614,571)	(906,554)	(361,674)
9	MATERIALS, SUPPLIES & PREPAYMENTS	409,194,079	367,468,477	41,725,602	367,468,477	213,464,249	146,393,612	3,737,240	2,908,959	964,417
10	ACCUM. DEFERRED TAXES	(2,639,765,552)	(2,206,834,700)	(432,930,852)	(2,206,834,700)	(1,413,363,736)	(743,357,519)	(15,874,443)	(24,246,078)	(9,992,924)
11	REGULATORY ASSETS	373,194,607	324,563,826	48,630,781	324,563,826	230,084,643	88,270,395	2,112,479	2,531,984	1,564,325
12	DECOMMISSIONING FUND	713,866,000	699,088,974	14,777,026	699,088,974	422,822,832	264,701,513	7,566,980	3,426,557	571,093
13	GAIN FROM DISP. OF PLANT	(4,887,000)	(4,785,839)	(101,161)	(4,785,839)	(2,894,570)	(1,812,100)	(51,802)	(23,458)	(3,910)
14	MISCELLANEOUS DEFERRED DEBITS	125,606,562	102,010,534	23,596,028	102,010,534	66,010,041	34,154,949	918,340	627,237	299,966
15	CUSTOMER ADVANCES	(123,052,363)	(103,193,820)	(19,858,543)	(103,193,820)	(63,518,034)	(39,346,022)	(153,279)	(175,744)	(741)
16	CUSTOMER DEPOSITS	(72,306,606)	(72,306,606)		(72,306,606)	(37,599,435)	(33,257,771)	(739,563)	(498,448)	(211,388)
17	**TOTAL RATE BASE**	**7,378,527,724**	**6,216,597,792**	**1,161,929,932**	**6,216,597,792**	**3,979,549,643**	**2,093,715,540**	**45,843,743**	**68,320,220**	**29,168,646**
18										
19	**DEVELOPMENT OF RETURN**									
20	REVENUES FROM RATES	2,896,933,742	2,828,139,997	68,793,745	2,828,139,997	1,437,421,622	1,332,634,743	29,640,752	19,973,390	8,469,490
21	OTHER ELECTRIC REVENUE	592,011,071	565,177,360	26,833,710	565,177,360	311,955,249	242,388,439	7,668,313	2,474,819	690,541
22	**TOTAL OPERATING REVENUES**	**3,488,944,813**	**3,393,317,357**	**95,627,455**	**3,393,317,357**	**1,749,376,871**	**1,575,023,182**	**37,309,065**	**22,448,209**	**9,160,031**
23										
24	**OPERATING EXPENSES**									
25	OPERATION & MAINTENANCE	1,876,691,588	2,012,076,433	(135,384,845)	2,012,076,433	1,061,535,946	911,914,839	25,764,871	10,304,703	2,556,074
26	ADMINISTRATIVE & GENERAL	218,678,783	200,092,070	18,586,713	200,092,070	132,501,024	63,974,302	1,697,758	1,270,138	648,849
27	DEPRECIATION & AMORT EXPENSE	437,911,200	384,549,577	53,361,623	384,549,577	243,678,093	132,717,114	3,113,558	3,573,852	1,466,959
28	AMORTIZATION ON GAIN	(4,233,612)	(4,146,332)	(87,280)	(4,146,332)	(2,540,326)	(1,538,461)	(44,068)	(20,114)	(3,363)
29	REGULATORY ASSETS	(31,155,535)	(31,155,535)		(31,155,535)	(18,843,483)	(11,796,663)	(337,229)	(152,708)	(25,451)
30	TAXES OTHER THAN INCOME	171,583,429	141,004,082	30,579,347	141,004,082	90,279,756	47,407,007	972,785	1,645,307	699,227
31	INCOME TAX	249,269,119	210,201,180	39,067,939	210,201,180	56,371,627	149,039,287	1,960,206	1,618,045	1,212,013
32	**TOTAL OPERATING EXPENSES**	**2,918,744,972**	**2,912,621,475**	**6,123,497**	**2,912,621,475**	**1,562,982,637**	**1,291,717,426**	**33,127,881**	**18,239,224**	**6,554,308**
33										
34	**OPERATING INCOME**	**$ 570,199,841**	**$ 480,695,882**	**$ 89,503,959**	**$ 480,695,882**	**$ 186,394,234**	**$ 283,305,756**	**$ 4,181,184**	**$ 4,208,985**	**$ 2,605,723**
35										
36	**RETURN**	**570,199,841**	**480,695,882**	**89,503,959**	**480,695,882**	**186,394,234**	**283,305,756**	**4,181,184**	**4,208,985**	**2,605,723**
37										
38	**RATE OF RETURN (PRESENT)**	**7.73%**	**7.73%**	**7.70%**	**7.73%**	**4.68%**	**13.53%**	**9.12%**	**6.16%**	**8.93%**
39										
40	**INDEX RATE OF RETURN (PRESENT)**	**1.00**	**1.00**	**1.00**	**1.00**	**0.61**	**1.75**	**1.18**	**0.80**	**1.16**
41										
42	**REVENUE REQUIREMENT @ 8.07%**	**2,938,457,585**	**2,862,651,331**	**75,806,254**	**2,862,651,331**	**1,659,025,311**	**1,144,603,209**	**28,848,821**	**22,118,576**	**8,055,413**
43										
44	**% OF TOTAL COST OF SERVICE (Line 20/Line42)**	**98.59%**	**98.79%**	**90.75%**	**98.79%**	**86.64%**	**116.43%**	**102.75%**	**90.30%**	**105.14%**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	TOTAL GENERAL SERVICE (10)	E-20 (Church Rate) (11)	E-32 TOU (0-100kW) (12)	E-32 TOU (101-400kW) (13)	E-32 TOU (401+ kW) (14)	School TOU (15)	E-30, E-32 (0 - 100 kW) (16)	E-32 (101 - 400 kW) (17)	E-32 (401+ kW) (18)	E-34 (19)	E-35 (20)
1	**SUMMARY OF RESULTS**											
2												
3	**DEVELOPMENT OF RATE BASE**											
4	ELECTRIC PLANT IN SERVICE	$ 4,310,123,653	$ 35,465,034	$ 11,035,090	$ 20,038,100	$ 67,819,345	$ 57,962,198	$1,632,916,352	$1,017,355,664	$ 767,997,651	$ 230,796,405	$ 468,737,814
5	GENERAL & INTANGIBLE PLANT	417,906,299	2,936,164	1,144,355	1,916,946	6,459,431	4,804,818	168,910,053	95,131,173	70,645,864	22,106,648	43,850,848
6	LESS: RESERVE FOR DEPRECIATION	(1,880,485,209)	(15,243,058)	(4,781,134)	(8,797,111)	(29,315,512)	(25,066,230)	(704,629,757)	(446,230,399)	(334,126,582)	(103,625,655)	(208,669,771)
7	OTHER DEFERRED CREDITS	(441,199,733)	(2,924,543)	(1,180,540)	(2,195,358)	(7,478,100)	(5,286,334)	(157,947,882)	(107,137,744)	(80,521,359)	(25,673,854)	(50,854,020)
8	WORKING CASH	(28,376,526)	(261,715)	(69,000)	(127,496)	(418,359)	(410,406)	(10,840,254)	(6,664,970)	(4,988,377)	(1,510,464)	(3,085,485)
9	MATERIALS, SUPPLIES & PREPAYMENTS	146,393,612	828,991	413,746	757,489	2,705,215	1,632,284	51,519,122	35,882,297	27,549,623	8,396,144	16,708,701
10	ACCUM. DEFERRED TAXES	(743,357,519)	(6,479,695)	(1,869,274)	(3,378,740)	(11,323,857)	(10,315,205)	(286,044,669)	(173,989,362)	(131,024,802)	(39,104,849)	(79,827,065)
11	REGULATORY ASSETS	88,270,395	718,282	242,579	355,508	1,168,922	1,023,396	40,805,765	18,405,997	13,447,478	4,023,705	8,078,763
12	DECOMMISSIONING FUND	264,701,513	2,141,598	642,479	1,284,959	4,140,423	3,640,717	91,589,008	65,247,352	48,257,342	15,990,598	31,767,037
13	GAIN FROM DISP. OF PLANT	(1,812,100)	(14,661)	(4,398)	(8,797)	(28,345)	(24,924)	(627,002)	(446,672)	(330,361)	(109,469)	(217,472)
14	MISCELLANEOUS DEFERRED DEBITS	34,154,949	226,004	94,755	160,828	549,508	383,869	13,498,701	7,877,516	5,886,741	1,837,463	3,639,566
15	CUSTOMER ADVANCES	(39,346,022)	(125,459)	(123,621)	(193,785)	(650,007)	(329,953)	(14,814,576)	(10,105,587)	(7,207,275)	(1,833,122)	(3,962,637)
16	CUSTOMER DEPOSITS	(33,257,771)	(104,611)	(104,702)	(163,820)	(549,685)	(277,326)	(12,531,157)	(8,544,916)	(6,092,303)	(1,545,426)	(3,343,825)
17	**TOTAL RATE BASE**	**2,093,715,540**	**17,162,329**	**5,440,336**	**9,648,724**	**33,078,978**	**27,736,904**	**811,803,703**	**486,780,348**	**369,493,640**	**109,748,124**	**222,822,454**
18												
19	**DEVELOPMENT OF RETURN**											
20	REVENUES FROM RATES	1,332,634,743	4,192,158	4,194,856	6,564,382	22,028,749	11,114,344	502,045,850	342,410,751	244,146,500	61,931,557	134,005,594
21	OTHER ELECTRIC REVENUE	242,388,439	1,069,414	809,770	1,189,439	3,705,644	2,360,388	99,550,621	61,544,569	39,015,468	11,288,437	21,854,687
22	**TOTAL OPERATING REVENUES**	**1,575,023,182**	**5,261,573**	**5,004,627**	**7,753,821**	**25,734,393**	**13,474,732**	**601,596,471**	**403,955,320**	**283,161,968**	**73,219,995**	**155,860,281**
23												
24	**OPERATING EXPENSES**											
25	OPERATION & MAINTENANCE	911,914,839	3,698,238	2,605,547	4,504,544	16,247,189	8,473,906	309,443,816	219,299,899	179,515,623	53,540,511	114,585,565
26	ADMINISTRATIVE & GENERAL	63,974,302	455,510	174,937	291,243	979,511	738,313	26,057,883	14,496,761	10,755,428	3,357,936	6,666,779
27	DEPRECIATION & AMORT EXPENSE	132,717,114	1,032,881	347,037	621,459	2,109,619	1,709,706	50,597,078	31,221,507	23,519,520	7,144,151	14,414,157
28	AMORTIZATION ON GAIN	(1,538,461)	(13,227)	(3,629)	(7,334)	(23,165)	(21,917)	(535,817)	(377,944)	(277,817)	(92,867)	(184,746)
29	REGULATORY ASSETS	(11,796,663)	(95,442)	(28,633)	(57,265)	(184,522)	(162,252)	(4,081,747)	(2,907,808)	(2,150,632)	(712,636)	(1,415,727)
30	TAXES OTHER THAN INCOME	47,407,007	398,742	122,153	216,576	739,177	640,296	18,412,432	11,044,555	8,370,821	2,449,924	5,012,332
31	INCOME TAX	149,039,287	(251,503)	647,410	762,148	1,976,862	551,479	71,138,839	46,666,637	21,258,270	1,883,020	4,406,124
32	**TOTAL OPERATING EXPENSES**	**1,291,717,426**	**5,225,200**	**3,864,822**	**6,331,370**	**21,844,672**	**11,929,532**	**471,032,485**	**319,443,608**	**240,991,214**	**67,570,038**	**143,484,485**
33												
34	**OPERATING INCOME**	**$ 283,305,756**	**$ 36,373**	**$ 1,139,804**	**$ 1,422,451**	**$ 3,889,721**	**$ 1,545,201**	**$ 130,563,986**	**$ 84,511,712**	**$ 42,170,755**	**$ 5,649,956**	**$ 12,375,796**
35												
36	**RETURN**	**283,305,756**	**36,373**	**1,139,804**	**1,422,451**	**3,889,721**	**1,545,201**	**130,563,986**	**84,511,712**	**42,170,755**	**5,649,956**	**12,375,796**
37												
38	**RATE OF RETURN (PRESENT)**	**13.53%**	**0.21%**	**20.95%**	**14.74%**	**11.76%**	**5.57%**	**16.08%**	**17.36%**	**11.41%**	**5.15%**	**5.55%**
39												
40	**INDEX RATE OF RETURN (PRESENT)**	**1.75**	**0.03**	**2.71**	**1.91**	**1.52**	**0.72**	**2.08**	**2.25**	**1.48**	**0.67**	**0.72**
41												
42	**REVENUE REQUIREMENT @ 8.07%**	**1,144,603,209**	**6,409,942**	**3,042,469**	**5,505,683**	**20,022,118**	**12,254,255**	**395,071,562**	**268,034,299**	**223,833,308**	**67,204,977**	**143,224,596**
43												
44	**% OF TOTAL COST OF SERVICE (Line 20/Line42)**	**116.43%**	**65.40%**	**137.88%**	**119.23%**	**110.02%**	**90.70%**	**127.08%**	**127.75%**	**109.08%**	**92.15%**	**93.56%**

ARIZONA PUBLIC SERVICE COMPANY
ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31,2014
($)

Line #	2014 Cost of Service	TOTAL RESIDENTIAL (21)	RESIDENTIAL SOLAR (ENERGY) (22)	RESIDENTIAL SOLAR (DEMAND) (23)	RESIDENTIAL E-12 (24)	RESIDENTIAL ET-1 & ET-2 (25)	RESIDENTIAL ECT-1 & ECT-2 (26)
1	**SUMMARY OF RESULTS**						
2							
3	**DEVELOPMENT OF RATE BASE**						
4	ELECTRIC PLANT IN SERVICE	$ 7,873,908,648	$ 227,066,300	$ 13,974,152	$ 2,220,780,957	$ 3,929,347,969	$1,482,739,270
5	GENERAL & INTANGIBLE PLANT	852,085,017	23,801,280	1,377,171	278,800,684	403,251,817	144,854,065
6	LESS: RESERVE FOR DEPRECIATION	(3,400,040,425)	(97,754,814)	(6,010,997)	(968,817,303)	(1,690,971,271)	(636,486,039)
7	OTHER DEFERRED CREDITS	(707,151,484)	(20,168,625)	(1,260,897)	(204,037,048)	(348,020,690)	(133,664,223)
8	WORKING CASH	(54,258,104)	(1,573,588)	(96,681)	(15,011,121)	(27,334,068)	(10,242,645)
9	MATERIALS, SUPPLIES & PREPAYMENTS	213,464,249	6,099,954	390,204	60,090,414	105,222,632	41,661,045
10	ACCUM. DEFERRED TAXES	(1,413,363,736)	(40,813,063)	(2,496,130)	(398,947,345)	(706,454,669)	(264,652,528)
11	REGULATORY ASSETS	230,084,643	6,359,919	346,704	80,577,581	106,555,014	36,245,426
12	DECOMMISSIONING FUND	422,822,832	12,278,495	785,253	111,720,029	214,945,053	83,094,002
13	GAIN FROM DISP. OF PLANT	(2,894,570)	(84,056)	(5,376)	(764,816)	(1,471,476)	(568,847)
14	MISCELLANEOUS DEFERRED DEBITS	66,010,041	1,845,547	108,054	21,367,143	31,301,992	11,387,304
15	CUSTOMER ADVANCES	(63,518,034)	(636,180)	(84,322)	(19,174,546)	(31,437,442)	(12,185,543)
16	CUSTOMER DEPOSITS	(37,599,435)	(370,358)	(49,741)	(11,362,681)	(18,604,967)	(7,211,688)
17	**TOTAL RATE BASE**	**3,979,549,643**	**116,050,811**	**6,977,393**	**1,155,221,949**	**1,966,329,893**	**734,969,598**
18							
19	**DEVELOPMENT OF RETURN**						
20	REVENUES FROM RATES	1,437,421,622	14,156,717	1,901,647	434,362,994	711,276,594	275,723,670
21	OTHER ELECTRIC REVENUE	311,955,249	5,574,020	446,431	93,540,065	151,316,821	61,077,912
22	**TOTAL OPERATING REVENUES**	**1,749,376,871**	**19,730,738**	**2,348,078**	**527,903,058**	**862,593,415**	**336,801,582**
23							
24	**OPERATING EXPENSES**						
25	OPERATION & MAINTENANCE	1,061,535,946	19,172,212	1,503,007	303,128,486	522,984,567	214,747,674
26	ADMINISTRATIVE & GENERAL	132,501,024	3,699,772	213,306	43,509,755	62,650,449	22,427,742
27	DEPRECIATION & AMORT EXPENSE	243,678,093	6,975,271	425,091	71,080,821	120,157,603	45,039,307
28	AMORTIZATION ON GAIN	(2,540,326)	(73,900)	(4,703)	(669,626)	(1,295,140)	(496,957)
29	REGULATORY ASSETS	(18,843,483)	(547,202)	(34,995)	(4,978,905)	(9,579,221)	(3,703,160)
30	TAXES OTHER THAN INCOME	90,279,756	2,600,644	158,466	25,800,529	44,901,732	16,818,386
31	INCOME TAX	56,371,627	(5,870,999)	(33,522)	24,029,501	28,959,146	9,287,501
32	**TOTAL OPERATING EXPENSES**	**1,562,982,637**	**25,955,798**	**2,226,649**	**461,900,561**	**768,779,136**	**304,120,493**
33							
34	**OPERATING INCOME**	**$ 186,394,234**	**$ (6,225,060)**	**$ 121,429**	**$ 66,002,497**	**$ 93,814,279**	**$ 32,681,089**
35							
36	**RETURN**	**186,394,234**	**(6,225,060)**	**121,429**	**66,002,497**	**93,814,279**	**32,681,089**
37							
38	**RATE OF RETURN (PRESENT)**	**4.68%**	**(5.36%)**	**1.74%**	**5.71%**	**4.77%**	**4.45%**
39							
40	**INDEX RATE OF RETURN (PRESENT)**	**0.61**	**(0.69)**	**0.23**	**0.74**	**0.62**	**0.58**
41							
42	**REVENUE REQUIREMENT @ 8.07%**	**1,659,025,311**	**39,794,627**	**2,627,925**	**479,132,655**	**817,952,180**	**319,517,925**
43							
44	**% OF TOTAL COST OF SERVICE (Line 20/Line42)**	**86.64%**	**35.57%**	**72.36%**	**90.66%**	**86.96%**	**86.29%**

DIRECT TESTIMONY OF ASHLEY C. BROWN

On Behalf of Arizona Public Service Company

Docket No. E-00000A-14-0023

February 25, 2016

Table of Contents

DIRECT TESTIMONY OF ASHLEY C. BROWN
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. <u>INTRODUCTION</u>

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

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

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.

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

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

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

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

A. Yes. I submitted Surrebuttal Testimony recently in the UNS Electric Docket No. E-04204A-15-0142. I have also testified before FERC and various state commissions as well as before Congressional and state legislative committees.

Q. ON WHOSE BEHALF DO YOU OFFER TESTIMONY?

A. On behalf of the Arizona Public Service Company.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain why regulators should view "value of solar" (VOS) analyses with a great deal of skepticism. It is an approach to pricing that is completely inconsistent with the two tested and proven methods of pricing electricity: costs and/or markets. Most advocates for a VOS approach do not even suggest that it is a pricing methodology that should be broadly applied, but seek to use it for the sole purpose of guiding (or perhaps actually setting) the price of rooftop solar, while pricing every other generating resource, including large scale renewables, using the traditional basis of costs and/or market. That, of course, would result in a discriminatory, largely incoherent, approach to pricing in the increasingly competitive electricity market, and have potentially disruptive effects on the overall efficiency of the power sector. VOS approaches are, as will be shown below:

- highly subjective;
- focused on generalities and largely lacking in the granularity demanded by the complexities of the electric sector;
- arbitrary and policy presumptive about selecting which externalities to consider; and
- often devoid of such critical contexts as costs, markets, technology evolution, and the full range of options in the marketplace.

In short, the value of a VOS analysis is, at best, highly marginal. It is, in the ultimate irony, eerily reminiscent of a major policy mistake in the power sector less than three decades ago.

Q. WHAT IS YOUR OPINION OF "VOS" ANALYSIS, GENERALLY?

A. I have serious reservations about the whole notion of VOS analysis; reservations that go well beyond any disagreements about the methodology used in particular studies. I question whether "VOS" analysis is a technique that should be used at all because of its inherent vulnerability to distortion and to the extent it is applied to distributed solar and not to other resources, it is already a skewed, market distorting, analysis.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony:

- Establishes a benchmark through a brief review of the two bases of traditional pricing: markets and costs;
- Examines the historical parallels of Public Utility Regulatory Policies Act (PURPA) implementation, reviewing the problems of "avoided costs" analysis under PURPA, which give a good picture of the kinds of problems "value" analysis may also encounter;
- Discusses the problems of VOS analysis, progressing from the most general to the most particular, as follows:
    - Problems inherent in the idea of "VOS" analysis;
    - Common conceptual problems in framing approaches to "VOS" analysis;
    - A review of the specific VOS categories proposed by IREC; and
    - A review of four "VOS" studies, which illustrate key issues related to VOS analysis;
- Discusses some of the policy implications of the problems with VOS analysis; and

- Concludes with some high-level recommendations to the Commission about how VOS studies should (and should not) be used in decision-making.

II. THE BENCHMARK: MARKET PRICING AND COST-BASED PRICING

Q. IN YOUR VIEW, WHAT IS THE BEST WAY TO ESTABLISH PRICES?

A. Optimally, prices should be established by market forces. This is not always possible. Where market imperfections exist, the discipline of a competitive market is missing, and it is appropriate to regulate based on costs in order to best replicate what would have happened if the market were shorn of its imperfections. Prices determined by a competitive market or derived from cost-based regulation are essentially subject to an external discipline that should both result in efficient resource decisions that are devoid of arbitrary or "official" preferences. Subjective consideration of the "value" of particular technologies and where they may rank in the merit order of "social desirability" effectively removes the discipline that is more likely to produce efficient results. Whereas both the marketplace and transparent cost-based regulation are likely to produce coherent pricing that allows us to enjoy a degree of comfort knowing that efficient performance will likely lead to productivity, subjective consideration of soft criteria, like a laundry list of "values" of solar, independent of any comparison with other resources, are a step away from coherence, efficiency, and consumer benefits.

III. HISTORY: PURPA AND THE PITFALLS OF 'AVOIDED COSTS'

"Those who don't know history are doomed to repeat it." George Santayana

Or, "Hegel remarks somewhere that all great world-historic facts and personages appear, so to speak, twice. He forgot to add: the first time as tragedy, the second time as farce." Karl Marx

Or, "Déjà vu all over again." Yogi Berra

Q. WHAT IS THE RELEVANCE OF HISTORY TO THE VOS DISCUSSION?

A. The debate over resource value and how to assess it is not new. For those of us who were involved in the power sector in the efforts to implement certain aspects of the Public Utilities Regulatory Practices Act (PURPA) in the 1980's, this entire VOS discussion is pure déjà vu. We have the real benefit of knowing what the outcome was, so we can use that knowledge to avoid repeating the policy/pricing errors.

Many advocates of VOS approaches, however, would have us repeat the same mistakes made just a generation or so ago. The attempt at the time was to administratively impose prices without regard to costs or markets, to somewhat arbitrarily try to monetize some externalities and not others, to impose cross subsidies or skew competition to achieve "desired" outcomes in technology and market position, and to define "avoided costs" in ways that were often less reflective of the economics than of predetermined policy biases. The results were arbitrarily high, or in other cases, arbitrarily low, figures for avoided costs; stranded assets and/or forfeiture of potentially valuable assets; power plant contraptions designed to take advantage of policy prescriptions rather than efficiency and productivity potential; and a highly inefficient market for generation that administratively determined winners and losers.

The "avoided costs" debate was not exclusively focused on one resource, as the VOS debate today exclusively focuses on rooftop solar. The concept, however, and to a remarkable degree the "calculations" and reasoning, were substantially the same then as they are now. The results of the 1980's experience was that the FERC was forced to intervene and impose a market-based bidding regime to discipline a process that had clearly gone awry.

So why are we doing this again, in the time when we have smart technology, a highly competitive market in generation, much smarter prices, and a completely changed environmental context? We have evolved significantly, and yet, with the use of VOS analysis, we are at risk of replicating a process whose ending, we all know, was most unhappy.

Q. WHAT HAPPENED IN THE 1980S?

A. In 1978, Congress enacted PURPA. Among other things, PURPA encouraged the development of alternative power, including renewable energy and cogeneration, by requiring utilities to purchase energy and capacity from qualifying facilities (QFs) at their incremental or avoided costs. "Avoided costs" was defined as: "[T]he incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source."[1]

FERC further required that each state define the appropriate avoided cost rate, and allow smaller QFs to access that rate as a "standard offer rate" (larger QFs could be required to go through a process of individual negotiation.)[2] The implementation of PURPA was largely left to the states, although FERC retained certain oversight and definitional powers.

Q. WHAT WAS THE EXPERIENCE WITH "AVOIDED COSTS" UNDER PURPA?

A. "Avoided costs," originally, were a kind of very simple value analysis, including only avoided energy and capacity costs. Over time, however, states not only took quite diverse paths to ascertaining the avoided costs, but many went beyond energy and capacity and factored environmental and other externalities into their calculations. The calculations were also handicapped by the fact that wholesale markets and transmission

---

[1] 18 CRF §292.101(b)(ii)(6) (Public Utility Regulatory Policies Act of 1978).

[2] Fox-Penner, Peter, Will Forman, Bob Mudge, Jens Schoene, Sanem Sergicic, and Bruce Tsuchida. *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area.* The Brattle Group, July 2015, p. 6. *Please see:* *http://www.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.*

pricing, while in existence, were by today's standards rather primitive and yielded incomplete and constrained cost and market data. The absence of sophisticated pricing in the wholesale energy market was an important factor in this complexity, resulting in multiple competing methods for determining the cost savings from energy provided. Further complicating matters were attempts to offer long-term contracts to QFs, which necessitated assumptions about fuel costs, factoring in future, but then unknown, environmental regulation, the effects of enabling new technologies in the marketplace, alleged system benefits, and many other factors projected well into the future.[3] It should also be noted that states were all over the board on how they considered existing capacity in determining which costs were avoidable and which were not.

