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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
JAN - 3 2017
DOCKETED BY

COMMISSIONERS

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

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

DOCKET NO. E-00000J-14-0023

DECISION NO. 75859

OPINION AND ORDER

DATE OF HEARING:	November 4, 2015, (Procedural Conference), April 15, 2016, (Pre-Hearing Conference), April 19-22, 25, 27, 29, May 5-6, 10-11, June 8-9, and 13, 2016
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Teena Jibilian
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TABLE OF CONTENTS

I. INTRODUCTION 3
II. BACKGROUND 5
A. ACC RENEWABLE INITIATIVES 5
B. NET METERING 6
III. PROPOSED METHODOLOGIES, AND RESPONSES OF OTHER PARTIES 6
A. APS 7
1. Overview 7
2. APS'S Proposed COSS Methodology for Determining Costs to Serve Rooftop Solar Customers 9
a. Step One - Cost Functionalization and Classification 10
b. Step Two – Separating Out Rooftop Solar Customers 11
c. Step Three – Allocating Costs 12
1) Transmission And Distribution Cost Allocations 13
2) Production Cost Allocation 14
d. Step Four - Crediting Rooftop Solar Customers 14
3. Comments on APS's Proposed COSS Methodology 15
a. Vote Solar 15
1) Transparency Issues 15
2) COSS Methodology 16
3) Rooftop Solar Customers as Partial Requirements Customers 18
b. TASC 19
1) Transparency Issues 19
2) COSS Methodology 19
3) Rooftop Solar Customers as Partial Requirements Customers 20
c. Staff 21
1) Transparency Issues 21
2) COSS Methodology 22
3) Rooftop Solar Customers as Partial Requirements Customers 22
4. APS'S Responses to Comments on its Proposed COSS Methodology 23
a. Transparency Issues 23
b. COSS Methodology 24
c. Rooftop Solar Customers as Partial Requirements Customers 25
5. APS'S Analysis of Residential Rooftop Solar Self-Use and Exports 25
6. APS'S Proposed Short-Term Avoided Cost Methodology 27
7. Comments on APS'S Proposed Short-Term Avoided Cost

Methodology 28
a. TEP/UNSE 28
b. AIC 28
c. Vote Solar 28
d. TASC 29
e. Staff 30
8. APS's Responses to Comments on its Proposed Short-Term Avoided Cost Methodology 30
9. APS's Proposed Grid-Scale Adjusted Methodology 31
10. Comments on APS'S Proposed Grid-Scale Adjusted Methodology 33
a. TEP/UNSE 33
b. AIC 33
c. Vote Solar 33
d. TASC 33
e. RUCO 38
f. Staff 38
11. APS's Responses to Comments on its Proposed Grid-Scale Adjusted Methodology 39
B. TEP/UNSE 41
1. Overview 41
2. TEP/UNSE's Proposed CCOS Methodology ("Utah Model") 45
a. Fixed Cost Studies 45
b. Energy Cost Studies 47
c. Future Benefits 48
3. Comments on TEP/UNSE's Proposed CCOS Methodology ("Utah Model") 49
a. APS 49
b. AIC 49
c. Vote Solar 49
i) COSS 49
ii) CCOS 50
d. TASC 52
i) COSS 52
ii) CCOS 52
iii) Rooftop Solar Customers as Partial Requirements Customers 53
e. RUCO 53
f. Staff 53
i) COSS 53
ii) CCOS 54
4. TEP/UNSE's Proposed PPA Proxy Methodology 54
5. Comments on TEP/UNSE's Proposed Proxy Methodology 54
a. APS 54

b. Vote Solar ... 55
c. TASC ... 55
d. RUCO ... 55
e. Staff ... 56
6. TEP/UNSE's Responses to Comments on it Proposed PPA Proxy Methodology ... 56
C. VOTE SOLAR ... 57
1. Overview ... 57
2. Vote Solar's Proposed Long-term Benefit and Cost Methodology ... 58
a. General Principles ... 58
i. Determination of Value of Exports ... 58
ii. Results Should Inform Modifications to Net Metering or Rate Design ... 58
iii. Analysis Required Prior to any Modification to Net Metering or Rooftop Solar Rate Design ... 59
iv. Value of Rooftop Solar Exports to Non-DG Customers ... 59
v. Near-Term Forecast of Rooftop Solar Penetration ... 59
vi. Residential and Commercial/Industrial Rooftop Solar ... 59
vii. Discount Rate ... 60
viii. Transparent and Reliable Data ... 60
b. Methodology ... 60
i. Utility Distributed Solar Costs ... 61
ii. Energy Generation Savings ... 62
iii. Generation Capacity Savings ... 63
iv. Transmission Capacity Savings ... 64
v. Distribution Capacity Savings ... 64
vi. Environmental Benefits ... 65
vii. Economic Development Benefits ... 65
viii. Grid Security Benefits ... 66
3. Net Metering ... 66
4. Comments on Vote Solar's Proposed Long-Term Benefit and Cost Methodology ... 66
a. APS ... 66
b. TEP/UNSE ... 68
c. GCSECA ... 69
d. AIC ... 70
e. RUCO ... 72
f. Staff ... 72
5. Vote Solar's Responses to Comments on its Proposed Long-Term Benefit and Cost Methodology ... 73

D. TASC 77
1. Overview 77
2. Analysis in Other Jurisdictions 78
3. TASC's Proposed Long-Term Avoided Cost Methodology 79
a. Avoided Energy Costs 80
b. Avoided Line Losses 80
c. Avoided Utility Generation Capacity 80
d. Avoided Transmission and Distribution Costs 81
e. Avoided Marginal Transmission Costs 81
f. Extended Life of Distribution and Transmission Equipment 81
g. Fuel Hedging Costs 82
h. Market Price Mitigation 82
i. Societal Benefits 82
i. Water Savings 82
ii. Carbon Reduction 82
iii. Air Pollution Reduction 83
iv. Local Economic Benefits 83
j. Policy Considerations and Non-Monetary Benefits 83
i. New Capital Investments 83
ii. Future Technologies to Enhance Value of DG 83
iii. Competition 84
iv. High-Tech Synergies 84
v. Self-Reliance 84
4. Comments on TASC's Proposed Long-Term Avoided Cost Methodologies 84
a. APS 84
b. TEP/UNSE 86
c. GCSECA 87
d. IBEW Locals 88
e. AIC 89
RUCO 91
f. Staff 91
5. TASC's Responses to Comments on its Proposed Long-Term Avoided Cost Methodology 93
E. RUCO 94
1. Overview 94
2. Key Details of RUCO's Preferred Analysis Framework 95
3. RUCO's Market Fixed Contract and Step-Down Mechanism Proposal 96
4. Valuation/Compensation of Self-Consumption 97
5. Comments on RUCO's Proposals 98
a. APS 98
b. TEP/UNSE 98

c. **GCSECA** 99
d. **AIC** 99
e. **Vote Solar** 100
f. **TASC** 101
g. **Staff** 102
F. **STAFF** 103
1. **Overview** 103
2. **Cost of Service Issues** 104
3. **Net Metering** 104
4. **Staff's Proposed Avoided Cost Methodology** 106
a. **Categories of Benefits and Costs** 106
b. **Methodology for Considering the Benefits and Costs** 106
c. **Avoided Energy Costs** 107
d. **Avoided Generation Capacity Costs** 107
e. **Avoided Transmission and Distribution Costs** 108
f. **Adders to Incentivize DG with Added System Value** 108
1) **Geographic and West-Facing System Adders** 108
2) **Renewable Energy Credits ("REC") Adder** 109
3) **Responsive System and Storage adders** 109
4) **Water** 109
5) **Adders for Added System Value May be Difficult to Demonstrate** 109
g. **General Opposition to Including Environmental Benefits, Local Economic Development Benefits, Fuel Hedge Benefit, Reliability** ... 110
5. **Comments on Staff's Proposed Avoided Cost Methodology** 110
a. **APS** 110
b. **TEP/UNSE** 111
c. **AIC** 112
d. **Vote Solar** 112
e. **TASC** 112
f. **RUCO** 114
6. **Staff's Responses to Comments on its Avoided114 Cost Methodology** 114
7. **Staff's Proposed Resource Comparison Proxy Methodology** 114
a. **Components** 115
b. **Results for APS** 116
c. **Results for TEP/UNSE** 116
8. **Comments on Staff's Proposed Resource Comparison Proxy Methodology** 117
a. **APS** 117
b. **TEP/UNSE** 118
c. **GCSECA** 119

d. AIC 120
e. Vote Solar 120
f. TASC 121
g. RUCO 122
9. Staff's Responses to Comments on its Proposed Resource Comparison Proxy Methodology 122
a. APS 122
b. TEP/UNSE and AIC 123
c. Vote Solar and TASC 124
IV. POSITIONS OF PARTIES NOT PROPOSING A SPECIFIC124 METHODOLOGY 124
A. GCSECA 124
1. GCSECA'S Position 124
2. Responses to GCSECA's Position 127
a. TASC 127
b. Staff 127
B. IBEW Locals 127
1. IBEW Locals' Position 127
C. AIC 128
1. Overview 128
2. Avoided Cost for Exports 130
3. Subsidies in Rate Design and Retail Export Credit 130
4. Rooftop Solar Customers as Partial Requirements Customers . 131
5. Demand Rates 132
V. CONCLUSIONS 133
A. Overview 133
B. Recommendations of the Parties 134
1. APS 134
2. TEP/UNSE 135
3. Vote Solar 135
4. TASC 136
5. RUCO 136
6. Staff 137
7. GCSECA 138
8. IBEW Locals 139
9. AIC 139
C. Establishing a Value of DG Methodology in This Proceeding 140
1. TASC's Request 140
2. APS's Response 141
3. AIC's Response 142
4. Staff's Response 142
5. Resolution 143
D. COSS 143
1. COSS Models 143

2. Rooftop Solar Customers as Partial Requirements Customers 145
E. Net Metering 146
F. Value of DG Methodology 147
1. Analysis of DG Exports 147
2. Methodology 147
a. Staff's Avoided Cost Methodology with Five-Year Forecasting 149
b. Staff's Resource Comparison Proxy Methodology with a Five Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years) 150
G. Other Issues 152
1. Implementation 152
2. Grandfathering 155
3. Cooperatives 156
FINDINGS OF FACT 157
Procedural History 157
Determinations 169
CONCLUSIONS OF LAW 176
ORDER 177

BY THE COMMISSION:

I. INTRODUCTION

On December 3, 2013, the Arizona Corporation Commission ("Commission" or "ACC") issued Decision No. 74202 in Docket No. E-01345A-13-0248. Among other things, Decision No. 74202 ordered that this generic docket be opened on net metering issues, and that workshops be held with all stakeholders to help inform future Commission policy on the value that distributed generation ("DG") installations bring to the grid.

On January 24, 2014, this generic docket was opened, and on January 27, 2014, the Commission's Utilities Division ("Staff") filed a memorandum in this docket. The memorandum listed categories of DG values and costs, and solicited written comments as to their relevance and significance. Staff also requested recommendations on other DG-related issues that should be considered in this docket, and solicited comments regarding the process and methodology for assigning monetary values to DG costs and values.

On May 7, 2014, and June 20, 2014, workshops were held in this docket as Special Open Meetings of the Commission.

On October 20, 2015, at its regularly scheduled Open Meeting, during the course of the Commission's consideration of Docket No. E-01345A-13-0248, the Commission ordered that an evidentiary hearing on the value and cost of DG be held in this generic docket.

Parties to this case are: The Alliance for Solar Choice ("TASC"), Clean Power Arizona, Freeport Minerals Corporation ("Freeport Minerals"), Arizonans for Electric Choice and Competition ("AECC"), Arizona Solar Deployment Alliance ("ASDA"), Vote Solar, Arizona Utility Ratepayer Alliance ("AURA"), Arizona Investment Council ("AIC"), the Residential Utility Consumer Office ("RUCO"), Grand Canyon State Electric Cooperative Association, Inc. ("GCSECA"), Arizona Competitive Power Alliance (the "Alliance"), Western Resource Advocates ("WRA"), Ajo Improvement Company ("Ajo"), Arizona Electric Power Cooperative, Inc. ("AEPCO"), Arizona Public Service Company ("APS"), Columbus Electric Cooperative, Inc. ("CEC"), Dixie-Escalante Rural Electric Association, Inc. ("Dixie-Escalante"), Duncan Valley Electric Cooperative, Inc. ("DVEC"), Garkane Energy Cooperative, Inc. ("Garkane"), Graham County Electric Cooperative, Inc.

("GCEC"), Mohave Electric Cooperative, Inc. ("MEC"), Morenci Water and Electric Company ("MWE"), Navopache Electric Cooperative, Inc. ("NEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"), Trico Electric Cooperative, Inc. ("Trico"), Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNSE"), Patricia Ferré, Nancy Baer, Arizona Solar Energy Industries Association ("ARISEIA"), Local Unions 387, 1116 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW Locals"), Lewis M. Levenson, Susan Pitcairn, Richard Pitcairn, and Staff.

On October 28, 2015, a Procedural Order was issued in this docket, and served on all parties to Docket No. E-01345A-13-0248, setting a procedural conference to be held on November 4, 2015, regarding the evidentiary hearing. The Procedural Order set forth procedural issues to be discussed, including the appropriate means for making the evidentiary record produced through this generic hearing process available to specific ratemaking proceedings.

On November 4, 2015, the procedural conference convened, and procedural matters related to the evidentiary hearing were discussed. A deadline for interested parties to file written comments on procedural matters was set for November 13, 2015.

On December 3, 2015, a Procedural Order was issued setting the hearing to commence on April 18, 2016, and setting associated procedural deadlines. In consideration of the purpose and subject of the evidentiary hearing in this docket, the Procedural Order joined all Arizona jurisdictional electric utilities as parties to this proceeding.[1]

The hearing on this matter commenced on April 18, 2016, and concluded on June 13, 2016. The parties presented the testimony of their witnesses in accordance with the procedural schedule set by Procedural Order in this docket and modified during the course of the hearing, and were allowed the opportunity to cross-examine witnesses who presented testimony.[2] After the filing of Initial

[1] On December 23, 2015, following some utilities' objections to their joinder as parties to this matter and to the notice requirements set forth in the December 3, 2015 Procedural Order, a Procedural Order was issued that widened the acceptable means for Arizona jurisdictional utilities to provide notice of the hearing to their customers; allowed for the addition of introductory language of a utility's choosing to precede the notice; extended the notice deadline; and extended the intervention deadline.

[2] The following parties presented testimony of their witnesses at the hearing: APS, TEP/UNSE, SSVEC, GCSECA, IBEW Locals, AIC, Patricia Ferré, TASC, Vote Solar, RUCO, and Staff.

Closing Briefs and Reply Closing Briefs by the parties who chose to file briefs,[3] this matter was taken under advisement.

II. BACKGROUND

A. ACC Renewables Initiatives

The Commission began its renewable initiatives beginning in 1996 or earlier, when the Commission's rules provided for a solar portfolio standard which set a goal of .02 percent from solar energy by 1999 and 1 percent by 2003.[4] Subsequently, the Commission approved an Environmental Portfolio Standard ("EPS") requiring regulated utilities to generate 0.4 percent of their power from renewables in 2002, increasing to 1.1 percent in 2007-2012, and requiring solar power to make up 50 percent of total renewables in 2001, increasing to 60 percent in 2004-2012.[5]

In 2006, the Commission adopted a new Renewable Energy Standard and Tariff ("REST Rules"), which are contained at Arizona Administrative Code ("A.A.C.") R14-2-1801 through 1815.[6] The REST Rules require regulated utilities to produce at least 15 percent of their retail sales from renewable resources by 2025, and to meet a Distributed Renewable Energy Requirement carve-out pursuant to A.A.C. R14-2-1805.

In 2007, the Commission adopted the Public Utilities Regulatory Policies Act of 1978 ("PURPA") standard on net metering ("NEM") and directed Staff to begin a rulemaking process for net metering rules.[7] In 2008, the Commission adopted Net Metering Rules, which are contained at A.A.C. R14-2-2301 through 2308.[8]

Since the mid-1990s, the Commission has approved funding to support utility-sponsored energy efficiency ("EE") initiatives.[9] In Decision No. 71819, the Commission adopted the Electric Energy Efficiency Rules, which include requirements for EE and demand-side management ("DSM"), which

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[3] The following parties filed briefs: APS, TEP/UNSE, GCSECA (Initial Closing Brief only), IBEW Locals, AIC, TASC, Vote Solar, RUCO, and Staff. Parties who presented testimony at the hearing but chose not to file briefs are SSVEC and Patricia Ferré.

[4] Staff Initial Closing Brief ("Br.") at 2.

[5] *Id.* at 2-3; Decision Nos. 62506 (May 4, 2000), 63364 (February 8, 2001), and 63486 (March 29, 2001).

[6] Staff Br. at 3; Decision Nos. 68566 (March 14, 2006) and 69127 (November 14, 2006).

[7] Staff Br. at 3; Decision No. 69877 (August 28, 2007).

[8] Staff Br. at 3; Decision No. 70567 (October 23, 2008).

[9] Staff Br. at 3.

is a type of EE.[10] The Electric Energy Efficiency Rules are contained in A.A.C. R14-2-2401 through 2419 ("Energy Efficiency Rules"), and require affected utilities to achieve cumulative annual energy savings equivalent to at least 22 percent of the affected utility's retail electric energy sales for 2019.[11]

B. Net Metering

As Staff outlined in its Initial Closing Brief, the Commission's Net Metering Rules (A.A.C. R14-2-2301 *et seq.*) allow electric utility customers to be compensated for generating their own electric energy from renewable resources, fuel cells, or Combined Heat and Power systems, all of which are forms of DG.[12] Staff described the function of the Net Metering Rules as follows:

> If the customer's energy production exceeds the energy supplied by the electric utility during a billing period, the customer's bill for subsequent billing periods is credited for the excess generation. That is, the excess kWh generated during the billing period is used to reduce the kWh billed by the electric utility during subsequent billing periods. Effectively, this credit process compensates the customer (and incents the development of distributed generation) by requiring the electric utility company to acquire the customer's excess generation at the customer's current effective retail rate. In order to prevent abuse of the NEM incentive, the Arizona NEM Rules limit the size of customer DG systems to a maximum of 125 percent of the NEM customer's total connected load.
>
> Once each year (or for a customer's final bill upon discontinuance of service), the electric utility credits the customer for the balance of any remaining excess kWh. The payment for the purchase of these year-end excess kWh is at the electric utility's annual average avoided cost, which is specified on the electric utility's NEM Tariff. A.A.C. R14-2-2302(1) defines avoided cost as "the incremental cost to an Electric utility for electric energy or capacity or both which, but for the purchase from the NEM facility, such utility would generate itself or purchase from another source."
>
> What distinguishes DG solar from other forms of DSM programs, is the export function where excess power from the facility can flow back to the grid. If the DG solar customer did not export power to the grid, there would be no need for NEM.
>
> Like many state net metering rules, the Arizona rules provide for "banking" or accumulation of credits for excess power. When the meter runs "backwards," the customer receives credit for his generation exports at the retail rate.

Staff Br. at 5-6.

III. PROPOSED METHODOLOGIES, AND RESPONSES OF OTHER PARTIES

Not all parties to this case participated in this proceeding, and not all parties who participated

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[10] Decision No. 71819 (August 10, 2010).

[11] Staff Br. at 3-4.

[12] *Id.* at 5.

in the hearing filed briefs. The positions of the parties who filed briefs are set forth here.

A. APS

1. Overview

APS proposes that the value of solar should be established using market based or cost based data.[13] APS presented a Cost of Service Study ("COSS") that it proposes be used for the purpose of ascertaining the costs to serve rooftop solar customers, and for setting rates for rooftop solar customers. APS also presented two methodologies, either of which it recommends for the purpose of ascertaining the appropriate level of compensation to be paid to rooftop solar customers for their exported energy: a Short-Term Avoided Cost methodology, and a Grid-Scale Adjusted methodology.[14]

APS contends that setting rates based on costs provides checks and balances to protect customers, and contends that when ratemaking moves away from embedded costs to rely instead on speculative values that may not materialize, customers may end up paying for benefits they do not receive.[15] APS contends that any policy that would determine a value of solar using assumptions about future events is flawed, and would fail to protect customers from overpaying for electricity.[16] APS believes that the appropriate level of compensation to rooftop solar customers for their contribution to demand-driven infrastructure cost savings should be based on how effective the rooftop solar system is at offsetting peak loads.[17]

Currently under net metering, utilities purchase exported rooftop solar energy at the full retail rate. APS asserts that while the utility initially purchases the exported energy, the utilities' customers ultimately subsidize the purchase through rates.[18] APS urges a change to net metering, because continuation of the status quo would force non-DG customers to overpay for rooftop solar exports by paying a retail rate for a wholesale product.[19] APS contends that as more rooftop solar is installed, the net-metering caused cost shift will deepen, and left unchecked, the cost shift will become more difficult

[13] APS Br. at 1.
[14] APS Br. at 2.
[15] *Id.*
[16] *Id.*.
[17] *Id.*
[18] APS Br. at 23-24.
[19] *Id.*

to correct.[20] APS believes that its proposals for an alternative to the current net metering status quo, both of which would establish a price for rooftop solar exported energy based either on actual data from the market or on cost, would balance the interest of all customers with the interests of the rooftop solar industry.[21] APS proposes that the Commission adopt one of its two proposed methodologies for determining the price utilities pay for rooftop solar exports.[22]

APS equally recommends its Short-Term Avoided cost methodology and its Grid-Scale Adjusted methodology. According to APS, its Short-Term Avoided Cost method, which reflects the cost that would be incurred to replace the rooftop exports with energy from realized wholesale market solar energy prices, would provide a lower incentive to rooftop solar, but would reduce costs for all of APS's customers. APS states that its Grid-Scale Adjusted method, which uses actual reported prices for grid-scale solar Purchase Power Agreements ("PPAs"), would provide a higher incentive to rooftop solar, but would also result in higher rates for non-solar customers.

APS contends that in no event should the price paid for rooftop solar export energy exceed the price of grid-scale solar.[23] APS asserts that its proposed grid-scale price cap is justified, because: (1) both rooftop and utility-scale solar applications rely on solar photovoltaic ("PV") panels; (2) grid-scale solar is more valuable to the system than rooftop solar, due to operational differences; (3) both PV applications achieve environmental and social benefits; and (4) grid-scale PV achieves those benefits at a much lower cost than residential-scale PV.[24] APS's witness Bradley Albert testified that in APS's service territory, non-solar customers pay approximately 14-16 cents/kWh for rooftop solar exports.[25] APS contends that "utility customers could pay approximately 4 cents/kWh" for solar energy from grid-scale solar facilities instead, and that solar energy from grid-scale solar facilities is more valuable than rooftop solar exports.[26]

APS acknowledges that it is within the power of the Commission to incentivize rooftop solar

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[20] APS Reply Brief ("Reply Br.") at 1-2.
[21] APS Br. at 24.
[22] APS Br. at 25.
[23] *Id.*; APS Reply Br. at 7-8.
[24] APS Br. at 25, citing to Exh. APS-5, Direct Testimony of APS witness Bradley Albert, at 3, 27-32; APS Reply Br. at 7-8, citing to Exh. APS-8, Direct Testimony of APS witness Ashley Brown, at 17.
[25] Tr. at 477 (APS witness Bradley Albert).
[26] APS Br. at 23, citing to Tr. at 365 (APS witness Bradley Albert), and Exh. APS-5, Direct Testimony of APS witness Bradley Albert, at 27-32.

over and above the market based value of grid-scale solar as a matter of policy.[27] APS believes that such a policy objective is best accomplished via separate, transparent, effective, least-cost and fair incentives that are calibrated to reflect market conditions, and not through hidden subsidies provided through net metering.[28]

2. APS's Proposed Methodology for Determining Costs to Serve Rooftop Solar Customers

APS states that determining the cost to serve customers through a COSS would provide the technical foundation for a fair allocation of costs between customers, and believes that its proposed COSS methodology fairly allocates costs and appropriately assigns cost responsibility to cost causers.[29]

A COSS is a fundamental ratemaking tool used to allocate a utility's costs among its customers based upon their responsibility for incurring those costs, and serves as a foundation upon which appropriate pricing structures are developed.[30] APS's witness Mr. Snook described a COSS generally as follows:

> 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.[31]

APS asserts that its proposed COSS methodology fully credits customers with rooftop solar systems for all cost savings resulting from the capacity and energy their systems provide to the grid.[32] Mr. Snook testified that a COSS is objective and verifiable because it is based upon embedded historical

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[27] APS Reply Br. at 9.
[28] *Id.*
[29] APS Br. at 2, 5.
[30] *See, e.g.,* Exh. APS-1 (Direct Testimony of APS witness Leland Snook) at 7.
[31] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 7.
[32] APS Br. at 2, 5.

costs.[33] For an electric utility, the cost-allocation study enables a determination of unit costs, by function, that the utility incurs to provide energy, demand, and customer services to each customer class and subclass.[34] The COSS also allows the utility to determine the portion of those costs that each customer class and subclass are currently contributing through their rates.[35]

APS's witness Mr. Snook testified that APS prepared its COSS methodology using industry-accepted functionalization, classification, and allocation principles,[36] and that the methodology "takes into account not only the cost to serve customers with rooftop solar, but also all of the demonstrable benefits which include all of the energy produced by the rooftop solar system and a 19 percent credit for capacity savings."[37]

APS's proposed COSS Methodology for valuing solar consists of four steps. APS states that it conducted an embedded COSS using data for the twelve month period ending December 14, 2014, and using industry-accepted Cost of Service Functionalization, Classification, and Allocation principles, consistent with Commission-approved methods.[38] An embedded COSS is based on the actual incurred historical costs and operating experience of a utility during the selected Test Year, as verified through audited financial data.[39] As Mr. Snook explained:

> 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.[40]

a. Step One – Cost Functionalization and Classification

APS grouped the expense and rate-base items that comprise all of APS's costs into major categories, such as Plant in Service or Operating and Maintenance ("O&M") Expense, functionalized into Production, Transmission, Distribution or Customer related costs, and then classified as Demand,

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[33] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 7-8.
[34] *Id.*
[35] *Id.*
[36] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 8.
[37] Tr. At 103-104 (APS witness Leland Snook).
[38] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 8.
[39] *Id.*
[40] *Id.*

Energy, or Customer.[41]

Functionalization refers to the process of attributing each rate base or expense item to a particular function. For electric utilities, functionalization categories include Production (the generation of electricity), Transmission, Distribution, and Customer related (metering and billing).[42]

Classification refers to the process of determining the factor or factors that drive the magnitude of the cost. APS's witness Mr. Snook provided the following examples: if a cost to serve is driven by the amount of kWh consumed, it is classified as Energy; if a cost to serve is driven by the rate at which energy is consumed (kW capacity), it is classified as Demand; and if a cost to serve 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.[43]

b. Step Two – Separating Out Rooftop Solar Customers

APS grouped rooftop solar customers into two subgroups: those on energy-based rate schedules (including energy-based time of use, or "TOU" rate schedules), and those on demand-based TOU rate schedules. APS believes it is appropriate, and consistent with COSS cost causation principles, to analyze customers with rooftop solar as a separate subclass of partial requirements customers.[44] APS asserts that if a subclass of customers is sufficiently different from the sub-group's current classification in regard to service, load, or cost characteristics, it is appropriate to place that sub-group into a separate class.[45] APS asserts that using traditional COSS methodologies fail to reflect that rooftop solar customers take different services than typical customers, and result in rates that do not fairly reflect causation.[46]

According to Mr. Snook's testimony, the load data demonstrate that as a group, rooftop solar customers meet all three of these criteria.[47] He testified that rooftop solar customers, who are partial requirements customers (because they supply a portion of their own energy needs) have very different

[41] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 9, 10.
[42] *Id.* at 8, 9.
[43] *Id.* at 9.
[44] APS Br. at 20.
[45] APS Br. at 15, citing to Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 11.
[46] APS Reply Br. at 2.
[47] Tr. at 108, 110, 116, 174 (APS witness Leland Snook).

load characteristics than typical residential customers.[48] APS asserts that a typical rooftop solar customer requires only 30 percent of the energy used before adopting solar, but still requires 81 percent of the capacity, and that while a rooftop solar customer supplies a significant portion of its own energy needs, there is still a need for utility infrastructure to serve that customer's needs during most of the customer's peak demand.[49]

APS asserts that in addition to the different load profiles of rooftop solar customers, which makes it appropriate to treat them as a separate subclass of customers than other residential customers, utilities incur different costs to serve partial requirements customers.[50] According to APS, rooftop solar customers require additional services that other residential customers do not require.[51] APS claims that such real-time system operational services include standby service for times when a customer's rooftop solar unit production drops to zero, the inrush current that is necessary to start motors such as air conditioners, frequency control, phase balancing and voltage stabilization, and additional grid management requirements due to rooftop solar energy exports.[52]

c. Step Three – Allocating Costs

APS developed allocation factors based on kW, kWh and number of customers, in order to allocate the functionalized and classified costs to the ACC retail jurisdiction, and to the various retail customer classes and sub-classes.[53] From the data set of APS's entire load, APS developed the traditional coincident (system) peak demand ("CP") allocations, non-coincident (class-specific) peak demand ("NCP") allocations, and Sum of Individual Max demand (the sum of the individual peak loads or demands of all customers within a particular customer class) allocations, and the energy allocations. APS states that it has traditionally used the allocation methods it used in the COSS methodology which the Commission has accepted for many years.[54]

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[48] *Id.*
[49] *Id.*
[50] APS Br. at 17-20.
[51] *See* APS Br. at 17-20.
[52] APS Br. at 19, citing to Exh. TEP-2, Rebuttal Testimony of TEP/UNSE witness Carmine Tilghman, at 7-8.
[53] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 9, 10.
[54] *Id.* at 11.