Given all of those uncertainties, as well as the resource and technology biases in various jurisdictions, not surprisingly, the resulting "standard offer rates" varied widely among states. Some states used very conservative avoided cost estimates; others were extremely generous. In a few states, extremely generous standard offer rates resulted in a flood of QFs from which utilities were required to purchase power at prices many utilities claimed were far above their actual avoided costs. While many states tried to monetize all of the benefits or costs associated with avoided cost calculations, the resulting prices were the result of administrative discretion largely undisciplined by either costs or markets. Worsening the problem, avoided cost projections made near the height of the energy crisis seriously overestimated the future prices of oil and natural gas, with the result that many utilities entered into long-term agreements to purchase power under PURPA that were based on wildly overestimated values for future "avoided costs."[4] The result was chaotic. In many jurisdictions QF's contracts were highly priced and therefore

[3] In most cases, it was the regulators who did the calculations, but, occasionally it was the legislatures. New York, for example, had a statute that said that QF contracts had to be at least 6 cents per kWh. New York Public Service Law §66-c(2)(a).
[4] Basheda, Greg, Frank Graves and Philip Hanser. *PURPA: Making the Sequel Better than the Original.* Prepared for EEI (December 2006) at pgs. 12-13. *Please see:* http://www.eei.org/issuesandpolicy/stateregulation/Documents/purpa.pdf.

attracted many investments, the totality of which drove up prices for consumers. By the 1990's, newspapers were reporting billions of dollars of additional costs going to support poorly maintained projects producing power at as much as five times the going rate.[5] In other states, the avoided cost was set so low that very little non-utility generation materialized.

FERC's response to the situation evolved over time. In 1998, in response to appeals from New York utilities arguing against New York's intentional adoption of a rate well above actual "avoided costs," FERC changed its original position to rule that states could not set above-market avoided cost rates, citing "the proliferation of qualifying facilities" as one of the reasons for this change.[6] Similarly, FERC eventually gave up on trying to correct and improve administrative avoided cost determinations, beginning with a Notice of Proposed Rulemaking in 1988, but by 1998 abandoning this effort and instead endorsing state efforts to use competitive procurement mechanisms to establish costs.[7] And, in fact, perhaps in part as a reaction to the obvious problems of PURPA, by 1998, utility restructuring was underway in many parts of the country.[8]

Thus, the use of highly subjective criteria for pricing generation proved to be a very serious policy mistake, which, while well intentioned, had the adverse effect of imposing unreasonable prices (too high in some states and too low in others), and misallocating capital in ways that rendered markets less efficient and failed to incent productivity gains. The lessons of that experience were costly, but once they were fully

[5] Bailey, Jeff. "Carter-era Law Keeps Price of Electricity Up in Spite of a Surplus." *Wall Street Journal* 17 May 1995.

[6] *Re Orange & Rockland Utilities, Inc., Rockland Elec. Co., Pike County Light & Power Co.*, 92 P.U.R.4th 1 (F.E.R.C. Apr. 14, 1988).

[7] *Admin. Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, & Interconnection Facilities,* 84 FERC ¶ 61265, 62300 (F.E.R.C. Sept. 21, 1998).

[8] "Indeed, restructuring itself may have been partly induced or encouraged by the sometimes imbalanced and uneconomic results of PURPA. There is a strong correlation between the states with the largest PURPA supply and their early pursuit of retail access." Basheda, Greg, Frank Graves and Philip Hanser. *PURPA: Making the Sequel Better than the Original*. Prepared for EEI (December 2006) at p. 2.

understood, we adhered to policies in which prices were highly disciplined by increasingly competitive and sophisticated markets, or, where a market failed to accomplish that, by cost based regulation, both of which are highly disciplined and far less vulnerable to subjective manipulation.

Q. SO WHY IS THE PURPA EXPERIENCE RELEVANT TO THE IDEA OF A "VOS" ANALYSIS?

A. The attempts to use laundry list, out of context, VOS analyses,[9] either to set rates, or even as a guideline to assessing the reasonableness of prices (e.g., those under Arizona's net metering regime) is, for the most part, an effort to replicate and reinstate, albeit solely for the advantage (or in a few cases the disadvantage) of a single technology (rooftop solar), a pricing methodology that proved to be highly undisciplined, misallocated capital in inefficient ways, distorted prices for both consumers and producers, skewed both energy and capacity markets, effectively chose winners and losers on an administrative rather than performance basis, and ultimately led to FERC having to intervene in matters heretofore subject to state regulation.

Another dynamic of the VOS debate that is reminiscent of the PURPA implementation issues of the 1980's is the use and abuse of monopoly power. Rooftop solar interests routinely argue that utilities want to preclude competition from rooftop solar in order to preserve their monopoly. While I do not subscribe to that point of view, it is worth noting that there is a supreme irony in that contention. Solar advocates who call for the use of VOS analysis in either guiding or actually setting the prices for rooftop solar, are, in fact, trying to take advantage of monopoly power and lack of customer choice to

[9] By "laundry list, out of context, VOS analyses," I am not trying to devalue rooftop solar, but, rather, I am referring to the common genre of efforts that monetize a long laundry list of "values," based on inherently unreliable long-term projections of value, without any reference to other competing options to attain the same values more cost-effectively. What I am referring to throughout this paper when I refer to "VOS" analysis is this kind of laundry list in a vacuum (derived in a carefully selected, arbitrary, and often biased way) approach, not efforts like those of witness Albert to evaluate rooftop solar within the full context of other competing technologies.

enable the price paid for rooftop solar to be escalated above market or costs, by administratively and creating highly selectively adders to the price paid for rooftop solar to reflect claims of non-economic or fully internalized "benefits," while at the same time ignoring similar non-economic or non-internalized costs. No competitive or cost-based pricing regime would allow that to happen. But it is doable in a monopoly setting, and that is precisely what a number of the VOS studies are advocating, much like some interest groups did on the PURPA debates of the 1980's. The irony, of course, is that those advocating such an approach are, in fact, trying to claim for themselves the advantages of monopoly power. In short, much like in the PURPA debate in the 1980s, certain new entrants into the market are not trying to compete on a level playing field, but rather are trying to take a piece of that monopoly power to get far above-and out-of-market prices for their product. So the question of the use and abuse of monopoly power is very much a part of this issue.

Q. SO ARE YOU SAYING "VOS" ANALYSIS IS PURPA'S "AVOIDED COST" ANALYSIS ALL OVER AGAIN?

A. VOS analyses have all of the problems of historical avoided cost analyses, and more. VOS studies/arguments, are, like PURPA implementation prior to FERC's imposition of marketplace discipline into pricing, an attempt to administratively and selectively choose criteria to alter pricing that would otherwise be set by either the market or costs. VOS approaches also can lead to the use and abuse of market power in order to benefit particular products and services.

Historically, we have used two methods of pricing electricity, cost-based regulation and competitive markets. PURPA modified those a bit by offering a variation of cost-based regulation, namely avoided costs. That in itself, as I discuss, created many problems. The idea of a "value" analysis takes matters even further. We have never used subjective notions of "value" to set prices. There is good reason for that. Value is subjective, easily manipulated, generally non-transparent, and lacks the discipline imposed by markets and cost-based regulation. There is also little or no precedent in U.S. regulation, or regulation anywhere, to use a "value of" approach to one resource, while applying the rigors of markets and/or regulation to other competing resources. It has been well-recognized that such widely varying methods of pricing applied to competing resources has adverse consequences, such as reducing market efficiency, distorting price signals, and misallocating capital. The history of PURPA teaches us the pitfalls of "avoided cost" analysis. If anything, a "VOS" analysis, straying even farther from the discipline and transparency of markets and cost-based pricing than an avoided cost analysis, has the potential to lead to even more problems than those experienced during the implementation of PURPA.

In short, we know how the VOS movie will end, so why are we going to replay it? More specifically, why would we want to play it out in the context of 2016, when we have much more sophisticated technology and far more efficient energy markets, both of which enable smart and precise prices to be set by the markets, or if need be, by cost of service regulation.

IV. <u>WHAT'S WRONG WITH A "VOS" ANALYSIS?</u>

Q. CAN YOU GIVE AN OUTLINE OF WHAT YOU SEE AS THE PROBLEMS OF VOS ANALYSIS?

A. Yes. I organize my discussion of the problems of VOS analysis in order from the most general and inherent to more and more specific issues, ending with an overview of some key problems in four specific VOS studies.

i. <u>Problems that can't be fixed: "VOS" analysis is inherently subjective, readily manipulated, and inherently skewed</u>

Q. WHY DO YOU SAY THAT "VOS" ANALYSIS IS SUBJECTIVE AND READILY DISTORTED?

A. Studies of the "VOS" are highly subjective and readily manipulated because there is no established methodology, and, furthermore, given the complexity of the analyses needed to assess all the various "VOS" claims, no analysis can effectively avoid the need to make multiple subjective analytical judgments. Thus, every such analysis is subject to the biases and policy predispositions of the authors and/or sponsors of such studies. This reality is well illustrated by the extraordinarily wide variance in the conclusions of such studies. The range is dramatic, with a VOS study in Louisiana which found a negative value, while a VOS study in Maine calculated a value of 33.7 cents/kWh.[10,11,12]

The reason we see such wide variation is that VOS studies are inherently subjective and arbitrary. Study findings are easily distorted in subtle ways to match any agenda. There is no commonly accepted methodology for doing VOS analysis. Indeed, there are not even any commonly accepted criteria to assess in ascertaining value.

---

[10] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers. Prepared on behalf of the Louisiana Public Service Commission.* Prepared on Behalf of Louisiana Public Service Commission Draft, February 27, 2015. *Please see:* http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5

[11] Grace, Robert C., Philip M. Gruenhagen, Benjamin Norris, Richard Perez, Karl R. Rabago, and Po-Yu Yuen. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission. Revised April 14, 2015. *Please see:* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[12] To put the 33.7 cents /kWh valuation in perspective, that number is roughly double the full retail rate of Maine's largest electric utility. In other words, the authors of that study calculated that the "value" of the energy produced by each rooftop solar installation is worth double the full delivered cost of electricity. That is the equivalent of saying that the value of a part of a product is worth double the value of the entire product.

Q. IS THE FREQUENTLY-CITED IREC "GUIDEBOOK" A HELPFUL STEP TOWARDS ESTABLISHING AN UNBIASED METHODOLOGY?

A. No. The problem of lack of a standard methodology was recognized by a leading solar energy advocacy group, Interstate Renewable Energy Council (IREC), which tried to fill that vacuum by publishing *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* It offers a list of criteria that I analyze in my testimony below. Instead of solving the problem, however, IREC proves my point. IREC's criteria constitute a self-selected, self-serving, heavily-biased laundry list of subjects that, remarkably, fails to include costs and market prices, as well as attributes that might diminish value, such as subsidies/cross-subsidies, job losses as well as the job gains claimed, risks associated with using rooftop solar to reduce carbon, market distortions, etc. IREC's *Regulator's Guidebook* also fails to include other obvious subjects any credible study would have to examine, such as impact on merit order dispatch, the energy resource mix in the state being studied, disparate social impact of rooftop solar subsidies, market effects, impact on energy efficiency, a comparison of costs with other resources that can accomplish similar objectives, environmental considerations beyond simply carbon, full cycle impacts (i.e., manufacture through generation) of solar panels and installations. An even-handed, disciplined, and thorough analysis would have to include these variables, along with an almost infinite host of others. And IREC does not even try to make the case for why rooftop solar prices should either be guided or actually set by VOS, while all other resources should be priced by cost or market. Thus, what purports to be a methodological guide is, in fact, a transparent example of how to manipulate VOS studies to validate a predetermined outcome.

Given the highly subjective, often biased, nature of VOS analysis, it is hardly surprising that one finds an extraordinarily wide variance in conclusions. Moreover, it is fairly clear that the biases of whoever is authoring and/or paying for these reports bring heavy influence to bear on not only the conclusions, but, in fact, on how the studies are carried out and what factors are included and excluded from consideration. My point about all this is that this kind of analysis, in practice, is completely subjective; you could drive up the VOS, you could drive down the VOS-it's easy to manage the results in either direction. This is one of these "garbage in, garbage out" ways of analyzing. VOS analyses are inherently skewed.

Q. WHY DO YOU SAY VOS ANALYSES ARE "INHERENTLY SKEWED?"

A. VOS studies are technology specific (almost always limited to rooftop solar). This makes them one-sided. As noted earlier, the studies never answer the question of why, if we would use value-based pricing for rooftop solar why we don't use value-based pricing for every other resource? Why are we singling out rooftop solar? VOS studies rarely, if ever, look at the opportunity costs associated with spending money on rooftop solar, as opposed to using that money on something that produces energy and/or reduce emissions more efficiently, incentivizes rooftop solar to be more efficient and more productive, and promotes overall market efficiency and system benefits.

If we're going to use a VOS analysis to establish prices, then why in the world don't we do that for nuclear, coal, natural gas, wind, and every other resource? Or, for that matter, establish a value for the grid itself? It is very difficult to discern any justification for singling this technology out for an analysis that is completely different from and, frankly, historically foreign to, the way that we set prices for energy in the U.S.[13]

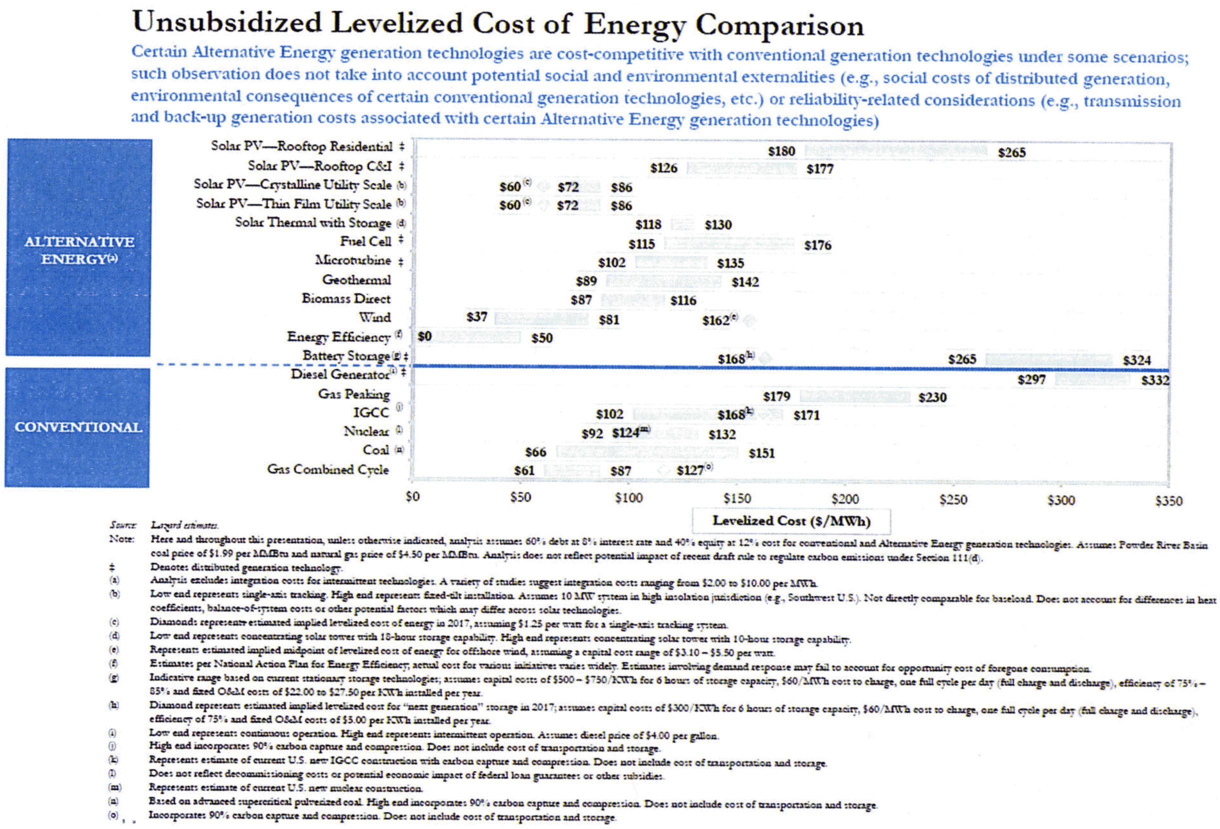
Q. CAN YOU GIVE AN EXAMPLE OF HOW THE ONE-SIDED FOCUS OF VOS ANALYSIS CAN CONTRIBUTE TO BAD POLICY?

A. A classic example of the kind of problem this single focus of "value" analysis relates to the question of whether distributed solar has extra value because it does not emit carbon. While rooftop solar does not, in the process of producing energy, emit carbon, VOS

[13] At a minimum, if one were determined to pursue a value analysis (which I do not in any case recommend), competing renewables should be considered.

studies do not even address the question of its cost of doing so in comparison with other non-emitting energy sources, despite the fact that much has been written on the efficiency of using various methods to reduce carbon emissions, and distributed solar generally ends up at the low end.

Rooftop solar is the most expensive form of generation widely used today. The chart that follows illustrates that point:[14]



No less an environmental advocate than Amory Lovins acknowledges that solar energy (even grid-scale solar energy) is less cost effective than wind and hydro in terms of reducing carbon emissions.[15] An interesting dialogue occurred recently between Charles Frank, an economist at Brookings, and Amory Lovins of the Rocky Mountain Institute, based on an effort by Mr. Frank to develop an analysis of the cost-effectiveness of solar

---

[14] *Lazard's Levelized Cost of Energy Analysis, Version 8.0*. 2014. p. 2. *Please see:* https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.

[15] Lovins, Amory B. "Sowing Confusion about Renewable Energy." *Forbes* 5 August 2014.

PV as a carbon reduction tool, taking into account not only the levelized cost of energy, but some of the considerations about peak production and effects on the functioning of the overall energy system discussed above.[16] Their dialogue, while contentious on many points, includes, on both sides, numbers that show agreement on the fact that solar is the least cost effective of all commonly-deployed renewable resources in reducing emissions.[17]

A recent study by the Brattle Group comparing generation costs of grid-scale and rooftop solar in Colorado confirms that rooftop solar is likely even less efficient at reducing emissions than grid-scale solar: "Simply stated, most of the environmental and social benefits provided by PV systems can be achieved at a much lower cost at grid-scale than at residential-scale."[18]

That is, of the renewable generation choices commonly available, rooftop solar is the highest cost way of reducing carbon emissions. Nevertheless, VOS papers almost always ascribe significant value to the carbon reduction value of rooftop solar. What is never asked, however, is how that value compares with the stepped up utilization of grid-scale renewable or energy efficiency in reducing emissions, and what the opportunity cost is for diverting capital from more efficient means of carbon reduction to the less efficient means of rooftop solar. What most, if not all of these studies lack, is

---

[16] *See* Frank, Charles R. Jr. *The Net Benefits of Low and No-Carbon Electricity Technologies.* Global Economy and Development at Brookings Working Paper 73, May 2014. *Please see:* *http://www.brookings.edu/~/media/Research/Files/Papers/2014/05/19%20low%20carbon%20future%20wind%20solar%20power%20frank/Net%20Benefits%20Final.pd;* and Lovins, Amory. *An initial critique of Dr. Charles R. Frank, Jr.'s working paper 'The Net Benefits of Low and No-Carbon Electricity Technologies,' summarized in The Economist as 'Free exchange: Sun, wind and drain.* 'Rocky Mountain Institute, 2014. *Please see:* http://www.rmi.org/Knowledge-Center/Library/2014-21_Frank-Rebuttal.

[17] As Frank puts it, even after addressing Lovins' criticisms, "Wind continues to rank number four and solar ranks number five by a large margin." Frank, Charles. *"Alternative Energies Debate—The Net Benefits of Low and No-Carbon Electricity Technologies: Better Numbers, Same Conclusions"* September 4, 2014. http://www.brookings.edu/blogs/planetpolicy/posts/2014/09/04-low-carbon-tech-lovins-response-frank. Lovins, Amory B. "Sowing Confusion about Renewable Energy." Forbes 5 August 2014.

[18] The Brattle Group Study at 3.

context; VOS study authors, as general rule, ignore context and view rooftop solar as if it exists in an almost perfect vacuum.

Q. WHAT IS THE RISK OF STICKING WITH AN APPROACH THAT ONLY LOOKS AT THE "VALUE" OF ONE RESOURCE?

A. A major risk is losing sight of the big picture, and making decisions without considering the overall context and alternatives. Whatever "value" you are pursuing, you should think about multiple ways to get there, and what the most cost-effective approach will be to obtain the value in question. I discuss the huge example of carbon emissions. The problem with promoting rooftop solar as a solution to carbon emissions is not only inefficiency, but that doing so is a threat to the goal itself. If you choose pathways that are not cost effective, if effective at all, you run the very real risk of exhausting resources and public support without really impacting the problem. It is important to note that not a single VOS paper I have reviewed even looks at this very critical question.

i. <u>Foundational problems that can throw off the whole framework of a study: Common conceptual problems in framing approaches to "VOS analysis;"</u>

Q. TURNING FROM THE MOST GENERAL LEVEL OF PROBLEMS WITH THE THEORY OF A VOS ANALYSIS TO MORE SPECIFIC LEVELS, ARE THERE RECURRING PROBLEMS YOU OFTEN SEE IN FRAMING APPROACHES TO A VOS ANALYSIS?

A. Yes, and I will detail some of them below. Note that this is not an exhaustive list—many other issues, such as choice of discount rate, estimates of likely rooftop solar penetration in the future, etc., have been raised as at least needing careful treatment. The issues below, in my opinion, are some of the most fundamental conceptual problems:

- VOS studies are often unclear about the question they are answering;
- VOS studies often struggle with how to forecast costs and benefits into the future;

- VOS studies are sometimes not realistic (or even consistent) about what marginal power will be offset by rooftop solar;
- VOS studies often fail to account for costs, as well as benefits; and
- VOS analysis generally ignores the regressivness of existing net metering policies.

Q. WHY DO YOU SAY THAT VOS STUDIES ARE OFTEN UNCLEAR ABOUT THE QUESTIONS THEY ARE ANSWERING?

A. To ask "what is the value of solar?" is not in itself a complete question. You need to complete the thought by specifying whose value you are asking about, and in what policy context. Does the study seek to establish value according to rooftop solar customers? All customers? The rooftop solar industry? The utility? The state as a whole? The general public? There is usually a policy reason behind this question, and being clear about what policy question is being answered is important. Which costs and values are appropriate to consider will vary, depending on what you are examining.[19] Such differences in perspective are behind certain disagreements about specific elements of the VOS, such as whether payments to net-metering customers count as a cost of rooftop solar from the perspective of the utility and of non-net metering customers, these payments certainly do. On the other hand, a study of the VOS to rooftop solar customers would include net metering payments.

The question gets a little tricky if the study seeks to establish benefits for a whole state (which many do). Rooftop solar customers are part of the state, so one might argue that benefits to them should count in the analysis. (Analyses that include benefits to solar customers, should of course, include the costs they incur to install and maintain solar

[19] Let me acknowledge here that I am not the first person to point this out. The need to clarify "stakeholders" is often advised. But, judging from some of the VOS studies I have reviewed, this is a rule often honored in the breach.

panels as well). This is where understanding the policy question you want to answer becomes important. You might do an analysis including costs and benefits to solar customers if the question you want to answer is, "Does support for rooftop solar improve the well being of the state as a whole, disregarding whether it transfers wealth from non-rooftop solar to rooftop solar customers or causes other wealth transfers within the state?" On the other hand, much more often, the study is being done to answer the implicit or explicit question: "Is this investment in rooftop solar, an investment that solar customers make independently, outside the planning process of the utility, beneficial to the rest of the state? (And, if so, by how much?)," and the related question, "What is the rest of the state getting in return for its support of rooftop solar?" If this is the question you are trying to answer, costs and benefits to solar customers themselves must be excluded.

Similarly, it matters who is asking the question. If a public service commission is asking the question as part of a review of their own policies in regard to rooftop solar, one argument is that the answer is likely to be most helpful if it excludes elements over which the Commission has no control-in this case, both the investment decisions made by rooftop solar customers, as well as state and federal solar energy subsidies. On the other hand, if you believe that state subsidy expenditures are caused by net energy metering policies (that is, the state offers a tax incentive for rooftop solar investment, but it won't be used by customers without the additional support of net energy metering), then you might choose to include state subsidy costs. In many states, that decision may make the difference between finding net costs or net benefits for rooftop solar. This was the case in the Louisiana study conducted by Dismukes, and discussed later in my testimony, notable for finding the "VOS" to be negative.

Q. WHY DO YOU SAY THAT VOS STUDIES STRUGGLE WITH HOW TO FORECAST COSTS AND BENEFITS?

A. Most analyses of the VOS, recognizing that rooftop solar systems are supposed to have a lifetime of at least twenty years, aim to do more than assess the value of a rooftop solar system in its first year of operation, or the value of rooftop solar in a state in one year.

The problem here is not the conceptual idea that the VOS might change over time, but rather the fact that layering the uncertainty of future predictions on top of the inherent complexity of presently valuing solar multiplies the ways in which analysis can go wrong. Furthermore, the different approaches studies take to this problem make it hard to meaningfully compare study results.

Marginal price comparisons (fuel price comparisons) for solar vs. fueled generation are increasingly uncertain the farther out in time they go. Today, analyses done as recently as a year ago already look dated, due to their assumptions about increasing natural gas prices. As recently as January, 2015, the EIA was forecasting average 2016 natural gas prices at the Henry Hub of $3.86/MMBtu.[20] Although it is of course too early in the year to say with certainty that this forecast is wrong, it is looking unlikely that average prices for 2016 will be anywhere near predicted levels-so far, they have hovered not far about $2/MMBtu (with one notable dip below the $2 mark).[21] Using long-term price forecasts for energy, particularly for our fuel prices, is notoriously unreliable.

Some studies do a better job of handling future uncertainties than others. Let me contrast VOS studies in Minnesota and Maine on this. Minnesota explicitly calls for an annual adjustment, and one factor to be adjusted is the cost of fuel. Maine, on the other hand,

---

[20] *Platts*, US EIA sets 2016 natural gas price forecast at $3.86/MMBtu. January 13, 2015. *Please see:* http://www.platts.com/latest-news/natural-gas/washington/us-eia-sets-2016-natural-gas-price-forecast-at-21834965.

[21] *EIA*, Henry Hub Natural Gas Spot Price. *Please see* https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm.

assumes a 3% or 4% increase in natural gas prices every year for 25 years (based on NYMEX futures and EIA projections).[22]

In fact, of course, we don't know what will happen with these prices. 25-year forecasts, regardless of who they come from, are notoriously inaccurate. In fact, the only thing you know about those 25-year fuel forecasts is that they're wrong. Minnesota's VOS approach to the fuel price issue is more sensible in that it recognizes this uncertainty and, rather than relying on unreliable long-term forecasts and ignoring market forces, proposes adjustments on an annual basis to reflect what's actually going on in the marketplace.

Projections of future values need to be treated with caution. Recent experience has dramatically demonstrated how wrong projections of ever-increasing natural gas prices can be. Nor is there much certainty about the likely costs of future CO2 allowance prices (there seems to be even less certainty about this since the Supreme Court granted a stay on implementation on the CPP).

Q. WHY DO YOU SAY THAT VOS STUDIES ARE SOMETIMES NOT REALISTIC (OR EVEN CONSISTENT) ABOUT WHAT MARGINAL POWER WILL BE OFFSET BY ROOFTOP SOLAR, AND WHY IS THIS A FOUNDATIONAL PROBLEM?

A. With respect to the many dimensions of a VOS analysis (energy value, capacity value, and environmental value, for example), you have to look at what's being dispatched and what marginal resource is being displaced. If the solar resource is modeled as displacing relatively clean energy, as opposed to coal, then the cost of energy you are displacing

---

[22] Fuel price projections are commonly used in the power sector for planning purposes. But the Maine study suggests is that they should be used for purposes of pricing long term contracts with rooftop solar providers, particularly when the price of the energy procurement by the utility is not further disciplined by a competitive solicitation. In short, many VOS studies, and the one in Maine quite notably, simply imply that the fuel price is as projected and ignore the competitive market forces that influence the price of every other energy source. This does not reflect market realities. *See Maine Distributed Solar Valuation Study.*

might be higher than if you were displacing coal. But the externality value is a whole lot less, and the study needs to identify that trade off. To actually quantify this trade off, you must get to a high level of granularity in the study.[23]

Maine's study (discussed in more detail below) is a particularly egregious example of doing this wrong. As discussed in more detail below, some parts of the study assume gas is the marginal fuel displaced; other parts assume (improbably) that coal is being displaced. Picking and choosing the marginal power source is another potential source of subjectivity in VOS studies.

Q. WHY DO YOU SAY THAT VOS STUDIES OFTEN FAIL TO ACCOUNT FOR COSTS, AS WELL AS BENEFITS? WHAT COSTS DO YOU HAVE IN MIND?

A. "VOS" analyses also tend to be one dimensional, identifying benefits without balancing that off against related costs. Frequently (though not always), the discussion does not include any serious consideration of costs associated with rooftop solar and policies enacted to support it—lost utility revenues, which must be made up for by non-rooftop solar customers; costs to the rest of the system incurred in order to integrate intermittent renewable energy while keeping power supply steady; the need for additional reserves to back up a pool of generation that can vary unpredictably with the weather;[24] the need to maintain standby generation (spinning and non-spinning reserves) to maintain system frequency, despite solar intermittency; transaction costs; distribution changes required to

[23] Because most coal fired plants are baseload and not engineered for ramping, and because the natural gas plants are the generating resources typically on the margin, rooftop solar is likely displacing the lower emitting gas plants rather than the higher emitting coal plants. That likelihood is enhanced by the fact that rooftop solar is intermittent. Thus, it is impossible to assign a carbon emissions value without knowing precisely what is being displaced.

[24] "Unexpected short-term changes in solar generation require additional backup capacity to avoid temporary mismatches between supply and demand." Baker, Erin, Meredith Fowlie, Derek Lemoine, and Stanley S. Reynolds. "The Economics of Solar Electricity." American Review of Resource Economics vol. 5 (June 2013), p. 404.

accommodate bidirectional flows; and costs to the economy as a whole (including job losses) associated with higher energy costs.[25]

Q. WHY DO YOU SAY VOS ANALYSIS GENERALLY IGNORES THE REGRESSIVENESS OF EXISTING NET METERING POLICIES?

A. A VOS analysis typically ignores the social impact of policies, such as net metering implemented to support distributed solar. Empirical studies on this subject have indicated that net metering pricing has a regressive social impact.[26] It is, in fact, a wealth transfer from lower-income people to higher-income people. Rarely do you find this wealth transfer assessed in VOS studies. But it is a social cost, and it ought to be assessed. The failure to consider this wealth transfer is part of the selectivity you often see relative to how externalities are included and excluded from VOS studies.

i. Specific problems with IREC's proposed "VOS" categories

Q. HOW DO THE GENERAL ISSUES ABOVE APPLY TO THE ANALYSIS OF SPECIFIC "VALUES" OFTEN ATTRIBUTED TO SOLAR?

A. There are a number of different ways potential benefits and costs are addressed in different studies. In many cases, the "values" proposed are either non-existent, or presented in a one-sided manner that ignores offsetting costs. Even benefits, such as avoided energy costs (which seem undeniable), can be very hard to quantify reliably, especially when attempts are made to look decades into the future. For the purpose of

---

[25] *Id.* at 405.

[26] Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 28, 2013); Hernandez, Mari. *Rooftop Solar Adoption in Emerging Residential Markets*. Center for American Progress, May 29, 2014. *Please see:* https://cdn.americanprogress.org/wp-content/uploads/2014/05/RooftopSolar-brief3.pdf; and Hernandez, Mari, *Solar Power and the People: The Rise of Rooftop Solar Among the Middle Class*. Center for American Progress, October 21, 2013. *Please see*: https://www.americanprogress.org/issues/green/report/2013/10/21/76013/solar-power-to-the-people-the-rise-of-rooftop-solar-among-the-middle-class; and Staff Report/Open Meeting Memorandum on Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013.

this testimony, let me review the categories proposed by the previously referenced IREC Guide—a list frequently mentioned when a "VOS" analysis is urged.

Q. WHAT ROLE DOES ENERGY PLAY IN THE VOS?

A. Avoided energy use is one impact of rooftop solar that seems to have the virtue of being clear and uncontroversial. However, there are often contentious issues regarding how to calculate those energy savings. The issue is whether the savings should be calculated on an average basis, or calculated more precisely by establishing the energy costs saved in the hour the rooftop solar system generates electricity. Since rooftop solar is almost always non-coincident with peak, crediting rooftop solar at average prices fails to precisely capture the market value of the energy. Thus, determining the value of the energy becomes a subject for debate, as we have seen in the recent UNES rate proceeding.[27] Hence, every VOS study will have to make assumptions about how to calculate energy value, and those assumptions are both controversial and can, in and of themselves, be manipulated in order to drive the value calculations up or down.

Moreover, as noted above, the longer such calculations are projected out in time, the greater their potential for distorting value. That risk is not necessarily remedied by the use of futures markets and forecasts of natural gas prices, resources that many VOS analyses rely upon. These are, to understate the point, far from infallible. For example, I don't believe any of them predicted the current natural gas prices of approximately $2/MMBtu. The fact is that the price of energy is in a constant state of hourly flux, but authors of VOS studies typically ignore the realities of those market prices and substitute some proxy that helps achieve a desired outcome.

[27] Arizona Corporation Commission Docket No. E-04204A-15-0142.

Q. WHAT IS YOUR ASSESSMENT OF THE VALUES ASSOCIATED WITH AVOIDED SYSTEM LOSSES AND CONGESTION?

A. Whether or not rooftop solar systems "reduce the amount of energy lost in generation, long distance transmission and distribution" is a fact specific question. It is flat wrong to claim that solar PV systems, ipso facto, reduce losses. On distribution systems, even the theory underlying this claim is controversial among experts. The truthful answer appears to be that sometimes rooftop solar reduces energy losses on the distribution system, but often does not, and, indeed, could in some circumstances actually cause more losses. The validity of the claimed loss avoidance is very situation specific.

With regard to transmission losses, it is certainly true that solar PV on distribution systems does not rely on high voltage transmission. Despite that, rooftop solar does, in fact, impact the transmission system because of its intermittent nature and its steep ramps up and down, which require utilities to be able to quickly bring other resources on line in ways that can have impacts on transmission congestion, depending on the specific configuration of a given system. Rooftop solar also can have very real impact on congestion because the amount of energy being imported or not imported into the low voltage distribution grid inevitably makes its impact felt in the flows on the transmission grid. That value could be positive or negative depending on precisely what is occurring, so the *ipso facto* presumption of a positive value for congestion is simply baseless.[28] The same is true in regard to system losses, at both the distribution and transmission levels.

[28] Congestion is a real cost on all transmission systems. While Arizona is not part of an organized market that explicitly prices congestion, that fact does not alter the reality that congestion costs are incurred.

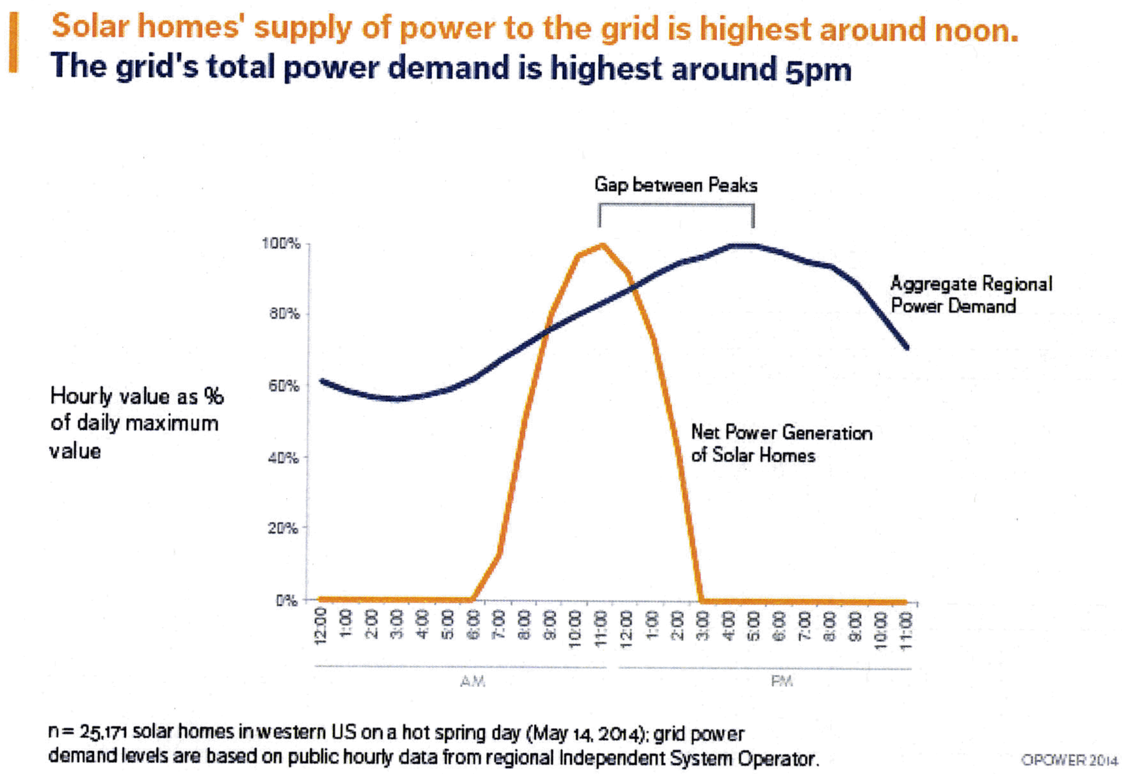
Q. WITH RESPECT TO GENERATION CAPACITY, HOW DO YOU ASSESS THE AVAILABILITY/CAPACITY VALUE OF ROOFTOP SOLAR?

A. Many VOS studies assign a value to the capacity provided by rooftop solar. In some cases, this value is quite large (see the Crossborder Arizona Study discussed below).

But the capacity value of a generating asset is derived from its availability to produce energy when called upon to do so. By its very nature, rooftop solar on its own, without its own backup capacity (e.g., storage), can only produce energy intermittently. It is completely dependent on sunshine in good atmospheric conditions. Unless sunshine is guaranteed at all times at which rooftop solar is called upon to produce, it cannot be relied upon to be available when needed. Moreover, even if all days were reliably sunny, the energy derived from the sun is only accessible at certain times of the day. Utilities, however, are required to serve all of the demand of customers in their service territory at all times. That means utilities must plan for the capacity needed to serve peak demand, largely without regard to the existence of rooftop solar.

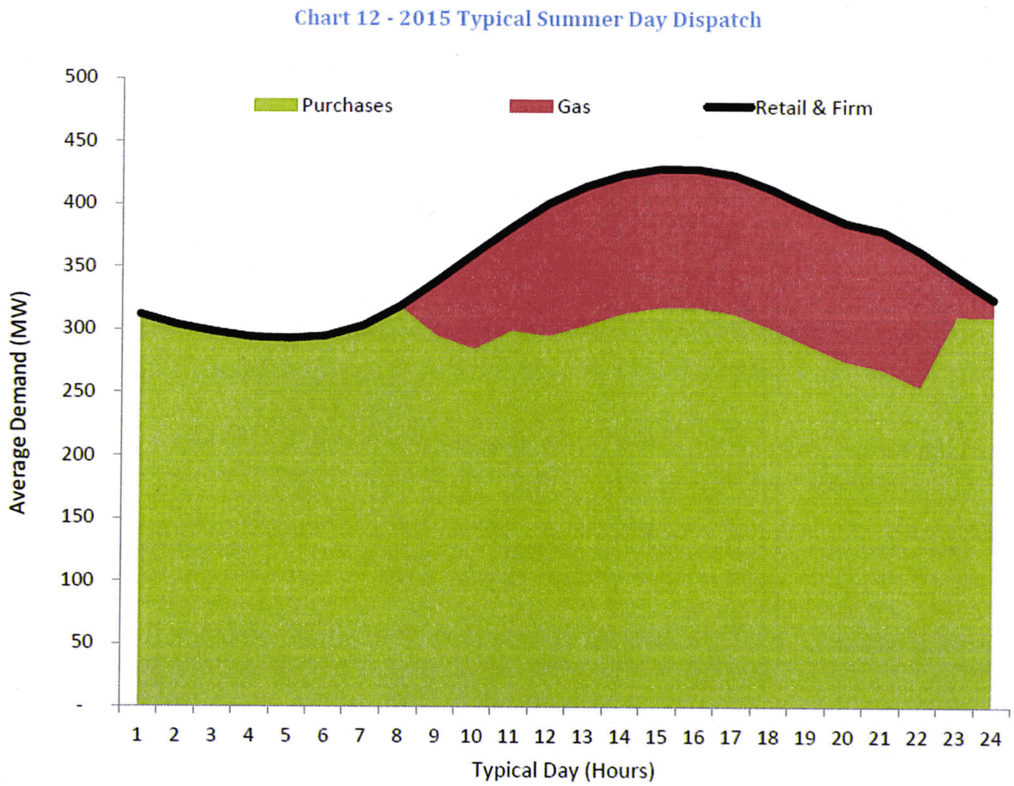
The capacity value of rooftop solar is even further diminished by the fact that the presence and potency of sunshine is not coincident with peak demand. Rooftop solar capacity is generally at its peak in the early afternoon, while peak demand occurs later in the afternoon or in early evening.

The chart below prepared by Opower, based on data from California, nicely illustrates what this disjunction looks like:[29]



In the APS territory, as well, the highest demand peak is between 5pm and 6pm in the hottest summer months a time at which solar production is "significantly reduced" from its noon peak.[30] As illustrated in the chart below, elsewhere in Arizona, UNSE sees a similarly late-afternoon peak:[31]

[29] Fischer, Barry and Ben Harak. *9% of solar homes are doing something utilities love. Will others follow?* Opower blog December 1, 2014. *Please see*: https://blog.opower.com/2014/12/solar-homes-utilities-love/.(Downloaded 2016).
[30] *See* Direct Testimony of Bradley Albert at p. 9.
[31] UNS Electric's 2014 Integrated Resource Plan. Arizona Corporation Commission Docket No. E-0000V-13-0070 (April 1, 2014) p. 59. (*See* Chart 12 below).



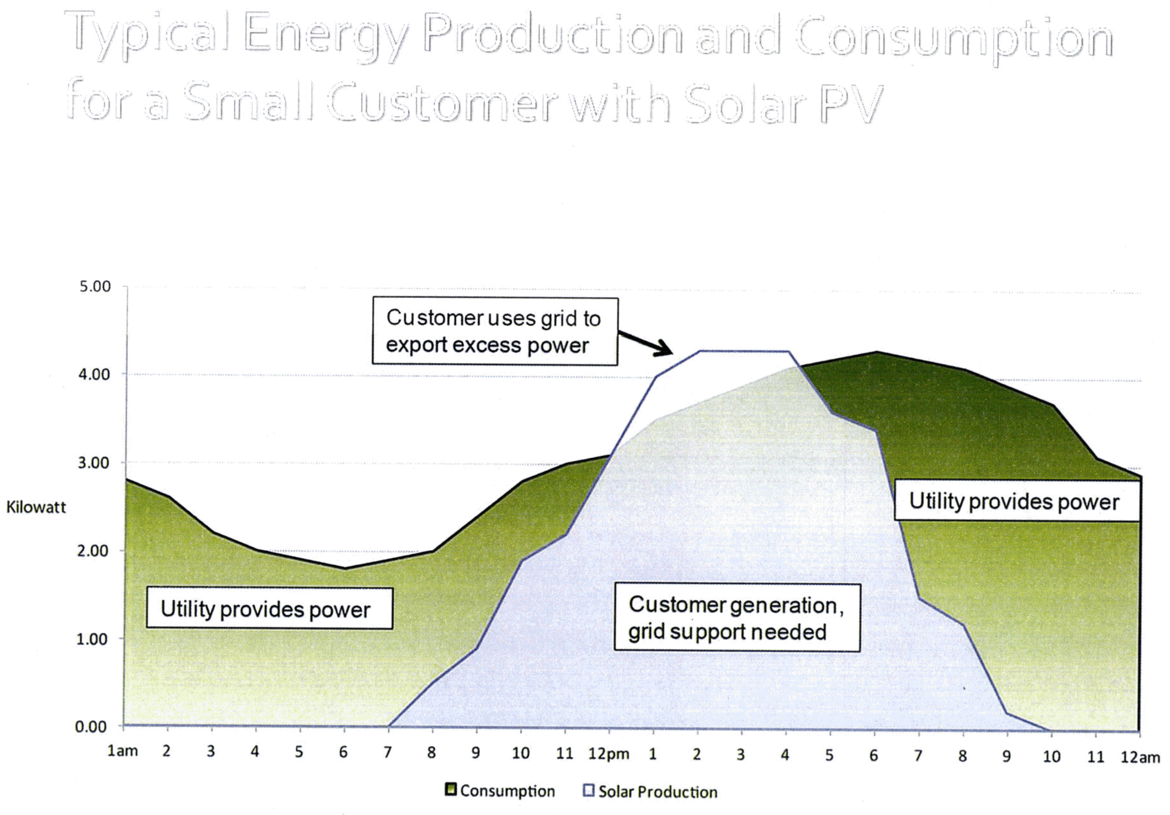
Because utilities can't count on it to be available, and because the utility's peak demand occurs well after peak solar production, rooftop solar can play only a limited role in offsetting capacity costs, either for transmission or generation.[32] At best, capacity value would be only a small fraction of nameplate capacity. In fact, some studies find that adding rooftop solar increases costs associated with reserve requirements significantly.[33]

---

[32] Capacity value can be enhanced by adding battery storage or optimizing the solar installation's orientation to capture the maximum amount of sunlight at peak. Ironically, neither of these actions are routinely undertaken, in large part because net meter pricing fails to provide inappropriate signals to do so.

[33] A study of the Duke Carolina system by Pacific Northwest National Laboratory cited by the Brattle group "found that adding distributed solar capacity equal to 20% of the peak load caused planning reserve requirements to increase by 30% and regulation to increase by 140%, compared to a case without PV capacity added. These increases led to a system cost increase of $1.43 to $9.82 per MWh of PV energy…" *See* Brattle Group Study at 35; and *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*, Pacific Northwest National Laboratory (March 2014). *Please see:* http://www.duke-energy.com/pdfs/carolinas-photovoltaic-integration-study.pdf.

Another graph, from EPRI, reveals the same pattern on a national level:



Analysts point out that the gap between solar peak production and demand peak is likely to grow as higher penetrations of solar depress demand more and more during solar producing hours—further eroding the capacity value of rooftop solar.

Q. HOW HAVE SOME VOS ANALYSES ATTEMPTED TO HANDLE THE ISSUE OF SOLAR'S INTERMITTENCY?

A. Despite this disjunction between solar production peak and actual peak demand, and the other weather-related uncertainties of solar power, it has become fairly common practice among utility planners and many VOS analysts to calculate an "effective load carrying capacity" (ELCC) percentage based on the capacity of rooftop solar discounted for its intermittency. Typically, ELCC numbers are in the 50%-60% range—but it is acknowledged that the higher the solar penetration, the lower the ELCC is likely to be. Estimates for California have gone as low as 17%. Determining the ELCC adjusted value of rooftop solar is a fact-specific question that, if it is to be used, needs to consider capacity availability resulting from the timing of generation and less than optimal placement of photovoltaics.[34]

Q. WHAT IS YOUR PERSPECTIVE ON THE CAPACITY VALUE OF SOLAR POWER AS A FORMER REGULATOR?

A. While it is true that one can develop probabilistic models for utility planning purposes that are theoretically sound, that is quite different matter than how to price rooftop solar from a regulatory perspective. The regulator needs to determine what is used and useful for providing service to the customer before requiring consumers to pay. In my view, a capacity provider should stand ready to deliver energy when called upon to do so, and if the provider is unable to deliver, then he must assume responsibility for replacing what he is unable to provide, or, alternatively, reimburse the utility for the marginal costs it incurred in remedying his default. Thus, any "capacity" that fails to meet that test is entitled to, at best, minimal compensation, if any, and under no circumstance should it be entitled to payment consistent with its nameplate capacity, unless it meets the test I just articulated. As a regulator, I would apply a very strict scrutiny to the amount of cost recovery for capacity for a resource that is not readily dispatchable, and whose provider assumes no liability for an inability to be dispatched when called upon. The real question is how much benefit of the doubt should we give to an intermittent, non-readily dispatchable resource, whose provider assumes no liability for inability to be dispatched. The question for regulators is how they assess capacity value in light of these factors.

[34] *See* Baker et al, at. 405, who cite study by Lamont (2008).

Q. ARE THERE ANY OTHER LIMITING FACTORS IN EVALUATING THE CAPACITY VALUE OF DISTRIBUTED SOLAR POWER?

A. Yes. The value of capacity is also, of course, driven by whether capacity is required. If, for example, a utility has sufficient capacity[35] to meet all anticipated demand (including reasonable reserves), voluntarily paying for more capacity would raise questions about prudency. Thus, there is no basis to assume, as many VOS authors do, that the installation of new rooftop solar units renders them automatically entitled to capacity payments. Indeed, I know of no other circumstance where any generator would be entitled to such a presumption, without actual examination of the particular circumstances. Even in the context of where the utility has a need for new capacity, economies of scale are important. New plants might be built that could have scale economies and serve multiple purposes, but do so at lower unit costs than small plants, such as rooftop solar, which lack economies of scale. Given the lack of scale economies in rooftop solar, prevailing in a competition would be difficult. Capacity markets are, and ought to be, competitive; thus, even if rooftop solar possessed capacity value, it should have to compete to monetize that value. This is entirely contrary, however, to the way that most VOS authors approach the issue of capacity value. They simply assume that solar installations are entitled to compensation for being there, without having to compete with other possible capacity providers. They simply assume value associated with a deferral of capacity procurement, despite the fact nothing may be deferred at all. Moreover, the value calculation is often made at nameplate capacity levels, as opposed to ELCC. Using nameplate capacity levels serves the purpose of driving up the "value" calculations they make, but does so in a context entirely outside the realities of the capacity market.

[35] From a regulatory perspective, utility capacity includes both units owned by the utility and units owned by a third party entity with a contractual obligation to provide the utility with capacity. I note this because solar advocates sometimes argue that utilities are opposed to rooftop solar because it competes with the utility's generation. For regulatory purposes, capacity owned by another company, but contractually obligated to the utility to serve capacity requirements, has the same system worth as utility owned generation for purposes of capacity. Ownership has nothing to do with it.

Q. WHAT ABOUT VALUES ASSIGNED TO TRANSMISSION AND DISTRIBUTION CAPACITY?

A. Advocates of a "VOS" approach often assert that real transmission savings are achieved through the deployment of DG. The argument is that by producing energy at the distribution level, less transmission service will be required, thereby reducing or deferring the need for new transmission facilities. It is also, as already noted above, often contended that rooftop solar will reduce congestion costs, and perhaps even provide some ancillary services. All of that is theoretically possible, but certainly not uniformly or even inevitably true.

Of course it is true that, absent any adverse, indirect effect rooftop solar might have on the operations of the high voltage grid (e.g., congestion), rooftop solar does not incur any transmission costs in bringing its energy to market. However, as discussed above, avoiding transmission delivery charges is quite different from asserting that rooftop solar provides actual transmission savings. In fact, it would be incorrect to simply conclude that rooftop solar will achieve transmission savings.

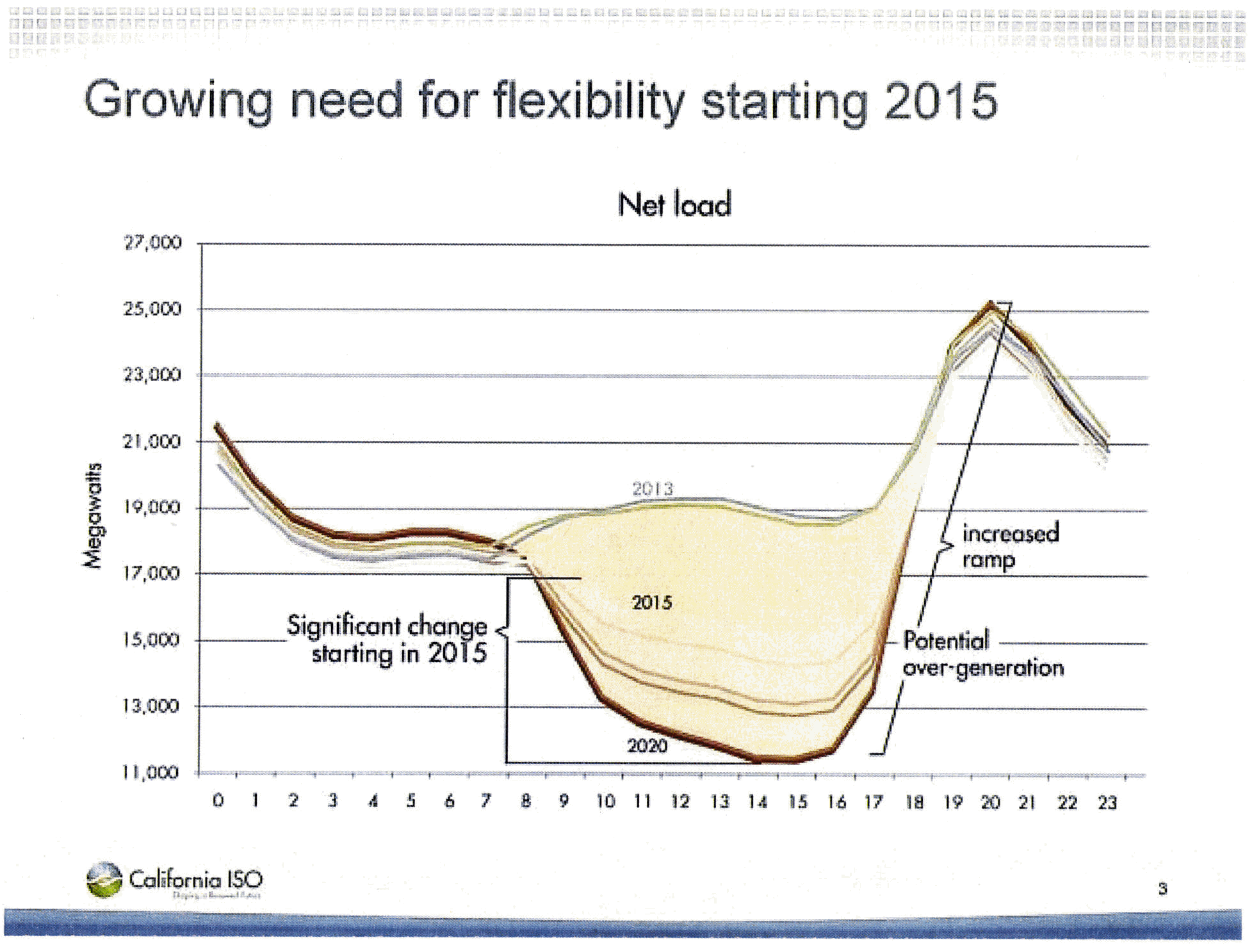
It is possible that there could be transmission savings associated with rooftop solar deployment, but that can only be ascertained on a fact- and location-specific basis. Such savings, as already discussed, would most likely be derived from reducing congestion or providing ancillary service of some kind. It is also theoretically possible, but highly unlikely, that massive deployment of rooftop solar will eliminate (or defer) the need to build new transmission facilities. However, for a variety of reasons, including the complexities of transmission planning, the time horizons involved, the complex interactions of multiple parties, economies of scale in building transmission, and the politics of siting, it is improbable that rooftop solar actually saves any investment in transmission capacity.