1) Transmission and Distribution Cost Allocations

APS states that its allocation of transmission costs effectively assumed that each customer class pays the cost of transmission service, even though rooftop solar customers do not pay those costs.[55]

Because distribution plant is generally designed to meet a customer class's peak load, which may or may not be coincident with CP, APS allocated costs related to distribution substations and primary distribution lines based on NCP loads.[56] APS allocated costs related to distribution transformers and secondary distribution lines based on Individual Max demand.

2) Production Cost Allocation

APS allocated costs related to its production-related assets[57] between ACC and non-ACC jurisdictions based on the average of the system peak demand occurring in the four summer months of June, July, August and September ("4CP").[58] APS states that this allocation methodology is consistent with the allocation method required by the Federal Energy Regulatory Commission ("FERC"), and has been accepted by the Commission for many years.[59]

APS then allocated production costs within the Commission-jurisdictional customer classes, based on the Average and Excess Demand ("AED") method, which it states is required by Decision No. 69663 (June 28, 2007).[60] AED uses the sum of the NCP Average Demand allocator and the System Peak Excess Demand allocator.[61] The NCP Average Demand allocator uses each class's NCP demand weighted by the class load factor, calculated using the class energy and the NCP demand.[62] The System Peak Excess Demand allocator is determined by first calculating the NCP Excess Demand, which is the difference between each class's NCP and that class's average demand. The sum of NCP Average Demands is subtracted from the single system peak demand, to derive the System Peak Excess Demand.[63] The System Peak Excess Demand is then allocated to each class based on the proportionate

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[55] *Id.* APS assigned transmission plant directly to the non-ACC jurisdictional portion of the COSS, but brought a portion of transmission costs back into the ACC-jurisdictional cost of service to offset the Open Access Transmission Tariff ("OATT") revenues, to ensure no double counting of transmission costs between the ACC and non-ACC jurisdictions.
[56] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 11.
[57] Production-related assets are generally designed and built to enable a utility to meet its peak system load.
[58] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 10.
[59] *Id.*
[60] *Id.*
[61] *Id.*
[62] *Id.*
[63] *Id.* at 10, 11.

share of the sum of NCP Excess Demands.[64]

APS's cost allocation for rooftop solar customers used data for their entire load. APS believes that the only way to fully account for all costs and benefits associated with rooftop solar is to first use a rooftop solar customer's entire load to allocate costs, and then to separately credit back the energy and capacity savings from the rooftop solar customer's production.[65] According to APS, the only alternative method would be to use delivered load, i.e., only the customer's load directly served by the utility, but as APS's witness testified, using such an alternative would underestimate the costs incurred to serve rooftop solar customers, because it would not capture all the services provided by the utility.[66] APS contends that because utilities incur real costs to provide "behind the meter" services even when a rooftop solar customer is self-supplying a portion of its own energy needs, those costs must be allocated fairly.[67] APS states that such cost-causing behind the meter services include generation backup in the event of a rooftop solar system fails or is turned off; start-up, or inrush, power needed to power larger motors, such as air conditioners and pool pumps; and voltage quality to ensure the operation of sensitive equipment.[68]

d. Step Four – Crediting Rooftop Solar Customers

APS states that it then credited the rooftop solar customer for (i) all of their self-provided capacity based on a comparison to the APS-delivered customer load; and (ii) their entire energy production, including both what the customer consumed on site and what was delivered to the grid. For the energy credit, APS applied its filed avoided cost of 2.895 cents/kWh to each metered kWh produced by the rooftop solar unit.[69] For the capacity credit, APS used metered data to determine the capacity contribution of rooftop solar to APS's peak needs, by measuring how much rooftop solar was produced at the time of CP and at the time of the residential NCP.[70] Then, using the AED method for allocating demand costs, APS took half of that CP contribution and half of that NCP contribution to

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[64] Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 11.
[65] APS Br. at 8.
[66] APS Br. at 8, 10, citing to Tr. at 109-110 (APS witness Leland Snook).
[67] APS Br. at 9.
[68] APS Br. at 9, citing to Tr. at 1369, 1375, 1380, and 1377 (Staff witness Howard Solganick).
[69] Exh. APS-1 (Direct Testimony of APS witness Leland Snook) at 16-17.
[70] *Id.* at 16, 18.

arrive at a capacity credit of 19 percent to demand-related costs.[71]

3. Comments on APS's Proposed COSS Methodology

a. Vote Solar

1) Transparency Issues

Vote Solar claims there are significant transparency issues with the cost of service studies performed by APS, because Vote Solar and other parties were unable to fully analyze the study results.[72] Vote Solar contends that because proprietary third-party systems were used to develop the study, other parties' ability to fully analyze the study and study results were limited.[73] Vote Solar states that it raised the transparency and accessibility issues with APS during discovery, and while APS made efforts to assist Vote Solar, Vote Solar was still unable to fully review the studies in a timely manner.[74] Vote Solar asserts that the proxy model and spreadsheets containing the inputs and outputs to the model materials which APS provided did not allow parties to fully evaluate and assess COSS results under alternate scenarios.[75] Vote Solar asserts that APS understates the difficulty involved in replicating its study, and points to Ms. Kobor's testimony that she would consider APS's model "a black box."[76] Vote Solar asserts that the transparency issues provide cause to reject the study, and provide evidence that it is preferable that an independent third-party conduct future value of solar analyses.[77] Based on its contention that the cost of service studies presented in this proceeding are irrelevant, Vote Solar believes it is not unduly prejudiced by its inability to fully review them in this proceeding, but asserts that if the Commission concludes that the cost of service studies are relevant, the transparency and

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[71] *Id.* at 16.
[72] Vote Solar Br. at 35, 40-41; Vote Solar Reply Br. at 21-22.
[73] Vote Solar Reply Br. at 21; Vote Solar Br. at 40-41, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 8-9. Ms. Kobor's Rebuttal Testimony was pre-filed in this docket on April 7, 2016. Therein, on p. 8, fn. 12, Ms. Kobor stated, in regard to the APS COSS:

> APS has indicated that they are using a new cost-of-service model with a proprietary back-end. They have provided spreadsheets with inputs and outputs to the model as well as a proxy version of the model, but the proxy version is not linked to the inputs and outputs provided and therefore does not enable a full evaluation nor assessment of results under alternate scenarios. In conversations with APS they indicated that they would not be willing to re-run the model with alternate assumptions in this case.

Despite the concerns expressed by Ms. Kobor, Vote Solar requested no extension of the deadline for filing its testimony, and filed no motions related to the discovery issues recounted in Ms. Kobor's pre-filed testimony, at the hearing, or in its briefing.
[74] Vote Solar Br. at 41.
[75] *Id.*
[76] Vote Solar Reply Br. at 21-22, citing to Tr. at 1711 (Vote Solar witness Briana Kobor), and Exh. Vote-Solar-9.
[77] Vote Solar Br. at 41.

accessibility issues it raises provide cause for their rejection.[78] Vote Solar agrees with Staff's recommendation that in future proceedings, APS be required to provide a workable model with linked inputs and outputs, so that parties can vary the inputs and assumptions.[79]

2) COSS Methodology

Vote Solar contends that the cost of service studies presented by APS are irrelevant to a value of solar analysis because calculating the costs and revenues associated with providing electricity to solar customers is an independent and distinct analysis from valuing the net benefits rooftop solar provides.[80] Vote Solar asserts that the types of costs included in a cost of service study therefore play no role in a value of solar analysis.[81] Vote Solar states that APS has recognized that the cost of service analysis and the value of solar analysis are fundamentally different, and points out that none of its methodologies incorporate its cost of service results.[82] Vote Solar contends that even if the studies were relevant, they are flawed and overestimate the costs to serve solar customers, and should not form the basis of any findings in this proceeding.[83]

Vote Solar contends that APS's COSS fails to accurately reflect the benefits rooftop solar provides, because it only incorporates short-term avoided energy and generation capacity savings as they occur, while it omits any savings for transmission and distribution costs, and does not include environmental and economic benefits.[84] Vote Solar argues that it is inappropriate to wait to ascribe value for capacity benefits until APS acquires additional capacity, asserting that a better approach is to value benefits on a continuous basis, and that the modularity and scalability of rooftop solar can offset or delay capacity additions.[85]

Vote Solar contends that APS's COSS is methodologically flawed regarding rooftop solar, and

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[78] *Id.*; Vote Solar Reply Br. at 22.
[79] Vote Solar Reply Br. at 22, citing to Staff Br. at 33.
[80] Vote Solar Br. at 36; Vote Solar Reply Br. at 19.
[81] Vote Solar Reply Br. at 19.
[82] Vote Solar Br. at 36; Vote Solar Reply Br. at 19, citing to Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 29.
[83] Vote Solar Br. at 35, 36.
[84] Vote Solar Reply Br. at 21, referring to Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 29.
[85] Vote Solar Reply Br. at 21, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 25 (the traditional utility planning model cannot, by design, properly account for the benefits of rooftop solar).

disagrees with the conclusion APS drew from its COSS regarding a cost shift.[86] Vote Solar contends that the results of the COSS are skewed by APS's decision to allocate costs based on rooftop solar customers' total load, including load served on-site by the rooftop solar system, instead of allocating costs based only on delivered load.[87] Vote Solar contends that costs should instead be allocated only on delivered load, just as it is allocated to non-DG customers, and asserts that because of this disparate treatment of rooftop solar customers, APS's COSS overestimates energy-related and peak demand-related costs by 28 to 38 percent.[88] Vote Solar argues that because these costs drive approximately 63 percent of the revenue requirement, such an overestimation substantially impacts the study results. Vote Solar asserts that APS's allocation also inflates the costs related to NCP by 3 to 7 percent, and costs related to individual maximum peak by 7 to 10 percent.[89]

Vote Solar Does not accept APS's view that allocating costs to rooftop solar customers' total load is necessary to account for APS's costs of providing start-up power, voltage quality, and generation backup.[90] Vote Solar asserts that such services are not unique to solar customers, and that allocating costs based only on delivered load would fully account for them.[91] Vote Solar states that APS provided no evidence of incremental costs associated with those services, and argues that even if they exist, allocating costs based on total load is not appropriate.[92] Instead, Vote Solar asserts, APS should identify incremental expenses, and then attribute them based on delivered load.[93]

Vote Solar opposes APS's method of crediting of rooftop solar customers, asserting that it does not appropriately value rooftop solar's benefits because it includes only capacity and energy benefits, and does not include transmission and distribution benefits, and other rooftop solar benefits that Vote Solar believes should be included.[94] To account for the value of exports, APS credited rooftop solar

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[86] Vote Solar Br. at 37-39; Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 9-21; Vote Solar Reply Br. at 19-21.
[87] Vote Solar Br. at 37, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 10-13; Vote Solar Reply Br. at 20.
[88] Vote Solar Br. at 37-38, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 17.
[89] *Id.*
[90] Vote Solar Reply Br. at 20, referring to APS Br. at 9-13.
[91] Vote Solar Reply Br. at 20.
[92] *Id.*
[93] *Id.*
[94] Vote Solar Br. at 38, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 13-14; Tr. at 132-134 (APS witness Leland Snook), and Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen, at 16-18, 19.

customers for their entire energy production at the net metering rate of 2.895 cents/kWh, and credited them for self-provided capacity with a portion of the production demand costs.[95] Vote Solar would prefer that costs be allocated to rooftop solar based only on delivered load, rather than allocated on the entire load, with a partial credit back based on a portion of production demand costs.[96]

Vote Solar claims that APS's COSS improperly understates the revenues received from rooftop solar customers for the electricity APS provided to them.[97] APS totaled the revenues received by rooftop solar customers, then subtracted the net metering compensation APS paid for their exports. Vote Solar asserts that it is improper to include the compensation APS pays to rooftop solar customers in the COSS, because the costs are not related to providing electricity to rooftop solar customers.[98]

3) Rooftop Solar Customers as Partial Requirements Customers

In its Reply Brief, Vote Solar argues that the establishment of a separate rate class for rooftop solar customers as proposed by APS, and supported by AIC, is outside the scope of this proceeding.[99] Vote Solar argues that "[s]ingling out solar customers as a separate class is a paradigmatic rate design decision, and it would be inappropriate for the Commission to do so in this generally-applicable value of solar docket."[100] Vote Solar contends that there is insufficient evidence in the record of this proceeding to conduct a fact-specific inquiry comparing rooftop solar customers to a utility's other residential and small commercial customers.[101] Vote Solar argues that "merely listing how one type of customer in a rate class differs from other types of customers does not by itself justify disparate treatment."[102] Vote Solar believes that in order to avoid unconstitutional discriminatory rate treatment, there must be a determination "[w]hether the differences between the average solar customer and the average non-solar customer result in any meaningful impacts that would justify singling out solar customers for differential rate treatment" and that such a holistic and comprehensive analysis is not

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[95] Vote Solar Br. at 38, referring to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 14; and citing to Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen, at 17-18.
[96] Vote Solar Br. at 38.
[97] Vote Solar Br. at 38-39, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 17-18.
[98] Vote Solar Br. at 39.
[99] Vote Solar Reply Br. at 22.
[100] *Id.* at 23.
[101] *Id.*
[102] *Id.*

possible in this proceeding.[103]

Vote Solar opposes classification of rooftop solar customers as partial requirements customers, because a household or small business that installs rooftop solar is different from large and sophisticated partial requirements customers.[104] Vote Solar argues that the term partial requirements customer is typically used to refer to large commercial and industrial customers with complex energy needs and sophisticated loads.[105] Vote Solar argues that unlike traditional partial requirements customers, a rooftop solar customer does not require the utility to incur additional costs or change its infrastructure, and that rooftop solar customers continue to rely on the same transmission and distribution infrastructure as before they installed their rooftop solar systems.[106]

b. TASC

1) Transparency Issues

TASC agrees with Vote Solar that APS's COSS is based on a proprietary model that limits full evaluation of its assumptions and inputs.[107]

2) COSS Methodology

TASC argues that it is inappropriate to use a COSS methodology to determine the value of DG.[108] TASC asserts that due to the retroactive nature as a tool to measure costs in a historical test year, a COSS cannot capture expected future benefits of rooftop solar resources, such as their ability to offset the need for future development of transmission, distribution, or generation upgrades.[109] TASC charges that the utilities' claims that the current rate structure causes non-DG customers to subsidize rooftop solar customers are based on cost of service studies that exclude long-term value streams that accrue with additional rooftop solar deployment.[110]

TASC disputes APS's assertions that its COSS methodology accounts for all rooftop solar

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103 Vote Solar Reply Br. at 23-24.
104 Vote Solar Br. at 5; Vote Solar Reply Br. at 25.
105 Vote Solar Br. at 25, citing to Tr. at 1623-1625 (Vote Solar witness Curt Volkmann).
106 Vote Solar Reply Br. at 25.
107 TASC Br. at 16, citing to Exh. Vote Solar-8, Direct Testimony of Vote Solar witness Briana Kobor, at 15; TASC Reply Br. at 12, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 15 and Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 8.
108 TASC Br. at 15
109 TASC Br. at 15, citing to Tr. at 2029 (TASC witness William Monsen); TASC Reply Br. at 10.
110 TASC Br. at 1-2.

benefits; fully credits residential solar customers for all cost savings resulting from the capacity and energy supplied to the grid; that it is more appropriate to allocate distribution costs based on NCP; and that rates would reflect a 19 percent demand credit on an ongoing basis as the benefit provided by rooftop solar is actually received.[111] TASC argues that because a cost of service study is based on embedded rather than marginal costs, a test year change in cost of service as a result of rooftop solar adoption has no direct link to how the utility's cost may actually be reduced in the future.[112]

Like Vote Solar, TASC asserts that APS's allegations of cost shifting from rooftop solar customers to non-DG customers are based on an improper allocation of costs in its COSS.[113] TASC objects to APS's choice to allocate costs to rooftop solar customers based on their total load as opposed to their delivered load. TASC asserts that this allocation is inappropriate, and that it inflated rooftop solar customers' allocated costs by 28 to 38 percent.[114] TASC contends that the capacity value APS assigned to rooftop solar is far too low, given its contribution to the top 10-15 percent of APS's top load hours.[115]

TASC claims that APS omitted any potential benefits related to transmission and distribution from the credits it assigned to rooftop solar, that APS ignores the generation demand reductions associated with exports.[116] TASC argues that APS's COSS prematurely determined that the value of solar is zero.[117]

3) Rooftop Solar Customers as Partial Requirements Customers

TASC disagrees with assertions by APS, TEP and AIC that rooftop solar customers should be placed in a separate rate class, and argues that the assertions are unsupported and constitute discriminatory treatment of rooftop solar customers.[118] TASC argues that placing rooftop solar

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[111] TASC Reply Br. at 9, citing to APS Br. at 6, 10, 12, 14.
[112] TASC Br. at 15, citing to Exh. TASC-27, Rebuttal Testimony of TASC witness R. Thomas Beach, at 27.
[113] TASC Reply Br. at 12.
[114] TASC Reply Br. at 12, citing to Tr. at 136-137 (APS witness Leland Snook) and Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 16-17 and Table 2.
[115] TASC Br. at 7, referring to Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen at 16-18 and Exh. TASC-27, Rebuttal Testimony of TASC witness R. Thomas Beach, at 14-15.
[116] TASC Br. at 17; TASC Reply Br. at 12, citing to Tr. at 111, 133, 136-137, (APS witness Leland Snook), Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen, at 19, and Exh. TASC-27, Rebuttal Testimony of TASC witness R. Thomas Beach, at 19-21.
[117] TASC Reply Br. at 12-13, citing to Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen, at 19.
[118] TASC Br. at 21, 22; TASC Reply Br. at 17, 18.

customers in a separate class skews the COSS results.[119] TASC also argues that it is improper for the utilities to have run their cost studies using a separate class prior to a Commission determination in a rate case that a separate class is justified.[120]

TASC disputes assertions that a difference in rooftop solar customers' load profiles justifies a separate customer class, arguing that other demand-side technologies can also produce significant changes is customers' load profiles.[121] TASC asserts that the utilities ignore that there are significant variations in load shapes, both among customers with similar end uses in their residences and between customers who have installed various load-modifying technologies.[122] TASC claims that APS's analysis provides no compelling evidence that rooftop solar customers have load shapes that are outside of normal variation in loads seen in the residential class.[123]

c. Staff

1) Transparency Issues

Staff states that its primary concern with the cost studies submitted by both APS and TEP is that other parties cannot use the studies to support their own positions in a rate case.[124] Staff is concerned that the parties were not able to conduct a thorough review of the models, and in particular the APS model, because the model is proprietary and the vendor would not agree to make it available for the parties' use in this proceeding, without the purchase of software at a cost of around $250,000.[125] Staff believes that more transparency on the models would be helpful, not only in this proceeding, but in future proceedings, where there may be questions on cost of service and on the parties' abilities to interact with the models the utilities use.[126]

Staff believes that since APS's COSS model is proprietary, APS should be required to make a spreadsheet available with inputs linked to output, so that all parties will have access to a workable

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[119] TASC Reply Br. at 17.
[120] *Id.* at 17-18.
[121] TASC Br. at 21, citing to Exh. TASC-29, Rebuttal Testimony of TASC witness William Monsen, at 9; TASC Reply Br.at 18.
[122] *Id.*
[123] TASC Br. at 22.
[124] Staff Br. at 30, Staff Reply Br. at 14.
[125] Staff Br. at 30-31.
[126] *Id.* at 32.

model that they can use to vary the inputs in support of their positions.[127] Staff suggests that APS could request funding for this in its upcoming rate case.[128]

Staff asserts that resolution of future transparency issues in this proceeding will facilitate use of all types of models in future proceedings.[129] Staff recommends that models used by the Commission should follow the transparency guidelines that Mr. Huber outlined in his testimony, and that all models used should be: (1) transparent in that all inputs, assumptions, and calculations should be clearly described and explained; (2) accessible, i.e., the cost-benefit calculation should be made available to the public in the form of an electronic spreadsheet that is published on the Commission's website; and (3) there is an ability to change inputs and assumptions used in the calculation, which are likely to change over time.[130]

2) COSS Methodology

Staff does not believe that the transparency issues parties raised in this proceeding with respect to the COSS models bars Commission consideration of the substantive issues raised.[131] Regardless of any methodology adopted in this proceeding, Staff contends that no party is precluded from raising issues in a rate case with respect to the cost study.[132]

3) Rooftop Solar Customers as Partial Requirements Customers

Staff states that rate design issues have an impact on the level of cost shift between DG and non-DG customers, and asserts that this proceeding is not the appropriate docket for adoption of changes to a utility's rate design, including the issue of whether rooftop solar customers should be treated as a separate class for rate design purposes.[133] Staff argues that the issue of a separate rate class is not part of the methodology for determining either the cost or the value of solar, but is instead a rate design issue that should be examined in the context of each utility's rate case, along with other rate design issues involving rooftop solar customers.[134]

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[127] *Id.* at 33.
[128] *Id.*
[129] Staff Reply Br. at 14.
[130] Staff Br. at 33, citing to Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 8-9.
[131] Staff Reply Br. at 14.
[132] *Id.*
[133] Staff Reply Br. at 17.
[134] *Id.*

4. <u>APS's Responses to Comments on its Proposed COSS Methodology</u>

a. Transparency Issues

APS responds that Vote Solar's arguments that it could not separately run its own scenarios using APS's COSS model are inaccurate, and a red herring.[135] APS states that it detailed its methodological assumptions, provided all of the COSS inputs, and shared the full output of its model, and that any party could have taken the provided information and replicated the analysis using their own COSS tool.[136] APS states that private litigants intervene on a regular basis to contest various complicated analytical aspects of utility cases such as a COSS, and they are able to spend their own funds to get licenses from appropriate vendors, such as the COSS licensor UI in this case, or acquire their own cost of service model, or hire a third party to perform a full COSS for them.[137] APS points out that Vote Solar's witness admitted that she could review the assumptions that APS made in its proposed COSS methodology, and that Vote Solar chose not to raise a concern about accessing APS's COSS methodology prior to the filing of its testimony.[138] APS asserts that to the extent other litigants are able to fully assess, debate, and critique utilities' methodological ratemaking choices, it is not clear why utilities should be required to fund private parties' efforts to protect their interests.[139] Finally, APS asserts that because this proceeding concerns the selection of an appropriate methodology, and not the precise outcome of that methodology, Vote Solar's stated concerns regarding the transparency of the model are irrelevant.[140] APS argues that if Vote Solar had accessed the APS COSS tool to run alternative scenarios, all that Vote Solar would have accomplished would be to determine the effect of its methodological changes, and not the soundness of the methodology from a policy perspective. APS contends that once Vote Solar was able to assess APS's COSS methodology assumptions and offer its detailed criticisms thereof, Vote Solar had no need to run alternate scenarios, and the issue of transparency became moot.[141]

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[135] APS Br. at 37.
[136] APS Br. at 37, citing to Tr. at 115 (APS witness Leland Snook).
[137] APS Reply Br. at 11.
[138] APS Br. at 38, citing to Exh. VS-8 (Rebuttal Testimony of Vote Solar witness Briana Kobor) and Tr. at 1719 (Vote Solar witness Briana Kobor).
[139] APS Reply Br. at 12.
[140] APS Br. at 38.
[141] *Id.*

b. COSS Methodology

In response to Vote Solar's assertion that APS's COSS methodology fails to recognize the long-term value of solar, APS responds that the COSS does in fact recognize the long-term value, but recognizes the benefits only at the time they actually occur.[142] APS points out that its methodology would recognize known and measurable benefits by providing a 19 percent demand credit under the COSS presented in this proceeding, and would recognize known and measurable benefits in each rate case on a going-forward basis.[143]

APS's witness testified that APS agrees with TASC that transmission and distribution should have been included in its COSS methodology, and that APS plans to include it in its APS pending rate case filing, but that their inclusion must incorporate both costs and benefits.[144] APS states that because only a portion of rooftop solar production occurs during peak periods, incorporating transmission and distribution benefits and costs into the COSS methodology would increase the net costs allocated to rooftop solar customers.[145]

In response to TASC's assertion that APS gave no credit for generation demand for solar rooftop exported energy, APS states that it did recognize the impact of export energy on APS's cost structure, but that the data shows there is no impact.[146] APS states that if rooftop solar exported energy would have occurred in a meaningful quantity during peak periods, it would have been recognized by APS's COSS methodology.[147] Mr. Snook testified that solar rooftop energy is exported at times when APS's loads are considerably lower than the actual peak hours, and as a result, exported energy does not affect the capacity cost drivers that are measured by CP and NCP.[148]