The fact is that transmission is built for the bulk power market, sized for the long term, and designed to capture economies of scale. It is built, not based on incremental, year by year, needs, but with a view toward the long term. Since rights of way are generally scarce and hard to obtain, transmission lines are built to maximize scale so that future line siting battles can be avoided or at least deferred. Thus, the addition of rooftop solar, absent a truly massive amount of installation, will almost inevitably have no impact on transmission capacity planning. Indeed, since transmission must be sufficient to serve peak load, the fact that rooftop solar is intermittent, and non-coincident with peak, means that it will have no real impact on transmission capacity. In addition, with new technologies being deployed on the grid, the most common form of transmission expansion relates to technological enhancements, the deployment of which is completely unaffected by rooftop solar.

Indeed, a mere glance at the California ISO duck chart, which shows the need for ramping capacity to make up for the intermittent availability of rooftop solar, is almost a prima facie case for believing that the opposite is true-that rooftop solar may actually cause a need for more transmission to be built.

For anyone not already familiar with California's famous fowl, here is the "duck chart," which shows the dramatic and increasing ramp needed to meet residential demand as the sun sets-a ramp that taxes the resources of the system and may well put significant strains on the transmission system:[36]

[36] *See* Rothleder, Mark. *Long Term Resource Adequacy Summit.* California ISO (February 26, 2013 at slide 3. *Please see:* https://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.



It is virtually impossible to demonstrate that rooftop solar will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit. At the same time, the development of this "duck" pattern creates new costs for the grid—it is not easy or free to arrange for large amounts of generation to come on line quickly ("ramping"). Keeping up with the steep ramping curve created as solar power drops off the grid is an additional expense that would need to be included in VOS analysis.

Q. DOES DISTRIBUTED ROOFTOP SOLAR AVOID DISTRIBUTION COSTS?

A. No. It is more likely that rooftop solar will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require adjustments and maintenance. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless perhaps when a rooftop solar host leaves the grid, to envision a circumstance where rooftop solar would effectuate distribution savings.

In a number of states, regulators are working to introduce more market elements in the distribution grid in order to handle the additional costs and complexities (as well as to create efficiency opportunities) related to distributed energy resources. This project itself, of course, represents a significant cost.

Q. IS THERE VALUE ASSOCIATED WITH ROOFTOP SOLAR RELATED TO ANCILLARY SERVICE PROVISION TO THE GRID?

A. It is technically possible that smart inverters could provide ancillary services to help stabilize energy flow on the grid. However, in the absence of a properly designed incentive to provide these services, this is a theoretical possibility, not an actual value. In the meantime, the more intermittent resources on the grid, the more ancillary services are needed to preserve power quality and reliability.[37]

Q. IS THERE A FUEL HEDGE VALUE ASSOCIATED WITH ROOFTOP SOLAR?

A. The theory advanced by some rooftop solar proponents is that because the marginal cost of solar is zero, it serves as a hedge against price volatility. In theory that might make sense. In reality, however, rooftop solar is an intermittent resource that cannot serve as a meaningful hedge unless such zero-cost energy is produced both in sufficient quantities and in a timely manner. Thus, rooftop solar is the equivalent of a risky counter party whose financial position renders him incapable of assuring payment when required. Moreover, the value of a hedge depends on the amount of money the purchaser of the hedge is obliged to pay and the size and probability of the price he/she seeks to

[37] Baker et al., at 404-405.

avoid paying. With a rooftop solar system (or the high-priced "VOS" approach that the rooftop solar industry seeks), the price paid is highly likely to exceed the fuel or energy price against which most utilities would hedge against. In short, the argument ventures into the realm of the absurd. It amounts to: Pay me a fixed price that is higher than the price you want to avoid, in order to avoid price volatility.

Q. WHAT ABOUT THE VALUE OF "MARKET PRICE SUPPRESSION?"

A. Another supposed value attributed to rooftop solar in many VOS studies is that by reducing demand, rooftop solar will suppress the market price for energy. This argument is seriously flawed in more than one way.

In the first place, under retail net metering, the price of rooftop solar is not market-based, or even cost-based. In fact, where there is retail net metering, the rooftop solar price is unreasonably and arbitrarily linked to the full retail price of delivered electricity, as opposed to the level of energy prices, where it should be. While, arguably, the availability of highly-subsidized rooftop solar could have the effect of reducing demand for wholesale energy (although considering the scales involved it seems improbable that the reduction would materially impact wholesale energy prices), there would be no price benefit for consumers since rooftop solar, priced at full retail levels, or at the levels dictated by the inflated claims of many VOS papers, would consume all of the savings and leave little or no benefit for customers.

Setting aside the high price customers are being asked to pay for this "savings," the second problem to flag here has to do with the different market effects of a low-priced competitive resource and a low-priced subsidized resource. If a competitively priced, not heavily subsidized, source of energy caused prices to decline, that would be a good thing, but that is not at all what VOS studies are suggesting will happen with rooftop solar. Rooftop solar is subsidized by tax credits, REC/SREC markets, and by the cross-subsidy inherent in net metering and volumetric rate design. It is hard to find any economic logic to support the notion that markets are well served by using heavily subsidized products, such as rooftop solar, to drive down prices in the competitive marketplace.

To the extent that highly subsidized products compete with unsubsidized products in the marketplace, this distorts the market, rather than strengthens it, making it hard for otherwise competitive energy generators to stay in business. In the long run, this distortion exacerbates the capacity issues that many markets struggle to correct through capacity payments. Thus, if one assumes that rooftop solar somehow suppresses prices in the energy market, this would be highly unfortunate—it could do very serious damage to the power sector. The claimed price suppression "value" is not a value at all.

Q. WHAT ABOUT THE AVAILABILITY AND RELIABILITY OF ROOFTOP SOLAR?

A. Many rooftop solar advocates assert that rooftop solar enhances overall reliability because the units are small and widely distributed, but close to load and not reliant on the high voltage transmission system. It is argued that they are somehow less impacted by disasters and weather disturbances. These claims are highly speculative and, for the reasons I will explain, inaccurate.

It would be a mistake to simply assume that rooftop solar improves reliability. First, it should be noted that the vast majority of outages are distribution (not transmission related), thus the fact that rooftop solar does not use the transmission grid is almost completely irrelevant to the reliability issue. Beyond that, rooftop solar is subject to disaster as much as any other installation. Strong winds, for example, can harm rooftop solar as much as any other facility connected or not connected to the grid. Cloudy conditions can disrupt solar output while not affecting anything else on the grid.

Solar's intermittency makes it unable to assure its availability when called upon to deliver energy. Indeed, it is far more likely that a thermal unit will have to provide reliability to back up a solar unit than the other way around.

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

That argument ignores one highly relevant fact: in a system outage the power inverter, an electronic device or circuitry that converts direct current to alternating current, is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line workers from encountering live voltage they do not anticipate. Thus, if a rooftop solar unit is functioning properly, when the grid goes down, the rooftop solar customer's inverter will also go down, rendering it useless in an outage. If the inverter is not functioning properly, then the unit may be producing, but will do so at a considerable risk to public safety and to workers trying to restore service. The result, of course, is that the solar panel provides virtually no reliability to anyone.

In fact, when it comes to reliability, it is much more accurate to say the grid provides reliability to rooftop solar than the other way around. Not only does the grid ensure service when the sun is not shining, but in case of an outage, a solar-powered home does not, on its own, have the ability to re-start the home's systems without a boost of energy from the grid. As contrasted with the reliability provided by the grid, there are virtually no reliability benefits for the system from distributed solar, and therefore there is no basis for calculating a payment for such service.

Q. BESIDES LACK OF AVAILABILITY DURING OUTAGES, ARE THERE OTHER ASPECTS OF RELIABILITY THAT ARE RELEVANT FOR CONSIDERATION?

A. Yes. Attributing reliability benefits to an intermittent resource is a stretch. By definition, intermittent resources are supplemental to baseload units. The only possible exceptions to that are, as noted above, where there are individual reliability benefits or where the availability of the unit is coincident with peak demand. Absent those circumstances, and absent storage, it is almost certainly the case that the system provides reliability for rooftop solar, rather than the other way around. That is particularly ironic given that in the context of net metering, rooftop solar hosts do not pay for that service while generating electric energy, and collect payments for distribution service they rely upon rather than provide.

Indeed, from a reliability perspective, net metering and most other VOS formulations are truly perverse, because non-solar customers pay rooftop solar providers for reliability benefits that rooftop solar does not provide them, while rooftop solar customers do not pay for the reliability benefits they actually do receive. From an investment perspective, rooftop solar pricing methods like NEM, which redirects distribution revenues from utilities to rooftop solar providers who offer no distribution services, are detrimental to reliability because they deprive utilities of the revenue needed to maintain high levels of service.

Q. DESCRIBE THE EFFECTS OF DIVERSION OF REVENUES RELATED TO THE NETWORK FROM UTILITIES TO ROOFTOP SOLAR PROVIDERS, WHO OFFER NO NETWORK SERVICES, ON RELIABILITY AND REVENUE REQUIREMENTS FOR PROVISION OF NETWORK SERVICES.

A. For utilities, the diversion of funds leaves them with the Hobson's choice of either delaying maintenance and/or needed investment, foregoing earnings,[38] or seeking a rate increase—in effect, a cross-subsidy from non-rooftop solar users. Over the long term,

[38] Foregoing earnings increases investor perception of risk. That perception will inevitably drive up a utility's cost of capital, so that option will also lead to rates being increased.

that effect could lead to reliability problems associated with inadequate or less reliable network capacity, especially at times of peak demand.

Q. DO YOU SEE VALUE IN "ENVIRONMENTAL SERVICES" RELATED TO CARBON AND OTHER FACTORS?

A. Many VOS studies include one or more values related to environmental impacts (or lack of impact) of rooftop solar. Before delving into the issue of the environmental externalities benefits claimed for rooftop solar, it is important to note that the issue of taking externalities into consideration is a controversial one. It would, of course, take a policy decision by the Commission to look at the claims of environmental values beyond what is currently required by law. That is, of course, the Commission's call I am not, in my testimony, suggesting that the Commission should or should not take externalities, environmental or otherwise, into consideration in reviewing the idea of VOS analysis. If the Commission does decide to consider externalities, however, as a matter of soliciting a full range of information and analysis from interested parties, it might want to leave open the issues of what rooftop solar related externalities the parties might want to address. That way, the parties seeking to provide input to the Commission will face no entry barriers to do so. How the Commission chooses to weigh those comments, of course, is very much the Commission's decision. For purposes of my testimony, however, since I am talking about VOS studies that look at externalities, I will specifically address the issues explored in those studies, and perhaps some others as well, but my testimony is not intended to be an exhaustive list of all affected externalities.

There are many potential issues here. First there is no certainty that rooftop solar reduces carbon emissions. There is, for example, the case of Germany, where a massive switch to solar and wind resulted in an increase in the use of coal, and stalled reductions (and in some years increases) in carbon emissions.[39] While the German experience was also influence by the closing of the country's nuclear plants, the point is that one simply cannot assume that increasing the amount of intermittent renewable generation, including rooftop solar, will, ipso facto, lead to reductions in emissions.

Moreover, the degree to which rooftop solar does reduce carbon is not an easy figure to derive. To correctly ascertain the amount of reductions per dollar spent, one would have to identify what generation and emissions are being avoided by rooftop solar generation. In today's market, the marginal resource is likely to be natural gas—with emissions much less than other resources on the grid, such as coal—resulting in significant consequences for the value of the emissions averted by rooftop solar. To try to ascertain a meaningful number, a VOS researcher would have to do a location (or at least region) specific analysis with substantial granularity. VOS papers typically do not do that; rather they simply make assumptions, the factual basis for which are at best suspect and at worst meaningless.

Second, as in other issues, VOS studies almost never look at the opportunity cost associated with rooftop solar. In specific regard to carbon emissions, VOS studies assume a reduction and try to assess a monetary value for that achievement. What they rarely, or ever do, is look to see if that money is well spent in the context of alternative ways of achieving the same result. As noted earlier in my testimony, rooftop solar is a remarkably expensive way to reduce carbon emissions. Energy efficiency, grid-scale solar, and wind, for example, all reduce more emissions per dollar spent on rooftop solar, and do so without having to prepare VOS studies to make the case for special compensation. Thus, a balanced VOS would discount the claimed value of emissions

---

[39] *DW.Com.* "German CO2 Emissions Targets at Risk." (November 19, 2015). *Please see:* http://www.dw.com/en/german-co2-emissions-targets-at-risk/a-18862708

reduction to compensate for the opportunity cost of not having chosen the least cost option. Most (if not all) studies fail to do this.

Third, the methodology used to quantify emissions reductions in VOS studies often suffer from serious flaws. There appears to be the potential double counting and paradoxes among the different categories of analysis suggested for the "environmental services" category. For example, IREC suggests a list of values within the "environmental services" category that includes both "utility avoided compliance costs" and "carbon." The "carbon" category suggests that additional value attaches to rooftop solar because it reduces the amount of carbon emissions in the state; on the other hand, the "avoided compliance cost" category suggests that there is value to rooftop solar because it reduces the amount of other renewables in the state. Puzzling through the relationship between these two arguments is like trying to make sense of an Escher print—at first glance, the steps seem to be going up, but at second glance, they are going down, and it is impossible to resolve the contradiction.

Q. HOW DO CAP AND TRADE AND RENEWABLE PORTFOLIO STANDARDS FIT INTO YOUR ANALYSIS?

A. It is also apparent, but ignored in most if not all VOS studies, that in jurisdictions with a renewable portfolio standard or a cap and trade system, additional rooftop solar does not necessarily change the amount of emissions being reduced. Indeed, it could have adverse effects. That is because, cap and trade turns carbon from an externality to a cost that is fully internalized into the cost of service, and set asides or preferential prices to selected technologies (i.e. rooftop solar), actually have the effect of disrupting the ability of the market to find the most efficient way of reaching the emission reduction requirement. In regard to RPS, the cost of compliance with the standards is also internalized into the cost of service, so whatever carbon reductions are attained under RPS are automatically captured and internalized into the cost of service. The rooftop solar set aside in the Arizona (and other states with similar requirements) RPS, however, is a bit of an outlier with perverse results. That is because it mandates that a specified percent of renewable must be dedicated rooftop solar, a resource that is less efficient economically and less efficient in reducing carbon emissions than are other renewable resources. It is remarkable that the authors of VOS studies, for the most part, simply choose to ignore this issue.

Q. WHAT ABOUT RENEWABLE ENERGY CREDITS AND SOLAR RENEWABLE ENERGY CREIDTS?

A. This issue becomes even more complex and problematic in cases in which customers and/or rooftop solar installers are awarded RECs or SRECs for their projects. Clearly, if customers or solar installation companies are selling RECs or SRECs associated with their renewable energy, care should be taken not to count the associated environmental "value" more than once.

Q. WHAT IS THE EFFECT OF THE LONG TERM COST PROJECTIONS FOUND IN VOS STUDIES?

A. It is perverse on both economic and environmental grounds. As noted elsewhere in my testimony, long-term forecasts of fuel and energy prices are notoriously inaccurate and should not be relied on for purposes of pricing long-term contracts[40]. In regard to carbon reduction and other environmental effects, it is impossible to overstate the perversity of setting long-term prices. That is not only because, as regards to rooftop solar, you are giving pricing preference to the least efficient technology for reducing carbon, but for an even more important reason. Environmental standards, particularly market-based approaches such as cap and trade, are formulated in ways that incentivize new and more efficient technology to achieve the desired ecological result. What most

[40] Utilities and many other businesses often rely on such projections for planning purposes, but use the projections solely as indicators of trends, not as is suggested in VOS studies, for establishing the price for long-term contracts.

of the VOS studies propose to do, however, is lock in high prices projected out for 20-25 years for a technology we already know to be inefficient relative to other options, and reduce the opportunities to seize upon options that we can be certain will appear in that time frame that will achieve the desired environmental results at lower cost to consumers. Simply stated, it is very poor policy to lock in long term prices for a technology we know is inefficient and thereby reduce our opportunity to take advantage of new technology that will inevitably appear in the marketplace.

Q. HOW DO YOU ASSESS THE VALUE CLAIMED RELATED TO "SOCIAL SERVICES" (PRIMARILY, ECONOMIC DEVELOPMENT AND JOBS)?

A. In the case of economic impact, benefits are frequently claimed for rooftop solar without regard to costs. Advocates for rooftop solar claim this will give rise to many good solar energy jobs. Maybe that's true, maybe that's not true. We certainly have some reason to doubt this, given that as of 2015, the US produced only about 2% of PV cells and PV modules in the world, while making up 16% of PV installations. (China dominates worldwide solar PV cell and PV module production, with a more than 60% share of the world market).[41] Rooftop solar may have produced more jobs in China than in the U.S. Regardless, if one is to consider the economic development or jobs aspects of rooftop solar, any study of the issue must be balanced and look not only at solar jobs, but also at secondary impacts on the job market. These include job loss caused by the increased electric rates that come with selecting a higher cost technology over a lower cost technology to provide electricity (e.g., rooftop solar instead of utility scale solar or wind). Employment impacts are a two-edged sword when it comes to green energy. The one-sided, myopic view of the jobs issues found in VOS studies are strangely reminiscent of people who argue that we ought not to regulate carbon emissions because

[41] IEA, *Trends 2015 in Solar Photovoltaic Applications.* Report IEA-PVPS T1-27:2015. Available online at http://www.iea-pvps.org/fileadmin/dam/public/report/national/IEA-PVPS_-_Trends_2015_-_MedRes.pdf. See pages 31 and 40.

doing so would lead to job loss in coal mining. That argument is one dimensional and myopic in the same sense that the green jobs argument is one dimensional and myopic.

In fact, recent research modeling on the effects on the Arizona economy of rooftop solar subsidies highlights what is missed with a one-dimensional look at rooftop solar jobs. This study found that subsidies for rooftop solar, over the years, lead to significant job losses and decreased wealth for the state.[42] The central problem is that the money spent on DG reduces the amount available to be spent in other sectors of the economy. Thus, while the model does predict additional jobs associated with rooftop solar installation and other services, "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."[43] Over the twenty-year period studied, with results varying depending on the level of penetration of rooftop solar, the model in fact predicts billions of dollars of lost gross state product and thousands of "job years" lost.[44] The effort of the ASU Study to examine both sides of the economic impact of expenditures on distributed solar is unfortunately rare in VOS analyses, which almost never balance predictions of job growth against job costs. The usual VOS jobs argument simply lacks balance and credibility.

Q. ARE THERE ANY SOCIO-ECONOMIC ISSUE THAT ARE NOTABLY IGNORED IN VOS STUDIES?

A. One issue that VOS studies never reference, but which has been studied on several occasions, is that cross-subsidies in rates derived through net metering or inflated value claims by the rooftop solar industry inevitably have a regressive social effect in that they

---

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

[43] ASU Study at i.

[44] A job year is not the same as a job. It is one year of employment

constitute, in the aggregate, a transfer of wealth from less affluent households to more affluent ones.[45] That reflects a very real social cost, but one that VOS authors routinely ignore.

i. Case Studies: How the problems of VOS analysis play out in specific studies

Q. CAN YOU GIVE EXAMPLES OF HOW THE GENERAL AND SPECIFIC ISSUES DESCRIBED ABOVE PLAY OUT IN VOS STUDIES?

A. Yes. In what follows I give, not a complete review of all aspects of the studies mentioned, but a "highlights" (or perhaps more accurately, "lowlights") tour of what I perceive to be the major problems with the VOS analysis illustrated by each study. I review one study in Louisiana, two contrasting Arizona studies, and a recent study of the VOS in Maine.

Q. WHAT, IN YOUR VIEW, IS THE KEY LESSON OF THE LOUISIANA STUDY?

A. It matters a lot what subsidies you count, as demonstrated by the Louisiana study.[46] This study, a rare example of an analysis that finds the costs of rooftop solar to be greater than its benefits, proved controversial, and has remained in "draft" purgatory since it was submitted to the Commission that requested it. Many criticisms of the study have focused on the author, David Dismukes, himself, arguing that his past work for oil companies makes him likely to be biased. (I wonder how many energy consultants in Louisiana have not worked for oil companies).[47] More substantive critiques noted the

---

[45] Energy and Environmental Economics, *California Net Energy Metering Ratepayer Impacts Evaluation*. Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 28, 2013); Hernandez, Mari. *Rooftop Solar Adoption in Emerging Residential Markets*. Center for American Progress, May 29, 2014. and Hernandez, Mari, *Solar Power and the People: The Rise of Rooftop Solar Among the Middle Class*. Center for American Progress, October 21, 2013; Staff Report/Open Meeting Memorandum on Arizona Public Service Company – Application for Approval of Net Metering Cost Shift Solution. Arizona Corporation Commission Docket No. E-01345A-13-0248, September 30, 2013.

[46] *See* Dismukes, Davide E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.*

[47] Furthermore, it is a leap to assume that the interests of oil companies are opposed to solar electricity (which does not directly compete with oil). In fact, many oil companies have investments in renewables, and even more have an interest in natural gas—which becomes more in demand for electricity generation as a flexible firming resource for intermittent renewables on the system. Oil companies'

inclusion of the State of Louisiana's generous solar tax credits in costs—and, in fact, Dismukes would have found a net benefit for rooftop solar if he had excluded the cost of this state support.

A review of the study points to a few observations. First, Mr. Dismukes was working with severely limited data provided by Louisiana's "dumb" meters. He seems to have made heroic efforts, combining GPS coordinates with weather data, to extrapolate likely levels of rooftop solar energy production at different hours of the day. His methodology seems reasonable to me, but I have not reviewed it in detail.

The study itself contains multiple analyses. In addition to his net benefits/costs analysis, Dismukes analyzes the impact on the contributions to cost of service by NEM customers, finding (as one would expect) that NEM customers contribute far less to the cost of service than they would have done had they not installed rooftop solar and received service under a NEM tariff. This analysis is interesting in that it illustrates the scope of the shift of costs from NEM to standard rate customers. However, it is vulnerable to the criticism that it does not consider any reductions in the overall cost of service resulting from the rooftop solar installations. (APS witness Leland Snook calculated these savings in APS's service territory and concluded that rooftop solar customers reduce energy costs and provide a modest capacity benefit to APS). He goes on to analyze evidence that the transfer here is from lower-income to higher-income households, finding considerable evidence that this is the case.

Focusing on the most-reported finding, that the costs of solar NEM installations are greater than the benefits to ratepayers, I note that in some of his assumptions, Dismukes is relatively generous to rooftop solar. For example, he assumes the price of natural gas

---

economic interests, to the extent they are impacted by electricity policy at all, would be to support bringing more intermittent renewables onto the system.

would be constant at \$3.50/MMBtu—a price that today seems high.[48] He also includes capacity value (for generation, transmission, and distribution) in his analysis, despite the intermittency of rooftop solar, using an ELCC factor to calculate avoided generation capacity costs, even though the value of the capacity is limited by the prevalence of excess capacity in area markets. Dismukes is similarly generous in calculating transmission and distribution capacity savings. He assumes benefits in transmission and distribution capacity which, as I argue above, are highly dependent on the particular configuration of the utility system, and of rooftop solar within that system. Finally, though it is not part of his main analysis, he includes a sensitivity analysis which looks at how his findings would change if a \$40 per ton cost of carbon were included (and finds that rooftop solar remains in the red, even with this additional included benefit).

How is it possible, then, that his results are so different from some other studies? Critics of the study quibble about his omission of certain "values" they consider relevant. But the biggest differences seem to be the following:

- Dismukes presents a balanced assessment of the impact of NEM and solar subsidies on jobs and the economy of Louisiana. Thus, he counts the benefits of jobs and economic activity associated with the subsidy—but he also counts the negative economic impact of higher electricity prices. In this, he is absolutely correct. Any analysis of positive job impacts of solar subsidies needs to include the impact on jobs caused by the resulting higher energy costs (and the reduction in state revenues associated with tax rebates, if state government costs and incentives are considered). It would be wonderful news if it were possible to create cost-free jobs and economic growth through government subsidies for any industry (green or not) —but, as economists like to say, "There is no such thing as a free lunch." This is not to say industry subsidies are never helpful or a good

[48] Dismukes, at 112.

idea—but industrial economic policy is a complex topic, and any presentation that suggests that benefits come without costs is deeply wrong.

- In addition, Dismukes includes a big ticket cost that many other studies omit—the cost of state tax incentives (in addition to the NEM subsidy) provided to customers who invest in rooftop solar (Louisiana offers a tax rebate of up to $12,500 per system).[49] This tax subsidy has a huge impact on his analysis, accounting for roughly 70% of the costs of historical solar installations he identifies.[50] (It's worth noting here that he does not include costs associated with the federal solar tax incentive.) Although it has been correctly pointed out that these state costs are not within the jurisdiction of a utility commission, this is a perfectly legitimate cost to identify. Just like jobs (which are also outside of a utility commission's jurisdiction) how tax incentives should impact decision-making depends on the priorities of the Commission, recognizing that a decision to end net energy metering may not eliminate these costs.

Q. HOW DO YOU INTERPRET THE VERY DIFFERENT RESULTS OF THE TWO STUDIES OF VOS IN ARIZONA ITSELF?

A. Two roughly simultaneous studies of the "VOS" in Arizona beautifully demonstrate how easy it is to do a "value analysis," using many of the same assumptions, and come to radically different conclusions. The SAIC Report analysis, published in May 2013[51], estimates a rather small 2025 VOS to the APS system of 3.56 cents/kWh (expressed in 2013 dollars). A study by Thomas Beach and Patrick McGuire of Crossborder Energy, also published in May 2013, criticizes the SAIC Report study, offering instead an estimate of "levelized benefits" over twenty years (it is not clear to me exactly which

---

[49] *Id.* at 128.
[50] *Id.* at 135.
[51] SAIC, 2013 Updated Solar PV Value Report of Arizona Public Service (May 10, 2013). *(SAIC Report). Please see:* *https://azenergyfuture.files.wordpress.com/2013/04/2013_updated_solar_pv_value_report.pdf*

twenty years, but I think the analysis may be from 2014-2034) of 21.5-23.7 cents/kWh-more than six times what SAIC Report found.[52] In part, this can be traced to the inclusion by Crossborder Arizona Study of the category of "avoided renewables"—not considered by SAIC Report. But this accounts for only 4.5 cents of the difference. The rest can be traced mostly to differences in estimates of generation capacity and transmission savings, and to some extent to difference in energy costs. What is happening here? Below, I review a few key issues of conflict between the two analyses.

"Snapshot" vs. "levelized cost" analysis

One area of apparent disagreement is really a question of data presentation, but it is a difference that makes clear comparisons between the two studies difficult. SAIC Report presents "snapshots" of the VOS in three different years: 2015, 2020, 2025—capturing how this value changes as natural gas prices are assumed to rise, along with the price of carbon allowances, and integrating different capacity savings values depending on whether solar capacity is judged to be adequate to postpone capacity additions in the given year. Crossborder Arizona Study prefers the (to me, rather confusing) "levelized" analysis, over the years from approximately 2014-2034 (I don't see the exact dates identified anywhere in the text, however). For this reason, it is difficult to know what comparisons between the exact numbers of the Crossborder Arizona Study and the SAIC Report mean-though the best comparison may be between SAIC Report's 2025 numbers (approximately the midpoint of Crossborder's range of years) and Crossborder's "levelized" number.

---

[52] Beach, Thomas R., and Patrick G. McGuire. *The Benefits and Costs of Solar Distribution Generation for Arizona Public Service*. Crossborder Energy Consulting (May 8, 2013). (*Crossborder Arizona Study) Please see*: http://www.solarpowerdemocracy.org/wp-content/uploads/2014/03/Crossborder_AZ_2013.pdf

Highly technical methodology debates

There is a significant difference in the estimates of avoided energy costs that is difficult to understand, even once you get beyond the differences of "levelized" vs. "snapshot" analysis. SAIC Report's "snapshot" of solar PV value in 2025 estimates avoided variable costs (including fuel and carbon charges) of only 5.93 Cents/kWh. Crossborder Arizona Study sticks with its "levelized analysis," so it does not present a number that can be exactly compared—but its weighted annual 20 year levelized cost figure for its base case is 7.1 cents.

It is impossible to tell, based on the discussion available in the two papers, what the source of the discrepancy is. Assumptions (generous, in hindsight) about the rising cost of natural gas seem to be the same. Both studies assume (plausibly) that the marginal generation being displaced by rooftop solar will be natural gas. Crossborder Arizona Study actually assumes a slightly lower carbon allowance cost than the SAIC Report, so that can't be the reason for Crossborder's higher numbers for the cost of the energy likely to offset by rooftop solar power. Crossborder Arizona Study suggests that an analysis of implied heat rates points to unrealistic assumptions on the part of the SAIC Report about how efficient natural gas plants will be in the future.[53] Further technical discussion would be needed to clarify this point, identify whether it is the source of the discrepancy; and determine if the heat rate assumptions in the model used by the SAIC Report are reasonable. For now, it serves nicely to illustrate the complexity of value analysis, and how easy it is to come up with significantly different values, even when working with similar assumptions.[54]

---

[53] Crossborder Arizona Study at 8.

[54] The differences in methodology between SAIC and Crossborder, and trying to ascertain which report is more accurate is a perfect example of why relying on "value" analysis is so subjective and easy to bias. Why one would choose to use it, and get into an esoteric methodological debate, when market data and/or cost accounting is readily available and quite transparent, is inexplicable unless proponents of "value" analyses were dissatisfied with the results of cost accounting and/or the market. That constitutes good reason to approach VOS studies very cautiously, with eyes wide open for built in bias.

Capacity and peak

The SAIC Report correctly understands the relationship between capacity and peak load. Capacity needs are determined by peak load, not average load. Given that, as the SAIC Report says, "{t]he APS system peak is somewhat unique, in that it extends past sunset due to the impact from the desert heat," there is what the SAIC Report describes as a "lower coincidence with solar PV production than otherwise would be expected."[55] I would say that is putting it mildly. To the extent that peak occurs after sunset, there is zero coincidence with solar PV production. It mystifies me how solar can be considered to have any meaningful capacity impact in this circumstance; however, the SAIC Report merely "discounts" solar's capacity by about 50% and goes on to consider its impact on the need for major projects. The SAIC Report's valuation of rooftop solar's capacity value is generous.

Capacity

The topic of capacity is where the studies diverge the most. Here there is sharp contrast between the SAIC Report's fact based approach and what can only be described as speculative hand-waving in the Crossborder Arizona Study.

The SAIC Report takes the generating resource mix as of 2012 as a given, and asks what capacity additions will be needed, and whether and when additional rooftop solar might allow capacity investments to be deferred. The SAIC Report notes that APS's capacity needs are fully met until 2017, and finds only limited prospects for deferral of investment after that time.

Crossborder does not disagree that no new capacity is needed before 2017-but it claims credit for existing solar for "contributing to" preventing the need for new capacity up to

[55] SAIC Report at 2-18.

that date. It does not present any evidence that without solar, additional investment would have been needed, but goes ahead and "credits" solar "installed before 2017" with "greater value."[56] This is all poorly defined and explained. How much value is being attributed here? Why are they talking about solar panels installed before 2012 at all, when this report seemed to be about the VOS installed in 2014? If capacity additions to 2017 are deferred based on 2012 capacity by itself, why should rooftop solar added between 2012 and 2017 share the "credit" for this, as Crossborder suggests it should?

One or two paragraphs of speculation follow about possible hedging value if there are sudden losses of capacity (rooftop solar is only a "hedge" against unexpected costs if committing ahead of time to incur the highest costs possible reduces anxiety), and whether peak demand might shift into higher-solar hours—but it is all summarized in a table (table 4 on page 10 of the Crossborder study) which assumes that every unit of solar effective load-carrying capacity offsets an actual investment in capacity, without regard to whether additional capacity is needed in the system or not, or whether the limited additional peak capacity offered by solar is enough to make building a new power plant unnecessary.

There is no coherent argument here. The analysis does not bear comparison with the SAIC Report's careful fact-based analysis of actual planned capacity needs in the system and how solar might contribute.

Avoided Renewables Cost

I discuss above the flaws with valuing this category of benefits, including that it is so often combined with "values" attributed to "avoided emissions," even though rooftop solar is an extremely inefficient way to pursue emissions reductions. In the case of Arizona, although the Crossborder study claims benefits here, the fact that APS already

[56] Crossborder Arizona Report at 9.

had plenty of renewables to meet it state requirement means that the benefits of the additional renewables, from the point of view of meeting requirements, are zero

Q. IS IT RELEVANT, AS THE CROSSBORDER STUDY SUGGESTS, THAT "IT IS CUSTOMERS WHO MAKE INVESTMENTS IN DG RESOURCES?"[57]

A. Not in terms of the value provided to the utility. Customers (and, especially, rooftop solar installation companies) who make investments in rooftop solar are not making a free contribution of capital to the system. They are making a calculated investment, based on their own assumptions about utility rate policy, that the utility will more than compensate them for the full value of the investment. So far, they have been right about this in all cases I am aware of. In effect, what is happening is that customers are making investments on the utility's behalf, over which it has no oversight or control, but the cost of which the utility is obliged to fully repay, with interest (plus a healthy profit margin to the rooftop solar company).

Q. WHAT IN YOUR VIEW IS THE KEY PROBLEM ILLUSTRATED BY THE MAINE STUDY?

A. The Maine study illustrates the crucial importance of getting marginal energy right. Among the studies I examine here, the Maine study takes the prize for the highest identified "VOS," with a "levelized" value of 33.7 cents per kWh over the 25 years analyzed.[58] It also, in my view, takes the prize for the most blatant and inexcusable distortion.

Avoided Environmental Costs

This category is much higher in the Maine study than in many other studies (a levelized value of 9.6 cents per kWh), and rewards closer examination. The Maine study gets a

[57] Crossborder Arizona Study at 13.
[58] *See* Maine Distributed Solar Valuation Study.

significant amount of this value from the calculation of avoided costs related to sulfur dioxide (SO2) and nitrous oxide emissions (NOx), which can have significant and costly health impacts. The Maine study is not the only one that includes costs related to SO2 and NOx emissions, but, compared to other studies examined here, it finds a much greater effect—surprisingly large, assuming rooftop solar generally replaces natural gas generation, since natural gas generation has very low emissions of these pollutants. The big culprit in SO2 and NOx emissions is coal-fired generation.

So is the marginal resource in Maine that is being displaced coal generation? Analysis elsewhere in the Maine study would suggest not—avoided energy cost calculations are tied to natural gas futures and price forecasts. However, if you read the appendix (to its credit, unlike many other VOS reports, which are not as thorough in documenting their methodology, the Maine report clearly documents its dubious analytical choices—though the reader must be diligent to find the necessary information), the authors note that the AVERT data used to calculate emissions "includes New York, which is not part of the ISO-NE control area."[59] The appendix goes on to clarify that if the authors had in fact limited the analysis to "FTA rates"—emissions rates for units fueled with oil and natural gas (closer to what they assume is being displaced in their marginal cost analysis) emissions rates would have been radically lower—the appendix goes on to acknowledge that "If the FTA rates were used rather than the AVERT results assumed for this study, the displaced emissions and the net social costs calculated below would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively."[60] What this boils down to, in my opinion, is an admission that the "value" attributed to SO2 and NOx emission reduction is a complete fiction, based on a calculation that rooftop solar in Maine would somehow reduce coal plant emissions in New York. This is ridiculous. Coal is at all times unlikely to be used as a marginal

[59] *Id.* at 83
[60] *Id.* at 84.

resource—and these coal plants are not even part of the same dispatch system as Maine! While it is to their credit that the authors so clearly explain the problem in the appendix, why the authors use this number as if it means something in the main body of the report is beyond me. The tone of the report suggests a sober, earnest, scholarly analytical effort—but this shameless distortion makes me think that what is really going on is an attempt to use analytical tricks to inflate the VOS in whatever way is possible.[61]

Taking this egregious problem together with other issues, Maine study's 33.7 cent "levelized value" is extremely doubtful. "Social cost" analysis in the Maine study adds up to 9.6 cents of the "levelized" 33.7 cent/kWh value—a significant percentage of the value that is found. Another 10.3 cents of "value" are attributed to categories which, as I argue above, should not be considered at all in "value" analysis—market price response (that is, buyer side market power that creates long-term capacity problems) and avoided fuel price uncertainty (in this analysis, the uncertainty that seems to be avoided is lower natural gas costs). The avoided energy cost of 8.1 cents per kWh is tied to what it is already clear are erroneous forecasts of ever increasing natural gas prices. And the avoided generation capacity costs (5.6 cents/kWh) do not reflect that this is intermittent and off peak capacity, and therefore has negligible, if any, impact, on capacity needs—hardly savings the utility can take to the bank. The staggering Maine avoided cost numbers just do not stand up to scrutiny.

[61] I believe the same problem impacts estimates of avoided CO2 emissions—once again, the report relies here on annual avoided emissions calculated from AVERT—which includes coal plants, whose CO2 emissions are significantly higher than natural gas plants.

V. POLICY IMPLICATIONS OF PROBLEMS WITH VOS ANALYSIS

Q. YOU HAVE RAISED A NUMBER OF CONCERNS ABOUT VOS ANALYSIS, AND GIVEN EXAMPLES OF SEVERAL ANALYSES THAT ALL COME TO WIDELY DIFFERENT (BUT DOUBTFUL) FIGURES FOR THE VOS. WHAT ARE THE POLICY IMPLICATIONS OF DOING VOS ANALYSIS WITH THESE LIMITATIONS?

A. I see several significant policy implications here:

First, VOS analysis overlooks how certain methods of rewarding "value" disincentivize efficiency and innovation, and it overlooks opportunity cost of privileging dumb solar over smarter solar.

The VOS studies largely ignore the issue of how rate design and pricing affect the long term viability of rooftop solar as an energy resource. They focus almost exclusively on establishing a specified value for purposes of setting prices today. Given that these studies are called "Value of Solar," that is a remarkable omission. This is an important point. It's a point that was really made in the MIT study.[62] Prices for solar arrangements should encourage innovation by incentivizing storage, incentivizing methods of capturing system benefits such as encouraging western as opposed to southern exposure to make it more coincident with peak, or incentivizing the use of smart invertors, among other options. But if instead you simply subsidize or come up with an above market price[63] for the most primitive use of the technology, you do a positive harm to the future of solar. You're not incentivizing increases in productivity. In fact, you incentivize exactly the opposite.

Second, VOS analysis is often used to justify incentives that seem to be distorting the market

[62] *The Future of Solar Energy*. MIT. 2015. (MIT Study) *Please see*: https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

[63] The Louisiana study, of course, does not try to artificially raise the price of rooftop solar, but almost all of the others do so, Nonetheless, that study also suffers from the flaw of considering how prices and rate design could incentivize a more prominent role for rooftop solar.

What's really interesting is that VOS analysis often overlooks (and I've never seen this in any study) the fact that the cost of solar panels have declined rapidly in the past few years. That's a good thing. But as pointed out by the Lawrence Berkeley Lab, installation costs curiously remain high.[64] In fact, of the major economies in the world, with the exception of France, the United States has the highest installation costs of solar anywhere in the world.[65] Why? One possibility is that because net metering sets such an arbitrarily high price, solar vendors and lessors don't need to compete against other resources in the energy market and face no pressure to pass on declining costs to customers. In fact, they pocket those costs. Without any impetus to pass savings onto customers, rooftop solar vendors and lessors derive almost all of the benefits associated with declining panel costs.[66]

Not a single VOS study looks at the costs of devising subsidies and cross subsidies to insulate rooftop solar vendors/lessors from the ordinary pressures of the market. Stated a bit differently, they never raise the seminal question of whether rooftop solar, and consumers in general, would do better in the long run by competing in the long run, as opposed to being priced at the artificial levels derived from highly subjective VOS studies, or the equally artificially high rate inherent in net metering. The VOS studies blithely ignore the fact that there is a functioning marketplace for energy (or its functional equivalent through cost-based regulation, and create a kind of fantasy world where neither exists. The VOS studies fail to even acknowledge markets and regulation

[64] Barbose, Galen and Naim Darghouth. *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2015). *Please see*: http://energy.gov/sites/prod/files/2015/08/f25/LBNL%20Tracking%20the%20Sun%20August%202015.pdf.

[65] *Id.* at 23.

[66] This theory is supported by the most recent 10K filing by the nation's largest rooftop solar provider, Solar City, in which they state: "We compete mainly with the retail electricity rate charged by the utilities in the markets we serve,.." In other words, they make no effort to be price competitive with other energy sources, but, rather, with the much higher full cost of delivered energy. Thus, the full and substantial differential between the cost of energy alone and the full delivered cost of energy is left for the rooftop solar vendors to capture for themselves.

as benchmarks to assess the reasonableness of the "value" figure derived from the studies.

Third, VOS analysis neglects other renewable resources, market realities, and the future of solar itself

If you look at the major renewable resources—wind, large scale solar, distributed solar—where you have renewable portfolio standards, rooftop solar almost always comes out at the bottom in terms of efficiency in reducing carbon. And yet we're paying the highest price for the least efficient product. Why? What justifies this discrepancy? For the purposes of understanding VOS, we need to look at this issue and determine how it affects the VOS. This inefficiency detracts from the value of distributed solar, and needs to be reflected in any analysis of the value. It is noteworthy that most, if not all, VOS studies simply do not address why other, more efficient forms of renewable energy should be treated differently, for pricing purposes, than rooftop solar. They do not even suggest that perhaps the price of grid-scale solar and wind might be used as a benchmark to assess the reasonableness of the value figure they derive. They also fail to address the fact that artificially high prices for a less efficient resource will inevitably lead to a reallocation of capital toward the less efficient resource, a development with adverse consequences. Significantly, VOS studies simply do not even consider what their valuation, and the pricing that follows from it, does to the future of solar; whether it would incentivize or disincentivize productivity gains, technological innovations, or enable rooftop solar to be more responsive to the needs of the overall system. These are very serious failures in VOS studies and substantially reduces, if not entirely eliminates, their contribution to the debate over how to price rooftop solar.

VI. RECOMMENDATIONS

Q. SO WHAT DO YOU RECOMMEND?

A. A first step would be to get very clear about a number of things that VOS is not:

VOS is not the same as what solar costs or how it ought to be priced

Appropriate pricing for generation should be based on the competitive market, or, absent that, cost based regulation. VOS-based pricing is neither of these, and, for the reasons I have noted, it is simply an artificial, largely arbitrary and meaningless construct. Calling for VOS studies seems premised on the assumption that neither competition nor cost-based regulation will capture all of the values associated with rooftop solar. That may or may not be true. But regardless, the same may or may not be true about every other resource, so why single out rooftop solar, the least efficient of our commonly used renewable energy resources, for special consideration? Absent a market or cost basis, there's no intrinsic assessment of whether rooftop solar is the most cost-effective way of providing a given value. If we paid for everything that way, things would get very expensive (think of what the value of the grid would be, subjected to a similar analysis.)

Second, VOS is not a good tool for environmental policy.

A key element in value of solar analyses comes from factoring in externalities, such as carbon emissions. It may be appropriate to recognize these as "values," in a value of solar analysis, but it is important to be clear that this may not appropriately translate into pricing. Reflecting such values in pricing is a policy decision, not an administrative decision.

Third, inflating the VOS number is not in the long-term interests of the development of solar energy or of customers, solar and non-solar alike.

VOS analyses tend to focus on preserving, and perhaps even enhancing, cross subsidies inherent in pricing such as net metering, and not on increasing productivity and efficiency in ways that will incentivize solar to be even more competitive. Shielding the rooftop solar industry from cost pressure, however, does not translate into increased deployment or productivity of rooftop solar, nor into customer benefits. Often, it simply translates into increased rooftop solar industry profits. When we pay for something without market competition and/or cost based regulation, we aren't giving the technology incentives to maximize value, as discussed above, even by a simple measure such as ensuring solar panels are facing the right way. We are certainly not giving incentives to pursue more ambitious efficiency maximizing efforts, such as incorporating battery storage, or leveraging the potential of smart inverters associated with rooftop solar installations to help regulate power flow.[67]

Fourth, VOS is NOT a justification for backdooring things that are properly public policy issues—we need to think about who has responsibility/authority for internalizing externalities, and where that discussion/decision should take place.

I talked earlier about values related to environmental services. Often, VOS studies approach this issue as a merely technical discussion of the health and environmental impacts of emissions. However, there are important policy issues at stake here that should be consciously considered, not assumed to be simple questions of technical analysis.

For example, the issue of how best to incorporate the cost of carbon emissions into calculations of the VOS is complex and involves many judgments calls. It's true that if you're anticipating that carbon is going to be regulated and you want a hedge against that risk, there's a logic to taking appropriate action. The problem is that there's also a

[67] Potential marketization of services like those provided by smart inverters was discussed in a seminar presentation by Michael Caramanis on the topic, "Extending Locational Marginal Cost Pricing to Retail Electricity Markets and Distributed Energy Resources," seminar presented at Harvard University, September 21, 2015. Slides available at http://www.hks.harvard.edu/m-rcbg/cepr/CaramanisHarvardSept21%202015.pdf.

huge risk associated with guessing wrong. If you pick a technology that turns out not to be the most cost effective, or one that turns out to stick the state with a lot of costs as it develops its implementation plans, utility customers can experience significant consequences. That point was driven home in the EPA's proposed Clean Power Plan rules, recently stayed by the U.S. Supreme Court. In the originally proposed rules, rooftop solar was accorded basic building block status for compliance, but in the revised, final rules, that status was taken away. Thus, while rooftop solar could still be used for compliance purposes, it no longer carried with it the imprimatur of a basic building block. Hence its value for complying with emissions regulation was reduced. No VOS study even recognizes the risk that heavy investment in rooftop solar to reduce carbon emissions may end up being a costly mistake as a strategy to reach carbon goals. How much reliance can be placed on a study that fails to even acknowledge that risk, or for that matter, as the German experience has demonstrated, that rooftop solar might not even reduce carbon emissions at all? Indeed, the claims found in most VOS studies that rooftop solar is a hedge against future environmental regulation, may, in fact, turn out not to be a hedge at all, but rather a very costly leap of faith, a risk most VOS authors either overlook or choose to ignore.

Q. SO CAN/SHOULD VOS ANALYSIS BE USED?

A. VOS studies add very little value to the debate over rate setting. While they may add something to the debate in regard to specific issues that they examine, taken as a whole, VOS studies that simply add up long-term projected "benefits" without any market context are not worth the paper they are written on. They are too subjective, too arbitrary, too biased, too methodologically suspect, and too disconnected from the realities of costs and markets to be of much use in establishing principles for pricing rooftop solar.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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 Regulacíon e Infraestructura, Fundación Getulio Vargas, Rio de Janéiro, 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

PUBLICATIONS

Brown, Ashley, Jillian Bunyan. "Valuation of Distributed Solar: A Qualitative View." The Electricity Journal. 27.10 (2014): 27-48.

Brown, Ashley. "Power of Connections." The Indian Express, March 10, 2014.

Brown, Ashley and Louisa Lund. "Distributed Generation: How Green? How Efficient? How Well Priced?" The Electricity Journal, April 6, 2013.

Brown, Ashley, and Victor Loksha. "International Experience with Open Access to Power Grids: Synthesis Report." ESMAP Knowledge Series 016/13, November 2013.

Brown, Ashley. "Concessions, Markets and Public Policy in the Brazilian Power Sector." September 5, 2012.

Brown, Ashley. "Coming Out of the Dark: For one, prices must communicate to customers the actual cost of energy at the time of consumption." The Indian Express, August 8, 2012.

Tolmasquim, Mauricio T. Power Sector Reform in Brazil. Preface by Dilma Rousseff. Afterword by Ashley C. Brown. 2012 Empresa de Pesquisa Energetica (EPE).

Brown, Ashley, and Francesca Ciliberti-Ayres. "Development of Distributed Generation in the United States." A Report Prepared for Empresa de Pesquisa Energetica (EPE), November 20, 2012.

Brown, Ashley, Steven Levitsky, and Raya Salter. "Smart Grid and Competition: A Policy Paper." Prepared for the Galvin Initiative, July 28, 2011.

Brown, Ashley. "Can Smart Grid Technology Fix the Disconnect Between Wholesale and Retail Pricing?" Vol. 24, Issue 1 (Jan./Feb. 2011): 1040-6190.

Brown, Ashley, and Raya Salter. "Smart Grid Issues in State Law and Regulation." White Paper sponsored by the Galvin Electricity Initiative, September 17, 2010.

Brown, Ashley, and James Rossi. "Siting Transmission Lines in a Changed Milieu: Evolving Notions of the 'Public Interest' in Balancing State and Regional Considerations." *University of Colorado Law Review* 81, no. 3 (Summer, 2010).

Brown, Ashley. Infrastructure: The Regulatory and Institutional Dimension. June 2010. 36 pages.

Brown, Ashley, James F. Bowe Jr., Julio A. Castro, and Sonia C. Mendonca (Dewey & LeBoeuf LLP) The Financial Crisis and Implications for U.S.-Mexico Brazil's New Natural Gas Law. *Latin American Law and Business Report* Volume 17, Number 5, May 31, 2009. 5 pages.

Brown, Ashley and James Rossi. *Siting transmission lines: evolving the "public interest" to balance state and regional considerations.* Version 1.0, dated August 3, 2009. The paper was originally prepared for the National Renewable Energy Laboratory" s Conference on Multistate Decision Making for Renewable Energy and Transmission: Spotlight on Colorado, New Mexico, Utah, and Wyoming, August 11, 2009, Denver, Colorado.

Brown, Ashley. *Equitable Access to Basic Utilities: Public versus Private Provision and Beyond. Poverty in Focus.* International Policy Centre for Inclusive Growth Poverty Practice, Bureau for Development Policy, UNDP. Number 18, August 2009. 36 pages.

The Funding of Independent Regulatory Agencies. A Special Report to the Public Utilities Commission of Anguilla. June 2008. Report, 66 pages.

Walking the Tightrope: Balancing Competing Interests in Pursuit of Good Public Policy. Fair Trading Commission of Barbados, Third Annual Lecture. 23 February.19 pages.

Baldick, Ross and Ashley Brown, James Bushnell, Susan Tierney and Terry Winter. *A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles*. September, 2007.

Brown, Ashley C.; Stern, Jon; and Tenenbaum, Bernard. *Handbook for Evaluating Infrastructure Regulatory Systems.* Washington, DC: World Bank Publications, 2006.

Brown, Ashley C. Epilogue to *Keeping the Lights On: Power Sector Reform in Latin America* (Millan, Jaime, and Nils-Henrik M. von der Fehr, editors), Inter-American Development Bank (ISBN 1-931003-55-6).

Brown, Ashley C. and Damon Daniels: "Vision Without Site; Site Without Vision," *The Electricity Journal* (October 2003), Vol. 16, Issue 8: 23-34.

Brown, Ashley C. "Regulators, Policy-Makers, and the Making of Policy: Who Does What and When Do They Do It?" *International Journal of Regulation and Governance* (June 2003), Vol. 3, No. 1: pp 1-11.

Brown, Ashley C. "SMD Drawing RTO Battle Lines," *Electric Light & Power* (February 2003): 4.

Brown, Ashley C. "Strengthening of the Institutional and Regulatory Structure of the Brazilian Power Sector," The World Bank: December 2002.

Brown, Ashley C. "The Duty of Regulators to Have Ex Parte Communications," *The Electricity Journal* (March 2002): 10-14.

Brown, Ashley C. "The Privatization of Brazil's Electricity Industry: Sector Reform or Restatement of the Government's Balance Sheet," Inter-American Development Bank (January 2002).

Brown, Ashley C. "Confusing Means and Ends: Framework of Restructuring, Not Privatization, Matters Most, " *International Journal of Regulation and Governance* (January 2002), Vol. 1, No. 2: 115-128.

Brown, Ashley C. "Six Critical Choices of Regulatory Models for Brazil," *The Journal of Project Finance* (2002), Vol. 4, No. 1: 29-40.

Brown, Ashley C. "When do Risk Mitigation Measures Exacerbate Risks in Infrastructure Industries Abroad? Some Long-Term Considerations for Investors." In *Global Infrastructure Development, World Markets in 1999*, London: World Market Research Centre, McGraw-Hill Companies, Inc. 1998.