APS argues that TASC's proposed modifications to APS's COSS methodology attempt to enhance the benefits attributed to rooftop solar.[149] APS states that its COSS methodology found that rooftop solar customers on an energy rate contributed only 37 percent of the cost to provide them

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[142] APS Br. at 14.
[143] *Id.*
[144] APS Br. at 11, citing to Tr. at 111 (APS witness Leland Snook).
[145] APS Br. at 11.
[146] *Id.*
[147] *Id.*
[148] Tr. at 112 (APS witness Leland Snook).
[149] APS Br. at 36.

service.[150] APS argues that the fact that TASC's own COSS methodology concludes that rooftop solar customers fall short of paying the cost to serve them supports APS's position that the cost shift is significant; that rooftop solar customers should be placed in their own separate customer subclass; that APS's COSS methodology is theoretically sound; and that there is a need for a COSS methodology that accurately reflects the demonstrated costs and benefits of rooftop solar.[151]

c. Rooftop Solar Customers as Partial Requirements Customers

In response to arguments that rooftop solar customers should not be treated differently from other customers that have different load shapes in comparison to the typical residential customer, APS asserts that comparing rooftop solar customers with other customer subgroups only highlights the fact that rooftop solar customers are in a class of their own on the basis of load, service, and cost.[152] APS asserts that no other subgroup of customers – whether energy efficiency customers, seasonal customers, vacant homes, customers with swimming pools, or apartment dwellers, has the particular load profile of rooftop solar customers.[153] In particular, APS points out that energy efficiency customers create a permanent overall load reduction, such that their load curve exhibits an overall reduction, while rooftop solar customers' load shape does not.[154] APS argues that the fact that customers other than rooftop solar customers may also have different load shapes than typical residential customers does not justify failing to use rate design to address the growing rooftop solar subclass.[155]

5. <u>APS's Analysis of Residential Rooftop Solar Self-Use and Exports</u>

APS agrees, as do all parties to this proceeding (with the exception of RUCO), that to establish a value for rooftop solar exported energy, the benefits of the export energy must be examined separately from the rooftop solar customer's self-consumed energy.[156] APS's witness Mr. Bradley explained that the value of self-use and export energy differ:

> The value of energy to the utility varies by hour and the capacity value of a generating resource depends upon its output during the hours of peak customer demand. It is logical that rooftop solar customers will self-consume more of their solar output at times

[150] *Id.* at 37.
[151] *Id.*
[152] APS Br. at 22.
[153] *Id.*
[154] *Id.*
[155] APS Br. at 21.
[156] APS Br. at 22-23; Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 11.

when it is more valuable. On hot summer afternoons at 5 p.m., energy is more valuable precisely because consumption is high and demand is greater relative to supply. It is also clear that customers will export more energy at times when it is less valuable, i.e. the non-summer midday, when consumption, and therefore demand, is lower. To value export energy the same as one values self-consumption grossly overstates the value of the exported rooftop solar energy.[157]

APS conducted an export energy analysis using real system conditions and actual metered data, using the data for 28,826 residential customers with rooftop solar that was operational for all of 2015.[158] On August 15, 2015, which was APS's 2015 peak load day, at the time of peak customer consumption (5 p.m.), 5 percent of rooftop solar energy was being exported (as a percentage of nameplate rating).[159] Over the course of the peak day, rooftop solar customers self-consumed 74 percent of output, while exporting 26 percent.[160] APS also looked at the amount of rooftop solar energy exported during the top 90 peak hours (which APS uses as a proxy for a full Effective Load Carrying Capability ("ELCC") analysis). During the top 90 peak hours, 7 percent of rooftop solar energy was being exported.[161]

APS found that over the course of the year, rooftop solar customers exported more than they used to offset their own consumption.[162] In the summer, between June and September, the amount of solar generated is high, with rooftop solar customers self-consuming about 60 percent and exporting about 40 percent of their production.[163] During non-summer months, when APS's system load is much lower than in summer, the supply of rooftop solar exports is highest.[164] Rooftop solar customers' highest exports occur in April and May, when they export about two-thirds of the total energy they

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[157] Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 12.

[158] Exh. APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 12-13. At the end of 2015, APS had 39,171 rooftop solar residential customers on its system. Exh. APS-6 at 13.

[159] Exh. APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 12.

[160] Exh. APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 16.

[161] *Id.* APS prepared a table with a summary of its analysis which appears in Exh. APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 15, Figure 2. That Figure 2 is reproduced here:

Residential Systems Included	28,826
Nameplate Rooftop Solar Capacity (MWs-AC)	170
Total Rooftop Solar Production at Peak Load Hour (MWs)	72.8
Self-Consumption at Peak Load Hour (MWs)	64.0
Total Exported at Peak Load Hour (MWs)	8.8
Maximum Export on April 16, 2015 at 1 p.m. (MWs)	128.6
Average Exported Over Top 90 Hours (MWs)	11.5

[162] Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 14-15.

[163] *Id.* at 15 and 16, Figure 3.

[164] *Id.* at 17, and Figure 5.

produce.[165]

APS believes that the value of solar exports must be based on the specific time it is delivered to the grid.[166] According to APS, the collected data demonstrate that it is rooftop solar customers themselves who receive the majority of capacity-related benefits from their rooftop solar generation, and that there are "very little generation, transmission, or distribution capacity related benefits left to be allocated to the export portion of the rooftop solar energy production."[167] APS states that during periods of low system demand, the relatively high supply of rooftop solar energy exports is not very valuable.[168]

6. APS's Proposed Short-Term Avoided Cost Methodology

APS's proposed short-term avoided cost methodology for establishing a price for rooftop solar exported energy is based on avoided energy costs and energy losses in a near-term period.[169] Using production meter data, the short-term avoided cost methodology cross-references the timing of rooftop solar energy exports onto APS's system with the price at the Palo Verde Hub for short-term solar energy. The result can be averaged over a test year to determine a single per kWh payment amount for all rooftop solar exported energy.[170]

APS believes that its proposed short-term avoided cost methodology has the advantage of transparency while also fairly reflecting objective market costs.[171] APS states that its proposed short-term avoided cost methodology is consistent with historic test year ratesetting, is transparent and verifiable, can be readily calculated using third-party sources of data, and is the only proposal in this proceeding that does not require judgment to implement. APS contends that because no judgment or administrative advocacy is required in this method's calculation of an export price, it is the methodology most likely to avoid any influences that might result in cross-subsidization by non-DG customers.[172]

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165 *Id.* at 15, 17.
166 *Id.* at 18.
167 *Id.* at 16.
168 *Id.* at 18.
169 In its prefiled testimony, APS presented a proposed long-term avoided cost methodology. APS is not requesting consideration of that methodology, and it is therefore not addressed herein.
170 APS Br. at 25-26.
171 *Id.* at 26-27.
172 *Id.*

7. Comments on APS's Proposed Short-Term Avoided Cost Methodology

a. TEP/UNSE

TEP/UNSE state that they would be able to support this APS proposal.[173]

b. AIC

Of the methodologies proposed by APS, AIC supports the short-term avoided cost methodology.[174]

c. Vote Solar

Vote Solar has three general criticisms of the methodologies proposed by the utilities in this proceeding: (1) the utilities' proposed methodologies would not analyze the full set of benefits of rooftop solar exports, and would thereby undervalue rooftop solar exports; (2) the utilities' proposed methodologies are not typically used elsewhere to value rooftop solar; and (3) the utilities' proposed methodologies are results-driven and influenced largely by the utilities' views on appropriate compensation for rooftop solar exports, rather than an attempt to accurately value solar.[175] Vote Solar asserts that the utilities' proposals conflate the two separate inquiries it believes that the Commission must make – first to calculate the value of rooftop solar exports, and then, to determine in a rate case the compensation that utilities will pay rooftop solar customers for those exports.[176]

In its arguments against proposed methodologies other than the long-term benefit cost approach it espouses, Vote Solar asserts that there are two distinct inquiries at issue in this proceeding: (1) calculating the value of rooftop solar exports; and (2) determining the compensation paid to solar customers for their exports.[177] Vote Solar contends that other proposed methodologies "improperly conflate the value of solar analysis with the utilities' views on compensation for solar exports,"[178] that any "[r]esolution of these compensation issues should wait until a later time, after a full and fair value of solar analysis is conducted and a utility has proposed a concrete compensation proposal," and that "[k]eeping these distinct issues separate and focusing only on the value of solar methodology in this

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173 TEP/UNSE Br. at 14; TEP/UNSE Reply Br. at 5.
174 AIC Br. at 19.
175 Vote Solar Br. at 1-2.
176 *Id.* at 2, 25, 28, 34-35.
177 Vote Solar Br. at 2; Vote Solar Reply Br. at 3.
178 Vote Solar Br. at 2, 25, 28, 34-35.

proceeding will simplify the Commission's task here."[179]

Vote Solar contends that APS's short-term avoided cost methodology does not accurately value rooftop solar because it only incorporates a small subset of short term benefits, and ignores many benefits of rooftop solar, such as transmission and distribution capacity savings, as well as environmental, economic development, and grid security benefits.[180] Vote Solar argues that APS's proposed short-term avoided cost methodology is unreasonable, because it takes the long-term benefits of rooftop solar off the table in the name of simplicity and in order to avoid the need to make forecasting judgments.[181] Vote Solar contends that avoiding forecasting is an unreasonable approach, because the objective should be to fully and accurately value rooftop solar.[182] Vote Solar disagrees with claims that ignoring future benefits is reasonable because they may not materialize in the future, asserting that even if a small proportion of customers were to stop operating their rooftop solar systems, it would not materially impact the long-term benefit cost analysis Vote Solar proposes.[183] Vote Solar claims that APS is attempting to avoid calculating the data that may justify net metering, while simultaneously pointing to the lack of data as a reason to eliminate net metering.[184]

d. TASC

TASC argues that it makes sense for a rooftop solar customer to be paid the same amount for energy exported as for energy consumed, and that current Net Metering rates, which are based on the utilities' retail rates, should therefore remain in place as the export compensation rate.[185] According to TASC, the current Net Metering compensation method provides a cost-effective method for the Commission to carry out its renewable energy policies and goals.[186] TASC asserts that adopting a different compensation methodology, such as those proposed by the utilities, would require the

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[179] *Id.* at 35.
[180] Vote Solar Br. at 25-26, 29; Vote Solar Reply Br. at 11.
[181] Vote Solar Reply Br. at 11-12.
[182] *Id.* at 11-12.
[183] Vote Solar Br. at 26, referring to Exh. APS-5, Direct Testimony of APS witness Bradley Albert, at 17, 26 (utilities lack assurance that rooftop solar systems will remain available and capable of producing over their expected life); and Exh. TEP-3, Direct Testimony of Edwin Overcast, at 46 (payment of a levelized total cost is inconsistent with rates and creates issues of intergenerational inequity and potential excess payments due to the lack of obligation for the system to continue producing power at rated capacity over its useful life).
[184] Vote Solar Reply Br. at 6.
[185] TASC Br. at 21.
[186] *Id.*

Commission to constantly ascertain, determine, and finalize a compensation rate and would create uncertainty for new rooftop solar customers.[187]

TASC's general comments in opposition to the use of utility-scale solar as a proxy for the value of rooftop solar exports are set forth below, in TASC's comments to APS's proposed Grid-Scale Adjusted methodology.

e. Staff

Staff disagrees with APS's proposal to cap the results of its Proposed Short-Term Avoided Cost methodology at the price paid for a grid-scale solar PPA with adjustments.[188] Staff asserts that APS has failed to provide sufficient justification for doing so.[189] In addition, Staff contends that such a cap fails to recognize that there may be geographic value in some cases that would not be accounted for with the proposed cap on avoided cost.[190] Staff is also concerned with APS's choice of grid-scale solar PPA for use as a cap.[191]

8. APS's Responses to Comments on its Proposed Short-Term Avoided Cost Methodology

APS argues that Vote Solar's contention that the short-term avoided cost methodology fails to capture the long-term value of rooftop solar is false, because rooftop solar exports would always be purchased at their market value, whether at today's market value or in the future, at the market value at that time.[192] APS believes that its short-term avoided cost methodology "captures the long-term value of DG as that future happens."[193] APS asserts that Vote Solar's future values are hypothetical, and its methodology moves those hypothetical future values forward through an administrative process, in an attempt to avoid actual market or cost data.[194] In response to arguments that because rooftop solar is a long-term resource, short-term market prices should not be used to compensate exported energy, APS responds that long-term evaluations are not used to set rates.[195]

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[187] *Id.*
[188] Staff Br. at 24.
[189] *Id.*
[190] *Id.*
[191] *Id.*
[192] APS Br. at 30.
[193] *Id.*
[194] *Id.* at 31.
[195] *Id.* at 27.

Vote Solar is critical of APS's proposed short-term avoided cost methodology because grid-scale PPA developers receive fixed pricing over the 20-30 year term of the PPAs.[196] APS responds that a PPA is an enforceable contract, with built-in enforceable guarantees for utility customers should the developers fail to perform.[197] In addition, APS points out, utilities only enter into PPAs following a competitive selection process aimed at procuring the least cost solar resource.[198]

APS disagrees with Staff's criticism that APS failed to offer sufficient justification for a grid-scale cap on compensation, stating that its witnesses Mr. Brown and Mr. Albert both proffered testimony that the benefits of rooftop solar PV are achieved by grid-scale solar PV at a lower cost.[199] APS argues that it has a responsibility to protect its customers from undue cost burdens by carefully weighing and planning investments, including meeting its resource needs with least-cost alternatives.[200] APS states that rooftop solar provides value associated with solar energy, but that grid-scale solar provides solar energy value, but at a significantly lower price, and that from the customer perspective, it is not clear why a higher price should be paid for a lower value resource.[201] APS contends that a grid-scale cap on compensation for rooftop solar exports would provide a balance between the interests of its customers with rooftop solar and its customers without rooftop solar[202]

9. APS's Proposed Grid-Scale Adjusted Methodology

APS asserts that its proposed grid scale adjusted methodology for establishing a price for rooftop solar exported energy recognizes that both rooftop solar and grid-scale solar use the same PV technology, while also recognizing the operational and cost differences in the two solar PV applications. APS believes that "[f]rom the perspective of all customers, DG and non-DG alike, the grid-scale adjusted value represents the cost at which the utility could realize the same value attributes that rooftop solar systems supply."[203] APS states that its proposed grid scale adjusted methodology does not require the Commission to consider and quantify the "value" of solar attributes, because grid-

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[196] *Id.* at 29, referring to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 31.
[197] APS Br. at 29-30.
[198] APS Br. at 30, citing to Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 4.
[199] APS Reply Br. at 7-8.
[200] *Id.* at 8.
[201] *Id.* at 9.
[202] *Id.* at 8.
[203] APS Br. at 33.

scale solar energy provides almost all the attributes that rooftop solar energy provides to all utility ratepayers.[204]

APS's proposed Grid-Scale methodology first involves determining a per kWh PPA price obtained from recent, publicly available information.[205] APS's witness Mr. Albert testified that the cost of grid-scale solar PV can be determined based on RFP quotes, or from publicly available costs of regional solar energy acquisitions.[206]

APS's proposed Grid-Scale methodology then adjusts that per kWh PPA price to account for operational differences between grid-scale systems and rooftop solar systems.[207] APS notes the following operational differences between rooftop and grid-scale solar PV systems:

a. differences in scale, with an average 7 kw size for a typical rooftop application, and between 15,000 kW - 20,000 kW (15 - 20 MW) size for a typical grid-scale application;

b. differences related to the fixed nature of rooftop PV systems, compared to the typical sun-tracking technology of APS's grid-scale PV systems;

c. the fact that grid-scale applications are competitively procured, while rooftop solar energy is not; and

d. the utilities' ability to curtail grid-scale solar, but not rooftop solar production, when wholesale market prices are negative.[208]

APS states that while the adjustments require judgment, they are data driven, based on when grid-scale facilities produce power in relation to APS's peak, actual losses avoided by rooftop solar, and recorded instances of negative market pricing.[209]

To account for the operational differences in grid-scale and rooftop solar PV systems, APS's grid scale adjusted methodology adjusts the PPA price as follows:

a. Upward to reflect the energy losses that rooftop PV solar avoids;

b. Downward to reflect the higher capacity values of grid-scale PV solar;

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[204] *Id.*
[205] *Id.* at 31.
[206] *Id.*
[207] *Id.* at 31, citing to Tr. at 424-425 (APS witness Bradley Albert).
[208] APS Br. at 31-32.
[209] *Id.* at 32-33.

c. Downward to reflect that grid-scale PV solar produces energy later in the day when it is more valuable; and

d. Downward because grid-scale PV solar can be curtailed to take advantage of negative energy prices in the market.[210]

APS's calculation of the four adjustments resulted in a 20 percent reduction to the PPA price.[211]

10. Comments on APS's Proposed Grid-Scale Adjusted Methodology

a. TEP/UNSE

TEP/UNSE state that they would be able to support APS's proposed Grid-Scale Adjusted methodology.[212]

b. AIC

AIC supports APS's proposed Short-Term Avoided Cost methodology over APS's proposed Grid-Scale Adjusted methodology.[213] If the Grid-Scale Adjusted methodology is chosen, AIC proposes including the difference between avoided cost and the resulting payment in APS's fuel adjustment clause or REST surcharge and requiring that all customers, with and without rooftop solar, be required to pay the additional sum.[214]

c. Vote Solar

Vote Solar contends that the utility grid-scale methodology is improper, because rooftop and utility-scale solar are not interchangeable resources.[215] Vote Solar believes that the utility grid-scale methodology would undervalue rooftop solar, thereby undercutting its continued growth in Arizona, and would prolong the contentious rooftop solar disputes.[216] Vote Solar asserts that the purpose of utility-scale benchmarking methodologies is only to reduce the compensation of rooftop solar exports, and that they fail to accurately reflect the categories of benefits and costs ascribable to rooftop solar in any way.[217] Vote Solar asserts that the utilities have not pointed to any other jurisdictions that have

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[210] *Id.* at 32. APS asserts that its ability to curtail grid-scale solar increases its value relative to rooftop solar, citing to Exh. APS-5, Direct Testimony of APS witness Bradley Albert, at 27-28.
[211] APS Br. at 32, citing to Tr. at 2094-2095 (APS witness Bradley Albert).
[212] TEP/UNSE Br. at 14; TEP/UNSE Reply Br. at 5.
[213] AIC Br. at 19.
[214] *Id.*
[215] Vote Solar Br. at 29; Vote Solar Reply Br. at 13-14.
[216] Vote Solar Br. at 32.
[217] Vote Solar Reply Br. at 13.

used the utility grid-scale methodology to calculate the value of solar.[218]

Vote Solar argues that its valuation methodology is superior, because the wholesale prices that utilities pay for utility-scale solar do not actually quantify the many environmental and other benefits solar provides.[219] Vote Solar argues that while rooftop solar and utility-scale solar both produce clean, renewable energy, there are significant differences between the two resources:

> For example, distributed rooftop solar provides: (1) higher generation capacity value due to the geographic diversity of distributed solar systems spread across a utility's territory, (2) potentially greater avoided distribution costs and grid services from distributed solar, (3) greater local employment benefits, (4) customer capital investments that benefit the utility and non-solar customers, (5) scalability with developing storage technologies, (6) beneficial competition with utility-provided energy, (7) increased customer knowledge and acceptance of distributed energy resources, and (8) increased energy independence for households and small businesses.[220]

Vote Solar argues that the unique benefits that a utility-scale solar project provides may make it appropriate to "pay more for the same sun" for rooftop solar exports.[221]

Vote Solar points to the DG carve-out in the REST Rules as a recognition by the Commission that DG solar and utility-scale solar are not interchangeable resources.[222] Vote Solar notes that a 2005 Staff Report noted that DG could reduce line losses and the need to build new transmission lines, and that the Commission discussed benefits of DG accruing to non-DG customers in its Decision adopting the REST Rules.[223] Vote Solar notes that Colorado, Illinois, Minnesota, and New Mexico have similar DG carve-outs, that if DG and utility-scale solar provided interchangeable value, there would be no reason for specific requirements for minimum levels of DG solar, and that the carve-outs recognize that rooftop solar provides unique benefits compared to centralized renewable resources.[224]

In response to APS's position that rooftop solar exports should be priced based on markets or

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[218] Vote Solar Br. at 31.
[219] *Id.* at 23; Vote Solar Reply Br. at 13-14.
[220] Vote Solar Br. at 29; Vote Solar Reply Br. at 13-14, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor at 34, fn. 78, and Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 28-29, 30-32, Exh. TASC-26, Direct Testimony of TASC witness Thomas Beach at 29-32, and Exh. TASC-27, Rebuttal Testimony of TASC witness Thomas Beach at 9, 24.
[221] Vote Solar Br. at 14.
[222] *Id.* at 29-30; Vote Solar Reply Br. at 14.
[223] Vote Solar Br. at 29-30; Vote Solar Reply Br. at 14, citing to p. 12 of the Staff Report attached to the February 3, 2006, Draft Rules Package for the Environmental Portfolio Standard Rules, filed in Docket No. RE-00000C-05-0030, and to Decision No. 69127 (November 14, 2006) at p. 6 of Appendix B.
[224] Vote Solar Br. at 29-30; Vote Solar Reply Br. at 15.

costs, Vote Solar argues that "it is infeasible to price rooftop solar exports in the same manner as large-scale central resources," because the market for rooftop solar exports is limited to one purchaser, the utility.[225] Vote Solar further argues that compensating each rooftop solar customer on the costs of the rooftop system is also impractical because utilities have thousands of rooftop solar customers, and the costs of systems vary widely.[226] Vote Solar believes that due to the difficulties in fairly and efficiently pricing solar exports based on markets or costs, its value of solar methodology is superior.[227] Vote Solar further argues that the utilities' arguments that utility scale solar provides many of the same benefits, but at a lower price, ignore the fact that utilities do not offer their customers access to utility-scale solar at wholesale PPA prices, and for this reason, the price utilities pay for utility-scale solar has no bearing on the value of rooftop solar.[228]

Vote Solar argues that compensating rooftop solar customers differently from other generation resources is justified, because they differ from wholesale power generators, utility-scale solar developers, and traditional partial requirements customers.[229] Vote Solar states that the majority of rooftop solar customers are residential and small commercial customers, who are constrained to locate their solar panels only on their roofs, are subject to size limitations for their system of no more that 125% of their load, and do not install their systems with the aim of making a significant profit on their investment; while large and sophisticated utility-scale developers can strategically choose where to develop their projects.[230]

d. TASC

TASC objects to APS's characterization of rooftop solar benefits as "intangible" in its statement on brief that its Grid-Scale Adjusted methodology "sidesteps the need for the Commission to consider and quantify the intangible 'value' of individual solar attributes."[231] TASC argues that the benefits are not intangible, as they have been shown, in past studies commissioned by APS, to provide present value

[225] Vote Solar Br. at 10.
[226] *Id.*
[227] *Id.*
[228] *Id.* at 31.
[229] *Id.* at 10, 30.
[230] *Id.*
[231] TASC Reply Br. at 16, referring to APS Br. at 33.

to utilities of as much as 14.11 cents/kWh.[232] TASC lists specific issues with APS's Grid-Scale Adjusted methodology as follows:

1) APS is conflating a wholesale product with a retail one;

2) APS has set forth no justification to "cap" the rate;

3) Using only one PPA as a proxy can lead to manipulation by the utility;

4) The "adjustments" by APS are subjective and do not take into account the full value of DG; and

5) APS is not using its own PPA as a proxy, but rather a PPA from another utility in Nevada or California and has provided no justification for using these out of state proxies.[233]

TASC asserts that the utilities' proposed methodologies are "flawed from the start and should be rejected." [234] TASC contends that utility-scale valuation methods suffer from the same risk of manipulation issues they claim to be present in the utilities' cost of service methodologies.[235] TASC further contends that utilities would be incentivized to choose a portfolio of projects for comparison that would result in the lowest proxy rate possible.[236]

TASC argues that while utility-scale and rooftop solar use similar technology to produce energy, there are numerous differences which make the use of utility-scale solar a proxy for rooftop solar inappropriate.[237] Like Vote Solar, TASC asserts that the Commission has already recognized the difference between the two resources with the adoption of the DG carve-out in the REST Rules, and TASC contends that because the REST Rules require the utilities to utilize rooftop solar, its unique benefits must be recognized.[238] TASC states that even the utilities acknowledge that some adjustments would be required to a utility-scale proxy to set a compensation rate. However, TASC asserts that

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[232] TASC Reply Br. at 16, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 14-15, n. 7. After summarizing the results of the three studies commissioned by APS in the past, Ms. Kobor also stated that "[s]uch a large variation in results can be problematic for policy makers to use as a basis for decision-making." Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 15.

[233] TASC Reply Br. at 17. In its comment regarding the PPA, TASC refers to Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 6.

[234] TASC Reply Br. at 4.

[235] *Id.* at 14.

[236] *Id.*

[237] TASC Br. at 18-20; TASC Reply Br. at 14-16.

[238] TASC Br. at 20; TASC Reply Br. at 15.

because such adjustments to market prices would be subject to manipulation by the utilities, only a long-term benefit cost analysis can be used to find "the fair value to use."[239]

TASC argues that because the market for rooftop solar exports significantly differs from the market for utility-scale solar exports (rooftop solar customers cannot build their systems in a location other than their roof, are limited in size and technology, and the only market for rooftop solar exports is the utility), the solar exports must be compensated differently from utility-scale solar energy.[240] TASC contends that when a generation facility is located behind the customer's meter at the point of consumption, it has added benefits that utility-scale solar cannot provide.[241] TASC argues that the following major differences between utility-scale solar and rooftop solar weigh against the use of utility-scale solar as a proxy for rooftop solar:[242]

> 1) DG can be deployed with a much shorter lead time and when complemented with other distributed resources helps provide more local service resiliency;[243]
>
> 2) Utility-scale solar generates a different product- wholesale electricity. The value proposition for wholesale energy that requires delivery to an end-user differs greatly from the on-site retail product generated by DG;[244]
>
> 3) The distributed nature of DG makes it more reliable and better and reducing intermittency than utility scale;[245]
>
> 4) Unlike utility-scale, DG has the capability to provide deferral of local distribution capacity and operation expenses (voltage control, transformer loading);[246]
>
> 5) DG's location, at or near the site of consumption, means that the energy generated from utility scale solar incurs greater line losses prior to delivery than does DG energy;[247]
>
> 6) The majority of the output of a rooftop solar facility provides power directly to end-use retail loads, behind the meter, where it displaces

[239] TASC Br. at 19.
[240] *Id.* at 18-19; TASC Reply Br. at 15-16.
[241] TASC Br. at 19.
[242] TASC Reply Br. at 14-15.
[243] TASC Reply Br. at 14, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 31.
[244] TASC Reply Br. at 15, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 29-33.
[245] TASC Reply Br. at 15, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 29-30.
[246] TASC Reply Br. at 15, referring to Exh. TASC-19.
[247] TASC Reply Br. at 15, citing to Exh. Vote Solar-4, Rebuttal Testimony of Vote Solar witness Curt Volkmann, at 15-16.

retail power from the utility whereas utility-scale solar power is often delivered over high-voltage transmission systems in competition with other large power sources;[248] and

7) DG represents a more efficient usage of environmental resources via avoidance of biological impacts of the significant land areas and costly transmission facilities required by utility-scale solar projects.[249]

TASC lists other key differences between the two solar energy resources: "size of the system, target customer, competitive forces, location, interconnection, and investment."[250] TASC asserts that rooftop solar is a retail product, in contrast to the wholesale nature of utility-scale solar.[251] TASC argues that a valuation methodology must recognize and account for the differences between rooftop solar and utility-scale solar when determining a compensation rate.[252]

e. RUCO

RUCO contends that a utility-scale proxy is not an optimal solution because (1) it can overpay rooftop solar; (2) it ignores key differences between utility-scale and rooftop solar; (3) the rate can unexpectedly change (and result in a "misvalue" of rooftop solar); and (4) it is confusing to customers.[253] RUCO asserts that "linking the export rate to solar PPAs provides a disincentive to utilities to incorporate more expensive tracking or dispatchable solar. If a utility desires a solar plus storage PPA, it will in effect be paying non-firm rooftop solar at an artificially high rate."[254]

f. Staff

Staff is concerned that APS did not use its own latest PPA to derive its grid-scale adjusted price, but instead used the PPA, or PPAs, of another western utility.[255] Aside from whether it would be appropriate to do so, Staff asserts that APS did not provide sufficient detail regarding how the PPA was selected, and why it is a good proxy for APS.[256]

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[248] Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 29 (the "minority of power is exported to the distribution grid, where it immediately serves neighboring loads, also displacing retail power from the utility.").
[249] TASC Reply Br. at 15, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 30.
[250] TASC Reply Br. at 14.
[251] TASC Br. at 20.
[252] *Id.*
[253] RUCO Reply Br. at 4, 7.
[254] *Id.* at 4.
[255] Staff Br. at 24.
[256] *Id.*

11. <u>APS's Responses to Comments on its Proposed Grid-Scale Adjusted Methodology</u>

In response to Vote Solar's criticism that use of grid-scale prices, which are set by the market, is inappropriate because rooftop solar customers can sell only to the utility, APS responds that the transaction is also guaranteed to the seller, because the utility has no choice but to purchase the rooftop solar exports. APS contends that basic economics dictates that the guaranteed nature of the sales transaction should result in a lower price for the seller.[257]

In response to Vote Solar's critique that this methodology fails to consider the level of costs rooftop solar allows non-DG customers to avoid, APS states that grid-scale solar PPA prices exceed the actual costs avoided by rooftop solar exports.[258] According to APS, compared to rooftop solar PV, grid-scale solar PV offers a higher capacity value; energy later in the day when it is more valuable; and the ability to curtail production to take advantage of negative market prices.[259]

TASC finds fault with APS's proposed grid scale adjusted methodology because it compares a wholesale product (grid-scale solar PV energy) to a retail product (rooftop solar PV energy that displaces another retail product provided by the utility). APS responds that TASC's asserted wholesale/retail distinction is non-extant, because title to exported energy transfers to the utility exactly the same whether it is exported from a rooftop solar array or from a grid-scale facility, and then the utility resells the purchased wholesale energy at retail.[260]

APS argues that TASC (and Vote Solar) advocate the use of long-term forecasts and their ability to manipulate assumptions regarding long-term benefits in order to justify the current valuation of exported energy at the full retail energy rate, through net metering.[261] APS disagrees with assertions that relying on assumed long-term benefits is the only fair and legitimate methodology for establishing compensation for rooftop solar exports. APS contends that using long-term forecasts to quantify benefits which have not yet occurred, and may not occur, is contrary to well-settled legal ratemaking principles that forbid such speculation.[262] APS argues that the proposed long-term valuation favors

[257] APS Br. at 34.
[258] *Id.*
[259] *Id.*, referring to Exh. APS-5 (Direct Testimony of APS witness Bradley Albert) at 29-32.
[260] APS Br. at 35, referring to Tr. at 1934 (TASC witness R. Thomas Beach).
[261] APS Br. at 39; APS Reply Br. at 3.
[262] APS Reply Br. at 2-4.

one technology with special treatment, and increasing rates for customers without rooftop solar to do so would serve to compound the inequity of using long-term forecasts to set rates.[263]

APS responds that while it is true that the Commission evaluates energy efficiency using cost-effectiveness tests, the results of those tests don't translate directly into rates, but are used to inform Commission policy on whether and how to fund DSM programs to allow the utilities to meet a defined DSM standard.[264] APS charges that TASC and Vote Solar want to rely on the aspects of the DSM cost effectiveness test that benefits their position, and ignore the aspects that protect ratepayers.[265]

APS believes it is inappropriate to rely on the IRP long-term forecasting process as supporting the use of long-term forecasts to establish the value of solar.[266] While acknowledging that IRP plans do involve forecasting benefits over the long-term, APS reiterates that it is actual costs that are used to set rates, not IRP forecasts.[267] An IRP is not a methodology that establishes rates or the amount customers pay.[268] APS also points to several distinctions between the proposed long-term forecasts and IRP processes that offer ratepayer protections, including the use of different scenarios with high and low cases, and obtaining input from stakeholders and the Commission. IRP forecasts are updated every two years, and once resource needs are identified, utilities issue RFPs and procure the least cost resource that fits the identified need.[269] The resource acquisition then faces regulatory prudency review in the utility's next rate case. APS states that TASC's and Vote Solar's long-term-forecast proposals include none of the protections present in the IRP process.[270]

APS contends that rooftop solar exports should be fully compensated at actual value verified by data.[271] APS believes that this proceeding provides an opportunity to encourage future advancement of rooftop solar technology, and that adopting its proposals would make progress toward making solar a long-term sustainable resource for utility portfolios.[272] APS argues against adopting a valuation

[263] *Id.* at 5.
[264] *Id.*
[265] Exh. APS-8, Direct Testimony of APS witness Ashley Brown at 8-9; Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 8-9.
[266] APS Br. at 46; APS Reply Br. at 6.
[267] APS Br. at 45, citing to Exh. APS-2 (Rebuttal Testimony of APS witness Leland Snook) at 6.
[268] APS Reply Br. at 5
[269] APS Br. at 45, citing to Exh. APS-2 (Rebuttal Testimony of APS witness Leland Snook) at 6.
[270] APS Br. at 45.
[271] APS Reply Br. at 17.
[272] *Id.*

methodology that would shield rooftop solar from pressure to innovate.[273]

B. TEP/UNSE

1. Overview

TEP/UNSE state that with increasing rooftop solar deployment, cost-recovery inequities are increasing. TEP/UNSE assert that this is due to the current rate design, coupled with the current net metering payment of retail rates for rooftop solar exports.[274] TEP/UNSE believe that changes are necessary, so that "ratepayers pay only for the true, known and measureable benefits of the avoided utility costs provided by DG as the value assigned to DG energy, particularly the exported DG energy that is ultimately paid for by the ratepayers."[275]

TEP/UNSE explain that when the current Net Metering Rules and policies were established to provide incentives, the net metering "retail rate" proxy did not necessarily overcompensate rooftop solar exports, because there were a limited number of DG installations; metering abilities were limited, and solar DG, as well as grid-scale solar, had higher installed per kW costs than today.[276] TEP/UNSE state that the situation has now changed, with rapid technological advances, a decline in prices for solar technology, and the availability of tax credits.[277] According to TEP/UNSE, the resulting increases in rooftop solar installations, coupled with much lower grid-scale solar costs, have led to:

> (i) a disconnect between the appropriate price signals for the market and technology adoption; (ii) a significant cost shift from DG customers to non-DG customers due to antiquated rate design structures; and (iii) inefficiencies in the design and placement of DG systems resulting in the promotion of more expensive DG technologies.[278]

TEP/UNSE contend that due to current Net Metering Rules and policies under the REST Rules, rooftop solar systems are not being designed and installed to promote demand reduction or system-wide benefits. Instead, rooftop installations are designed to maximize annual kWh production in order to offset charges for energy delivered by the utility.[279] In addition, TEP/UNSE explain, the current

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[273] *Id.*
[274] TEP/UNSE Br. at 1.
[275] *Id.*
[276] *Id.* at 1-2.
[277] *Id.* at 2.
[278] *Id.*, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 3-4.
[279] TEP/UNSE Br. at 2.

design orientation of rooftop solar systems results in the export of energy at times of low system load and times when wholesale energy costs are very low, and thereby fail to provide any benefit regarding peak system demand reductions.[280] TEP/UNSE believe it is no longer appropriate for utilities to pay full retail credit for rooftop solar exports now that the same amount of solar energy exported by rooftop solar could instead be obtained for approximately half the cost - either from the wholesale solar energy market, or from a grid-scale facility, both of which have the same attributes as solar energy.[281]

TEP/UNSE assert that current rate design exacerbates the subsidies that rooftop solar customers receive, because it recovers fixed costs through volumetric charges, which rooftop solar customers avoid.[282] TEP/UNSE state that this rate design caused inequity is in addition to the subsidy that rooftop solar customers receive because they export energy when demand and prices are low, but get credit for those exports at peak usage times, when demand and prices are high.[283] TEP/UNSE state that as long as rate design recovers fixed costs, and in particular capacity costs, through volumetric rates, non-DG customers will be subsidizing DG customers.[284]

TEP/UNSE state that the Commission's determination of the value of DG implicates several public interest considerations, including encouraging the deployment of cost-effective DG, creating a level playing field for different technologies, and preventing overpayment by ratepayers for DG energy.[285] They state that the overall financial impact on non-DG customers is not unduly substantial at this time due to the current level of rooftop solar installations, but that determinations in this docket have the potential to lock in financial impacts that could rapidly increase as more customers adopt rooftop solar.[286] TEP/UNSE believe that providing support to a particular business model must be carefully balanced against the resulting impacts on the public as a whole, and particularly against the impacts to ratepayers, who will ultimately foot the bill for that support. They urge the Commission to therefore be conservative in determining a value for DG exports.[287] TEP/UNSE believe that the

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[280] *Id.*
[281] *Id.* at 3.
[282] *Id.* at 2, 8, referring to Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 33, 41-44.
[283] TEP/UNSE Br. at 2, 8 referring to Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 41-44.
[284] TEP/UNSE Br. at 9.
[285] *Id.* at 10-12.
[286] *Id.* at 10-11.
[287] *Id.* at 11.

balancing of interests is made more challenging because the record in this proceeding is bereft of any specific information on rooftop solar business models.

TEP/UNSE urge the Commission not to set an artificially elevated value to create or sustain a particular DG model or market, and to instead give preference to least cost resources by sending correct price signals with value that reflects actual benefits to the grid and ratepayers.[288] They believe that the Commission should incent cost-effective deployment of DG, because ratepayers will ultimately pay the determined value of DG.[289] TEP/UNSE state that it is important that the Commission create a level playing field for different technologies, and that the current compensation for DG energy creates a significant subsidy with inaccurate price signals, which can act as a barrier to the development and deployment of technologies other than DG.[290] TEP/UNSE assert that by sending the right price signals, the Commission will allow all technologies to compete and provide the most cost-effective solutions which are not currently incentivized, including solar DG with active smart inverters providing VAR support, and west-facing solar DG to increase contribution at the system peak hour.[291]

TEP/UNSE assert that because rooftop solar customers have no legal obligation to provide energy or capacity, short-term avoided cost is a reasonable valuation, and consistent with PURPA legislation. TEP/UNSE contend that the value of rooftop solar energy to the utilities, and to the ratepayers, is similar to the utilities' short-term avoided cost of energy, similar to "as available" energy provided for qualifying facilities ("QFs") under PURPA and related FERC regulations.[292] TEP/UNSE note that most DG facilities are QFs under PURPA, and PURPA specifically requires utilities to purchase excess power exported from QF facilities at a state-regulated price that is based on the utility's avoided costs at the time of delivery.[293] TEP/UNSE contend that rooftop solar is a perfect example of an "as available" resource because the exports to the utility are completely at the discretion of the solar DG customer and subject to the customer's self-consumption, and that it has no capacity value, because it is not delivered to the system in its peak hour.[294]

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288 *Id.*
289 *Id.*
290 TEP/UNSE Br. at 12.
291 *Id.*
292 TEP/UNSE Br. at 3-4.
293 *Id.* at 9, referring to 18 CFR § 292.304(d).
294 TEP Br. at 9-10, citing to Exh. TEP-3, Rebuttal Testimony of TEP/UNSE witness Edwin Overcast, at 5.

TEP/UNSE states that rooftop solar does not meet the requirements of FERC regulations for different than "as available" treatment because rooftop solar has no legally enforceable obligation for delivery to the utility, such as a contract that provides for the committed capacity and energy pursuant to a schedule, a termination notice requirement, and sanctions for non-performance.[295] TEP/UNSE contend that because there is no enforceable contract between rooftop solar customers and the utility that satisfies those PURPA requirements, there is no basis to include avoided capacity costs in compensation for rooftop solar exports.[296]

TEP/UNSE presented two methodologies to calculate the appropriate amount to pay for rooftop solar exports. TEP/UNSE state that their proposed Comparative Cost of Service ("CCOS") methodology is a complex approach that may not be feasible for smaller utilities to use.[297] Its proposed PPA Proxy methodology is the simpler of their proposals, and uses a market proxy for the value of DG energy, and TEP/UNSE believe it would be simple to apply, once the appropriate proxy rate is determined.[298]

Both TEP/UNSE proposals eliminate any "banking" of excess rooftop solar exported to the grid.[299] TEP/UNSE assert that the concept of value of DG necessarily requires no banking of DG exports, and that if parties' DG exports are determined to be worth either more or less than bundled retail rates, the exports cannot be netted or banked.[300]

TEP/UNSE propose that the cost of payments to DG customers for their exports be recovered by passing them through TEP/UNSE's purchased power and fuel adjustment clause ("PPFAC"), and possibly through the REST surcharge, to the extent the payments exceed the market cost of comparable conventional generation ("MCCCG").[301] TEP/UNSE contend that if the Commission decides to include future benefits in the value of DG compensation, any costs paid for those benefits should be collected from customers through a separate charge, similar to the REST surcharge, for the sake of

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[295] TEP/UNSE Br. at 10, referring to 18 CFR § 292.304(d)(2), (e)(2)(iii).
[296] *Id.*, referring to 18 CFR § 292.304(e)(2).
[297] TEP/UNSE Br. at 4.
[298] *Id.*
[299] *Id.* at 5.
[300] TEP/UNSE Reply Br. at 2.
[301] TEP/UNSE Br. at 6.

transparency.[302]

TEP/UNSE state that ideally, payments for rooftop solar exports would reflect the location of the DG system on the grid, the system's impact on the grid, and the time of export.[303] However, because such granularity in establishing the value of rooftop exports is not possible with current technology, TEP/UNSE propose, as an intermediate step, a less complex approach that they believe will result in a more accurate and equitable valuation than current net metering.[304]

2. TEP/UNSE's Proposed CCOS Methodology ("Utah Model")

The CCOS methodology calculates the short term avoided benefits of DG by comparing a utility's cost of service both with and without DG. The COSS studies follow the standard process of functionalization (generation, transmission, distribution, and customer costs), classification, and allocation for each unbundled component of costs.[305] The purpose of cost allocation is to assign costs to customer classes to reflect the factors that cause the utility to incur the costs.[306]

TEP/UNSE believe that the known and measurable cost difference resulting from its proposed CCOS methodology provides a suitable basis for determining the value of rooftop solar exports.[307]

a. Fixed Cost Studies

TEP/UNSE's witness Dr. Overcast based his CCOS methodology on one adopted by the Public Service Commission of Utah, which compares two separate cost studies in order to determine the costs of serving rooftop solar customers.[308] The CCOS determines a utility's cost of service with existing DG, or the actual cost of service ("ACOS"), and compares it to the counterfactual cost of service ("CFCOS"), which determines what the cost of service would be if DG did not exist.[309] In his analysis, however, Dr. Overcast added a third study, a "Solar Class" study, to the ACOS and the CFCOS.

For each fixed cost study, Dr. Overcast used the 2015 test year fixed costs as filed in the TEP rate case, allocated using the same basic methodology of average and excess for production costs, and

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[302] *Id.*
[303] TEP/UNSE Br. at 4, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 10.
[304] *Id.*, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 20.
[305] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 24.
[306] *Id.* at 25-26.
[307] TEP/UNSE Br. at 5, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 7.
[308] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 21, referring to a decision issued , by the Utah Public Service Commission in its Docket No. 14-035-114 on November 10, 2015.
[309] TEP/UNSE Br. at 5-6.

the minimum system customer costs and class NCP for demand related delivery costs.[310] Dr. Overcast believes the allocation factors he used provide a solid, conservative basis to assess the revenue requirements differences between DG and non-DG residential customers.[311]

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[310] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 22.

[311] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 28. Dr. Overcast described the development of his allocation factors as follows:

> To develop the allocation factors for the cost study it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.
>
> Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data, the process consisted of a number of logical steps as follows:
>
> 1. Using basic number properties of mathematics we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the system. From this calculation we saved both the premise load and the excess energy for use in the various analyses. The value of this calculation cannot produce negative kWh. As a result, we eliminated about 200 observations from the data set because the excess kWh sold back to the utility were not possible. For example in one case the kWhs delivered to the utility in a month exceeded the 83,000 for a DG facility with 8.42 kW of capacity; a result that is physically impossible. This is an example of an obvious data error.
> 2. Using monthly total energy consumption of the premise and the residential hourly load shape based on the customer's monthly premise use, an hourly load shape of premise use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape.
> 3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual study.
> 4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value. (The Company data set did not have a kW capacity for all of the solar customers and those were excluded from the analysis.)
> 5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.
> 6. The solar net load shape is the premise hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base fixed cost study.
> 7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile and the solar customer net load profile.
> 8. Using this data it is possible to calculate the solar customers demand allocation factors for each fixed cost study and for the energy cost studies.
> 9. For the counterfactual profile we calculate the residential class Average and Excess Demand (AED) and NCP allocation factors and rerun the cost of service study. We also use the net load profile and calculate the AED and NCP allocation factors using only the net positive energy for AED and the higher of the positive or negative class maximum

The first study, the ACOS, is a standard cost study with rooftop solar customers allocated costs based on actual load characteristics.[312] The second study, the CFCOS, assumes that the rooftop solar customers did not adopt DG, but were full requirements customers, allocated costs in the same way as non-DG customers.[313] Dr. Overcast describes the CFCOS as "essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the customer premise.[314] Dr. Overcast believes the Solar Class study, which evaluates the embedded costs of solar DG customers as a separate customer class, is necessary because the CFCOS assumes the load and delivery capacity requirements to be the same for full and partial requirements customers, an assumption that he states is inherently biased.[315]

According to TEP/UNSE, their cost studies show that it costs at least as much to serve rooftop solar customers as non-DG customers.[316] They add that unlike customers who adopt energy efficiency measures that permanently reduce demand, rooftop DG customers do not necessarily reduce their demand on the system, and often have a higher demand than before installing rooftop DG.[317] TEP/UNSE state that this is because rooftop solar customers can require more system capacity to handle the exports that occur when the customer has minimal load.[318] Their studies show that the embedded cost of service for DG customers is higher than for non-DG customers,[319] and the demand on delivery capacity by solar DG customers is higher than the load demand, which increases DG customers' distribution cost over that of non-DG customers.[320]

b. Energy Cost Studies

TEP/UNSE's witness Dr. Overcast also prepared two energy cost studies using hourly costs, one for full requirements customers, and one for partial requirements customers, to assess energy

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> NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 26-28.

[312] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 21.

[313] *Id.*

[314] *Id.* at 21-22.

[315] *Id.* at 22.

[316] TEP/UNSE Br. at 9.

[317] *Id.* at 9, fn. 21, citing to Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 17-18

[318] *Id.*

[319] TEP/UNSE Br. at 9, citing to Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 21-48.

[320] TEP/UNSE Br. at 8, citing to Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 37 and Tr. at 834-835 (TEP/UNSE witness H. Edwin Overcast).

related costs and an analysis of marginal energy costs for each category of residential customers.[321] Like the fixed cost studies, these energy cost studies allocated TEP's fixed costs based on the COSS filed in TEP's current rate case.[322] Dr. Overcast stated that the two energy cost studies reflect the differences in how the system must respond to the load shape of rooftop solar customers as compared to full requirements customers.[323] Dr. Overcast explained that the first energy cost study analyzes the hourly energy costs based on the expected load in the test year, including the DG load, while the second energy study uses the counterfactual load shape and excludes the sale of excess energy back to the system, because under the counterfactual analysis, there is no excess generation.[324] He states that the studies also used the hourly energy cost analysis to compare the marginal and average energy costs associated with the full requirements customers and the partial requirements customers, essentially using a production costing model to compare energy costs with and without solar DG.[325]

c. Future Benefits

TEP/UNSE assert that any potential system benefits from residential DG systems are uncertain, and may be available only in the future, and therefore customers should not pay for them today.[326] Due to the uncertainty of any future benefits of DG, TEP/UNSE recommend against inclusion of any future benefits or costs in calculating a value of solar. However, to the extent that potential future benefits are included in the value of DG compensation, TEP/UNSE advocate that the total compensation should be capped at the rate of the most current distribution grid-tied solar PPA.[327] TEP/UNSE contend that ratepayers should not have to pay higher DG energy costs than necessary to obtain any potential future benefits of solar energy, and the most current distribution grid-tied solar PPA would provide all of the same external, societal and future benefits of smaller DG systems.[328]

TEP/UNSE state that if the Commission decides to identify anticipated benefits and costs of DG, they could be included in the CCOS calculation.[329] TEP/UNSE assert that by comparing the

[321] Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 21.
[322] *Id.*
[323] *Id.* at 22.
[324] *Id.* at 23.
[325] *Id.*
[326] TEP/UNSE Br. at 3.
[327] *Id.* at 6.
[328] *Id.*
[329] TEP/UNSE Br. at 5.

anticipated benefits and costs caused by existing DG systems with the anticipated benefits and costs if DG did not exist, the Commission could estimate whether there is any net future benefit to the utility and its customers from DG.[330] TEP/UNSE believe that if this is done, the timeframe for assessing potential future benefits should be carefully defined, because the further out estimates go, the more speculative values become, and ratepayers may pay far more than any future benefit actually received.[331] TEP/UNSE caution that levelization of future benefits over a long period of time further increases this risk to ratepayers.[332]

3. Comments on TEP/UNSE's Proposed CCOS Methodology ("Utah Model")

a. APS

APS states that it considers the CCOS methodology proposed by TEP/UNSE to be a strong alternative to its own.[333]

b. AIC

AIC agrees with TEP/UNSE's recommendation against inclusion of any future benefits or costs in calculating a value of solar because it would result in a payment for exported energy above avoided cost.[334] AIC contends that if the Commission wants to subsidize rooftop solar, the payment above avoided cost should be transparent and separately accounted for so that customers know the level of and reason for the subsidy.[335]

c. Vote Solar

i. COSS

Vote Solar claims there are significant transparency issues with the cost of service studies performed by TEP/UNSE, because Vote Solar and other parties were unable to fully analyze the study results.[336] Vote Solar contends that because proprietary third-party systems were used to develop the

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[330] *Id.*
[331] *Id.* at 5-6, referring to Tr. at 1344-1345 (Staff witness Howard Solganick).
[332] TEP/UNSE Br. at 5-6, referring to Tr. at 1349-1350 (Staff witness Howard Solganick).
[333] APS Br. at 39.
[334] AIC Br. at 20.
[335] *Id.*
[336] Vote Solar Br. at 35, 40-41; Vote Solar Reply Br. at 21.

studies, other parties' ability to fully analyze the studies and study results were limited.[337] Vote Solar states that it raised the transparency and accessibility issues with TEP/UNSE during discovery, and while TEP/UNSE made efforts to assist Vote Solar, Vote Solar was still unable to fully review the studies in a timely manner.[338] Vote Solar asserts that the transparency issues provide cause to reject the studies, and provide evidence that it is preferable that an independent third-party conduct future value of solar analyses.[339] Based on its contention that the cost of service studies presented in this proceeding are irrelevant, Vote Solar believes it is not unduly prejudiced by its inability to fully review them in this proceeding, but asserts that if the Commission concludes that the cost of service studies are relevant, the transparency and accessibility issues it raises provide cause for their rejection.[340] Vote Solar agrees with Staff's recommendation that in future proceedings, a workable COSS model with linked inputs and outputs should be provided, so that parties can vary the inputs and assumptions.[341]

ii. CCOS

Vote Solar contends that the cost of service studies presented by TEP/UNSE are irrelevant to a value of solar analysis because calculating the costs and revenues associated with providing electricity to solar customers is an independent and distinct analysis from valuing the net benefits rooftop solar provides.[342] Vote Solar contends that TEP/UNSE skewed its COSS results by overallocating costs to rooftop solar customers.[343] Vote Solar asserts that TEP/UNSE's COSS methodology, like the APS study, understates the revenues received from solar customers by subtracting the compensation paid for solar exports from the overall revenues received from solar customers for their electricity

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337 Vote Solar Reply Br. at 21; Vote Solar Br. at 40-41, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 8-9. Ms. Kobor's Rebuttal Testimony was pre-filed in this docket on April 7, 2016. Therein, on p. 9, fn. 13, Ms. Kobor stated, in regard to the TEP/UNSE study:

> In response to discovery due March 30, 2016 and negotiations between TEP/UNSE and Vote Solar regarding the confidentiality of the spreadsheet analyses, TEP/UNSE provided confidential work papers to its analyses on April 5, 2016, two days prior to the due date for filing rebuttal testimony in this case. I have not had a chance to conduct any substantive review of the work papers in advance of filing this testimony but may conduct such review in advance of the hearing a reserve the right to provide additional substantive response to the evidence at that time.

Vote Solar requested no extension of the deadline for filing its testimony, and filed no motions related to the discovery issues recounted in Ms. Kobor's pre-filed testimony, at the hearing, or in its briefing.

338 Vote Solar Br. at 41.

339 *Id.*

340 *Id.*; Vote Solar Reply Br. at 21.