Brown, Ashley C. "Six Critical Choices of Regulatory Models for Brazil." *The Journal of Project Finance*, Volume 4, Number 1 (Spring 1998): 29-40.

Brown, Ashley C. "Regulatory Risk: Is the Subject Still Relevant or do Markets Govern?" 13 *Yale Journal on Regulation,* (Winter 1996): 403-411.

Brown, Ashley C. "Honey, I Shrunk the Franchise!" *The Electricity Journal* (March 1995): 72-77.

Brown, Ashley C. "The Trinity of Transmission Issues: Siting, Access, and Pricing." *Maine Policy Review*, Volume 2, Number 1 (April 1993): 53-58.

Brown, Ashley C. "Electricity After the Energy Policy Act of 1992: The Regulatory Agenda." *The Electricity Journal*, (January-February 1993): 33-43.

Brown, Ashley C. "The Energy Policy Act of 1992: The Paradox Facing the States." *Public Utilities Fortnightly*, Volume 131, Number 1 (January 1, 1993): 26-28.

Brown, Ashley C. "Sunshine May Cloud Good Decision Making." *Forum for Applied Research and Public Policy*, Volume 7, Number 2 (Summer 1992): 113-116.

O'Neil, Richard P. and Brown, Ashley C. "Privatization and Regulation of the Oil, Natural Gas, and Electric Industries in Hungary." *Energy Law Journal*, Volume 13, Number 1 (1992): 25-42.

Brown Ashley C. and Barnich, Terrence L. "Transmission and Ratebase: A Match Not Made in Heaven." *Public Utilities Fortnightly*, Volume 127, Number 11 (June 1, 1991): 12-16.

Brown, Ashley C. "State Public Utility Regulation and Title IV." In *The New Clean Air Act: Compliance and Opportunity*, edited by Reinier Lock and Dennis P. Hakawik, 177-182. Arlington, Virginia: Public Utilities Reports, Inc., 1991.

Brown, Ashley C. "The Overjudicialization of Regulatory Decisionmaking." *Natural Resources and Environment*, Volume 5, Number 2 (Fall 1990): 15-16

Brown, Ashley C. "A Possible Tradeoff of Federal and State Transmission Jurisdiction." *Public Utilities Fortnightly*, Volume 124, Number 10 (November 9, 1989): 21-23.

Brown, Ashley C. "State Power Over Transmission Access and Pricing: The Giant Will Not Sleep Forever." *Public Utilities Fortnightly*, Volume 124, Number 10 (November 9, 1989): 21-23.

Brown, Ashley C. "The Balkans Revisited: A Modest Proposal for Transmission Reform." *The Electricity Journal*, Volume 2, Number 3 (April 1989): 32-39.

Brown, Ashley C. "Breaking the Transmission Logjam." *The Electricity Journal*, Volume 1, Number 1 (July 1988): 14-19.

Brown, Ashley C. "Percentage of Income Payment Plans: Regulation Meets Social Reality." *Public Utilities Fortnightly*, Volume 119, Number 6 (March 19, 1987): 9-12.

W. P. CAREY SCHOOL of BUSINESS
ARIZONA STATE UNIVERSITY
seidman research institute

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 ***Only positive <u>or</u> negative impacts***	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net ***Both positive <u>and</u> negative impacts***	• Alvarez et al., 2009 • Frondel et al., 2009	• 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
Maricopa County	*-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.

Table of Contents

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	*AECOM (July 2011)* Economic and Fiscal Impact Analysis of Residential Solar Permitting Reform
California	*Vote Solar Initiative (April 2013)* Economic and Job Creation Benefits of SB 43/AB 1014
Illinois	*Loomis, Jo and Alderman (December 2013)* Economic Impact Potential of Solar Photovoltaics in Illinois
Montana	*Comings, Fields, Takahashi and Keith (June 2014)* Employment Effects of Clean Energy Investment in Montana
Montana	*Energy and Telecommunications Interim Committee (January 2016)* Quantifying the Economic Impacts of Net Metering in Montana
Massachusetts	*Motamedi and Judson (March 2012)* Modeling the Economic Impacts of Solar PV Development in Massachusetts
Missouri & U.S.	*Treyz, Nystrom and Cui (October 2011)* A Multiregional Macroeconomic Framework for Analyzing Energy Policies
Nevada	*Vote Solar Initiative and Clean Energy Project (2011)* Economic and Job Creation Benefits of the Nevada Solar Jobs Now Proposal of 2011
New York	*NYSERDA (January 2012)* New York Solar Study
Rhode Island	*Berkman, Lagos and Weiss (2014)* Distributed Generation Contracts Standard Program and Renewables Energy Fund: Jobs, Economic and Environmental Impact Study
Andalusia	*Cansino, Cardenete, Gonzalez, and Pablo-Romero (2013)* Economic Impacts of Solar Thermal Electricity Technology Deployment on Andalusian Productive Activities: A CGE Approach
Germany	*Frondel, Ritter, Schmidt and Vance (2009)* Economic Impacts from the Promotion of Renewable Energy Technologies - The German Experience
Ontario	*Pollin and Garrett-Peltier (2009)* Building the Green Economy: Employment Effects of Green Energy Investments for Ontario
Spain	*Alvarez, Jara, Julian and Bielsa (March 2009)* 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 *Only positive <u>or</u> negative impacts*	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net *Both positive <u>and</u> negative impacts*	• Alvarez et al., 2009 • Frondel et al., 2009	• 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)	• 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	• 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:
	  ○ 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	• 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	• 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 \$)	• Current permitting scenario assumes:
	  ○ 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	• VSI (2010) Colorado; • VSI (2011) Nevada; • VSI (2011) Iowa; and • The Solar Foundation (2013) Colorado.
Objective(s)	• 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	• 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	• Crystalline Silicon – fixed mount commercial; single axis tracking utility scale.
	• For both pilots, study assumes the following local purchases:
	  ○ 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:
	  ○ 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	• 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 $)	• 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	• 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	• Installations profile: o 10% residential (80% retrofits, 20% new construction); o 10% small commercial; o 20% large commercial; o 60% utility-scale. • 100% local purchases: o Labor and soft costs (permitting and business overhead); and o 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 instate manufacturing per scenario – 0%, 5%, and 10%.
Solar Growth Projection Assumptions	• 2,292 MW, 2714 MW, or 11,265 MW by 2030.
Effects Scaled per Year (2015 $)	• For all 3 scenarios at 10% in-state manufacture: o 12.2 gross job years per MW installed; o Approximately $107,000 GSP per MW per year (2015 $); and o 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)	• Assess the economic impact of the
	  ○ Construction of 305 MW of solar PV, 2012-2018; and
	  ○ Operation of solar PV installations, 2012-2025.

Geography	Massachusetts
Time Period	• 2012-2018 construction; and • 2012-2025 operations.
Modeling Tool	REMI
Type of Effects Examined	• ***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	• 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	• 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 $)	• 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	• Construction impacts (RPS implementation), 2011-2021. • Operational impacts, 2011-2035.
Modeling Tool	REMI
Type of Effects Examined	• ***Partial Net*** study.

Model Assumptions	• 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:
	  ○ 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:
	  ○ 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:
	  ○ 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	• 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 $)	• 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,

[redacted]	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)	• Estimate employment impacts of construction and O&M activities associated: ○ Large-scale wind; ○ Large-scale solar PV; ○ Small-scale solar PV (rooftop), and ○ Energy efficiency.
Geography	Montana
Time Period	• 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	• ***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	• 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	• 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	• 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)	• Evaluate economic development impacts of the installation of net metering systems in terms of the following benefits and costs:
	  ○ 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	• 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	• 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:
	  ○ Consider *full* 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	• 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	• 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	• VSI (2010) Colorado; • VSI (2011) Iowa; • VSI (2013) California; and • The Solar Foundation (2013) Colorado.
Objective(s)	• 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	• This is a very simplistic and rather opaque ***Partial Gross*** analysis since it lacks *any* consideration of the negative impacts of expansion.
	• It is biased in terms of its assessment of economic impacts since it does not:
	  o Consider any non-solar energy sector losses;
	  o Take into account utility obligations from a transmission and distribution grid perspective in terms of savings, upgrades or modifications;
	  o Quantify the impact of a reduction in the demand for centralized power generation due to increased distributed generation;
	  o Consider the economic impacts of rebate dollars paid to DG homeowners and installers;
	  o Examine the economic impacts of reduced spending on other categories of expenditure throughout the expansion phase from capital expenditures on DG solar systems; and
	  o Consider the administrative costs associated with changing permitting rules.

Model Assumptions	• 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	• 365 MW installed 2011-2020.

Effects Scaled per Year (2015 $)	• Over the period 2011-2020, The Solar Jobs Now Proposal is estimated to have:
	  o A gross jobs impact of 28.5 job years/MW;
	  o $443,400 GSP per MW per year (2015 $); and
	  o $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	• ***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:
	  ○ 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:
	  ○ The above-market costs of PV;
	  ○ Net metering costs; and
	  ○ Savings generated by the suppression of wholesale electricity prices.
	• Net environmental impacts include:
	  ○ 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	• Three scenarios:
	  ○ 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	• Achieve 5,000 MW solar PV deployment by 2025.
	• Four policy options are analyzed to stimulate demand:
	  ○ 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 Scaled per Year (2015 $)	• 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	• 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)	• 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	• 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	• 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	• Three (assumed not forecast) scenarios above 2013 40 MW are assessed: ○ 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 $)	• Average annual GSP per MW: ○ 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: ○ 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)	• 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	• 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	• ***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	• 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	• For the single plant analysis:
	  ○ 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	• 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	• ***Count Net*** study which balances gross renewable sector gains with: ○ 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: ○ 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	• 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	• Germany had 5,311 MW installed PV capacity in 2008.
Effects Scaled per Year (2015 $)	• 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)	• Considers the employment benefits of two Ontario green investment agendas: o 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 o 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	• 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	• ***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	• Uses three factors to establish relative employment effects of alternative green investments: o Labor intensity of spending – that is amount spent on workers rather than land, energy, or materials; o Local content of spending; and o 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	• 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	• 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	• ***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	• 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	• Assumes that Spain has installed 2,934 MW solar PV by 2008.
Effects Scaled per Year	• 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
Gross *Only positive or negative impacts*	• 70 gross job years per MW	• Range of 5 to 73.5 gross job years per MW. • Range of $106,830 to $1.24 million GSP per MW per year.	• $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]
Net *Both positive and negative impacts*	• -8.99 private jobs per MW per year	• 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.

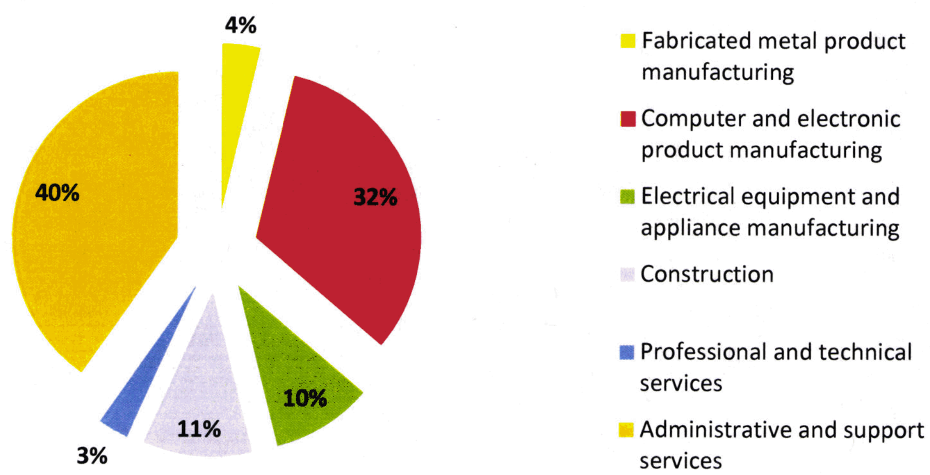
Approximately 86% of the solar installations are assumed to occur in Maricopa County, 5% in Pinal County, and 9% in Yuma County in each scenario.

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 Sectors[29]	**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 Sectors[36]	**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

Table8 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 Sectors[43]	**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 *Only positive or negative impacts*	• Pollin and Garrett-Peltier, 2009 • ETIC, 2016	• AECOM, 2011 • Loomis, Jo & Alderman ,2013 • Motamedi & Judson, 2012 • VSI and Clean Energy Project Nevada, 2011 • VSI, 2013 • Comings et al. , 2014	• Cansino et al. 2013
Net *Both positive and negative impacts*	• Alvarez et al., 2009 • Frondel et al., 2009	• 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.

ASU W. P. CAREY SCHOOL of BUSINESS
ARIZONA STATE UNIVERSITY
seidman research institute

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

DIRECT TESTIMONY OF BRADLEY J. ALBERT

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

February 25, 2016

Table of Contents

DIRECT TESTIMONY OF BRADLEY J. ALBERT
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Brad Albert. I currently serve as the General Manager – Resource Management for APS. In this position, I have responsibility for overseeing the Company's energy commodity trading activities, long-term resource acquisition, fuel supplies, and fuel transportation.

Q. DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from New Mexico State University in 1984. In 1990, I was awarded a Masters of Business Administration degree from Arizona State University.

I began my career with APS in 1984. In the almost 32 years that I have been with the company, I have served in various management and individual contributor roles in resource planning, energy trading, wholesale transaction structuring and pricing, risk management, and nuclear power plant licensing.

II. <u>SUMMARY OF TESTIMONY</u>

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. A major focus of this proceeding is estimating the value of residential distributed solar photovoltaic systems or rooftop solar. My testimony provides several methods for calculating the value of rooftop solar. Although these methodologies differ in several respects, the ultimate reason for conducting these types of analyses is to inform policy decisions regarding rooftop solar.

Retail rates must be based on actual costs and the application of cost of service principles, as discussed by APS witness Snook. However, a Value of Solar (VOS) calculation can play a valuable role for policy makers. The VOS can inform resource planning decisions and can be used to evaluate and even establish how rooftop solar is incentivized. For example, the Commission can consider the VOS in determining the amount paid to customers who export energy to the grid from their rooftop solar systems. The Commission could also use the VOS to establish additional transparent incentives, such as the up-front cash incentive that the Commission authorized for a period of time.

Q. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR TESTIMONY.

A. In my testimony, I present three different VOS methodologies:

- **Short-term avoided cost.** This would set a value for energy produced by rooftop solar based on reported market prices.
- **Long-term avoided cost.** This would begin with the methodology used in APS's 2013 SAIC study, with modifications that reflect additional information regarding system operations that APS has obtained since the SAIC study was conducted.
- **Adjusted grid-scale cost.** This methodology begins with a reported power purchase agreement (PPA) price for a grid-scale solar project, appropriately selected based on geography, timing, and other relevant factors. The

methodology then adjusts the grid-scale PPA price to account for real operational differences between grid-scale and rooftop solar applications.

These methodologies reflect the full range of appropriate values for rooftop solar. The short-term avoided cost method is at the lower end of the spectrum, and would provide less incentives to rooftop solar. However, it would reduce costs for all of APS's customers and is largely reflective of the cost that would have been incurred to replace the actual rooftop solar production with other power sources.

The long-term avoided cost and adjusted grid-scale cost are at the higher end of the spectrum, and would provide more rooftop solar incentives, but would also result in all other non-solar customers paying higher rates.

A benefit of both the short-term avoided cost method and the adjusted grid-scale methods is that they are both derived from competitive market sources. The short-term avoided cost method uses realized wholesale market energy prices while the adjusted grid-scale uses actual reported prices for grid-scale PPAs.

It is within the Commission's discretion to choose which methodology to adopt for determining the VOS. Based on the nature of the calculation, however, it appears that the price paid for a grid-scale solar PPA should be the ceiling for any VOS, after appropriate adjustments are made to reflect the operational differences between grid-scale and rooftop solar applications. Because both rooftop and grid-scale solar applications contribute the same benefits to the system, the goal should be to reduce costs to customers by obtaining those benefits for the least amount of money.

III. DESCRIPTION OF "VALUE OF SOLAR"

Q. DESCRIBE WHAT IS MEANT BY THE TERM "VALUE OF SOLAR."

A. Rooftop solar is simply another source of energy generation on APS' electric system. The APS electric system is comprised of many different sources of electric generation, each with its own characteristics like size, fuel source, responsiveness to dispatch control, etc. Solar generation is produced in many forms in the APS system including through heat generated by the sun (e.g., the Solana Generating Station near Gila Bend), larger "grid-scale" photovoltaic (PV) arrays that track the sun as it crosses the sky, and other fixed-position PV systems connected to the grid in other large arrays or on buildings throughout our service territory. Rooftop solar typically is associated with installations similar to the last example and are most commonly smaller scale, fixed position PV arrays built on customer homes and businesses. In the context of this case, the term "value of solar" refers to the value that the electric system receives from rooftop solar. Some of these benefits can be quantified and result in measurable cost savings to the electric system. For example, one can measure the cost savings of rooftop solar by how much it would have cost to produce the same amount of electricity from APS' other electric generation sources or, in some cases, to acquire low cost power in the wholesale market. Other purported benefits are difficult to quantify and don't result in a direct cost savings to the utility or utility customers.

Q. WHAT ARE SOME OF THE DIFFERENT WAYS TO CALCULATE THE "VALUE OF SOLAR"?

A. Calculations typically estimate the value of solar using either historical or prospective analyses. Using an historical perspective, for example, we could look at the rooftop solar electricity production yesterday and calculate how much it would have cost to either generate or purchase this electricity from other available sources. For this type of analysis, the inputs to the calculation are known — total customer demand, actual fuel prices, timing and availability of the resource, actual wholesale electricity market prices, etc.

Prospective analyses forecast the future benefits of a resource, relying on a set of assumptions, such as future customer demand growth, future fuel prices, cost, timing, availability and performance of alternative electric generation technologies, etc.

A third way to calculate the value of solar would be to estimate the cost of deploying solar PV technology at a grid-scale to achieve similar benefits.

Q. HOW SHOULD LONG-TERM ESTIMATES OF THE "VALUE OF SOLAR" BE USED?

A. To provide reliable and cost-effective service to customers, electric utilities make investments in assets with relatively long lives. For example, APS currently has generating plants that are providing service to our customers more than 40 years after they were initially placed into service. The initial decisions to make these long-lived investment decisions required the development of cost and value estimates that match the expected lifetime of the asset. Calculating the future value of solar is a function of resource planning and plays an important role in facilitating these types of long-range resource planning decisions.

Q. CAN YOU DIFFERENTIATE BETWEEN THE VALUE THAT AN INDIVIDUAL ROOFTOP SOLAR CUSTOMER RECEIVES VERSUS THE ELECTRIC SYSTEM "VALUE OF SOLAR"?

A. This is an important distinction. The "value" from the customer's perspective is the customer's net savings, versus not installing the rooftop solar system and receiving all of their electricity service from APS. There are also environmental benefits the customer might personally ascribe to the rooftop solar system.

Residential customers with rooftop solar systems have no incentive to minimize the overall cost of electricity production. Instead, they want to minimize their total cost of electricity service: the monthly bill they receive for service from APS, based on APS's tariff structure and net metering policies, plus the cost of owning or leasing the rooftop solar system.

Contrast this with the electric utility's perspective. APS' regulatory responsibility is to provide highly reliable electricity service to all of our customers at affordable prices. All other things being equal, our value of solar perspective must be based upon the cost of replacing the electricity produced by rooftop solar with other available production sources at the lowest possible cost. If a regulator mandates that environmental attributes are included in the valuation, the utility perspective is to obtain those attributes at the lowest possible cost for the benefit of all customers.

IV. "VALUE OF SOLAR" ATTRIBUTES

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST AND BENEFIT CATEGORIES OF ROOFTOP SOLAR REFERENCED IN CHAIRMAN LITTLE'S DECEMBER 22, 2015 LETTER.

A. In a December 22, 2015 letter to this docket, Chairman Little identified seven cost and benefit categories that should be addressed in this proceeding. They are:

1. Utility distributed solar costs, including incentive program, system integration cost, and utility revenue losses;

2. Energy generation savings;

3. Generation capacity savings;

4. Transmission capacity savings;

5. Distribution capacity savings;

6. Environmental benefits; and,

7. Economic development benefits.

APS witness Leland Snook discusses the cost of providing service to rooftop solar customers, which addresses the lost utility revenues, and APS witness Ashley Brown addresses the economic development benefits.

Q. ARE THERE OTHER COST AND BENEFIT CATEGORIES NOT INCLUDED IN THE SEVEN MENTIONED IN CHAIRMAN LITTLE'S LETTER?

A. Yes. Within my testimony, I discuss several other categories that are relevant to VOS, such as system-integration costs and curtailability.

Q. PLEASE DESCRIBE ENERGY GENERATION SAVINGS.

A. A rooftop solar system is a small-scale power production facility. The energy produced by this small-scale generator displaces energy that would have otherwise been produced by either another one of APS' generating units or by purchasing the energy from another entity in the wholesale market — if that is more cost-effective at the time.

The energy generation savings or "energy value" of the rooftop solar represents the cost the utility would have incurred if the energy had been produced/procured from another source by the utility. This energy value shows up in the form of fuel and purchased power cost savings — i.e., APS's overall fuel and purchased power expenses are lower by the amount of these energy value savings — which are passed through to customers via the Power Supply Adjustor (PSA) mechanism.

Q. IS THE ENERGY VALUE LIKELY TO CHANGE AS MORE ROOFTOP SOLAR IS ADDED?

A. Yes. Assuming that other variables remain constant, my expectation would be that the energy value will continue to decline with higher penetration levels of rooftop solar. As the penetration continues to increase, the rooftop solar production will displace even lower-cost production sources on the APS system. It will also lead to more start-stop cycles on conventional generating units that will be required to reliably meet customer demand during the time periods when rooftop solar is not capable of producing energy. These start-stop cycles increase the maintenance requirements on the conventional generating units which increases costs.

Q. SHOULD THE ENERGY GENERATION SAVINGS INCLUDE ENERGY LOSSES?

A. Yes. Whether they are included as part of energy generation savings, or accounted for separately, energy losses nonetheless merit discussion. However, it is important to recognize that there are new questions that have been raised within the industry regarding the magnitude of energy-loss savings when other impacts are also considered. I elaborate further on this question in a later section of my testimony.

Q. PLEASE DESCRIBE ENERGY LOSSES.

A. Energy losses occur as electricity is transmitted across the grid. A portion of the electricity produced by a remotely-located power plant is lost as that electricity moves across the transmission and distribution system before arriving at the customer's premises. Because of this, there is an advantage to having generation sources like rooftop solar that are located at the customer's premises. To the extent that this energy is consumed at the same site, energy losses are reduced because this power does not have to travel across the grid before arriving where it will be consumed.

Q. PLEASE DESCRIBE GENERATION CAPACITY SAVINGS.

A. A central tenet of electric utility resource planning and operations is to have sufficient generating capacity to reliably meet customer demand at all times. This means the utility must have sufficient generating capacity to meet expected customer demand at the instant of highest customer demand — referred to as peak demand — and at all other times of the year.

For APS, these occurrences of highest customer demand typically occur between the hours of 5 p.m. and 6 p.m. on hot summer afternoons during July or August. This need for generating capacity to meet peak demand drives generation costs — both significant capital investment decisions and purchase commitments to use generating capacity owned by other companies.

It is also important to understand that the utility must have sufficient capacity to reliably meet customer demand during all hours of the year. On the peak customer demand day of the year and on many other hot summer days, the hours immediately following the daily peak demand hour are also likely to be among the highest customer demand hours of the year. Rooftop solar production during these hours is likely to be even less than at the time of the peak because it is closer to nighttime. All of these factors must be considered in determining the generating capacity value of rooftop solar.

From a resource planning perspective, the question of generation capacity value revolves around how much rooftop solar contributes during the peak customer demand period. The degree of contribution affects APS's decisions regarding future generating capacity resources. Another important consideration is that the capacity value provided by solar PV declines as more is installed on the system.

Q. CAN YOU EXPLAIN WHY THE GENERATION CAPACITY VALUE REALIZED FROM ROOFTOP SOLAR WILL CONTINUE TO DECLINE AS MORE OF IT IS INSTALLED ON THE SYSTEM?

A. The generation capacity value of rooftop solar will continue to decline as more of it is added. APS has typically experienced peak customer demand at around 5 p.m. on a hot summer afternoon. However, the hours immediately after this are also very high customer-demand periods.

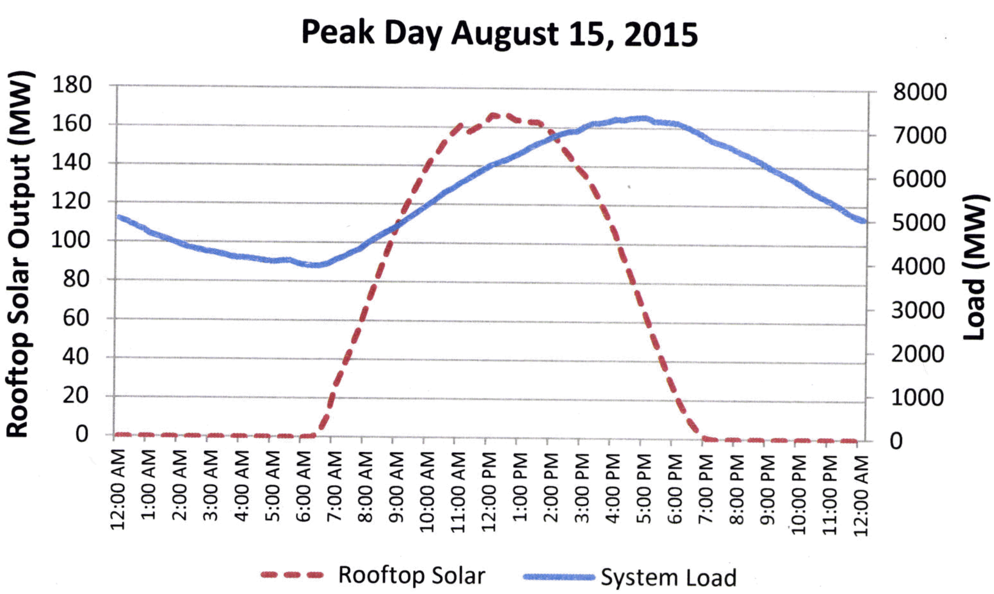
While increasing amounts of rooftop solar may continue to decrease the need for generation capacity during the 5 p.m. hour by the amount of energy that rooftop solar is producing at that time, it has less contribution during the nighttime hours that follow. Therefore, utility planners are beginning to plan for a customer peak demand occurring at 6 p.m. or even later if enough rooftop solar is added to the system. Said another way, as APS's customer base continues to grow, so does the peak customer demand. Additional rooftop solar may help mitigate the system demand up to and around the 5 pm hour, but nothing changes the fact that the sun will set and it will still be hot. Thus, after sunset, the demand for energy from rooftop solar customers and from non-solar customers will continue to drive a higher peak demand later in the early evening. As this peak demand time period is pushed to later in the evening, rooftop solar will have less and less impact on the generation capacity needed to meet peak customer demand.