341 Vote Solar Reply Br. at 22, citing to Staff Br. at 33.

342 Vote Solar Br. at 36.

343 Vote Solar Br. at 39-40; Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 21-27.

purchases.[344] Vote Solar contends that the COSS should analyze only the costs and revenues associated with the energy provided to rooftop solar customers, and that including the costs incurred for purchasing rooftop solar exports results in an overly-inflated calculation of shifted costs.[345] Vote Solar asserts that while the TEP/UNSE study allocated costs to customers based on delivered load for most categories, it incorrectly allocated delivery costs.[346] Vote Solar also contends that TEP/UNSE mischaracterized the maximum peak demand that rooftop solar customers place on the distribution system.[347]

In addition to Vote Solar's foregoing criticisms, Vote Solar contends that the TEP/UNSE COSS suffers from an additional methodological flaw that further skews the analysis and further inflates the amount of shifted costs.[348] Vote Solar states while the COSS used TEP's actual 2015 test year revenues, it calculated costs to serve rooftop solar customers based on its requested 12 percent increase in non-fuel revenues, and asserts that TEP/UNSE thus inflates its cost calculation by 12 percent compared to the revenue calculation.[349]

Vote Solar asserts that the "Utah Model" CCOS model is a seriously flawed method.[350] Vote Solar contends that using the CCOS model is inappropriate for valuing rooftop solar because (1) it is a cost of service analysis, and not a value of solar analysis; (2) it only considers benefits and costs that occur during a historical test year, ignoring future benefits and entire categories of benefits Vote Solar believes should be analyzed; and (3) because the methodology's required complex hypothetical comparative assumption that "rooftop solar never existed" creates challenges associated with determining a solar customer's load shape and projecting how utility costs would have changed but for rooftop solar offsetting a portion of the customer's load.[351] Vote Solar asserts that a better approach would be to first conduct its proposed long-term benefit and cost analysis, and then conduct a traditional COSS that analyzes the cost to serve solar customers based on delivered load.[352]

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[344] Vote Solar Br. at 39, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 24.
[345] Vote Solar Br. at 39.
[346] *Id.* at 39-40, citing to Tr. at 1714 (Vote Solar witness Briana Kobor).
[347] Vote Solar Br. at 40, citing to Tr. at 1629-1630 (Vote Solar witness Curt Volkmann).
[348] Vote Solar Br. at 40.
[349] *Id.*, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 23-24.
[350] Vote Solar Br. at 26-28.
[351] *Id.*; Vote Solar Reply Br. at 12.
[352] Vote Solar Br. at 28.

d. TASC

i. COSS

TASC agrees with Vote Solar that TEP/UNSE's APS's COSS is based on a proprietary model that limits full evaluation of its assumptions and inputs.[353] TASC charges that the utilities' claims that the current rate structure causes non-DG customers to subsidize rooftop solar customers are based on cost of service studies that exclude long-term value streams that accrue with additional rooftop solar deployment.[354] TASC argues that the TEP/UNSE COSS included factors not associated with cost causation, and that the study did not include any long-term benefits associated with rooftop solar.[355]

TASC asserts that the TEP/UNSE COSS conflates the costs and revenues associated with services provided by the utility with compensation paid for rooftop solar exports.[356] TASC agrees with Vote Solar that while the COSS used TEP's actual 2015 test year revenues, it calculated costs to serve rooftop solar customers based on TEP's requested 12 percent increase in non-fuel revenues, thereby over-representing the cost to serve and under-representing collected revenues.[357]

ii. CCOS

TASC asserts that the CCOS should be rejected in its entirety.[358] TASC contends that the CCOS methodology presented by TEP/UNSE suffers from the same flaws it points out in relation to the COSS, and that the addition of a comparative cost allocation to the COSS only adds complexity and the need for further assumptions such as rooftop solar customers' load shapes and utilities' costs, which TASC asserts increases the possibility of manipulation and corrupted results.[359]

TASC argues that it is inappropriate to use a COSS methodology to determine the value of DG.[360] TASC asserts that due to the retroactive nature as a tool to measure costs in a historical test year, a COSS cannot capture expected future benefits of rooftop solar resources, such as their ability

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[353] TASC Br. at 16, citing to Exh. Vote Solar-8, Direct Testimony of Vote Solar witness Briana Kobor, at 15; TASC Reply Br. at 12, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 15 and Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 8.

[354] TASC Br. at 1-2.

[355] TASC Br. at 17; TASC Reply Br. at 13, citing to Tr. at 1713-1715 (Vote Solar witness Briana Kobor).

[356] TASC Br. at 17.

[357] *Id.*, citing to Exh. Vote Solar-7, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 24, n. 52; TASC Reply Br. at 13.

[358] TASC Reply Br. at 13.

[359] *Id.*

[360] TASC Br. at 15

to offset the need for future development of transmission, distribution, or generation upgrades.[361] TASC argues that a COSS is not a valuation tool, and that it would be inappropriate to use a COSS for valuing rooftop solar, or any other generation resource.[362] TASC argues that rooftop solar is a long term resource and it would be unreasonable to assess the long term investment it represents using only a one year snapshot.[363] Instead, TASC argues, rooftop solar should be measured over its full economic life in the same way utilities assess other energy resource options.[364] TASC contends that utilities do not use a COSS to value their own generation resources, including PPAs, or to value demand side resources, but instead use the IRP process.[365]

iii. Rooftop Solar Customers as Partial Requirements Customers

TASC disagrees with assertions by APS, TEP and AIC that rooftop solar customers should be placed in a separate rate class, and argues that the assertions are unsupported and discriminatory against rooftop solar customers.[366] TASC's arguments on this issue appear in its response to APS's COSS, above.

e. RUCO

RUCO asserts that like TEP/UNSE's Proposed PPA Proxy methodology, the CCOS methodology is constantly subject to change.[367]

f. Staff

i. COSS

Staff states that it is concerned that the parties were not able to conduct a thorough review of the model used by TEP/UNSE in its COSS, but notes that TEP was willing to provide access to the model if the reviewer was willing to sign a non-disclosure agreement.[368] Staff believes that any efforts to provide more transparency on the models the utilities provide would be helpful, not only in this

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[361] TASC Br. at 15, citing to Tr. at 2029 (TASC witness William Monsen); TASC Reply Br. at 10.
[362] TASC Br. at 15, citing to Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 31; TASC Reply Br. at 8-12.
[363] TASC Br. at 16.
[364] *Id.*
[365] *Id.*, citing to Tr. at 2029 (TASC witness William Monsen); TASC Reply Br. at 10-11, citing to Tr. at 1847 (TASC witness R. Thomas Beach) and Exh. TASC-27 (Rebuttal Testimony of TASC witness R. Thomas Beach, at 6.
[366] TASC Br. at 21; TASC Reply Br. at 17.
[367] RUCO Reply Br. at 7.
[368] Staff Br. at 30, 33.

proceeding, but in future proceedings, where there may be questions on cost of service and on the parties' abilities to interact with the models.[369]

ii. CCOS

Staff states that it has not had sufficient opportunity to analyze the Utah Commission's models on which TEP/UNSE bases its CCOS proposal, but states that to the extent the models incorporate traditional avoided cost analysis, and would allow for either a short-term or long-term view, they may be appropriate for use in Arizona.[370]

4. TEP/UNSE's Proposed PPA Proxy Methodology

TEP/UNSE's PPA Proxy Methodology would base compensation for DG exports on the most recent PPA for a larger DG system connected to a utility's distribution grid.[371] TEP/UNSE assert that the wholesale price from a PPA is a viable proxy for the value of DG.[372] TEP/UNSE's witness states that there are a few differences between a PPA product and DG exports, such as distribution losses, control and dispatchability, and interconnection value.[373] TEP/UNSE state that depending on the location of DG to the distribution grid, a small adder could be applied to the PPA rate to reflect distribution losses, with the adder to be determined in a rate case based on accepted industry standards.[374]

TEP/UNSE believe their PPA Proxy Methodology effectively incorporates a "future" value of solar, because a solar PPA provides all the same external, societal and future benefits of smaller DG systems.[375]

5. Comments on TEP/UNSE's Proposed PPA Proxy Methodology

a. APS

APS is largely in agreement with TEP/UNSE's Proposed PPA Proxy Methodology, but believes that any grid-scale PPA rate should be adjusted downward by 20 percent to reflect the operational

[369] *Id.* at 32.
[370] *Id.* at 25.
[371] TEP/UNSE Br. at 6.
[372] *Id.*, citing to Exh. TEP-2, Rebuttal Testimony of TEP/UNSE witness Carmine Tilghman, at 2-3.
[373] Exh. TEP-2, Rebuttal Testimony of TEP/UNSE witness Carmine Tilghman, at 2.
[374] TEP/UNSE Br. at 6-7.
[375] *Id.* at 7.

differences between rooftop solar and grid-scale solar PV.[376]

b. Vote Solar

Vote Solar believes that the Commission should make clear in this proceeding that the utilities must conduct a long-term benefit and cost analysis in future rate cases, or in any other proceedings where the utilities propose changes to net metering or rate design.[377] Vote Solar argues that all the proposals presented in this proceeding, with the exception of its own proposal and that of TASC, are not actually methods for valuing rooftop solar, but instead are premature methodologies for compensating rooftop solar at rates less than current retail net metering. Vote Solar asserts that if the Commission selects one of the methodologies proposed by the utilities, RUCO, or Staff, "it would drastically alter solar compensation and the economics of rooftop solar without bothering to calculate the value of solar."[378]

c. TASC

TASC's general comments in opposition to the use of utility-scale solar as a proxy for the value of rooftop solar exports are set forth above, in TASC's comments to APS's proposed Grid-Scale Adjusted methodology.

TASC asserts that a single PPA is not representative of the full value of rooftop or of a utility's avoided cost, and that TEP/UNSE provided scant information to show that the PPA it selected is representative of its utility-scale solar costs.[379] TASC claims that TEP/UNSE seeks to subject rooftop solar customers to constantly adjusting prices, and that no renewable project developer would ever agree to such a pricing structure.[380] TASC contends that the issue of when and how the proxy rate would be updated under TEP/UNSE's PPA Proxy methodology are complex questions, and would deprive the rooftop solar customer of certainty.[381]

d. RUCO

RUCO's comments in general opposition to use of a utility-scale proxy appear in its comments

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[376] APS Br. at 47.
[377] Vote Solar Reply Br. at 7.
[378] *Id.* at 11.
[379] *Id.* at 17.
[380] *Id.*
[381] *Id.*

to APS's Proposed Grid-Scale Adjusted methodology, above.

e. Staff

Staff agrees with TEP/UNSE that a PPA proxy approach would be less burdensome than an in-depth avoided cost study, and that simplicity is an important consideration.[382]

6. TEP/UNSE's Responses to Comments on its Proposed PPA Proxy Methodology

TEP/UNSE caution against adopting a methodology that would overvalue DG based on future, uncertain benefits, which are not actual avoided costs because they are not incurred by the utility.[383] They state that they have not identified any appropriate elements to justify requiring ratepayers to pay for potential long-term benefits of DG under traditional cost of service historical test year ratemaking requirements, such as ratepayers paying only for expenses that are known and measurable, and for plant that was prudent at the time of acquisition and that is currently used and useful.[384] TEP/UNSE believe that potential future benefits identified by other parties such as avoided generation capacity, avoided transmission capacity, avoided environmental costs, and other societal benefits are speculative and depend on forecasts, which become more speculative the farther out they go. TEP/UNSE are concerned that the risk of the forecasts, some being recommended for 25-30 years in the future, are borne by non-DG customers. TEP/UNSE contend that with levelization of the forecasted values, the ratepayer impact increases, because the non-DG customers would then pay even more in the near term.[385]

TEP/UNSE point out that DG customers receiving payment for the speculative future benefits would be the only certain beneficiaries of a policy requiring ratepayers to pay for unknown and uncertain future benefits.[386] TEP/UNSE urge the Commission to err on the side of caution in allocating the risk of over-compensating DG, because non-DG customers may be left bearing the burden of over-valued DG export payments.[387] They contend that potential, yet speculative benefits are not an appropriate basis for imposing costs on ratepayers today.[388] TEP/UNSE assert that if forecasted benefits do not come to pass in the future, non-DG ratepayers would have paid for nothing, and it would

[382] Staff Br. at 26-27.
[383] TEP/UNSE Reply Br. at 1.
[384] TEP/UNSE Br. at 7.
[385] *Id.* at 8.
[386] *Id.*
[387] TEP/UNSE Br. at 11.
[388] TEP/UNSE Reply Br. at 1.

not be likely that the overpayments could be collected back from the DG customers who received them.[389]

C. Vote Solar

1. Overview

Vote Solar recommends that the Commission adopt its proposed long-term benefit and cost methodology to value rooftop solar exports because it analyzes the full set of benefits and costs that occur when a rooftop solar customer exports energy to the grid.[390] Vote Solar states that its proposed methodology "comprehensively analyzes all of the relevant costs and benefits that occur during the economic life of a rooftop solar system, which is typically twenty to thirty years."[391] Vote Solar asserts that its proposed methodology will also put new technologies on the horizon on a level playing field.[392] Vote Solar states that there have been numerous value of solar analyses conducted, including in APS's service territory, and while the specific methodologies vary, the majority have utilized the long-term benefit cost approach.[393] Vote Solar believes that Commission adoption of one of the narrower methodologies, as proposed by parties to this proceeding other than itself and TASC, would ignore many benefits of rooftop solar, thereby undervaluing it, and would do little to assist the Commission in future determinations regarding rooftop solar.[394] Vote Solar contends that its proposed methodology would provide an important tool to help the Commission make reasonable and rational decisions on modifications to net metering proposed by the utilities, and on solar rate design, and would be consistent with value of solar analyses in other states.[395]

Vote Solar provided in its testimony a summary of the results of three cost-benefit analyses that have been conducted in APS's service territory: The 2009 R. W. Beck study; the 2013 update to the 2009 study completed by SAIC, the company that acquired R. W. Beck; and the 2013 Crossborder

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[389] TEP/UNSE Br. at 8.
[390] Vote Solar Br. at 1, 6, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor at 25, and Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor at 35.
[391] Vote Solar Br. at 6.
[392] *Id.* at 7, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 30.
[393] Vote Solar Br. at 7, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor at 15-16, Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 3-10, and Exh. APS-4, Direct Testimony of APS witness John Sterling (discussing the Tennessee Valley Authority value of solar analysis).
[394] Vote Solar Br. at 25.
[395] *Id.* at 1, 25.

Energy study that was commissioned by the solar industry.[396] Vote Solar also provided a table summarizing the results of studies conducted in other states in 2014 and 2015.[397]

2. Vote Solar's Proposed Long-term Benefit and Cost Methodology

a. General Principles

i. Determination of Value of Exports

Vote Solar states that it is only when rooftop solar customers export their excess generation to the grid that the value of the energy should be at issue, and consequently, its long-term benefit and cost analysis should examine the value of solar exports.[398]

ii. Results Should Inform Modifications to Net Metering or Rate Design

Vote Solar states that while the results of its proposed methodology should be used to inform the Commission's decision on compensation, the results should not automatically determine the compensation rate for exports.[399] Vote Solar contends that if a full long-term benefit and cost analysis shows that rooftop solar and net metering result in a net cost, it may indicate that the Commission should revisit the current net metering policy, but if the analysis shows a net benefit, net metering should at least remain in place.[400] Vote Solar asserts that a utility's concerns about how the Commission would use the results of its proposed methodology should not be a reason to adopt a

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396 Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor at 14 and Table 1 at 15. Table 1 is reproduced below for convenience of reference:

Study Author and Year	Present Value of Distributed Solar (¢kWh)
RW Beck, 2009	7.91 to 14.11
SAIC, 2013	3.56
Crossborder Energy, 2013	21.5 to 23.7

397 Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor at 15 and Table 2 at 16. Table 2 is reproduced below for convenience of reference:

State	Date	Sponsor	Resulting Value
ME	Mar-2015	Legislature	33.7¢kWh levelized
VT	Nov-2014	Legislature	23.7¢kWh levelized
MS	Sep-2014	PSC	17.0¢kWh levelized
NV	Jul-2014	PUC	18.5¢kWh levelized
MN	Jan-2014	Dep't of Commerce	14.5¢kWh levelized

398 Vote Solar Br. at 11. Vote Solar contends that while the analysis should focus on exports, the underlying analysis may properly include data for both self-use and exports, if generation data specific to exports is not available. Vote Solar Br. at 11-12, at fn.34.

399 Vote Solar Br. at 8-9, 12.

400 *Id.* at 3, 12.

narrower approach.[401] Vote Solar urges that resolving compensation issues "should wait until a later day, after a full and fair value of solar analysis has been conducted."[402]

iii. Analysis Required Prior to any Modification to Net Metering or Rooftop Solar Rate Design

Vote Solar contends that it is imperative that an updated long-term benefit and cost analysis be conducted whenever a utility proposes a modification to net metering or rooftop solar rate design, so that the Commission can use the results to evaluate the proposal.[403]

iv. Value of Rooftop Solar Exports to Non-DG Customers

Vote Solar recommends that its proposed long-term benefit and cost analysis be used to determine the value of rooftop solar exports to customers without solar, in order to determine whether they are paying a fair price.[404] Vote Solar asserts that this value should include the impacts on utility rate and the environmental, economic development, and grid reliability benefits.[405]

v. Near-Term Forecast of Rooftop Solar Penetration

Vote Solar believes that the value of a rooftop solar system may vary based on the overall amount of rooftop solar in a utility's service territory, with value possibly lessening at higher levels of penetration.[406] For this reason, Vote Solar proposes to use a forecast of rooftop solar penetration over the next one to three years as part of its long-term benefit and cost analysis .[407] As penetration increases in the future, Vote Solar believes the analysis should be updated to provide a more accurate assessment of the value provided by the additional systems.[408]

vi. Residential and Commercial/Industrial Rooftop Solar

Vote Solar recommends that its proposed long-term benefit and cost analysis include all end-use retail customers, as the net metering rules and the REST Rules apply to both the residential and commercial sectors.[409] Vote Solar states that limiting the analysis to residential rooftop solar customers

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[401] *Id.* at 9-10.
[402] *Id.* at 10-11.
[403] *Id.* at 13.
[404] *Id.*, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 18.
[405] *Id.*
[406] Vote Solar Br. at 14.
[407] *Id.*
[408] *Id.*
[409] Vote Solar Br. at 15.

would lead to undervaluation of exports.[410] Vote Solar explains that this is because residential customers typically pay higher per kWh rates than commercial customers, whose per kWh rates are lower due to their demand charges, which makes the primary cost in Vote Solar's proposed analysis higher for residential customers, and lower net benefits than for commercial customers. [411]

vii. Discount Rate

Vote Solar states that choosing an appropriate discount rate is important for accurate results, given that its proposed long-term benefit and cost analysis spans 20 to 30 years.[412] Vote Solar recommends a societal discount rate similar to the rate of inflation, in order to reflect the time value of money to customers without solar.[413]

Vote Solar is opposed to using the utilities' weighted average cost of capital as the discount rate to be applied to the future benefits of rooftop solar systems, as suggested by some witnesses, because, Vote Solar argues, the analysis should be approached from the perspective of the ratepayers, and not the utility.[414] Vote Solar contends that while the societal discount rate should be applied to all costs and benefits, it should at a minimum be applied to benefit categories that are separate from utility costs, such as environmental, economic development, and grid security benefits.[415]

viii. Transparent and Reliable Data

Vote Solar recommends that the utilities retain an independent third party to conduct the analysis in order to insure impartiality and independence.[416] Whether the analysis is conducted by the utilities or by a third party, Vote Solar states that it is imperative that the data the utilities provide for the analysis be transparent, reliable, and subject to full review by other parties.[417]

b. Methodology

Vote Solar's proposed long-term benefit and cost analysis methodology consists of an examination of eight categories of benefits and costs that result when households and businesses with

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[410] *Id.*
[411] *Id.*
[412] Vote Solar Br. at 16.
[413] *Id.*, referring to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 23.
[414] Vote Solar Br. at 16, citing to Exh. TEP-4, Rebuttal Testimony of TEP/UNSE Edwin Overcast, at 52, and Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 26.
[415] Vote Solar Br. at 16, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 23.
[416] Vote Solar Br. at 16, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 50.
[417] Vote Solar Br. at 16-17.

rooftop solar export power to the grid. Vote Solar's witness Ms. Kobor states that the cost-effectiveness measure she advocates for in evaluating the value of DG exports is related to California's "Standard Practice Manual" for examining the cost-effectiveness of demand-side programs.[418] Ms. Kobor states that her methodology "could be considered a modified version of the Ratepayer Impact Measure ("RIM") test, plus adders from the Societal Cost Test ("societal adders")."[419] She states that "[t]he RIM test would capture the impact of DG exports on utility rates and the societal adders would allow for necessary incorporation of other benefits."

i. Utility Distributed Solar Costs

Vote Solar states that the two types of utility costs resulting from rooftop solar exports are (1) the compensation the utility pays to rooftop solar customers for exported energy, and (2) net integration costs.[420]

The primary cost in Vote Solar's proposed long-term benefit and cost analysis is the utility's cost of compensating rooftop solar customers for their exports. Current costs are the net metering rate, which are easily calculated, but in order to quantify the levelized costs over the 20 t0 30 year lifespan of a rooftop solar system, it is necessary to forecast future compensation rates. Vote Solar's proposal requires the utilities to project future compensation rates.[421]

The second category of utility costs is integration costs, which include the direct administrative costs related to rooftop solar exports and any required ancillary services. Vote Solar states that integration costs are typically minimal at the penetration levels currently present in Arizona, and points out that TEP and UNSE are unable to quantify any additional operational expenses attributable to rooftop solar at this time.[422] Vote Solar states that integration costs can also vary by location.[423]

In order to improve the accuracy of its proposed long-term benefit and cost analysis, and to encourage deployment of DG at locations providing the greatest value with the least interconnection

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418 Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 18.
419 *Id.*
420 Vote Solar Br. at 17, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 26.
421 Vote Solar Br. at 18, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 27.
422 Vote Solar Br. at 18, referring to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach at 16, and citing to Tr. at 689 (TEP/UNSE witness Carmine Tilghman).
423 Vote Solar Br. at 18, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 5-6.

costs, Vote Solar requests that the utilities be required to conduct a hosting capacity analysis.[424]

ii. Energy Generation Savings

Vote Solar asserts that when a rooftop solar customer exports energy to the grid, the utility will generate or purchase less energy from centralized power plants, and therefore the exported energy offsets the need for a kWh of energy generated from the marginal generation plant.[425] Vote Solar states that the energy generation savings will vary depending on the utility and the timing of solar exports, and as a result, it will be necessary for the utilities to supply data on the current export profile of their rooftop solar customers.[426] Vote Solar states that this export profile can then be used to develop assumptions about the marginal generator that would serve various portions of the load expected to be served by additional DG exports. Vote Solar's witness Briana Kobor describes Vote Solar's recommendations for valuing energy generation savings for its proposed long-term benefit and cost analysis methodology as follows:

> Once the type of marginal generator or generators is identified, it will be necessary to determine the avoided cost of energy from these plants. Avoided cost of energy from a natural gas-fired plant is a function of three key inputs: (1) natural gas price, (2) heat rate, and (3) variable costs of operations and maintenance ("O&M").
>
> While there is considerable uncertainty regarding the price of natural gas over the next twenty to thirty years, it is reasonable to develop a projection of future prices based on available information from the commodity futures trading market. I recommend that a natural gas price forecast be developed by examining available NYMEX futures trading data and extrapolating longer-term values based on publicly available forecasts, such as the twenty-five-year forecast developed by the Energy Information Administration ("EIA"). Market center prices would need to be converted to local burnertip prices by using futures data on basis swaps prices, as well as estimated costs to bring the gas to generators over the local gas transportation system. Developing a forecast of long-term annual gas prices is an exercise that brings significant uncertainty to the analysis. As a result, it would be reasonable to include sensitivity analyses based on higher- and lower-than projected natural gas prices to assess how this uncertainty may impact the overall DG value analysis.
>
> The heat rate assumption is specific to the type of plant and should reflect expected average heat rate, including accounting for long-term heat rate degradation that may occur over the period of the analysis. In addition, a reliable estimate of variable O&M must be developed and forecasted over the period of the analysis.

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[424] Vote Solar Br. at 18, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 6-8.
[425] Vote Solar Br. at 17-18, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 27-28.
[426] Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 28.

> Because DG exports offset the need for energy at or near customer load, the calculation of energy generation savings must also include avoided line losses associated with delivering electricity from a central station generator to customer load. Line losses vary by utility and are typically about 7%, though they may be higher during periods of congestion. Because line losses may vary by season and time of day, it is important that marginal line losses expected during the periods of DG exports be used to estimate the avoided line losses from DG. Because DG exports are expected to occur during heavier loading periods, estimating avoided line losses using average line loss figures would likely undervalue the benefit from DG exports. Avoided line losses must also be accounted for in the calculation of generation, transmission, and distribution capacity savings.

Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 28-29 (citations omitted).

iii. Generation Capacity Savings

Vote Solar contends that when rooftop solar customers export energy to the grid, it reduces the utility's need to build generation capacity to meet peak demand, and includes the resulting generation capacity savings in its proposed long-term benefit and cost analysis methodology.[427] Vote Solar asserts that peak demand in Arizona typically occurs in the late afternoon during the summer months, which is when rooftop solar produces energy, and therefore contributes to meeting the system's peak demand.[428] Vote Solar asserts that while individual DG systems may not be able to provide dependable peak capacity due to the potential for passing clouds to temporarily reduce generation, geographically diverse groups of DG systems can reliably contribute to peak capacity.[429] Vote Solar contends that the valuation of generation capacity savings should account for the modularity of rooftop solar installations and the marginal benefits of additional solar capacity. Vote Solar asserts that it is improper to base the analysis on large tranches of lumpy capacity rooftop solar additions and assume that rooftop solar provides no capacity benefits until a utility eliminates or defers a large capacity addition.

Vote Solar's witness Briana Kobor describes Vote Solar's recommendations for valuation of energy generation savings in its proposed long-term benefit and cost analysis methodology as follows:

> An appropriate analysis would examine the marginal benefit of additional DG capacity to delay or offset the need for future generation capacity additions. In order to quantify this benefit, assumptions must be made regarding the generation capacity additions that would be needed but for the additional DG export capacity. Capacity cost from a new generator can be estimated by developing assumptions for capital costs, fixed O&M, and gen-tie transmission costs to develop an estimate of the $/kWh of installed capacity.

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[427] Vote Solar Br. at 19.
[428] *Id.*
[429] Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 20.

> Once the cost of new installed capacity is developed, the analyst must determine the level of DG export capacity that is expected to contribute to the system peak. Such a calculation may be completed using an assessment of the effective load carrying capacity ("ELCC"). ELCC is a statistical measure of capacity that can be relied on by the utility to meet load that accounts for the intermittency associated with solar DG. The ELCC measures the load increase that the system would be able to carry while maintaining the designated reliability criteria. ELCC can vary by technology. For example, single-axis tracking PV has higher estimated ELCC than fixed-array PV. In developing the assumptions for ELCC of DG exports, it will be necessary to evaluate the expected technology of future DG additions.
>
> With these assumptions in place, calculating the generation capacity savings of DG is a relatively simple undertaking. As discussed above, under energy generation savings, marginal avoided line losses associated with DG capacity located at or near load must be accounted for by applying an adder to the expected cost of new generation capacity. In addition, utilities are required to maintain certain levels of capacity reserve margins (e.g., 15% above peak load) to ensure reliability in the event of extreme load circumstances or unexpected outages of transmission or generation infrastructure. Dependable DG capacity will reduce the need for additional capacity to meet the reliability criteria. This reduction in needed reserves should be accounted for by developing an adder to be multiplied by the cost of new generation capacity. The resulting value is then multiplied by the ELCC to determine the generation capacity savings attributable to DG.

Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 30-31(citations omitted).

iv. Transmission Capacity Savings

Vote Solar asserts that rooftop solar exports can decrease the peak load at substations and provide congestion relief, which allows the utility to defer or eliminate transmission system upgrades, and therefore transmission capacity savings should be included in its proposed long-term benefit cost methodology.[430] Vote Solar states that transmission and distribution capacity savings can vary based on circuit and location, so the analysis should use a detailed marginal cost of service methodology to value both transmission and distribution capacity.[431] Vote Solar contends that small and incremental contributions to transmission capacity also provide real benefits, so rooftop solar should be credited for transmission capacity benefits even if there is not an imminent capacity expansion project in the local area.[432]

v. Distribution Capacity Savings

Vote Solar contends that rooftop solar contributes distribution capacity savings in a manner

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[430] Vote Solar Br. at 20-21, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 16-17.
[431] Vote Solar Br. at 20-21, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 18.
[432] Vote Solar Br. at 20-21, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 18-19.

similar to the transmission capacity savings described by its witness, by allowing the utility to defer or eliminate distribution system upgrades, and that the marginal cost of service methodology it recommends for quantifying transmission capacity savings would therefore also be appropriate to quantify distribution capacity savings.[433] Vote Solar also includes in its proposed long-term benefit and cost analysis methodology a credit for distribution capacity savings based on incremental peak demand reductions, even if a utility does not have imminent plans for a distribution system project.[434]

vi. Environmental Benefits

Vote Solar states that rooftop solar provides clean, renewable energy that provides numerous environmental benefits. Vote Solar includes four types of environmental benefits in its proposed long-term benefit and cost analysis: (1) avoided utility compliance costs; (2) avoided carbon pollution benefits; (3) avoided non-carbon air pollution benefits, and (4) water conservation benefits.[435] Vote Solar contends that the environmental benefits provided by rooftop solar should be valued in the manner that its witnesses Ms. Kobor and Mr. Volkman described in their prefiled testimonies.[436] Vote Solar contends that even if some environmental benefits are difficult to quantify, it is unreasonable to ignore them, and that its proposed environmental valuation approach to quantification is similar to analyses conducted elsewhere.[437]

vii. Economic Development Benefits

Vote Solar includes in its proposed long-term benefit and cost analysis methodology the direct economic impacts of local jobs created by selling and installing rooftop solar systems, as well as additional tax revenues for state and local jurisdictions that result from solar employees' purchases of supplies and goods.[438] Vote Solar states that there are several ways to measure the economic benefits,

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433 Vote Solar Br. at 21-22, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 19-21, Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 32, and Exhibit BK-2 (A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, published by The Interstate Renewable Energy Council, Inc. "IREC Guidebook") at 26-29.

434 Vote Solar Br. at 22, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 21.

435 Vote Solar Br. at 22, citing to Direct Testimony of Vote Solar witness Briana Kobor, at 32; and Exhibit BK-2 (IREC Guidebook) at 26-29.

436 Vote Solar Br. at 22-23, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 32-35; and Exh. Vote Solar-3, Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 22-26.

437 Vote Solar Br. at 22, referring to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 32; and Exhibit BK-2 (IREC Guidebook).

438 Vote Solar Br. at 23.

including an economic input-output analysis that examines the potential multiplier impacts of rooftop solar, or by quantifying the tax enhancement value caused by increased employment.[439]

viii. Grid Security Benefits

Vote Solar's proposed long-term benefit and cost analysis methodology includes grid security benefits. Vote Solar asserts that rooftop solar systems can provide reliability benefits by avoiding service interruptions and providing backup power during outages, and that the benefits can be calculated based on the number and duration of avoided outages, multiplied by the estimated cost of an interruption.[440] Vote Solar states that a concern raised by TEP/UNSE's witness Mr. Overcast, that the current Institute of Electrical and Electronics Engineers ("IEEE") standards require rooftop solar to disconnect from a grid during an outage, are currently being amended, and that this benefit may soon materialize.[441]

3. Net Metering

Vote Solar asserts that current net metering is a simple and easily-understood method of valuing solar exports, and that numerous value of solar studies elsewhere have found that net metering, which currently provides rooftop solar customers with retail rate compensation for their exports, appropriately compensates, and may even undercompensate rooftop solar customers.[442] Vote Solar states that each of the methodologies presented which do not involve a long-term benefit and cost analysis would reduce the compensation rooftop solar customers receive for exports, and accordingly, would eliminate net metering.[443] Vote Solar asserts that the Commission cannot vacate or amend the Net Metering Rules unless it begins a new rulemaking process, in accordance with due process requirements of public notice and an opportunity for public comment.[444]

4. Comments on Vote Solar's Proposed Long-Term Benefit and Cost Methodology

a. APS

APS argues that the complexity of the inputs and assumptions in Vote Solar's proposed

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[439] *Id.*, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 35.
[440] Vote Solar Br. at 24, citing to Exh. Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 26-27.
[441] Vote Solar Br. at 24, citing to Tr. at 1634 (Vote Solar witness Curt Volkmann).
[442] Vote Solar Br. at 2, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor at 6, 15.
[443] Vote Solar Reply Br. at 25.
[444] *Id.* at 25-26.

methodology exposes the study findings to easy distortion to match any agenda.[445] APS contends that the IREC Guidebook, which Vote Solar proposes as a model for value of solar studies, is biased, in that it fails to assess several important questions. According to APS's witness Mr. Brown,

> 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.[446]

APS considers long-term value of solar methodologies such as the IREC Guidebook model to be political tools prone to manipulation in order to validate a predetermined outcome by administratively moving predicted future benefits to the present and having ratepayers pay for them now.[447] APS warns against such a practice, comparing it to PURPA legislation, which requires administrative determinations of avoided costs. APS states that the results of PURPA avoided cost calculations did not harm utilities, who were able to file rate cases and collect rates for the costs of highly-inflated PURPA contracts, but harmed customers, who were required to pay exorbitant costs in rates.[448]

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445 APS Reply Br. at 6, citing to Exh. APS-8 (Direct Testimony of APS witness Ashley Brown) at 13.
446 APS Reply Br. at 6-7, citing to Exh. APS-8 (Direct Testimony of APS witness Ashley Brown) at 14.
447 APS Reply Br. at 7.
448 *Id.*, referring to APS-8, Direct Testimony of APS witness Ashley Brown at 8-9. Mr. Brown described problems that occurred with administrative valuations of avoided cost under PURPA as follows:

> "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 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 [qualifying facilities], 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.
>
> APS-8, Direct Testimony of APS witness Ashley Brown at 7-8.

APS contends that the long-term benefits of DG are not inherently connected to the issue of whether net metering should continue, and that no party presented evidence that there is intrinsic value in net metering itself.[449] APS claims that the current artificially high net metering rate for rooftop exports threatens the long-term health of solar by shielding it from cost pressures, thus stifling innovation.[450] According to APS's witness Mr. Brown, by "[s]hielding the rooftop solar industry from cost pressure . . . [w]e are certainly not giving incentives to pursue more ambitious efficiency maximizing efforts, such as incorporating battery storage, or leveraging the potential of smart inverters . . . to help regulate power flow."[451]

b. TEP/UNSE

TEP/UNSE disagree with any proposal to include a levelized value of potential, yet speculative, future benefits in the value of solar.[452] They contend that such a methodology would unnecessarily and improperly increase costs to non-DG customers and is not in the public interest.[453] TEP/UNSE contend that non-DG customers should not pay more for DG export energy than a comparable market-proxy rate.[454]

TEP/UNSE are critical of the proposed long-term levelized value of benefits methodology for its failure to acknowledge the impact of the intermittent nature of solar energy, and the impact of the "as available" nature of rooftop solar exports.[455] TEP/UNSE contend that the proposed long-term levelized value of benefits methodology would result in payments for rooftop solar exports that exceed its value to the utilities, and to the ratepayers. TEP/UNSE contend that because rooftop solar customers are under no contractual or other commitment to provide certain amounts of energy or capacity, the value of rooftop solar exports are similar to "as available" energy provided by QFs under PURPA and related FERC regulation, and the existence of rooftop solar DG results in no long-term avoided costs.[456] TEP/UNSE argue that because the exports have no value beyond the utilities' short-term avoided cost

[449] APS Reply Br. at 15.
[450] *Id.* at 16.
[451] *Id.* at 16-17, citing to Exh. APS-8, Direct Testimony of APS witness Ashley Brown at 62.
[452] TEP/UNSE Br. at 15; TEP/UNSE Reply Br. at 3.
[453] TEP/UNSE Reply Br. at 3.
[454] *Id.* at 4.
[455] *Id.*
[456] *Id.*

of energy, under PURPA, a market-based proxy can satisfy the avoided cost payment standard.[457]

TEP/UNSE state that PURPA requires a market-based proxy to be comparable in nature to the energy for which it is a proxy.[458] They contend that a distribution grid-tied PPA is at least equivalent to rooftop DG, because it possesses similar renewable resource characteristics, as defined by the REST Rules,[459] and it is actually a superior resource from an operational perspective.[460]

c. GCSECA

GCSECA opposes any proposal to establish a value of DG methodology based on long-term forecasts such as that proposed by Vote Solar.[461] GCSECA also believes that Vote Solar's hosting capacity analysis should be rejected because it would require additional data gathering, analysis, and review that would impose economic and operational hardships on the Cooperatives.[462] GCSECA is also opposed to Vote Solar's proposed smart inverter requirements.[463]

GCSECA urges the Commission to reject Vote Solar's arguments that there is no cost shift.[464] GCSECA contends that there is overwhelming evidence in this docket demonstrating that the DG-caused cost shift is real, and demonstrating the cost-shift's inequitable impact on non-DG customers.[465] GCSECA states that under a rate design that recovers a major portion of a utility's fixed costs through the variable rate, utilities under-recover their fixed costs from DG customers due to their significant reduction in usage, and as a result, non-DG customers are forced to pay more than their fair share of those fixed costs.[466] GCSECA asserts that two of its members have demonstrated more than $1 million in annual lost fixed costs caused by DG, and that this is a substantial under-recovery for a rural

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457 *Id.*

458 *Id.*, citing to *Southern California Edison Company*, 133 FERC ¶ 61,059 at para. 29 (Issued October 21, 2010).

459 TEP/UNSE argue that FERC has clarified that setting a utility's avoided cost under PURPA based on all sources able to sell to the utility means that "where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement." TEP/UNSE Reply Br. at 4, citing to *Southern California Edison Company* at para. 29.

460 TEP/UNSE Reply Br. at 4.

461 GCSECA Br. at 5.

462 *Id.* at 5, fn. 18.

463 *Id.*

464 GCSECA Br. at 5-6.

465 *Id.* at 6.

466 *Id.* at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 3-5, Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 21-22, Exh. TEP-1, Direct Testimony of TEP witness Carmine Tilghman, at 3-4, Exh. AIC-1, Direct Testimony of AIC witness Michael O'Sheasy, at 9-10, Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 10, and Tr. at 1335-1337 (Staff witness Howard Solganick).

distribution cooperative.[467] GCSECA contends that the cost shift is exacerbated by the current net metering policy, and that the cost shift is a larger problem for the Cooperatives, due to their rural location, which necessitates a higher level of plant investment per customer, and due to their small size, which means there are fewer customers to absorb the subsidies created by DG.[468]

d. AIC

AIC disagrees with Vote Solar's proposal to use a modified version of the RIM test plus societal adders in order to value rooftop solar exports.[469] AIC believes that Vote Solar's proposal is biased to over-compensate today's solar customers for benefits that may or may not be realized in the future,[470] and that this type of valuation methodology does nothing to encourage the DG market due to its failure to send correct price signals that would enable the entry of new third-party technologies that are going to help transition the grid.[471]

AIC contends that any long-term benefit/cost analysis or cost effective analysis, such as those designed to analyze demand side management or energy efficiency, captures only subjective benefits, and even captures the subjective benefits inaccurately.[472] AIC states that the RIM and societal benefits tests used in energy efficiency dockets and IRP dockets are used only to determine which energy efficiency programs and resources are valuable, and not to calculate their value, or to set rates.[473] AIC states that it is misleading at best for Vote Solar to suggest that there is a nationwide trend to use a long-term benefit/cost approach to value solar, pointing to the fact that Nevada, which initially incorporated the category of "long-term benefits" into a value of solar analysis, later discarded the study.[474] AIC asserts that other jurisdictions, such as Utah, have chosen to blend historical rates with a conservative resource planning approach, thereby supporting a lower value of solar.[475]

AIC believes circumstances will undoubtedly change in the proposed 20 to 30 year time period

[467] GCSECA Br. at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 6-8.
[468] GCSECA Br. at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 8-10, 12-13.
[469] AIC Br. at 13.
[470] *Id.* at 13, 14, citing to Tr. at 371-372 (APS witness Bradley Albert), Tr. at 516 (AIC witness Michael O'Sheasy), and Exh. TEP-2, Rebuttal Testimony of TEP/UNSE witness Carmine Tilghman, at 15.
[471] AIC Br. at 15, citing to Tr. at 1010 (APS witness Ashley Brown), and 684-685, (TEP/UNSE witness Carmine Tilghman).
[472] AIC Reply Br. at 6.
[473] AIC Br. at 13, citing to Tr. at 877 (TEP/UNSE witness Edwin Overcast), and Exh. APS-3, Rebuttal Testimony of APS witness Leland Snook, at 5, 7.
[474] AIC Reply Br. at 7.
[475] *Id.*, citing to Exh. TEP-2, Rebuttal Testimony of TEP/UNSE witness Carmine Tilghman, at 3.

over which Vote Solar proposes to levelize future benefits, and that those future changes will likely prevent the assumed future benefits from occurring at the assumed level, if at all.[476] AIC contends that forecasts are always wrong, getting the price right depends on luck, and even if the price paid "miraculously proves right," it will most likely have been paid by customers who are not able to take advantage of it.[477] In addition, AIC asserts, the proposed Vote Solar methodology suffers from a fundamental matching flaw, in that while it would levelized the cost of electricity over 20 to 30 years, it would use near-term forecasts for rooftop solar penetration.[478] AIC is also critical of the Vote Solar proposals for rate treatment that would follow its proposed cost benefit analysis – that if there is any benefit found, net metering should remain in place, but if there is any cost found, that net metering should also remain in place, but with "possible modifications."[479] AIC characterizes such a rate scheme as "far from open, transparent, or based on verifiable data."[480]

AIC disagrees with Vote Solar's attempt to draw a distinction between the words "rate" and "compensation" for rooftop solar exports, which Vote Solar claims should be based on value, and not costs.[481] AIC argues that if a customer is required to pay a certain price (rate) for energy from the utility that is based on costs, then logically, the price a utility is required to pay for energy from a customer should be based on cost as well.[482]

AIC terms illogical Vote Solar's arguments that residential and small business owners with rooftop solar should be paid more for their exported energy than grid-scale producers because rooftop solar owners do not intend to sell electricity as a business enterprise, make a significant profit, or have complex energy management systems.[483] AIC is similarly critical of Vote Solar's argument that rooftop solar should garner a higher price than grid-scale solar because it can only be sold to one buyer, and claims that the converse is actually true, because basic economics dictates a lower price for rooftop

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[476] AIC Br. at 14, citing to Tr. at 1350 (Staff witness Howard Solganick).
[477] AIC Br. at 15, Tr. at 684-685, 811 (TEP/UNSE witness Carmine Tilghman), Tr. at 1353-1355 (Staff witness Howard Solganick), and Tr. at 1050-1051 (GCSECA witness David Hendricks).
[478] AIC Br. at 14, citing to Tr. at 1430 (Staff witness Howard Solganick).
[479] AIC Reply Br. at 5.
[480] *Id.*
[481] *Id.*
[482] AIC Reply Br. at 5-6.
[483] *Id.* at 10.

solar exports because they are guaranteed a market.[484]

AIC argues that despite Vote Solar's attempts to differentiate rooftop solar from grid-scale solar, the two products are much more alike than they are different, which makes using grid-scale solar as a proxy for rooftop solar exports a reasonable (if not preferable to AIC) alternative to basing the export energy rate on avoided cost.[485] AIC contends that Vote Solar's attempt to differentiate rooftop solar from grid-scale solar based on whether the generation asset is owned by a residential customer or a large sophisticated energy customer is a "distinction without a difference," that ignores the fact that both sources of generation produce electrons that flow onto the grid.[486]

e. RUCO

RUCO asserts that Vote Solar's position that the current net metering rate adequately compensates, or may even undercompensate rooftop solar exports has been disproven.[487]

For the sake of simplicity and sound ratemaking, RUCO believes some factors need to be limited or excluded, and recommends that the benefits and costs associated with macroeconomic impacts should be excluded from the valuation methodology.[488] RUCO states that while it "does not deny that there are costs and benefits associated with economic impacts, it would be very difficult, if not impossible to quantify these economic impacts."[489] For the same reasons, RUCO believes that benefits such as grid security should not be included.[490] RUCO asserts that Vote Solar provided no evidence regarding the size of the proposed grid security benefit, and did not demonstrate how a valuation could be quantified.[491]

f. Staff

Staff prefers a short-term avoided cost methodology as opposed to a long-term one, as proposed by Vote Solar. Staff's witness suggests that if a long-term avoided cost methodology is undertaken, it should be done "with great care because of the potential for overpayment."[492] Staff states that if a

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[484] *Id.*
[485] AIC Reply Br. at 11.
[486] *Id.* at 9.
[487] RUCO Reply Br. at 4.
[488] *Id.* at 8.
[489] *Id.*
[490] *Id.*
[491] *Id.*
[492] Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 13.

long-term approach is adopted, Staff agrees with RUCO that it should use only easily quantifiable long-term costs and benefits.[493] Staff also states that more frequent updates would lessen the risk of overpayment by non-DG customers.[494]

Staff agrees with the utilities that the utilities' weighted average cost of capital is a more appropriate discount rate than the inflation rate suggested by Vote Solar.[495]

Staff disagrees with Vote Solar's use of near-term forecasts for rooftop solar penetration for an analysis that spans 20 to 30 years.[496]

In regard to Vote Solar's proposal to use a modified version of the RIM test plus societal adders in order to value rooftop solar exports, Staff notes that the Commission's EE and DSM rules require utilities to use the Societal Test,[497] and states that rooftop solar is not currently subject to this test.[498] Staff asserts that the parties have presented enough evidence differentiating rooftop solar from DSM and EE that if the Commission deems it appropriate to consider the cost-effectiveness of rooftop solar, either the Societal Test or a different test could be used to do so.[499]

Staff states that it is "not opposed to the addition of costs/benefits to its avoided cost analysis so that it encompasses all of the well-recognized costs and benefits that have evolved over time," but notes that:

> Staff is likely to routinely recommend in most cases the exclusion of: 1) environmental impacts that are already considered in operating costs and the IRP process; 2) economic benefits which should only be considered "qualitatively" because they are difficult to quantify and are not included in the ratemaking formula for existing generation and other facilities; 3) fuel hedging benefits/costs; and 4) grid security benefits unless they can actually be demonstrated. Nonetheless, all benefits/costs should be included on the list for consideration.

Staff Reply Br. at 3 (citations referencing Staff Br. at 9, 15, 18, and 19 omitted).

5. <u>Vote Solar's Responses to Comments on its Proposed Long-Term Benefit and Cost Methodology</u>

Vote Solar argues that its long-term benefit and cost methodology is the only approach that

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493 Staff Br. at 9.
494 *Id.*
495 Staff Reply Br. at 13.
496 *Id.*
497 *Id.* at 12-13, referring to A.A.C. R14-2-2512(B). For ease of reference, R14-2-2512 is reproduced in a footnote to Staff's comments on TASC's proposed methodology, below.
498 Staff Br. at 12-13.
499 *Id.* at 13.

comprehensively determines the net benefits of rooftop solar exports, and fully values them by (1) analyzing each type of benefit and cost that occurs when rooftop solar customers export excess energy to the grid; and (2) examining those benefits and costs over the 20 – 30 year economic life of the rooftop solar PV system.[500]

Vote Solar argues that it is in the utilities' best interest to avoid quantifying the full value provided by rooftop solar exports, and that if the full value were actually calculated, it would likely significantly undercut their subsidy claims.[501] Vote Solar contends that without the information provided by its proposed analysis, the Commission cannot consider all of rooftop solar's benefits, and make reasonable and fully-informed decisions in upcoming utility rate case decisions on utility proposals to eliminate net metering or otherwise modify rate design applicable to rooftop solar.[502]

Vote Solar argues that it has never recommended that the results of its proposed analysis be automatically used to set the compensation rates for rooftop solar exports. Instead, Vote Solar asserts that results showing net benefits greater than the current retail rate compensation would indicate that net metering should remain in place, and if results demonstrate benefits that are less than current retail rates, it may be appropriate to reduce the compensation paid for rooftop solar exports.[503]

In response to criticisms about the accuracy of the long-term forecasting required by its proposal, Vote Solar asserts that the value of forecasts is not negated simply because they are not 100 percent accurate.[504] Vote Solar believes the utilities' concerns regarding accuracy are unfounded, because Vote Solar does not recommend that the results of its proposed analysis be automatically used to set the export rate, and because compensation rates for rooftop solar exports the analysis would be periodically updated, so that the value ascribed to rooftop solar is adjusted as future events and circumstances change.[505] Vote Solar asserts that the manner of forecasting of future events and costs required by its proposed methodology is an integral part of a utility's operations, is used to develop integrated resource plans ("IRPs") that analyze future conditions and select future resources over a 15

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[500] Vote Solar Reply Br. at 2.
[501] *Id.* at 6.
[502] Vote Solar Br. at 3-4; Vote Solar Reply Br. at 2, 7.
[503] Vote Solar Br. at 8-9; Vote Solar Reply Br. at 3, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 12, and Exh. Vote Solar-8, Rebuttal Testimony of Vote Solar witness Briana Kobor, at 5.
[504] Vote Solar Reply Br. at 4.
[505] *Id.* at 8; vote Solar Reply Br. at 4.

year planning period, and that the results influence the utilities' decisions on which resources to build or purchase.[506] Vote Solar argues that the predictive values in the IRP plans do not negate the value of the IRPs, and the Commission should therefore not reject a long-term benefit and cost analysis based on its use of forecasts.[507]

Vote Solar disagrees with criticisms that its proposed one to three year forecast of rooftop solar penetration creates a dichotomy with its proposed valuation methodology timeframe of 20 to 30 years.[508] Vote Solar claims that the benefits and costs of installed systems will accrue over their economic life, and the aim of the near-term penetration forecast is to determine the value of exports from currently installed or near-term new installations.[509] Vote Solar asserts that at current and near-term penetration levels, installed systems do not create any measurable integration costs or peak shift, but if future penetration levels do reach a point where benefits decrease, the net value of those future systems may be less.[510]

In response to APS's assertions that rooftop solar provides minimal generation capacity savings, Vote Solar responds that APS's 2013-2014 IRP plan forecasted a 2020 peak capacity contribution of 119 MW from rooftop solar,[511] TEP's 2013-2014 IRP plan forecasted a 2020 peak capacity contribution of 41 MW from rooftop solar,[512] and UNSE's 2013-2014 IRP plan forecasted a 2020 peak capacity contribution of 8 MW from rooftop solar. [513] Vote Solar argues that because the utilities' own IRP plans show that rooftop solar can reliably contribute to system peak, rooftop solar exports should be credited for reducing or delaying the need for additional system capacity.[514]

Vote Solar is critical of Staff's position regarding exclusion of all its proposed environmental but avoided environmental compliance costs, environmental costs identified in the IRP process, costs

[506] Vote Solar Br. at 8.
[507] *Id.*; Vote Solar Reply Br. at 4.
[508] Vote Solar Br. at 15.
[509] *Id.* at 14.
[510] *Id.* at 14-15.
[511] *Id.* at 20, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 30. Ms. Kobor cited to page 300 of the IRP filed by APS on April 1, 2014, in Docket No. E-00000V-13-0070.
[512] Vote Solar Br. at 20, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 30. Ms. Kobor cited to page 28 of the IRP filed by TEP on April 1, 2014, in Docket No. E-00000V-13-0070.
[513] Vote Solar Br. at 20, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 30. Ms. Kobor cited to page 20 of the IRP filed by UNSE on April 1, 2014, in Docket No. E-00000V-13-0070.
[514] Vote Solar Br. at 20.

based on emerging regulation, or costs that result in reductions in emission levels over and above required levels.[515] Vote Solar argues that all of its proposed environmental benefits should be included, even those that do not directly reduce the utility's compliance and operation costs, because they are significant and real.[516]

Vote Solar disagrees with Staff's omission of economic benefits in its analysis based on the fact that they are difficult to quantify and are not included in the ratemaking formula for existing generation, and not unique or incremental to DG.[517] Vote Solar asserts there is no insurmountable difficulty in quantifying economic benefits that both it and TASC have explained how the analysis should be performed.[518]

Vote Solar believes that rooftop solar provides real, localized economic benefits which should be included in the analysis of its value.[519] Vote Solar contends that because rooftop solar is installed by households and small businesses as opposed to sophisticated utilities, because it produces power used primarily on site as opposed to producing power for profit, and because it faces constraints different from utility-scale solar, and because its output can be sold only to utilities, rooftop solar merits different treatment from non-DG facilities.[520]

Vote Solar disagrees with Staff's contention that the record does not contain sufficient evidence regarding rooftop solar's contribution to grid reliability to include it in the analysis.[521] Vote Solar believes the expert testimony of its witness Mr. Volkman provides sufficient evidence for its inclusion.[522]

Vote Solar argues that all the proposals presented in this proceeding, with the exception of its own proposal and that of TASC, are not actually methods for valuing rooftop solar, but instead are premature methodologies for compensating rooftop solar at rates less than current retail net metering. Vote Solar asserts that if the Commission selects one of the methodologies proposed by the utilities,

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[515] *Id.* at 9.
[516] *Id.*
[517] Vote Solar Reply Br. at 10.
[518] *Id.*
[519] *Id.*
[520] *Id.*
[521] *Id.*
[522] *Id.*, citing to Exh Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 26-28 and Tr. at 1634-1635, 1655-1657, 1693-1694 (Vote Solar witness Curt Volkmann).