Figure 1 illustrates this point. The graph shows rooftop solar production and overall customer load on the peak day of 2015. There are two main points to note from the graph:

- It is clear that rooftop solar production falls off rapidly at approximately the time of peak customer demand as the sun falls lower on the horizon.
- The hours immediately following the peak hour are very close in terms of total customer demand to the peak hour.

In other words, even though the instant of highest customer demand occurred while rooftop solar still produced some energy, nearly all of APS's infrastructure is still needed to serve customers only a short time later, when it is dark and rooftop solar no longer produces energy.

Figure 1.



Q. PLEASE DESCRIBE SYSTEM-INTEGRATION COSTS.

A. System-integration costs refer to costs incurred to allow for continued reliable service to customers as intermittent production sources are added to the grid. Examples of intermittent production sources include both wind generation and solar photovoltaics, whether at grid-scale or rooftop-scale. Both of these renewable resource types are intermittent sources because their production level can vary based upon how hard the wind is blowing or, for solar, with passing clouds or storm systems. Since electric utilities must — at each moment in the day — maintain a constant balance between the supply of electricity and customer demand, flexible generating resources are required that can either increase or decrease production rapidly to offset production variability from the intermittent wind and solar sources. Additional costs are incurred to have additional flexible resources on-line and capable of regulating the overall system supply/demand balance.

For the APS system, we typically use natural gas generating units to provide this regulating service. Note that for purposes of this testimony, I have limited this definition to include only the grid-level system-integration costs. There could be other integration costs that could occur at the local distribution level.

Q. PLEASE DESCRIBE TRANSMISSION & DISTRIBUTION CAPACITY SAVINGS.

A. In many ways, this is similar to the previous discussion of generation capacity value. Because rooftop solar is located at the customer's premise, it reduces the amount of power flowing on the distribution system during the times that it is producing energy. However, transmission and distribution infrastructure investment is driven largely by being able to reliably serve customer demand during peak-demand periods. Therefore, the ability of rooftop solar to provide value in replacing or deferring the need for transmission and distribution infrastructure investments is a function of how much energy is contributed during times of peak demand on the wires infrastructure. Note that this timing can be different than the overall system peak demand and is a function of the type of customers and their demand patterns on each portion of the distribution system. Given that rooftop solar is installed predominantly on residential feeders and that such feeders typically experience their peak loads either coincidentally or later than the overall system peak, little benefit to the distribution system has emerged from the deployment of rooftop solar.

A different and developing issue in this area is whether upgrades will be required to portions of the distribution system that are experiencing relatively high penetration levels of rooftop solar. APS has begun to experience high-voltage conditions on certain distribution feeders at times of the year when customer demand is low and solar energy production is high on those feeders. This could necessitate the installation of additional equipment to mitigate this condition to maintain reliable service to all customers on those feeders.

In our previous VOS study, we had identified potential transmission savings to the extent that rooftop solar deferred new generating capacity resources. Specifically, the identified savings were associated with the transmission costs incurred to interconnect new generating resources to the electric grid.

Q. **PLEASE DESCRIBE THE VALUE OF ENVIRONMENTAL ATTRIBUTES.**

A. Like the Palo Verde Nuclear Generating Station, renewable resources like solar and wind do not emit CO2 or other types of emissions when generating electricity. While APS and other utilities across the country are moving to a cleaner, long-term energy portfolio, the precise benefits attributable to rooftop solar of carbon-free generation are difficult, if not impossible, to quantify. Other than for wholesale energy sales into

California, APS does not currently incur a cost associated with CO_2 emissions. However, APS does consider CO_2 emissions and other environmental attributes in our resource planning processes. Although APS does not currently incur those costs, future regulations may impose a cost of carbon. In making resource planning decisions, APS factors in this possibility using an abundance of caution.

Q. PLEASE DESCRIBE CURTAILABILITY.

A. Curtailability refers to the ability of an electric generation source to reduce, either partially or completely, generation output in response to either market conditions or system operating conditions.

For example, there are times when wholesale energy prices are negative in the desert southwest region. When this happens, APS has the opportunity to get paid to take power from a neighboring supplier. During these times, it is advantageous to curtail output from our owned, grid-scale solar plants because we can save money for our customers by taking delivery of a less expensive source of power than our grid-scale solar plants --- but, in order to do so, must reduce the output from our grid-scale solar plants in order to "make room" for the less expensive energy. The ability to curtail these grid-scale solar plants remotely is key to capturing these savings as these solar plant sites are not staffed and these market opportunities are not always predictable. This requires having the necessary communications and control capabilities to effectuate these curtailments from the central control center.

The ability to curtail can actually increase the value of a solar PV resource by allowing APS to take advantage of cheaper power sources when they are available.

With the necessary installation of communications and control capabilities, rooftop solar could be technically capable of curtailing production in response to grid conditions. That communication equipment, however, is not being installed, nor does APS or any utility have the ownership of and therefore the "right" to control customer-owned rooftop solar.

Moreover, there is a large disincentive for customers to curtail: Curtailment means reducing actual energy production, meaning that the rooftop solar owner would be sacrificing a substantial retail bill credit under the current regulatory construct.

Q. IS IT APPROPRIATE TO FACTOR THE COST OF THE PANELS INTO THE REIMBURSEMENT RATE FOR NET METERING? IF SO, HOW?

A. As stated in the Mr. Snook's testimony, rates for rooftop solar customers should be based upon the cost of providing service to those customers. For surplus energy that is exported by the rooftop solar customer to the grid, the reimbursement rate for this energy should be informed by VOS. These reimbursement rates should not be based upon the cost of the rooftop solar customer's panels. To do so would risk exposing the non-solar customers to costs that exceed the value of the energy exported to the grid. Nonetheless, the adjusted grid-scale methodology would capture fluctuations in the cost of panels because it is based on reported market PPA prices.

Q. DOES THE DEPLOYMENT OF DG SOLAR RESULT IN A REDUCTION IN THE USE OF WATER IN ELECTRIC GENERATION? HOW SHOULD THIS BE CONSIDERED WHEN DETERMINING DG SOLAR VALUE?

Just like other externalities, rooftop solar can reduce water consumption. Whether and how these broader public benefits are reflected in utility rates or inform the amount paid for exported energy is a policy decision for the Commission. However, water reduction benefits is another example of how a value attribute provided by rooftop solar can be achieved at a lower cost to customers with grid-scale solar.

Q. ARE THERE ANY IMPORTANT LIMITATIONS ON HOW THE RESULTS OF VALUE OF SOLAR ANALYSES SHOULD BE APPLIED?

A. The VOS methodologies that I describe can be applied to either the entire output of the rooftop solar system, or only the energy exported to the grid. The ultimate VOS conclusion will be different depending on whether total production or exported energy is selected. Energy is much more likely to be exported during seasons of the year when the value of the energy is lower than the annual average. This is because APS customers typically consume substantially higher amounts of energy during the summer months when their air conditioning systems are being used and they are more likely to be able to consume the solar energy that their solar PV system is producing. Customer energy consumption is typically lower in the non-summer months and it is during these times when more surplus energy is exported to the grid. This difference in export production pattern would be important to recognize when attempting to establish the value of the exported energy.

V. <u>OVERVIEW OF "VALUE OF SOLAR" METHODOLOGIES</u>

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF THE ALTERNATIVE APPROACHES TO VALUING ROOFTOP SOLAR

A. In my testimony, I describe the three ways of developing a value of rooftop solar that appropriately balance measurable value to APS's grid, the real impact rooftop solar has on APS's resource planning and system operations, and what is best for all APS customers over the long term. The three methods are:

1. Short-term avoided cost
2. Long-term avoided cost; and,
3. Grid-scale adjusted.

I describe each in turn.

VI. SHORT-TERM AVOIDED COST

Q. PLEASE DESCRIBE THE SHORT-TERM AVOIDED COST APPROACH TO VALUING ROOFTOP SOLAR.

A. The short-term avoided cost approach is based upon the avoided energy costs and energy losses in a near-term time window. For example, one could determine how much it would have cost for APS to produce or procure all of the energy produced by rooftop solar during 2015.

One of the advantages of this approach is that this calculation can use the actual production data captured from the meters installed on each of the systems. Therefore, the analysis does not rely upon a forecast of future production.

Second, the solar production can be valued based upon actual, realized wholesale energy market prices. This has the advantage of being relatively transparent while also being fairly reflective of APS' own system production costs. Therefore, the analysis does not rely upon forecasts of future fuel prices, underlying customer growth and all of the other forecast variables required to develop long-term avoided cost figures.

Also, this approach is consistent with the "historic test year" method established for setting utility rates in Arizona as described in Mr. Snook's testimony.

Q. PLEASE PROVIDE MORE DETAIL ON THE MECHANICS OF THIS VALUATION APPROACH.

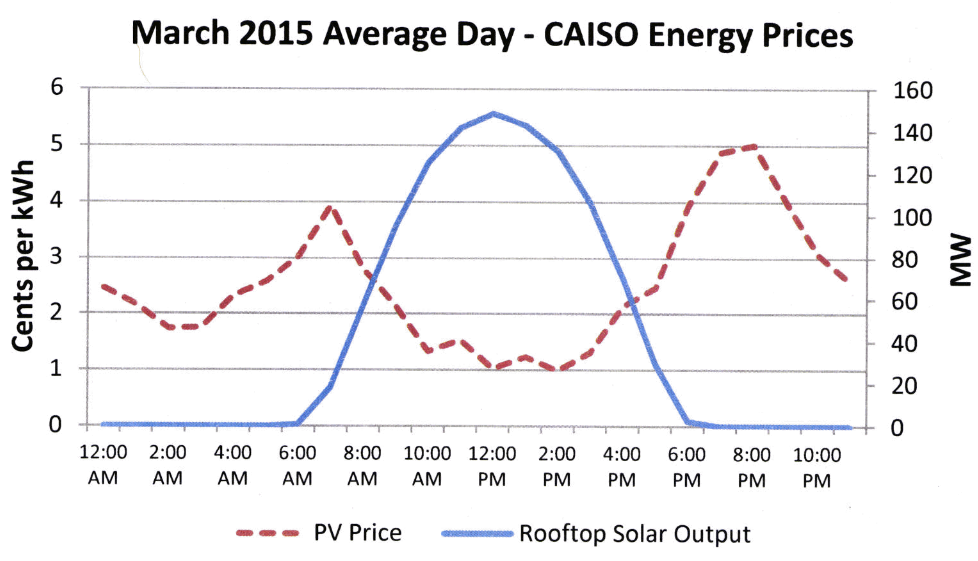
A. To illustrate this methodology, one could begin with aggregated actual rooftop solar production from the meter data for the residential systems in 2015. The meters provide production measurements for each 15-minute time segment. Then, one could use the actual wholesale market energy prices from the California Independent System Operator (CAISO) organized wholesale market to value the rooftop solar production. The CAISO market has a transaction point at the Palo Verde hub in Arizona.

APS uses this transaction point to conduct wholesale market transactions (either buy or sell) with the CAISO market. Therefore, these prices provide a good representation of the wholesale market conditions experienced in 2015 and also are a good indication of the price that APS would have paid to replace the electricity produced by rooftop solar.

It is important to note that one could select those market prices that align with the time of day that rooftop solar facilities actually provide energy. Doing so increases the accuracy of this market price analysis. Figure 2 illustrates this methodology. The graph shows average CAISO energy prices by hour for March 2015. The graph also shows the average rooftop solar production pattern by hour for the same month.

During the solar PV production periods, the CAISO energy prices were in the range of 1.0 to 2.5 cents/kwh. Additionally, the graph shows that the highest wholesale market energy prices occurred on either side of the solar PV production window. This coincides with periods of higher customer demand across the region.

Figure 2.



Q. DOES ROOFTOP SOLAR CONTRIBUTE ADDITIONAL VALUE BY AVOIDING ENERGY LOSSES?

A. Yes. An advantage of rooftop solar is that the electricity production occurs in the same place where the consumer uses the electricity. In contrast, if APS were to purchase the same electricity at the Palo Verde hub, that electricity would have to be transmitted from this wholesale market hub to the customer's premises. Energy losses of approximately 7% would be incurred in this delivery process.

Q. DOES THE SHORT-TERM AVOIDED COST APPROACH FAIL BECAUSE IT DOES NOT REFLECT LONG-TERM AVOIDED COSTS?

A. No. This criticism overlooks the fundamental difference between long-term resource commitments that a utility makes as part of a long-term resource planning and procurement process and rooftop solar. A utility procures long-term resources based on need. And once procured, a utility exercises control over the long-term resources. The utility can call on those resources when needed. And if a third-party supplier fails to perform, they pay contractual penalties.

In contrast, rooftop solar is a choice that each individual customer makes in response to their rate tariff options and prevailing net metering policy. The installed rooftop solar is not necessarily fulfilling a targeted need on the utility system. Additionally, the utility has no way of assuring that the rooftop solar system will remain available and capable of producing power over the expected life of the system.

As found by the Utah Public Utility Commission:

> Net metering generation results from a voluntary customer decision. The customers own and control their equipment, and customers make decisions about whether to install that equipment and how much capacity to install. The customer is under no obligation to maintain the system or to supply the utility with electricity. If a problem develops that prevents the customer from generating energy, the customer is under no obligation to cure it. More significantly, a customer is under no contractual obligation to provide any of the power it generates to the utility. Net metering customers may elect, at any time, to use their electricity however they choose.[1]

[1] *In re Cost and Benefits of PacifiCorp Net Metering Program*, Final Order at 13-14, Docket No. 14-035-114 (Pub. Ser. Comm'n of Utah, Nov. 10, 2015).

VII. LONG-TERM AVOIDED COST

Q. PLEASE DESCRIBE THE LONG-TERM AVOIDED COST VALUATION METHOD.

A. The long-term avoided cost approach is a resource planning methodology used by APS and others. This approach uses long-term forecasting tools to develop estimates of certain value components, such as energy, generation capacity, and energy losses. These studies are long-term in nature and are similar to studies that APS conducts to make long-term resource decisions.

Q. PLEASE DESCRIBE VALUE OF DG SOLAR STUDIES PERFORMED BY OR ON BEHALF OF APS IN THE PAST.

A. There are two significant studies undertaken on behalf of APS over the last decade. In 2009, APS engaged R. W. Beck to lead a stakeholder process to, among other things, assess the value provided by solar DE technologies in terms of both capacity and energy.[2]

This study involved more than 60 individuals representing 35 solar vendors, academic institutions, solar advocates, local builders and land developers, and solar-related construction firms as well as representatives from the regulatory community. This study developed methodologies and estimated values for generation, transmission and distribution savings that could potentially be realized under various solar DG penetration scenarios.

[2] "Distributed Renewable Energy Operating Impacts and Valuation Study" prepared for Arizona Public Service, R.W. Beck, January 2009, page xiv.

In 2013, APS engaged SAIC, a successor of R.W. Beck, to update the values from the 2009 study and using the same peer-reviewed methodology.[3] Both of these studies were filed with the Commission.

Q. WHAT WERE THE SPECIFIC ATTRIBUTES THAT WERE VALUED IN THESE STUDIES?

A. There are five broad categories of attributes that were identified and valued in these studies:

- Distribution System
- Transmission System
- Generation System
- Fixed O&M
- Fuel, Purchased Power, Emissions & Gas Transportation

Both of these studies estimated potential values at discrete points in time,[4] and both of them used widely accepted resource planning techniques to assess value.

Q. WHAT DO YOU MEAN BY RESOURCE PLANNING TECHNIQUES?

A. By this I mean that load and resource plans were constructed for various rooftop solar penetration scenarios, and that values were determined through prospective modeling of the forecasted generation and transmission systems and their respective investment and operating costs. In other words, cases including rooftop solar were compared to a case without rooftop solar. The case without rooftop solar used conventional resources to make up for the DG in the first case. The difference between the two cases represents

---

[3] 2013 Updated Solar PV Report, SAIC, May, 2009.

[4] R.W. Beck estimated values for 2010, 2015 and 2025; SAIC estimated values for 2015, 2020 and 2025.

the value of rooftop solar from a resource planning perspective. This is the methodology used in making resource decisions and is used extensively in APS's Integrated Resource Plan (IRP) filings.

Q. HAVE THESE LONG-RANGE RESOURCE PLANNING STUDIES BEEN USED TO SET RATES?

A. No, they have not. These studies are used as a tool that, at the resource planning stage, facilitate thoughtful decisions about which resources APS should procure to meet anticipated resource needs in the future. When APS conducts resource planning analyses, it updates its studies frequently. The goal is to have up-to-date analysis at the time the resource planning decision is made. Each study involves predicting values for future resources based on a number of different assumptions. Although these types of studies are not used to set rates, it is within the Commission's discretion to use these studies in establishing the amount paid for energy exported by rooftop solar systems. If the Commission were to select the long-term avoided cost methodology for this purpose, it would need to accept that the assumptions underlying the long-term projections will change and potentially change significantly. Because of this, using this methodology would cause APS's non-solar customers to inevitably pay an amount for exported solar energy that is significantly different than the actual costs avoided at the time the energy is received.

Q. WHAT SUPPLIES THE BULK OF THE VALUE IN THESE LONG-RANGE SOLAR VALUE STUDIES?

A. The vast majority of the predicted value comes from the energy produced by the rooftop solar. Rooftop solar energy production directly results in the Company consuming less fuel, buying less energy from the wholesale market, and incurring lower fuel transport costs. I generally refer to these as avoided-energy costs. In the R. W. Beck and SAIC studies, avoided-energy costs constitute between 58% and 90% of the total identified DG value.

Q. WHAT ARE YOUR OBSERVATIONS REGARDING GENERATION CAPACITY SAVINGS?

A. The second-largest value driver is related to avoided generation capacity savings. To some extent, installation of rooftop solar can defer future resource additions such as combustion turbines, along with their associated transmission, interconnection, and fixed O&M costs. Due to the diminishing capacity value of rooftop solar previously discussed, this value is limited because of the mismatch in the timing of peak rooftop solar production and the peak customer demands on APS's overall system and distribution system, and becomes less significant under high-penetration scenarios.

Q. PLEASE COMMENT ON THE DISTRIBUTION VALUES DERIVED IN THE R. W. BECK AND SAIC STUDIES.

A. In the first study, the distribution value was zero to very small, and in the second study, the value was zero. Potential distribution savings are very feeder specific. The savings depend on finding feeders that need upgrades, and that the upgrades needed can be deferred or eliminated by the addition of targeted rooftop solar. In both studies, all APS feeders were screened to determine whether the addition of rooftop solar could defer planned upgrades. The SAIC study concluded that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted rooftop solar installations to determine measurable capacity savings. Moreover, as APS obtains more data about solar penetration in its service territory, it becomes increasingly apparent that high DG penetration could lead to additional distribution costs to maintain system reliability and power quality, particularly during low customer demand periods.

Q. DID EITHER OF THESE STUDIES ACCOUNT FOR LOWER SYSTEM LOSSES THAT MAY OCCUR DUE TO SITING THE GENERATION AT THE CUSTOMER'S SITE RATHER THAN A REMOTE LOCATION?

A. Yes. Both studies captured the effects of reduced losses that may be associated with rooftop solar. Energy losses average about 7% over the course of the entire year and are estimated at approximately 12% at the time of peak demand. Both of these values are routinely factored into APS's load forecasts. To be clear, the values calculated for rooftop solar are higher than they would be otherwise because of the expected energy losses saved by reducing the need to transmit electricity from remotely located generation sources to the customer's site.

Q. IS THERE UNCERTAINTY AS TO WHETHER SOLAR DG WILL REDUCE SYSTEM LOSSES?

A. There is some discussion in the industry as to whether rooftop solar reduces or increases system losses. The logic that supports reduced losses is based on the actual mechanics of how electricity is transferred to customers. When energy is generated remotely, it goes through step-up transformers, is transmitted over long-distance transmission lines, gets transformed down to be put on the distribution system, and ultimately reduced to a voltage that customers can use. While this is an efficient means of transporting electricity over these distances, energy losses occur throughout this process. When the energy is generated locally, however, it doesn't go through this process. As a result, this logic concludes that locally generated energy avoids energy losses.

Equally valid logic supports the opposite conclusion. Rooftop solar increases voltage on the distribution feeder during certain times of the year. This higher-voltage level is a function of the quantity of energy produced by rooftop solar, and results in higher overall energy use by customers experiencing these higher-voltage conditions. The result is higher customer energy usage due to higher voltage levels.

Our previous studies have credited the value of rooftop solar with the value of the energy losses saved. However, we are actively monitoring research in this area, and the conclusions from this research could impact the results in subsequent studies. It should also be noted that equipment can be installed on distribution feeders to mitigate the high-voltage conditions caused by the rooftop solar generation. The cost of this equipment would have to be factored into the overall value proposition if it becomes necessary to mitigate the adverse impacts of rooftop solar generation.

Q. WHAT ARE THE OTHER IMPACTS OF THIS HIGH-VOLTAGE CONDITION CAUSED BY ROOFTOP SOLAR?

A. APS has begun experiencing high-voltage conditions during certain times of the year on some distribution feeders that have a high amount of rooftop solar generation relative to customer load. This condition tends to occur during times of the year in which customer demand is relatively low — during the spring time when temperatures are mild and customers are not running their air conditioning units, for example — and solar production is plentiful.

APS is actively investigating and monitoring these conditions as they can result in voltage conditions that are above specification for the feeder, trip rooftop solar systems off-line due to exceeding equipment protection setpoints, and have adverse impacts on customers. At some point, APS may need to install new equipment on the impacted distribution feeders to mitigate these high-voltage conditions.

Q. DOES ROOFTOP SOLAR DEPLOYMENT CHANGE THE NEED FOR NEW TRANSMISSION SYSTEM CAPACITY?

A. This question has been addressed in the previous R.W. Beck and SAIC studies. In both studies, the analysis did not identify opportunities to reduce planned upgrades to the transmission system. However, they did identify that transmission system upgrades needed to support incremental generation-capacity additions, sometimes referred to as interconnection costs, could be deferred to the extent that rooftop solar defers the need for incremental generation capacity additions.

Similarly, in the recently completed study in support of the Biennial Transmission Assessment (BTA) process, APS did not identify significant savings from forecasted future energy efficiency and DG additions. It should be noted that approximately 80% of the peak load reduction forecast for this analysis was due to energy efficiency and not DG.[5]

Q. PLEASE DISCUSS THE KEY DRIVERS OF SOLAR DG VALUE WHEN CALCULATED IN A PROSPECTIVE MANNER SUCH AS THAT USED IN THE AFOREMENTIONED STUDIES.

A. The largest value drivers are the cost of avoided energy production — largely driven by natural gas prices and solar penetration levels. Lesser drivers include the ability to defer new generating capacity and the cost of these resources.

Q. HAS THE OUTLOOK FOR ANY OF THESE DRIVERS CHANGED SIGNIFICANTLY SINCE THE R.W. BECK AND SAIC STUDIES WERE PERFORMED?

A. Yes, they have. The primary variables that have changed since the SAIC 2013 study are APS's load and resource forecast, fuel prices, market prices, rooftop solar penetration, and the cost and timing of APS's need for new generated capacity. Each of these variables has changed significantly and thus the long-range value predicted by this methodology has also changed significantly since 2013.

This propensity for change is a primary reason why long-range value studies should be used for resource planning, and not rate setting. Studies based on variable and unknown

[5] Technical Study, Effects of Distributed Generation and Energy Efficiency on Future Transmission Needs, filed by APS in Docket No. E-00000D-15-0001 (January 29, 2016).

factors such as fuel prices and customer behavior can produce significantly different values from one year to the next.

Q. ARE THERE LIMITATIONS TO THE APPLICABILITY OF THIS TYPE OF ANALYSIS?

A. Yes. The long-term avoided cost calculation should be based upon the least-cost manner in which the utility can achieve the same benefits. This is consistent with the utility least-cost planning philosophy. A grid-scale solar PV project can achieve similar benefits as rooftop solar, especially if adjustments are made for the operational differences as described below. Because a grid-scale solar PV project can achieve similar benefits as rooftop solar projects, the adjusted PPA price for a grid-scale solar project should be the ceiling for any value ascribed to rooftop solar.

VIII. GRID-SCALE ADJUSTED METHODOLOGY

Q. PLEASE DESCRIBE THE GRID-SCALE ADJUSTED VALUATION METHOD.

A. The third solar valuation approach begins with the recognition that both rooftop solar and grid-scale applications use the same basic technology — solar photovoltaic (PV) panels. Although they rely on the same basic technology, they apply this technology in different ways.

The first is related to scale. A typical grid-scale application for APS is in the 15-20 MW (15,000 to 20,000 kW) size range. By contrast, an average rooftop solar system is approximately 7 kW in size. The second main difference is that APS typically employs tracking technology on its grid-scale systems. The tracking technology allows the solar PV panels to track, and thus be pointed toward, the sun throughout the day. This tracking maximizes energy production and provides greater capacity contribution at the times of peak customer demand.

Rooftop solar systems, on the other hand, are mounted in a fixed position on the customer's rooftop. Their orientation relative to the sun depends entirely upon the orientation of the customer's roof. Because a residential rooftop system does not track the sun, it produces significantly less energy throughout the day, and produces less energy at the time of peak customer demand than a grid-scale solar PV facility.

The third difference is that grid-scale applications are selected through competitive procurement processes to ensure that APS customers receive the best deal at the time that the procurement decision is made.

A fourth difference was mentioned previously in my testimony. Grid-scale solar PV systems can be curtailed at times when wholesale market prices are negative. This curtailability increases the value of grid-scale relative to rooftop solar.

Due to these differences, grid-scale PV provides a more cost-effective means to acquire solar PV. At the same time, grid-scale PV also captures the value rooftop solar provides in relation to conventional generation. For instance, the environmental and energy benefits derived from rooftop solar can also be obtained from grid-scale solar PV systems. The grid-scale methodology is a market-based method. As such, it does not depend upon long-term forecasting assumptions like the long-term avoided cost methodology does.

Recognizing that the generating technology is the same, and that they both bring similar value to the system, albeit at different cost, the gid-scale adjusted methodology starts by deriving the current market price for grid-scale solar PV long-term power purchase agreements (PPA) from industry-reported transactions. This grid-scale PPA price is them adjusted for recognized valuation differences between grid-scale and rooftop solar, each of which is described below. The resulting adjusted grid-scale value would represent the cost at which the utility could realize the same value attributes that rooftop solar systems supply.

Q. PLEASE EXPLAIN THE BENEFITS OF USING THIS METHODOLOGY.

A. This methodology is based on the measurable cost of grid scale solar PV based on actual market pricing. Because the same basic solar PV technology is used with both grid-scale and rooftop solar PV, they deliver the same hard benefits and the same soft, or difficult-to-quantify, benefits. This approach avoids the controversial topic of how to value the difficult-to-quantify attributes such as environmental emissions, societal health benefits, or market-price mitigation. To the extent that these value attributes contribute value to rooftop solar, they are similarly obtained through either grid-scale or rooftop applications. The benefits that apply to both technologies become irrelevant, so we only need to focus on the differences. In short, there may be differences between capacity value, energy value, T&D benefits, system losses, and curtailment.