RUCO, or Staff, "it would drastically alter solar compensation and the economics of rooftop solar without bothering to calculate the value of solar."[523]

D. TASC

1. Overview

TASC contends that to ensure fair treatment of DG, the Commission must employ an accurate valuation methodology that permits a meaningful investigation of the benefits of rooftop solar.[524] TASC asserts that the Commission must balance the perspectives of all stakeholders, including rooftop solar customers, non-DG customers, the utility, the electric grid, and society as a whole.[525] TASC contends that the long-term benefits and costs of rooftop solar must be accounted for and credited and debited in every docket.[526] TASC's witness Mr. Beach states that there is a developing consensus that the suite of standard cost-effectiveness tests used for demand-side programs should be adapted to broader analyses of NEM and demand-side DG.[527] He states that evaluating the costs and benefits of DG using the same cost-effectiveness framework used for all demand-side resources, including EE and demand response, "will help to ensure that all of these resource options are evaluated in a fair and consistent manner."[528] TASC asserts that its proposed methodology would result in an "accurate assessment of the actual value of DG and further promote optimal DG policy."[529]

TASC charges that the utilities are "eager to thwart the growth of DG by ending [net metering] and pushing for the adoption of modified rate designs intended to destroy the economic benefit of investing in and adopting DG."[530] TASC claims that cost of service studies are based on embedded historical costs and cannot capture the full benefits of rooftop solar; and that utility-scale proxy methodologies utilize unjust comparisons to rates paid for utility-scale solar, can be manipulated, conflate wholesale and retail products, and do not take into account the added benefits found only in rooftop solar.[531]

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[523] Vote Solar Reply Br. at 11.
[524] TASC Br. at 1.
[525] *Id.*
[526] *Id.* at 2.
[527] Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 3-4.
[528] *Id.*
[529] TASC Br. at 2; TASC Reply Br. at 4.
[530] TASC Br. at 1.
[531] *Id.*; TASC Reply Br. at 4.

TASC contends that the goal of this proceeding is to investigate the costs and benefits of rooftop solar and "to create a record that can be accessed for potential use in future dockets wherein the value of solar and the specific valuation method is being dealt with for each utility."[532] TASC believes that this proceeding also provides the Commission with an opportunity to "reiterate its policy in support of full grandfathering of any DG customers in future rate cases."[533] TASC argues that rooftop solar is a demand-side resource and should be evaluated in the same manner as other demand-side resources for cost-effectiveness, and that only a long-term avoided cost methodology can fully account for, identify, and calculate all the relevant costs and benefits of a rooftop solar system.[534]

2. Analysis in Other Jurisdictions

TASC asserts that Nevada, California, and Mississippi have adopted frameworks that it believes exemplify best practices for conducting benefit-cost analysis of rooftop solar, and that California's Standard Practice Manual, which utilizes a benefit/cost approach, is used across the country as a framework for discussing specific valuation approaches.[535] TASC states that state-commissioned independent studies utilizing approaches like the one TASC espouses, in Nevada, Mississippi, Maine, Vermont, and Minnesota, have generally concluded that the value of DG solar is well above retail rates.[536] TASC states that Nevada initially used a demand-side analysis to conclude that DG was cost-effective even for non-DG customers, before ultimately adopting a short-term cost-benefit study provided by NV Energy.[537] TASC states that the actions of the Nevada Public Service Commission[538]

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532 TASC Reply Br. at 4.
533 TASC Br. at 2.
534 *Id.* at 1, 5; TASC Reply Br. at 4.
535 TASC Br. at 3, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 3-5, and Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 18.
536 TASC Br. at 4, citing to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 15-16.
537 TASC. Br. at 3, 4, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 5-8.
538 TASC states that

> The final order recognized the categories of long-term benefits of DG discussed [in TASC's brief], but assigned a "zero" valuation to them rather than attempting to analyze, determine, or assign actual values to such benefits. As a result of this short-sighted analysis, Nevada concluded that DG created an unreasonable cost shift and decided to terminate NEM; increase the fixed monthly customer charge for DG customers; and reduce the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only avoided cost rate of about 2.6 cents per kWh.

TASC Br. at 4, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 6-7, and Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 48.

are currently being appealed in Nevada Courts.[539]

3. TASC's Proposed Long-Term Avoided Cost Methodology

TASC asserts that three principles should be kept in mind when valuing rooftop solar: valuation should be levelized over the expected life of the DG system; utilities must regularly provide accurate and reliable data not based on proprietary models; and the valuation should consider a comprehensive list of benefits and costs such as those used in assessing the cost effectiveness of energy efficiency and demand response programs.[540] TASC contends that this proceeding is not about subsidies, cost shifting, partial requirements customers, or rate design, and that long-term forecasting is a tool commonly used by utilities, and is appropriate and essential to valuing rooftop solar.[541]

TASC's witness Mr. Beach conducted an illustrative value analysis for APS's service territory, using TASC's proposed benefits and costs, using data from APS's 2014 IRP, and based on a 20-year levelized cents/kWh value. Mr. Beach presented the results of his analysis in Exhibit 2 to his direct testimony (Hearing Exhibit TASC-26), and summarized them in Table 11, which appears at p. 22 thereof.[542] Mr. Beach found Direct and Societal benefits as follows: for south-facing rooftop solar systems, 24.8 cents/kWh (residential) and 25.5 cents/kWh (commercial); for west-facing rooftop solar systems, 31.1 cents/kWh (residential) and 30.9 cents/kWh (commercial); for an average of 28.0 cents/kWh (residential) and 28.2 cents/kWh (commercial).[543] Mr. Beach found Direct benefits alone as follows: for south-facing rooftop solar systems, 15.5 cents/kWh (residential) and 18.0 cents/kWh (commercial); for west-facing rooftop solar systems, 21.8 cents/kWh (residential) and 23.4 cents/kWh (commercial); for an average of 18.7 cents/kWh (residential) and 20.7 cents/kWh (commercial).[544]

The benefits TASC included in its valuation of rooftop solar exports, and that it recommends the Commission include, are as follows:[545]

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539 TASC Br. at 4, citing to *Vote Solar v. The Public Utilities Comm'n of Nevada,* No. 16 OC 1152 1B (Nev. Jul. 7, 2016); *The Alliance for Solar Choice v. The Public Utilities Comm'n of Nevada*, No. 16 OC 0072 (Nev. Jul. 7, 2016); and referring to Krysti Shallenberger, TASC Sues Nevada PUC To Overturn Net Metering Decision, Utility Dive (Mar. 22, 2016) http://www.utilitydive.com/news/tasc-sues-nevada-puc-to-overturn-net-metering-decision/416087/.

540 TASC Br. at 5-7.

541 *Id.*

542 *See* Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, Exhibit 2, Table 11 at p. 22.

543 *See id.*

544 *See id.*

545 TASC Br. at 6-15. *See also* Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, Exhibit 2, Table 11 at p. 22.

a. Avoided Energy Costs

TASC asserts that each kWh of rooftop solar exports DG offsets the need for electricity that would have been generated by the utility, and that energy generation savings represent the cost a utility would have incurred but for rooftop solar exports.[546] TASC asserts that any analysis should include fuel savings, the associated heat rate for the generation facility, and related variable costs of O&M saved by such reductions in generation.[547]

b. Avoided Line Losses

TASC asserts that DG output is consumed by neighboring non-DG customers, and that this results in the utilities avoiding up to 12 percent in avoided line losses associated with a utility sending electricity over the grid to those customers.[548]

c. Avoided Utility Generation Capacity

TASC asserts that DG rooftop solar helps avoid generating capacity and reserve margins.[549] TASC contends that the value of rooftop solar goes beyond short-term avoided energy costs because it affects utilities' need to build generation capacity to meet system peak demand.[550] TASC asserts that according to APS's 2014 IRP filing, new demand-side resources (including EE, DR, and rooftop solar) developed in 2014-2018, will contribute 862 MW to meeting APS's peak demands by 2018.[551] TASC's witness Mr. Beach responds to APS's assertions that as rooftop solar penetration increases, the capacity value of solar will decrease, because increased amounts of behind-the-meter solar resources shift APS's afternoon peak to later in the day. Mr. Beach states that with proper pricing signals, and if customers have a greater choice and control over where and when they consume electricity, customers may respond by shifting consumption of utility-provided power from the evening to the afternoon.[552]

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[546] TASC Br. at 6.

[547] *Id.*, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 20, Table 2; and to Exh. Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 28-29.

[548] TASC Br. at 6, citing to Exh. Vote Solar-4, Rebuttal Testimony of Vote Solar witness Curt Volkmann, at 16-18.

[549] TASC Br. at 7, referring to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p.6, 11-13.

[550] TASC Br. at 7.

[551] *Id.*, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 6, 11-12, and Table 4.

[552] Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 13.

d. Avoided Transmission and Distribution Costs

TASC asserts that rooftop solar defers or eliminates the need for increased transmission and distribution infrastructure.[553] TASC contends that the utilities' experts in this proceeding have acknowledged that there are calculable benefits and impacts that can be realized due to rooftop solar;[554] that realized savings to transmission and distribution systems can be "monumental;" and that any valuation framework must necessarily calculate and account for such value.[555] TASC notes that APS intends to calculate such potential savings in its pending rate case.[556]

e. Avoided Marginal Transmission Costs

TASC contends that rooftop solar slows capacity growth and provides for reduced loads, which defers or avoids the necessity for new transmission related investments.[557] TASC asserts that this is especially important and beneficial when solar production occurs during peak demand.[558] TASC believes that rooftop solar can also avoid transmission network upgrades associated with utility-scale projects that rooftop solar can displace.[559]

TASC contends that grid modernization projects provide benefits in addition to those aimed an integrating DG, including rooftop solar, into the grid, and that there is potential for smart deployment of rooftop solar to reduce grid modernization costs.[560] TASC asserts that quantifiable benefits of smart inverters attached to DG projects should be included in any value analysis.[561]

f. Extended Life of Distribution and Transmission Equipment

TASC asserts that the majority of rooftop solar that serves on-site load will reduce distribution system loads because the power does not flow onto the distribution system, and exports that serve local

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[553] TASC Br. at 7, referring to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 13-14; and to Exh. Vote Solar-4, Rebuttal Testimony of Vote Solar witness Curt Volkmann, Exhibit 3 at 16-18.

[554] TASC Br. at 9, citing to Tr. at 1015-1016 (TEP/UNSE witness Edwin Overcast); Tr. at 347-348 (APS witness John Sterling); Tr. at 402-404 (APS witness Bradley Albert); and Tr. at 110-111, 136-137 (APS witness Leland Snook).

[555] TASC Br. at 8-10.

[556] *Id.* at 9, citing to Tr. at 110-111, 136-137 (APS witness Leland Snook).

[557] TASC Br. at 8, referring to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 13-14.

[558] *Id.*

[559] TASC Br. at 8, referring to TASC's June 22, 2016, Responsive Supplemental Testimony of TASC witness R. Thomas Beach, at 7.

[560] TASC Br. at 8, referring to TASC's June 22, 2016, Responsive Supplemental Testimony of TASC witness R. Thomas Beach, at 10-11.

[561] *Id.*

neighborhoods also reduce distribution system loads.[562] TASC argues that as a result, rooftop solar avoids the costs of distribution system expansions or upgrades and extends the life of existing equipment.[563]

g. Fuel Hedging Costs

TASC asserts that rooftop solar mitigates utilities' exposure to volatility in natural gas prices by diversifying the overall portfolio of resources.[564]

h. Market Price Mitigation

TASC claims that as renewable generation continues to penetrate the APS service territory, it creates a downward trajectory of the region's energy market prices by displacing the most expensive power that a utility would have otherwise generated or purchased, and that this is a market price mitigation that is a quantifiable benefit of renewable generation.[565]

i. Societal Benefits

TASC terms benefits from rooftop solar that do not directly impact utility rates, but that are conferred on all citizens, as societal benefits. The benefits that TASC believes should be quantified are water savings, carbon reduction, air pollution reduction, and local economic benefits.

i. Water Savings

TASC asserts that as rooftop solar penetration grows, the utility requires less water used for generation cooling purposes, and that this benefit is easy to ascertain.[566]

ii. Carbon Reduction

TASC contends that there is a social cost to carbon, and while it may be difficult to quantify, ratemaking is often about policy decisions.[567] TASC's witness Mr. Beach chose a "mid-range real discount rate of 3%" to calculate the long-term benefits and costs of carbon reduction attributable to rooftop solar, calling it a "conservative assumption."[568]

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[562] TASC Br. at 8.
[563] *Id.*, referring to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 15.
[564] TASC Br. at 10, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 9 and p. 9 at note 16.
[565] TASC Br. at 10, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 10.
[566] TASC Br. at 11, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 20.
[567] TASC Br. at 11-12.
[568] *Id.* at 12, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 18.

iii. Air Pollution Reduction

TASC asserts that society benefits as a whole, especially in terms of improved human health, when air pollutant emissions are lowered, because exposure to particulates causes asthma, respiratory illnesses, cancer, and premature death.[569] TASC recommends that societal benefits stemming from air pollution reduction due to rooftop solar exports be quantified using the recently developed "health co-benefits from reductions in criteria pollutants that were developed by the EPA in conjunction with the Clean Power Plan."[570]

iv. Local Economic Benefits

TASC describes its proposed category of local economic benefits as costs uniquely attributable to rooftop solar, including installation labor, permitting, permit fees, customer acquisition, and marketing.[571] TASC differentiates the local economic benefits of rooftop solar from centralized generation, which it states are mostly not located in the area where power is purchased and used.[572]

j. Policy Considerations and Non-Monetary Benefits

TASC contends that there are many policy reasons for the Commission to continue promoting rooftop solar investment.[573] TASC contends that while the policy considerations and non-monetary benefits are difficult to quantify, they are desirable for DG customers and for society as a whole, and therefore any valuation framework the Commission uses should include a means for valuing or accounting for them.[574] TASC outlines such benefits as follows:

i. New Capital Investments

TASC asserts that each time a customer invests in rooftop solar, new capital is invested into clean energy sources and the power infrastructure.[575]

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[569] TASC Br. at 12, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 18, n. 39.
[570] TASC Br. at 12, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 18.
[571] TASC Br. at 12, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 20-21.
[572] *Id.*
[573] TASC Br. at 13-14.
[574] *Id.* at 14.
[575] TASC Br. at 13, citing to citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 31.

ii. Future Technologies to Enhance Value of DG

TASC states that advanced smart inverters, battery storage, and more efficient DG photovoltaic panels will enhance the value of solar, and make it contribute more to peak demand, grid reliability, and capacity.[576] TASC asserts that a valuation methodology other than a long-term benefit cost analysis as it and Vote Solar propose would "curtail the enhanced value of DG in the future."[577]

iii. Competition

TASC asserts that rooftop solar serves as a competitive alternative to power supplied by the utility, that such competition will increase with implementation of customer-sited storage, and that customer-sited storage may provide a new electric supply resource with qualities and reliability comparable to what the utilities currently provide.[578]

iv. High-Tech Synergies

TASC asserts that promoting rooftop solar also promotes other energy saving measures and clean technologies.[579]

v. Self-Reliance

TASC contends that rooftop solar allows customers to be more independent and self-reliant in the procurement of energy.[580]

4. <u>Comments on TASC's Proposed Long-Term Avoided Cost Methodology</u>

a. APS

APS is critical of the use of long-term, 20-30 year forecasts of over 30 variables to set the amount the utility, and subsequently customers, will pay for exported energy.[581] APS contends that in practice, the sheer number of variables in the proposed long-term forecasts almost ensures inaccuracy, and that maintaining the correctness of the relationship of the numerous variables to one another

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[576] TASC Br. at 13, referring to Exh. Vote-Solar 1; Vote Solar-3, Direct Testimony of Vote Solar witness Curt Volkmann, at 9-11, Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 13-14, and Tr. at 1206 (APS witness Ashley Brown).
[577] TASC Br. at 13, citing to Tr. at 1969-1970 (TASC witness R. Thomas Beach).
[578] TASC Br. at 13, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 31.
[579] TASC Br. at 13, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 32.
[580] TASC Br. at 14, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 32.
[581] APS Br. at 39, 41.

exponentially compounds the complexity and difficulty of making an accurate long-term forecast.[582] APS states that the risk of using inaccurate forecasting to set an export rate would unacceptably fall directly on non-DG customers, who would subsidize rooftop solar.[583] APS asserts that if forecasts are wrong, customers would have been paying rates that are not just and reasonable.[584] APS points out that TASC's witness Mr. Beach acknowledged that no state has used a long-term value of solar study to set rates.[585]

APS responds to TASC's proposal to use a target percentage cost to serve rooftop solar customers of 87 percent, by stating that for all customers, the target percentage cost to serve in a COSS is 100 percent as a starting point.[586] APS characterizes TASC's proposal as "putting a thumb on the scale to arrive at a desired outcome."[587] APS does not believe that prior policy decisions by the Commission which have resulted in residential customers paying only 87 percent of the cost to serve should be used as a factor favor rooftop solar customers, by having them start the COSS at 87 percent.[588]

APS contends that Vote Solar and TASC's proposals would misuse the concept of long-term resource valuations to create a value that would perpetuate the subsidy inherent in net metering.[589] APS states that utilities use long-term evaluation methods to assess resource procurement decisions, but that regulators do not use long-term evaluation methods to set rates. APS points out that neither TASC nor Vote Solar proffered an example of rates actually being set using a long-term valuation of resources.[590] APS states that the Public Utilities Commission of Nevada ("PUCN") uses a forward-looking marginal cost of service study only as a guide in setting revenue requirements by class.[591] APS asserts that the PUCN's use of a future forecast for this limited purpose does not resemble in any way the long-term

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[582] *Id.* at 40-41.
[583] APS Br. at 42.
[584] *Id.*
[585] APS Reply Br. at 6, citing to Tr. at 1932 (TASC witness R. Thomas Beach).
[586] APS Br. at 13.
[587] *Id.*
[588] *Id.*
[589] APS Br. at 28.
[590] *Id.*
[591] APS Br. at 29, citing to Exh. APS-11 (Modified Final Order on Application of Nevada Power Co., PUCN Docket No. 15-07041 (Feb. 12, 2016)("Nevada Order")) at ¶ 83.

methodologies proposed by Vote Solar and TASC for valuing solar exports.[592]

APS criticizes TASC's inclusion of predicted societal benefits in the value of solar because such externalities are not included in the utility cost of service, and in any event, grid-scale and rooftop solar have the same effect on carbon reduction.[593] APS notes that TASC's witness Mr. Beach acknowledged both points.[594] APS asserts that TASC's own study, which evaluated total rooftop solar output instead of only export energy, predicts that south-facing rooftop solar will cost APS non-DG customers 17.9 cents per kWh over the next 20 years, while providing only 15.5 cents per kWh in direct benefits.[595]

APS also criticizes TASC's cost/benefit methodology, because while TASC purports to establish the value of exported energy, Mr. Beach's study evaluated total rooftop solar output instead of exported energy, despite the availability of the data.[596] APS states that its own analysis of solar rooftop export energy found that at APS's 2015 peak of 7,000 MWs, rooftop solar energy exports reached only 8.8 MWs, or 0.12 percent of supply.[597] APS argues that if Mr. Beach had run his cost/benefit test using capacity values for rooftop solar exports instead of all production, he would have concluded that exported energy fails any cost/benefit measure by a wide margin.[598] When APS's witness Mr. Albert reproduced Mr. Beach's study using the capacity values of rooftop solar exports, residential rooftop solar failed three of the four tests, leading Mr. Albert to conclude that rooftop solar exports are not a cost-effective resource for anyone other than the rooftop solar customer.[599]

b. TEP/UNSE

TEP/UNSE disagree with any proposal to include a levelized value of potential, yet speculative, future benefits in the value of solar.[600] They contend that such a methodology would unnecessarily

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[592] APS Br. at 29.
[593] APS Br. at 43.
[594] *Id.*, citing to Tr. at 1966-1967 (TASC witness R. Thomas Beach).
[595] APS Br. at 43-44, referring to Exh. TASC-26 (Direct Testimony of TASC witness R. Thomas Beach) at Exhibit 2, pp. 22-23, and Tr. at 1971 (TASC witness R. Thomas Beach).
[596] APS Br. at 43-44, citing to Tr. at 1945 (TASC witness R. Thomas Beach).
[597] APS Br. at 44, citing to APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 12-14.
[598] APS Br. at 44.
[599] APS-6 (Rebuttal Testimony of APS witness Bradley Albert) at 19, and at 20, Figure 6 (showing substitutions made to Table 11 appearing in Exh. TASC 26 (Direct Testimony of TASC witness R. Thomas Beach), Exhibit 2 at 22.)
[600] TEP/UNSE Br. at 15; TEP/UNSE Reply Br. at 3.

and improperly increase costs to non-DG customers and is not in the public interest.[601] TEP/UNSE contend that non-DG customers should not pay more for DG export energy than a comparable market-proxy rate.[602]

TEP/UNSE disagree with including a levelized value of potential, yet speculative, future benefits in the value of solar.[603] TEP/UNSE are critical of the proposed long-term levelized value of benefits methodology for its failure to acknowledge the impact of the intermittent nature of solar energy, and the impact of the "as available" nature of rooftop solar exports.[604] TEP/UNSE contend that the proposed long-term levelized value of benefits methodology would result in payments for rooftop solar exports that exceed its value to the utilities, and to the ratepayers. TEP/UNSE contend that because rooftop solar customers are under no contractual or other commitment to provide certain amounts of energy or capacity, the value of rooftop solar exports are similar to "as available" energy provided by QFs under PURPA and related FERC regulation, and the existence of rooftop solar DG results in no long-term avoided costs.[605] TEP/UNSE argue that because the exports have no value beyond the utilities' short-term avoided cost of energy, under PURPA, a market-based proxy can satisfy the avoided cost payment standard.[606]

TEP/UNSE state that PURPA requires a market-based proxy to be comparable in nature to the energy for which it is a proxy.[607] They contend that a distribution grid-tied PPA is at least equivalent to rooftop DG, because it possesses similar renewable resource characteristics, as defined by the REST Rules,[608] and it is actually a superior resource from an operational perspective.[609]

c. GCSECA

GCSECA opposes any proposal to establish a value of DG methodology based on long-term

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601 TEP/UNSE Reply Br. at 3.
602 *Id.* at 4.
603 TEP/UNSE Br. at 15.
604 TEP/UNSE Reply Br. at 4.
605 *Id.*
606 *Id.*
607 *Id.*, citing to *Southern California Edison Company*, 133 FERC ¶ 61,059 at para. 29 (Issued October 21, 2010).
608 TEP/UNSE argue that FERC has clarified that setting a utility's avoided cost under PURPA based on all sources able to sell to the utility means that "where a state requires a utility to procure a certain percentage of energy from generators with certain characteristics, generators with those characteristics constitute the sources that are relevant to the determination of the utility's avoided cost for that procurement requirement." TEP/UNSE Reply Br. at 4, citing to *Southern California Edison Company* at para. 29.
609 TEP/UNSE Reply Br. at 4.

forecasts such as that proposed by TASC.[610] GCSECA also believes that TASC's marginal cost analyses should be rejected because they would require additional data gathering, analysis, and review that would impose economic and operational hardships on the Cooperatives.[611]

GCSECA urges the Commission to reject TASC's arguments that there is no cost shift.[612] GCSECA contends that there is overwhelming evidence in this docket demonstrating that the DG-caused cost shift is real, and demonstrating the cost-shift's inequitable impact on non-DG customers.[613] GCSECA disagrees with TASC's position that no cost shift exists because while non-DG customers may overpay in the short term, DG is expected to produce a long-term benefit "over time," and that having customers "live with" the cost shift is justifiable due to future societal benefits.[614]

GCSECA states that under a rate design that recovers a major portion of a utility's fixed costs through the variable rate, utilities under-recover their fixed costs from DG customers due to their significant reduction in usage, and as a result, non-DG customers are forced to pay more than their fair share of those fixed costs.[615] GCSECA asserts that two of its members have demonstrated more than $1 million in annual lost fixed costs caused by DG, and that this is a substantial under-recovery for a rural distribution cooperative.[616] GCSECA contends that the cost shift is exacerbated by the current net metering policy, and that the cost shift is a larger problem for the Cooperatives, due to their rural location, which necessitates a higher level of plant investment per customer, and due to their small size, which means there are fewer customers to absorb the subsidies created by DG.[617]

d. IBEW Locals

The IBEW Locals assert that the additional jobs that the solar advocates claim to be created by the rooftop solar industry are temporary and low-paying, and are counteracted by the long-run/legacy

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[610] GCSECA Br. at 5.
[611] GCSECA Br. at 5, fn. 5.
[612] GCSECA Br. at 5-6.
[613] *Id.* at 6.
[614] *Id.*, referring to Tr. at 1912-1913, 1923-1924 (TASC witness R. Thomas Beach).
[615] GCSECA Br. at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 3-5, Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 21-22, Exh. TEP-1, Direct Testimony of TEP witness Carmine Tilghman, at 3-4, Exh. AIC-1, Direct Testimony of AIC witness Michael O'Sheasy, at 9-10, Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 10, and Tr. at 1335-1337 (Staff witness Howard Solganick).
[616] GCSECA Br. at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 6-8.
[617] GCSECA Br. at 5-6, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 8-10, 12-13.

effects of lost gross state product and lost jobs caused by subsidizing rooftop solar.[618]

The IBEW Locals contend that solar advocates are "attempting to meld into the Corporation Commission's ratemaking process intangible, unmeasurable, and many uncertain benefits (which result in the subsidization of rooftop solar companies) for the purpose of gaining preferential market treatment."[619] They contend that protecting rooftop solar companies from what their advocates term "a total decimation of their business" has no place in ratemaking, and that the proper venue for addressing such concerns is the Arizona legislature.[620]

The IBEW Locals assert that the proposal to analyze benefits over a 20 year or more time period is "illogical, nonsensical, and impossible . . . a task bordering on alchemy."[621] They assert that the only near-certain prediction about the next two decades is that rooftop solar will change dramatically because innovation is everywhere, and point to the evolution the telecommunications industry as an example.[622] The IBEW Locals also point out that forecasting hypothetical and unmeasurable benefits and costs 20 years or more into the future is impossible, because it triggers an infinite inquiry of possible variables, with endless layers of potential costs and benefits.[623]

e. AIC

AIC contends that the Commission should not adopt a benefit/cost methodology to compensate rooftop solar exports, because there are too many subjective variables that can skew the value calculation.[624] AIC states that TASC's position that DG systems should not be examined as a "snapshot in time," ignores Arizona's ratemaking requirements, which require rates to be set based on costs incurred during a single historical test year, adjusted for known and measurable changes.[625] AIC argues that forecasting dozens of variables over two decades or more runs counter to these requirements, and places the risk of inaccurate forecasts on non-DG customers.[626] AIC contends that the analysis TASC

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[618] IBEW Local Br. at 6-7, citing to Exh. IBEW-2, Rebuttal Testimony of IBEW Locals witness Scott Northrup, at 5-6, and Tr. at 1726 (Vote Solar witness Briana Kobor).
[619] IBEW Locals Reply Br. at 2.
[620] *Id.* at 3.
[621] *Id.*
[622] *Id.*
[623] IBEW Locals Reply Br. at 4.
[624] AIC Br. at 17; AIC Reply Br. at 6.
[625] AIC Reply Br. at 6.
[626] *Id.* at 7.

presented demonstrates the dangers of misapplication of a long-term forecasting method, by its failure to factor in grid-scale solar, which could provide the same benefits as rooftop solar at a significantly lower cost.[627] AIC asserts that this failure violates one of the most basic principles of electric utility resource planning, which is to identify the least cost manner of meeting an identified resource need.[628] AIC also pointed to the error in the study addressed by APS, above, as demonstrating how errors in application of a long-term forecast methodology can result in dramatically inflated values.[629]