Q. PLEASE EXPLAIN THE COST OF GRID SCALE PV.

A. There are several ways that the cost of grid-scale solar PV can be determined. It could be based on quotes that APS obtains from conducting RFPs, or from publicly available costs of solar energy acquired by other utilities in the region. The advantage of this is that it is based on information that is known with certainty today, and not based on projections of value that may or may not materialize in the future. With this methodology, a PPA price should be selected from information regarding grid-scale for solar PV projects in regions that are likely to have similar solar conditions to Arizona.

Q. **PLEASE EXPLAIN THE ENERGY LOSSES ADJUSTMENT.**

A. The PPA price that forms the starting point for the valuation should be increased to reflect energy losses avoided by rooftop solar. APS experiences an average of 7% energy losses on its system over the course of a year. Under this methodology, the PPA price should be increased by 7% for rooftop solar installed on APS's system.

Q. **BECAUSE ROOFTOP SOLAR DOES NOT REDUCE OR AVOID DISTRIBUTION FACILITIES, SHOULD THE CORRESPONDING ADJUSTMENT BE ZERO?**

A. Yes. In both the R.W. Beck and SAIC studies, we went through a sophisticated and time-consuming process to estimate savings that may occur on the distribution system due to the presence of rooftop solar. In those cases, we identified zero to very small potential distribution savings that could occur as a result of high levels of rooftop solar. And in fact, rooftop solar may increase the need for distribution investments. If this were to be studied more, the developing investigations into rooftop solar requiring distribution upgrades would need to be considered.

Q. **PLEASE EXPLAIN THE TRANSMISSION SYSTEM ADJUSTMENTS.**

A. In our previous studies, we did not find significant transmission system deferral opportunities resulting from rooftop solar. What we did find is that we could defer transmission associated with peaking capacity deferrals.

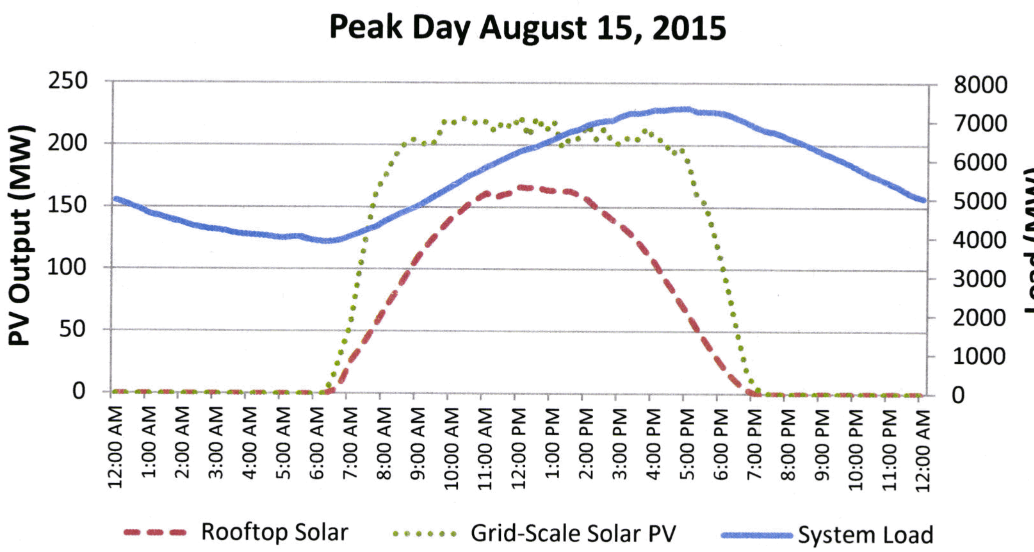
Q. **PLEASE EXPLAIN GENERATION SYSTEM VALUE ADJUSTMENT.**

A. As described previously, the grid-scale applications employ single-axis tracking technology that allows these systems to produce more energy during the late-afternoon / early-evening time period which better coincides with overall customer peak demand.

This adjustment should reflect the resulting capacity value difference between grid-scale and rooftop solar PV.

Figure 3 illustrates the difference between rooftop solar and grid-scale production during the peak season. The graph clearly shows the higher contribution of grid-scale PV during the specific timeframe when customer demand is at its highest.

Figure 3.



Q. PLEASE EXPLAIN THE ENERGY VALUE ADJUSTMENT.

A. Similar to the explanation of the Generation System Value Adjustment, because grid scale PV produces more power late in the afternoon when it is more valuable, there is an energy value adjustment. To establish the value of this difference, we could compare the value of grid scale PV and rooftop solar using actual market prices and production profiles of grid scale and rooftop solar.

Q. PLEASE DESCRIBE THE CURTAILMENT ADJUSTMENT.

A. As previously described, the market has changed significantly due to the vast amount of solar generation being put onto the grid in our neighboring state of California. In 2015, there were a significant number of hours of the year in which the market price of electricity was negative. With the ability to curtail power plant operations, APS's customers can benefit by APS being paid to receive energy from the market during these times. APS has the ability to curtail grid-scale PV operations during these negative market-price hours. APS does not, however, have this ability with rooftop solar. Again, we could use 2015 actual market prices and grid scale and rooftop solar production profiles to calculate the additional value of grid-scale due to the ability to curtail.

Q. WHAT ARE THE ADVANTAGES OF USING THIS METHODOLOGY?

A. Based upon the prudent utility planning principles that have been a basic premise upon which utility resource procurement decisions have historically been made, a utility has an obligation to seek out the lowest-cost, best-fit approach to fulfilling a resource need. The grid-scale adjusted methodology is consistent with this principle in that it identifies the lowest-cost, best-fit manner of achieving the same resource value.

IX. <u>CONCLUSION</u>

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Under present net metering policy, rooftop solar customers effectively receive the full retail rate for the energy they export to the grid. APS's retail rate, however, reflects the entire cost to provide electric service, of which energy is only a portion. Paying the full retail rate for energy overcompensates rooftop solar energy exports.

A VOS can be useful for important policy-making decisions. It can inform the resource planning process. It can also be used to determine the amount that should be paid to customers for energy exported to the grid from rooftop solar systems. Based on my experience, and observed operational and market data, there are three ways to establish a VOS.

The first is a short-term avoided cost, which uses actual data concerning market prices paid and rooftop solar production. The second, subject to the caveats described above, is a long-term avoided cost that uses a resource planning perspective to predict the future benefits of rooftop solar. The third is an adjusted grid-scale method, which adjusts the reported price paid for a grid-scale solar PPA to account for the operational differences between grid-scale and rooftop solar applications.

Each methodology falls along a spectrum of potential values. If the same resource - energy generated using the sun - can be obtained at a cost lower than the retail rate, APS believes that all customers should only be required to pay that lower cost. Nonetheless, if the Commission decides to compensate rooftop solar energy beyond the simple energy value, grid-scale solar PV can provide the same benefits as rooftop solar at a substantially lower cost. Therefore, the excess energy from rooftop solar customers should be compensated at a rate no higher than the cost of grid-scale solar PV.

DIRECT TESTIMONY OF JOHN STERLING

On Behalf of Arizona Public Service Company

Docket No. E-00000J-14-0023

February 25, 2016

Table of Contents

Contents

DIRECT TESTIMONY OF JOHN STERLING
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-00000J-14-0023)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Sterling, and my business address is 8737 E. Via de Commercio, Suite 220, Scottsdale, AZ 85258.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Senior Director, Research & Advisory Services at the Solar Electric Power Association (SEPA). My educational and professional experience are set forth in Attachment 1 to my testimony.

At SEPA, I am responsible for managing government grants where SEPA is either the prime or sub-contractor, as well as managing our advisory services practice that we offer to member companies. In this role I have consulted to dozens of utilities and other companies on solar strategic planning, community solar design, power procurement, and other related issues. Lastly, I have overall responsibility for SEPA's 51st State Initiative, which looks at developing long-term roadmaps to transition the electricity industry towards a future that creates equitable business models and integrated grid structures to ensure that electricity is provided safely, reliably, efficiently, affordably, and cleanly; and, to meet customer demand in the near and long term for solar and other distributed options.

Q. PLEASE BRIEFLY DESCRIBE SEPA.

A. SEPA is an educational non-profit dedicated to helping electric utilities integrate solar and other distributed energy resources into their energy portfolios in ways that benefit the utilities, their customers, and the general public. Established in 1992, SEPA now has over 530 utility and over 480 non-utility member organizations. Approximately 30 Arizona-based companies and organizations are SEPA members, including several solar developers, utilities, and government agencies.

SEPA operates under the following guiding principles:

- Utilities must be a critical part of the equation for solar and distributed energy resources to live up to their full potential in serving the public good;
- The long term economic health of utilities, technology companies, and their customers will be strengthened through partnership;
- The regulatory compact must evolve to support utility business models that encourage both central station and distributed energy resource deployment; and,
- Upgrades and advancements are needed to grid infrastructure, enabling technologies, and grid operations in order for solar and distributed energy resources to reach maximum potential.

II. <u>SUMMARY</u>

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

A. In 2014 and 2015, I served as the stakeholder facilitator for a working group created by Tennessee Valley Authority (TVA). This working group's purpose was to provide input and feedback on the creation of a methodology to calculate the value (defined as the net of benefits and costs) of different distributed generation resources on the TVA system. Specifically, this group focused on distributed solar as the first technology under consideration. The purpose of my testimony is to present the conclusions of the working group and discuss the components of the methodology that was agreed upon. SEPA is not an advocacy organization and does not engage in advocacy discussions. Consequently, my testimony is not meant to convey a preferred approach; rather, it is meant to provide additional information regarding the benefits and costs of distributed solar as determined by the TVA working group. This testimony is meant to serve as a reference point for the Arizona Corporation Commission.

III. BACKGROUND ON THE INITIATIVE

Q. PLEASE DESCRIBE TVA'S ROLE IN THEIR REGION.

A. TVA is an agency of the United States that provides generation and transmission to 155 local power companies (LPCs) and business customers in parts of seven southeastern states. Through those LPCs, which includes both cooperative and public power utilities, and their direct-serve customers, TVA ultimately provides energy for 9 million people. Under their agreements with the LPCs, TVA is the sole generation provider.

Q. HOW DID TVA HISTORICALLY FACILITATE DISTRIBUTED SOLAR TRANSACTIONS?

A. TVA has had a legacy solar program for several years that was developed to stimulate solar deployment via high incentive payments. These incentives stepped down over time and were scheduled to reach retail level at the end of 2015. The LPC community could voluntarily participate in this program, and over 130 of the 155 LPCs chose to do so. Because of TVA's power contract requirements, whenever a customer chose to go solar and participate in the program a tri-party agreement would be entered into. The system would receive a separate production meter and TVA purchased 100% of the generation from the customer at the retail rate plus the then-applicable incentive.

Q. WHAT WAS THE IMPETUS BEHIND THE TVA WORKING GROUP?

A. TVA's solar incentive program was scheduled to phase out at the end of 2015. Coupled with this, there was a growing recognition that understanding the true benefits and costs from these types of resources would be beneficial to all market participants, especially since TVA was also about to go through the creation of a new Integrated Resource Plan

(IRP). As part of the IRP initiative, a stakeholder group had been created to provide context and feedback on how various renewable resources should be treated from a modeling perspective. TVA decided to bring together a subset of that broader stakeholder group and create a discussion around the benefits and costs of distributed generation, and (in particular) distributed solar. This initiative was dubbed distributed generation – integrated value (DG-IV).

Q. WHAT TYPES OF ORGANIZATIONS WERE ASKED TO PARTICIPATE IN THE DG-IV WORKING GROUP?

A. TVA assembled a diverse group of representatives from organizations that participate in the Tennessee Valley region. This included four LPCs, the Tennessee Valley Public Power Association (TVPPA), several environmentally-focused non-governmental organizations, representatives from the local solar industry, two state government organizations, and two national research groups, including one national lab. SEPA was asked to serve as an independent third-party facilitator and subject-matter expert. In addition, the Electric Power Research Institute (EPRI) took a lead role in analyzing distribution system impacts. In total, 14 organizations were brought to the table.

Q. HOW DID YOU DEFINE "VALUE STREAMS" TO THE WORKING GROUP?

A. We defined a value stream as the *net* of the benefits and costs for a particular category of a distributed solar project's impact. To start the conversation, we specifically discussed the following value streams: avoided energy; generation capacity deferral; fixed and variable O&M; ancillary / grid support services impact; transmission system impact; distribution system impact; system losses; environmental; economic development; disaster recovery; and, security enhancement impact. Each of these was discussed in turn to provide a basic understanding of what each is intended to capture.

To ensure participants started off with a broad understanding of these types of methodologies, an overview of "value of solar" initiatives from other parts of the country, such as Austin Energy and the State of Minnesota, was provided. To provide additional context, particularly because we did not want to unduly influence the opinions of participants, we recommended three specific publicly-available reports that all stakeholders should review prior to the next meeting. Those included SEPA's "Ratemaking, Solar Value and Solar Net Energy Metering – A Primer" report, Rocky Mountain Institute's "A Review of Solar PV Benefit & Cost Studies", and "Minnesota Vale of Solar: Methodology", prepared for the Minnesota Department of Commerce by Clean Power Research. These documents were selected to provide a range of information on how different value streams were considered and subsequently calculated in other benefit / cost studies done nationally.

Q. ULTIMATELY, WHAT VALUE STREAMS WERE INCLUDED AS COMPONENTS OF THE FINAL DG-IV METHODOLOGY?

A. The final methodology includes the following value streams:

- Generation Deferral (Capital and Fixed O&M)
- Avoided Energy (Fuel, Variable O&M, and Start-up)
- Environmental (Compliance and Market)
- Transmission System Impact
- Distribution System Impact
- Losses (Transmission and Distribution)

Four components were identified as being beneficial to program design discussions that would leverage the DG-IV. Essentially, these items can be taken into consideration as part of the determination of the final price offered to customers in exchange for their solar production. Those were:

- LPC Costs & Benefits
- Economic Development
- Customer Satisfaction
- Local Differentiation

Lastly, five final components were identified as placeholder topics that should continue to be discussed in the context of the DG-IV:

- System Integration / Ancillary Services
- Additional Environmental Considerations
- Security Enhancement
- Disaster Recovery
- Technology Innovation

Q. WHAT IS THE SIGNIFICANCE OF BREAKING OUT THE ADDITIONAL TWO CATEGORIES OF COMPONENTS, SEPARATE FROM WHAT IS INCLUDED IN THE DG-IV METHODOLOGY?

A. The components that are incorporated into the final methodology are all currently quantifiable value streams that impact TVA and its LPCs directly and the working group agreed they should be valued as such. The additional two categories did not have universal consensus on inclusion; however, there were merits to the arguments behind their consideration and those arguments could be leveraged in subsequent conversations on how to design a program for distributed solar customers going forward.

One fact that bears mentioning is that TVA was up front telling the stakeholders that the ultimate numerical value that is calculated at the end of the process may or may not be high enough to cause a solar transaction in the region; however, that number would be very informative to everyone involved moving forward. A program would still need to get designed that leveraged the conversations around DG-IV, but recognized the need to create an ongoing solar market.

Q. PLEASE DESCRIBE HOW THE GENERATION DEFERRAL CALCULATION WAS DETERMINED.

A. The working group reached consensus on leveraging TVA's Capacity Expansion Model (CEM) that is run in support of the IRP process to determine generation capacity deferral, as well as fixed O&M. The CEM is a detailed resource planning tool that analyzes a variety of different potential resource decisions to determine the optimal capacity build-out to meet future needs. For this process, the group decided to take the base run that was being developed as part of the IRP, and then run a second case that considered 2,000 MW-ac of solar being added at zero cost. The model's second run resulted in a different, less expensive capacity build-out plan. Those reduced revenue requirements (compared to the base case) were then levelized to estimate the generation deferral value.

Q. DID THE STAKEHOLDERS DISCUSS THE TRADEOFF BETWEEN THIS DETAILED APPROACH AND THE FACT THAT THE MODELING ITSELF IS NOT VERY TRANSPARENT?

A. Yes, that was a specific discussion point of the group. In the end, many of the same stakeholders were also engaged in the IRP process where they had the opportunity to learn about these modeling approaches and provide inputs related to capacity value and other factors. While they all recognized that other approaches that we discussed would be simpler and far more transparent, it was agreed by stakeholders that the more accurate modeling that was possible by using the CEM was preferred.

Q. WAS A SIMILAR APPROACH TAKEN FOR AVOIDED ENERGY?

A. Yes it did. The working group decided to leverage TVA's Production Cost Model (PCM), the hourly dispatch counterpart to the CEM. This detailed model considers how to most economically dispatch the series of generation resources determined out of the CEM. The same two cases mentioned previously were run in the PCM and the reduced revenue requirements related to fuel, variable O&M, and reduced start-ups became the avoided energy deferral value. Again, this is a much more detailed and less transparent approach than had been done in other initiatives, but it was the approach that was supported by the working group.

Q. DID THE ISSUE OF TRANSPARENCY COME UP AFTER THE WORKING GROUP DETERMINED TO LEVERAGE THE CEM AND PCM FOR MODELING?

A. Yes, it did. During two additional meetings, significant time was allotted to make sure all stakeholders had an understanding of how these models worked and how the results were generated.

Q. PLEASE DESCRIBE HOW TRANSMISSION VALUE WAS DETERMINED.

TVA developed a series of transmission impact case studies, based on actual system conditions, which would create positive, negative, and neutral impacts from adding solar at a specific location. After reviewing this approach, one stakeholder suggested an alternative; namely, that TVA leverage its point-to-point transmission service rate as a proxy for the reduced usage on the transmission system from distributed solar. This rate was applied to monthly peak load factors to create the avoided transmission capacity value. This proposal was adopted by the working group. Interestingly, the final values from TVA's initial proposal and from the stakeholder's alternative were very similar; however, the stakeholder approach was much simpler to both calculate and understand, leading to the decision to adopt it.

Q. PLEASE DESCRIBE HOW DISTRIBUTION IMPACT VALUE WAS DETERMINED.

A. As mentioned previously, EPRI was brought in to conduct the analytics related to distribution system impact. During this process, they conducted a detailed technical analysis for two feeders within the Tennessee Valley, and conducted a financial impact analysis for each. Those two feeders were chosen from a set of sixteen that were representative of feeders common to the region. From those, five feeders were chosen for a hosting capacity analysis. Two of these five were then chosen to compute example results, based on the penetration of 500 kW of solar on each feeder. EPRI chose this amount, as it would be the approximate penetration on an average feeder that 2,000

MW-ac of distributed solar would cause. In that sense, they attempted to align their work with the CEM and PCM modeling process.

During this analysis, EPRI reviewed the impacts to: distribution capacity (the potential to defer capacity upgrades and equipment life); voltage (whether or not there were voltage deviations or regulation issues); protection (impacts to fault current along with mitigation options); losses; and, impacts to energy consumption (due to higher delivery voltages). A net financial impacts analysis was then completed.

Q. WHAT WERE THE RESULTS OF THAT WORK?

A. EPRI's analysis did not reveal meaningful system benefits being observed, and they showed a range of potential costs. Essentially, the feeders were not capacity constrained for the foreseeable future under today's planned growth assumptions, so benefits in the form of capacity deferral did not materialize. One of the two feeders did require mitigation to address voltage issues that arose at that level of solar penetration.

Q. HOW DID THE TVA WORKING GROUP DECIDE TO TREAT DISTRIBUTION SYSTEM IMPACT?

A. Ultimately, the decision was made to include the value stream at 0 cents per kWh. The working group agreed that further study was needed on this issue.

Q. PLEASE DESCRIBE THE APPROACH TO CALCULATING SYSTEM LOSSES.

A. System losses were broken down into two different buckets: transmission losses and distribution losses.

For transmission losses, TVA analyzed all transmission buses on an individual basis via a load flow modeling analysis. This was applied to approximately 1,300 transmission substation buses, with a goal of determining the effects of solar on load pockets across the TVA transmission system. TVA modeled a 1 MW-ac system at each substation bus, which roughly matched the other working assumption of 2,000 MW-ac of solar across the system. A marginal loss analysis was conducted by comparing system losses on a peak and off peak basis with and without the solar. The average marginal loss savings experienced was then used as the transmission loss value, which was calculated at 2.6%.

Distribution losses were calculated as part of EPRI's analysis. This, too, looked at marginal impacts; however, EPRI also took into account that localized energy consumption would increase due to higher voltages. The net impact of the reduced losses compared to the increase in consumption from higher voltage became the distribution loss value, which was calculated at 1.6%. That value was the mid-point for the two feeders that EPRI analyzed.

Q. PLEASE DESCRIBE THE DISCUSSION SURROUNDING ENVIRONMENTAL VALUE.

A. Environmental impact was the single most discussed value stream in the process, with a variety of viewpoints shared. TVA presented an environmental impact value that was calculated from its PCM run. This leveraged TVA's price curve for CO_2 that was being used in its IRP process. TVA showed annual data including costs and tons reduced by adding the 2,000 MW-ac of solar. In response to this, several stakeholders proposed using the social cost of carbon as had been done in the State of Minnesota. Alternatively, they suggested using voluntary Solar Renewable Energy Credit (SREC) market pricing until such time as TVA's CO_2 curve took effect.

After a thorough debate across several meetings about the different methods and components that could be leveraged in a valuation methodology, TVA proposed a solution that represented a compromise of positions. This solution was ultimately adopted with consensus support.

Q. WHAT WAS THE PROPOSED SOLUTION?

A. The environmental impact discussion would be broken down into three buckets: Environmental Compliance Value, Environmental Market Value, and Additional Environmental Considerations.

Environmental Compliance Value addressed the regulatory compliance components that are incorporated into TVA's IRP process via its price curve for CO_2.

Environmental Market Value captured the market value of the SREC created by the solar resource, which was referred to during the meeting as its "opportunity cost"; that is, TVA had an opportunity to sell the SRECs into voluntary markets to monetize their value, and that value could be captured in the methodology.

Additional Environmental Considerations recognizes that additional impacts may be appropriate to consider from a broader, regional perspective (including qualitative impacts from carbon, common pollutants, and water utilization).

The working group agreed that the first two components were to be valued and included in the methodology immediately and that Additional Environmental Considerations would be depicted as a range and leveraged in the future during program design discussions.

Q. DID THE TVA WORKING GROUP COME TO ANY OTHER AGREEMENTS RELATED TO ENVIRONMENTAL IMPACT?

A. Yes. Because the conversations surrounding the environmental impact value were so robust, the working group unanimously agreed that the final document that presented the methodology should adequately represent all arguments that were presented during our stakeholder process. To that end, TVA worked to include language crafted by specific stakeholders into the final document so that their viewpoints were accurately represented. TVA also lists as reference materials many documents provided by working group participants related to the differing viewpoints on environmental impact.

Q. HOW DO ALL OF THESE COMPONENTS COME TOGETHER?

A. The formula for developing the DG-IV is as follows: (G + E + ENVC + T + D) * (1 + TL + DL) + ENVM

Where:

- G = Generation Deferral
- E = Avoided Energy
- ENVC = Environmental Compliance Value
- T = Transmission System Impact
- D = Distribution System Impact
- TL = Transmission Losses
- DL = Distribution System Losses
- ENVM = Environmental Market Value

All values are grossed up for losses because the generation occurs at the load source, except for the Environmental Market Value. This was excluded from the loss gross-up because the SRECs are based on generation only and not system utilization.

Q. IS THIS REPORT PUBLICLY AVAILABLE?

A. Yes. This report can be accessed on TVA's website at tva.gov/dgiv.[1]

IV. <u>CONCLUSION.</u>

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[1] "Distributed Generation – Integrated Value (DG-IV): A Methodology to Value DG on the Grid" (October 2015).

ATTACHMENT JS-1

Statement of Qualifications

John Sterling

John Sterling is SEPA's Senior Director of Research and Advisory Services. He has 14 years of experience in the electric utility business. Mr. Sterling holds a Bachelor of Science degree in Finance and a Masters of Business Administration from Arizona State University.

Mr. Sterling's areas of expertise include distributed solar strategic planning and program design, community solar, stakeholder engagement, resource planning, and power procurement. Mr. Sterling has worked at SEPA for 3 years. Prior to this, he served in a variety of roles at Arizona Public Service Company and APS Energy Services for 11 years.

Mr. Sterling has authored numerous publications related to solar energy, including:

- Kaufmann, K. Pang, J. Sterling, J., & Vlahoplus, C. (2016). Postcards from Hawaii: Lessons on Grid Transformation. http://www.fortnightly.com/fortnightly/2016/02/postcards-hawaii-lessons-grid-transformation.

- Sterling, J. (2016). Time to Talk. Energy & Infrastructure. http://www.nxtbook.com/nxtbooks/phoenix/ei_2016winter/index.php#/0.

- Sterling, J. (2015). Getting Past Net Metering. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2015/12/getting-past-net-metering.

- Vlahoplus, C., Pang, J., Quinlan, P., & Sterling, J. (2015). Community Solar: Answers to Questions You Were Afraid to Ask. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2015/12/community-solar.

- Chwastyk, D., & Sterling, J. (2015). Community Solar Program Design Models. Solar Electric Power Association. http://www.solarelectricpower.org/media/422096/community-solar-design-plan_web.pdf.

- Sterling, J., Davidovich, T., Cory, K., Aznar, A., & McLaren, J. (2015). The Flexible Solar Utility: Preparing for Solar's Impacts to Utility Planning and Operations. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/64586.pdf.

- Joe, B., Hong, M., & Sterling, J. (2015). Impact of High Solar and Energy Storage Levels on Wholesale Power Markets. Black & Veatch and the Solar Electric Power Association. https://pages.bv.com/SolarandEnergyStorageImpacts.html.

- Taylor, M., McLaren, J., Cory, K., Davidovich, T., Sterling, J., & Makhyoun, M. (2015). Value of Solar: Program Design and Implementation Considerations. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy15osti/62361.pdf.

- Davidovich, T., & Sterling, J. (2015). Unlocking the Opportunity in Smart Inverters. Electric Perspectives. http://mydigimag.rrd.com/publication/frame.php?i=241464&p=&pn=&ver=flex.

- Pang, J., Vlahoplus, C., Sterling, J., & Gibson, B. (2014). Germany's Energiewende: Lessons Learned for U.S. Utilities – Drawn from First-Person

Fact-Finding. Public Utilities Fortnightly. http://www.fortnightly.com/fortnightly/2014/11/germanys-energiewende.

- Davidovich, T., & Sterling, J. (2014). Unlocking Advanced Inverter Technology: Roadmap to a Future of Utility Engagement and Ownership. Solar Electric Power Association. http://www.solarelectricpower.org/unlocking-advanced-inverter-functionality.aspx.
- Sterling, J., McLaren, J., Taylor, M., & Cory, K. (2013). Treatment of Solar Generation in Electric Utility Resource Planning. National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy14osti/60047.pdf.