AIC disagrees with TASC's claim that its proposed methodology is "commensurate with the way utilities evaluate the cost-effectiveness of their own supply-side utility rate base additions."[630] AIC asserts that this claim misrepresents how utilities make resource decisions, and ignores the fact that DSM, EE, and IRP valuation methods do not determine the monetary value of options, but instead evaluate how various options compare to each other and choose which should be pursued.[631] AIC states that the long-term valuation analyses used by utilities determine neither the monetary value assigned to the program being analyzed, nor the rate treatment it should be afforded, and they should not be used to value rooftop solar exports.[632] AIC asserts that the compensation that a rooftop solar customer receives for exported energy should be based on verifiable data, and that neither a cost-benefit analysis nor a societal cost test is appropriate for use as a methodology for assigning a value to rooftop solar exports.[633]

AIC argues that despite TASC's attempts to differentiate rooftop solar from grid-scale solar, the two products are much more alike than they are different, which makes using grid-scale solar as a proxy for rooftop solar exports a reasonable (if not preferable to AIC) alternative to basing the export energy rate on avoided cost.[634]

AIC is critical of TASC's argument that rooftop solar should garner a higher price than grid-scale solar because it can only be sold to one buyer, and claims that the converse is actually true,

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[627] AIC Br. at 16, citing to Tr. at 363 (APS witness Bradly Albert).
[628] *Id.*
[629] AIC Br. at 16-17.
[630] AIC Reply Br. at 8, citing to TASC Br. at 1.
[631] AIC Reply Br. at 8.
[632] *Id.*
[633] AIC Reply Br. at 7, 8.
[634] *Id.* at 11.

because basic economics dictates a lower price for rooftop solar exports because they are guaranteed a market.[635]

AIC contends that TASC's claim that rooftop solar exports are a retail product that should be compensated at a retail rather than a wholesale rate, based on the premise that rooftop solar exports have been "delivered to load" are unfounded.[636] AIC asserts that exports are delivered to the utility, who in turn resell the energy to their retail customers, rendering the exported energy "the quintessential wholesale product."[637]

AIC responds that relying on a TOU rate does not solve the rate design problem because approximately 70 percent of a customer's costs are fixed, or vary only with a customer's demand, and an energy-only price, or even a TOU price, will never accurately reflect the cost of providing service.[638] In regard to minimum bills, AIC argues that they still distort customer price signals, because they can overcharge high use customers and undercharge low use customers, and cannot be designed in a way that is reasonable, fair, and effective.[639]

f. RUCO

For the sake of simplicity and sound ratemaking, RUCO believes some factors need to be limited or excluded from a valuation methodology, and recommends that the benefits and costs associated with macroeconomic impacts should be excluded.[640] RUCO states that while it "does not deny that there are costs and benefits associated with economic impacts, it would be very difficult, if not impossible to quantify these economic impacts."[641] For the same reasons, RUCO believes that benefits such as grid security should not be included.[642] RUCO asserts that TASC provided no evidence regarding the size of the proposed grid security benefit, and did not demonstrate how a valuation could be quantified.[643]

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[635] *Id.* at 10.
[636] *Id.*
[637] *Id.*, citing to Exh. APS-6, Rebuttal Testimony of APS witness Bradley Albert, at 8.
[638] AIC Br. at 9, citing to Exh. APS-2, Rebuttal Testimony of APS witness Leland Snook, at 8.
[639] AIC Br. at 9, citing to AIC-2, Rebuttal Testimony of AIC witness Michael O'Sheasy, at 5, and Exh. APS-2, Rebuttal Testimony of APS witness Leland Snook, at 8.
[640] RUCO Reply Br. at 8.
[641] *Id.*
[642] *Id.*
[643] *Id.*

g. Staff

In response to TASC's position that the Commission must balance the perspectives of all stakeholders, including rooftop solar customers, non-DG customers, the utility, the electric grid, and society as a whole, Staff responds that the costs and benefits from rooftop solar can be considered from many different perspectives, including the DG customer, non-DG customers, the utility, utility shareholders, solar vendors, and regulators, all of whom have different perspectives and value propositions.[644] Staff believes that it is important to consider value from the perspective of all utility customers.[645]

Staff prefers a short-term avoided cost methodology as opposed to a long-term one, as proposed by TASC. Staff suggests that if a long-term avoided cost methodology is undertaken, it should be done "with great care because of the potential for overpayment," and Staff agrees with RUCO that a long-term avoided cost approach should use only easily quantifiable long-term costs and benefits.[646] Staff states that more frequent updates would lessen the risk of overpayment by non-DG customers.[647]

As set forth above in Staff's response to Vote Solar's proposed methodology, Staff does not oppose the addition of costs/benefits to its avoided cost analysis, so that it encompasses all of the well-recognized costs and benefits that have evolved over time, but that Staff is likely to recommend exclusion of benefits that are already recognized in the IRP process, economic benefits due to the difficulty in quantifying them, and grid security benefits unless they can be demonstrated.[648]

In regard to TASC's recommendation that the Commission evaluate the costs and benefits of DG using the same cost-effectiveness framework used for all demand-side resources, including EE and demand response, Staff notes that the Commission's EE and DR rules require utilities to use the

[644] Staff Br. at 11.
[645] *Id.*
[646] Staff Br. at 9, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 13, and Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 13.
[647] Staff Br. at 9.
[648] Staff Reply Br. at 3.

Societal Test,[649] and states that rooftop solar is not currently subject to this test.[650] Staff asserts that the parties have presented enough evidence differentiating rooftop solar from DSM and EE that if the Commission deems it appropriate to consider the cost-effectiveness of rooftop solar, either the Societal Test or a different test could be used to do so.[651]

5. <u>TASC's Responses to Comments on its Proposed Long-Term Avoided Cost Methodology</u>

TASC dismisses claims that forecasting creates risks for non-DG customers, asserting that there are many variables in the ratemaking process, and that rate cases exist to protect against inaccurate forecasts.[652] TASC argues that developing levelized costs and benefits for rooftop solar on a utility's system over 20 or more years "enables DG to be treated like a resource and evaluated in the same way that utilities consider the acquisition of other long-term resources."[653]

TASC asserts that adoption of its proposed methodology would allow future rate cases to

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[649] Staff Br. at 12-13, referring to A.A.C. R14-2-2512(B). R14-2-2512 provides as follows:

> Cost-effectiveness.
>
> A. An affected utility shall ensure that the incremental benefits to society of the affected utility's overall group of DSM programs exceed the incremental costs to society of the overall group of DSM programs.
>
> B. The Societal Test shall be used to determine cost-effectiveness.
>
> C. The analysis of a DSM program's or DSM measure's cost-effectiveness may include:
> 1. Costs and benefits associated with reliability, improved system operations, environmental impacts, and customer service;
> 2. Savings of both gas and electricity; and
> 3. Any uncertainty about future streams of costs or benefits.
>
> D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions resulting from implementation of DSM programs, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively. An affected utility, Staff, or any party may propose monetized benefits and costs if supported by appropriate documentation or analyses.
>
> E. Market transformation programs shall be analyzed for cost effectiveness by measuring market effects compared to program costs.
>
> F. Educational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy.
>
> G. Research and development and pilot programs are not required to demonstrate cost-effectiveness.
>
> H. An affected utility's low-income customer program portfolio shall be cost-effective, but costs attributable to necessary health and safety measures shall not be used in the calculation.

[650] Staff Br. at 12-13.

[651] *Id.* at 13.

[652] Vote Solar Reply Br. at 7-8.

[653] TASC Reply Br. at 7, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 18.

include discussion, argument, analysis, and valuation of the benefits of rooftop solar, but that in contrast, the utilities are arguing that those benefits should be ignored, assumed away, or otherwise barred from consideration.[654] TASC asserts that APS's attacks on the long-term valuation proposals in this proceeding stem from the threat of competition from rooftop solar, and argues that the combination of proposals APS has made in this proceeding are aimed at protecting APS's interests by requesting approval of policies that would result in APS's customers having no alternative but to purchase all their electric needs from APS.[655] TASC contends that its proposed Long-Term Avoided Cost methodology permits a full examination of benefits in order to ensure that an honest value assessment of rooftop solar takes place.[656]

TASC contends that DG technology has evolved, and will continue to evolve in new ways as long as customers are allowed to benefit from investment in clean technologies such as DG solar.[657] TASC states that the utilities, current and potential DG customers, and society as a whole have a stake in the outcome of this docket.[658]

E. RUCO

1. <u>Overview</u>

RUCO recommends that the Commission adopt a 20 year long-term, but conservative (due to future uncertainties), avoided cost methodology that considers both the long-term costs and benefits of rooftop solar, but which does not include hard-to-determine and de minimus cost/benefit categories,

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654 TASC Reply Br. at 4.
655 *Id.* at 19.
656 *Id.* at 20.
657 TASC Reply Br. at 25-26.
658 *Id.*

and does not include controversial economic and societal cost/benefit categories.[659] RUCO believes that intangible benefits should be considered as a policy matter, and not for purposes of ratemaking.[660]

RUCO asserts that its focus is on the value that non-DG residential customers (approximately 97 percent of customers) receive from DG, over a reasonable time period.[661] RUCO states that as a general principle, ratepayers should pay their cost for the service – no more and no less.[662] RUCO states that it recognizes the Commission's need to factor policy elements in its consideration of fair and reasonable rates, but that subsidies such as net metering were never meant to last forever.[663] RUCO chides the solar industry as being "more interested in attacking any proposed solution, while offering little if any reasonable solutions on their own."[664]

2. <u>Key Details of RUCO's Preferred Analysis Framework</u>

RUCO recommends that costs and benefits of DG solar be calculated as follows;

a. All DG solar generation is included (both exports and self-consumption);

b. Costs and benefits are calculated as levelized values over 20 years of DG energy production;

c. The methodology should only include costs and benefits that are easily quantified and focus on categories that are related to the energy system; and

d. Benefits or costs that are more indirect or speculative in nature (e.g., secondary economic impacts) should be considered qualitatively, but not be calculated in the value methodology.[665]

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[659] RUCO Br. at 2, citing to Tr. at 2154 (RUCO witness Lon Huber); RUCO Reply Br. at 1, 6; *See* Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 5, 13, 17-23. In its Initial Brief, RUCO describes in a cursory manner a "Renewable Portfolio Standard ("RPS") Bill Credit Option" that would decrease rooftop solar compensation over time based on REST compliance, and which RUCO states that it described in RUCO's Reply Brief filed in Docket No. E-04204A-15-0142 (UNSE Rate Case). RUCO Br. at 8. RUCO states that the methodology "could be viewed in this docket as a 'template' or potential methodology for both the consideration in valuing solar, and the implementation of the value of solar." RUCO Br. at 10. Unfortunately, RUCO filed no testimony in this proceeding regarding the methodology, and as such it was not subject to discovery or cross examination. RUCO did not mention it or recommend its adoption in its Reply Brief.

[660] RUCO Br. at 4, citing to Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 5. RUCO set forth in testimony a list of key inputs and assumptions for calculating benefits. *See* Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 20-21. However, RUCO's most recent recommendation supports either of the methodologies Staff proposes for adoption in this proceeding, in conjunction with RUCO's Proposed Market Fixed Contract and Step-Down Mechanism, discussed below. *See* RUCO's June 22, 2016 Responsive Comments.

[661] RUCO Br. at 2. Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 13-14.

[662] RUCO Br. at 6.

[663] *Id.* at 7.

[664] *Id.*

[665] Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 13.

RUCO asserts that in calculating the costs of rooftop solar, the utility's lost revenues and incremental utility system costs (integration costs, administration costs, etc.) should be considered, and that the most important cost assumption to be considered is "the change of revenue collected by the utility from the customer before and after the customer installs a DG system," which can be calculated "by looking at the average customer's contribution to fixed cost revenue compared to the DG adopter."[666]

3. RUCO's Market Fixed Contract and Step-Down Mechanism Proposal

Parties were invited to make responsive filings on June 22, 2016, and RUCO made a one-page filing describing its Market Fixed Contract and Step-Down Mechanism proposal, which merges either of Staff's proposed methodologies with RUCO's proposed Market Fixed Contract for rooftop solar adopters.[667] Under RUCO's Market Fixed Contract proposal, a solar adopter would be offered a fixed-price, 20 year contract that could either be applied to all its production, or only to its exports, at the customer's choice.[668] In its filing, RUCO states that the credit rate for the Market Fixed Contract would be based on a rate determined by either Staff's Proposed Avoided Cost methodology or Staff's Proposed Resource Comparison Proxy methodology.[669] (On brief, RUCO recommends that the Commission use a conservative long-term valuation methodology to identify a levelized value, and then design rates or other compensation mechanisms that do not pay more than this levelized value.[670]) As more rooftop solar customers interconnect, the credit rate would drop in a predictable and gradual manner, which RUCO asserts is a process identical to the way the Commission administered up-front incentives ("UFIs") for rooftop solar installations in the past.[671] RUCO asserts that the process of applying step-down schedules to the initially-established rate, and predictably and gradually lowering the rate, as market uptake increases and the cost of solar declines, will allow solar to "become a net benefit to all ratepayers – DG and non-DG customers alike."[672]

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[666] RUCO Br. at 11, citing to Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 14.
[667] RUCO's June 22, 2016 Responsive Comments.
[668] *Id.*
[669] *Id.*
[670] RUCO Br. at 10-11, citing to Tr. at 1483 (RUCO witness Lon Huber). RUCO notes that this recommendation "mirrors RUCO's RPS proposal." RUCO Br. at 11, fn. 4.
[671] RUCO's June 22, 2016 Responsive Comments.
[672] RUCO Br. at 11. *See also* RUCO Reply Br. at 6.

RUCO contends that an approach which locks in solar value at a single point in time, and fails to consider rapidly changing solar technology over time, would only be relevant for a short period of time.[673] RUCO contends that regardless of the long-term valuation methodology, a declining step down mechanism should be implemented that can be easily adjusted based on locational value, technology advances, REST compliance, and solar cost trends.[674] RUCO asserts that its approach is the least difficult to administer, and would provide rooftop solar customers with rate stability.[675]

4. Valuation/Compensation of Self-Consumption

RUCO acknowledges the agreement by all other parties that the value of solar methodology that emerges from this docket should concern only rooftop solar exports.[676] However, RUCO asserts that regardless of the valuation methodology adopted, the Commission should allow the resulting compensation to be applied to self-consumed rooftop solar or rooftop solar exports, as the Commission sees fit in future individual rate cases.[677] RUCO contends that analyzing only exports will undervalue solar, as solar energy consumed on-site provides energy and capacity benefits, and there is "no sound economic or technical justification to value them separately."[678] RUCO claims that limiting compensation to rooftop solar exports would (1) limit actionable data to Commissioners; (2) not help with rate design issues; (2) confuse customers by treating self-consumption differently from exports; (3) create two complex regulatory pathways to adjust solar compensation; and (4) could send potentially troubling price signals (such as if the retail rate is lower than the export rate).[679] RUCO asserts that self-consumption is "clearly a part of rate design – half of it in fact" and that the Commission should address both self-consumption and the export rate in this docket.[680] RUCO contends that "[s]urely there are costs and benefits to the non-solar ratepayer as well as the utilities

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673 RUCO Br. at 10.
674 RUCO Reply Br. at 2.
675 *Id.* at 8.
676 *Id.* at 4.
677 RUCO Reply Br. at 1; Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 13. RUCO also states that "customers can simply elect to be compensated for either their entire solar production or just their exports, at the credit rate set in this proceeding." RUCO Reply Br. at 5.
678 RUCO Br. at 4-5, 6.
679 RUCO Reply Br. at 2.
680 *Id.* at 2-3.

related to the solar customers' self-consumption . . . the solar customer who produces and uses his own generation can reduce or increase overall demand on the system."[681]

5. Comments on RUCO's Proposals

a. APS

APS states that it cannot support RUCO's proposal to value total rooftop solar production at a calculated long-term value.[682] While recognizing that RUCO does not advocate a continuation of net metering, APS views the proposal as flawed because it relies on a 20 year long-term forecast. APS contends that the weight of the evidence in this proceeding shows that long range forecasts are unproven and unreliable, and that rates set using a long-term forecast cannot be just and reasonable.[683] APS states that it does not oppose the concept, outlined in RUCO's Initial Brief, of starting at one value and stepping down over time base on pre-determined events, but that RUCO did not offer sufficient details to assess its proposal or to evaluate the impact it would have on customers.[684] APS believes it would be unwise to postpone a determination on the details due to the litigation that would likely ensue, but notes that Staff's Resource Comparison Proxy methodology, which APS could support, incorporates a built in method for downward adjustments that appears to capture the intent of RUCO's intent.[685]

b. TEP/UNSE

TEP/UNSE agree with RUCO's statement that the most important cost assumption that the Commission needs to consider is the change of revenue collected by the utility from a customer following its installation of a DG system.[686] TEP/UNSE point out that this is information that TEP/UNSE's cost studies provided.[687] TEP/UNSE are concerned with "the complexity of RUCO's RPS proposal, the challenge of setting initial parameters, the glide path for reducing the value of DG, the potential use of levelized values to approximate future benefits, and a variety of other factors that

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[681] *Id.* at 5.
[682] APS Br. at 50.
[683] *Id.* at 49-51.
[684] *Id.* at 9-10.
[685] *Id.* at 10.
[686] TEP/UNSE Reply Br.at 4-5.
[687] *Id.*

underlie the proposal."[688] TEP/UNSE state that it is unclear whether those elements would be determined on a utility by utility basis in rate cases or other proceedings, or whether an additional phase of this generic proceeding would be required to develop a template to apply to all utilities.[689] TEP/UNSE point to an additional challenge as well, and that is RUCO's intention to provide "a window of time for solar companies to be profitable with the subsidy."[690] TEP/UNSE point out that there is no evidence in the record regarding the details of solar company business models that could allow such an assessment.[691]

c. GCSECA

GCSECA opposes any proposal to establish a value of DG methodology based on long-term forecasts such as that proposed by RUCO.[692]

d. AIC

AIC agrees with RUCO that the current retail net metering policy was enacted to spur the deployment of rooftop solar in order to help the utilities meet REST requirements, and was designed and intended to terminate when the market became competitive and could survive on its own.[693]

AIC opposes RUCO's proposal because it is not based on historic costs, and because it would require long-term forecasting of benefits.[694] AIC is critical of beginning compensation of rooftop solar exports at or near the retail rate, asserting that the retail rate has no evidentiary correlation to the actual cost savings attributable to the energy produced.[695] AIC is also critical of the second step in RUCO's proposal, to decrease the compensation level over time based on the utilities' REST compliance, because this would require long-term forecasting and analysis, which AIC asserts is always wrong.[696] AIC contends that using subjective benefits to calculate the value of solar exports, instead of using evidence-based costs, means that the rate will never be correct, and therefore cannot be just and

[688] TEP/UNSE Reply Br. at 5.
[689] *Id.*
[690] *Id.*, citing to RUCO Br. at 8.
[691] TEP/UNSE Reply Br. at 5.
[692] GCSECA Br. at 5.
[693] AIC Reply Br. at 3, citing to RUCO Br. at 7.
[694] AIC Reply Br. at 9.
[695] *Id.*
[696] *Id.*

reasonable.[697] AIC is concerned that RUCO's proposal to offer a solar adopter a fixed 20 contract would inevitably overcompensate rooftop solar customers for benefits they will not actually bring to the system over the term of the 20 year contract.[698]

AIC reasserts its position that if the Commission wants to continue to bolster the solar industry, it should do so in a way that clearly lets customers know what they are paying for, and not by placing the subsidy in an artificially inflated "value of solar" rate.[699]

e. Vote Solar

Vote Solar asserts that the RUCO "step-down" methodology would only add to the problems of a utility-scale approach.[700] Vote Solar asserts that it is not a method for valuing rooftop solar exports, but a method for reducing the compensation for solar exports without any attempt to actually value the net benefits of solar.[701] Vote Solar argues that RUCO is "largely uninterested" in the initial valuation stage of its proposed methodology, noting that RUCO has proposed three different starting points from which to begin the step-down process: utility-scale solar prices, an avoided cost calculation, and current retail prices.[702] Vote Solar claims that using any methodology other than a full long-term benefit and cost analysis to set an initial value of rooftop solar is unreasonable, because it would not reflect the actual value of the resource, and that RUCO's proposal to decrease a value set by any other means over time would add an additional layer of unreasonableness.[703] Vote Solar contends that if the value of rooftop solar does in fact decline over time, the analysis should reflect that, but Vote Solar opposes an arbitrary decline based on policy considerations that are divorced from the actual value of the resource.[704] Vote Solar charges that this approach inappropriately fails to separate the issues of value of rooftop solar and the compensation paid for exports, and that the value of solar methodology should not be compromised or skewed to reflect a party's view of the appropriate compensation rate.[705]

Vote Solar contends that even if the Commission were to address compensation issues in this

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[697] AIC Br. at 17; AIC Reply Br. at 8.
[698] AIC Br. at 18.
[699] AIC Reply Br. at 9.
[700] Vote Solar Br. at 33, 34.
[701] Vote Solar Reply Br. at 17-18.
[702] *Id.*
[703] Vote Solar Br. at 33, 34; Vote Solar Reply Br. at 18.
[704] Vote Solar Br. at 33; Vote Solar Reply Br. at 18.
[705] Vote Solar Br. at 33-34.

proceeding, the RPS Bill Credit option RUCO referred to in its Initial Closing Brief is seriously flawed because it is a buy-all, sell all arrangement, under which the utility would purchase all of the rooftop solar output, and the customer would purchase all of its consumption from the utility.[706] Vote Solar argues that this would be a dramatic departure from current rate design, and would violate a customer's right to self-consume the energy generated behind the meter through its own investment.[707] Vote Solar opposes any infringement on this property right.[708]

Vote Solar responds to RUCO's contention that analyzing only exports will undervalue solar, as solar energy consumed on-site provides energy and capacity benefits, and there is no justification to value them separately. Vote Solar agrees that self-use of rooftop solar provides significant benefits, but believes focusing on exports is the better approach because the utility should not "look behind the meter" based on a customer's technology choices.[709] Vote Solar asserts that the only difference between a customer who adopts energy efficiency measures and one who adopts rooftop solar is when the rooftop solar customer exports energy to the grid.[710]

f. TASC

TASC objects to the timeliness and the lack of record support of RUCO's Step-Down proposal, and calls for its rejection.[711] TASC notes that it was proposed for the first time on the twelfth day of the 13 day hearing in this proceeding, and asserts that RUCO offered no evidence to support it.[712] TASC states that RUCO offered no rationale or proposal regarding how, when, or under what circumstances the proposed step-down would be triggered, lowering the compensation rate.[713] TASC argues that had RUCO presented such basic information about its proposal in the normal course of the proceeding, the record could have been developed, and other parties could have properly challenged it.[714] TASC asserts that due to its untimeliness, RUCO's proposal cannot be adopted.[715]

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[706] Vote Solar Reply Br. at 18.
[707] Vote Solar Reply Br. at 18-19.
[708] Vote Solar Reply Br. at 19.
[709] Vote Solar Br. at 8.
[710] *Id.*
[711] TASC Reply Br. at 24-25.
[712] TASC Reply Br. at 24.
[713] TASC Reply Br. at 24.
[714] TASC Reply Br. at 24.
[715] TASC Reply Br. at 24.

TASC asserts that RUCO's proposal to decrease compensation over time would add an additional layer of complexity to Staff's Resource Comparison Proxy methodology in an arbitrary manner that would "further divorce the rate from the true value of DG."[716] TASC believes that RUCO's proposal to step down compensation for exports over time would lead to further disputes, and contends that parties' resources would be better spent on a long-term avoided cost analysis.[717] TASC asserts that if the value of rooftop solar exports does in fact decline or increase over time, a long-term avoided cost methodology will reflect such a decline or increase on a going forward basis in future rate cases, where the value would be calculated and recalculated.[718]

g. Staff

Staff does not oppose RUCO's step-down approach when coupled with Staff's Resource Comparison Proxy methodology.[719] Staff notes, however, that the proposal may be administratively difficult to implement since it appears that many tranches of customers would be created, and the utilities would have to track the tranches from a billing perspective and an administrative perspective.[720] Staff also notes that the Resource Comparison Proxy methodology will by itself decline as new projects are added.[721]

Like the other parties, Staff opposes RUCO's position that the value of DG analysis should look at self-consumption in addition to exports.[722] Staff believes that "what happens behind the meter is the customer's business. The customer has the right to reduce load by conservation, insulation, high efficiency appliances, storage or the installation of a DG meter."[723] Staff contends that there is thus no need to include self-consumption in the analysis.[724] Staff adds that it views the export rate more in the nature of a wholesale rate, and not a retail rate, which would apply to self-consumption.[725]

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716 TASC Reply Br. at 24.
717 TASC Reply Br. at 24.
718 TASC Reply Br. at 24.
719 Staff Br. at 28. Staff notes that the parties were asked to consider a step-down approach in Commissioner Stump's June 13, 2016 letter to the docket.
720 *Id.*
721 *Id.*
722 Staff Br. at 13.
723 *Id.*, citing to Exh. Staff-7, Direct Testimony of Staff witness Howard Solganick, at 7.
724 Staff Br. at 13-14.
725 *Id.* at 14.

F. Staff

1. Overview

Staff believes that the Commission should use the determination resulting from the value of DG methodology adopted in this proceeding to inform its decision making on related policy and ratemaking issues in an electric utility's rate case, as it applies to all DG customers.[726] Staff states that all parties agree that value of DG methodologies should be based on an avoided cost study or an avoided cost proxy,[727] and that while all parties may not agree on how the resulting value of DG determinations should be applied, they all acknowledge that value of DG calculations can be considered in determining how rooftop solar customers who export energy to the grid are incentivized or compensated, or both, and to inform rate design.[728]

Staff presented two avoided cost methodologies in this proceeding. The Direct Testimony of Staff's witness Mr. Solganick included a presentation of Staff's Proposed Avoided Cost methodology, which is a traditional avoided cost methodology which Staff states can be based on a short-term analysis, or a long-term analysis, with a more cautionary determination of costs and benefits. Staff also presented, during the course of the hearing in this proceeding, another avoided cost methodology, Staff's Proposed Resource Comparison Proxy methodology. Staff designed its Resource Comparison Proxy methodology to determine a weighted average cost of the grid-scale solar resources owned by the utility and the utility's solar PPAs. This methodology was described by the Commission's Utilities Division Director Thomas Broderick at the hearing on June 13, 2016.[729] Foundational testimony regarding the utilities' responses to Staff's data requests, and utility spreadsheets showing the data, were also presented at the hearing on June 8, June 9, and June 13, 2016, by APS witness Bradley Albert and TEP/UNSE witnesses David John Lewis and Carmine Tilghman, and in associated Staff exhibits.[730]

[726] Staff Br. at 10, 14.

[727] Staff defines avoided cost as the "costs of energy that would have been produced or purchased but for the existence of the DG." Staff Br. at 8, citing to Exh. Staff-2, Direct Testimony of Staff witness Howard Solganick, at 10.

[728] Staff Br. at 8, 10.

[729] Tr. at 2322-2356 (Staff witness Thomas Broderick).

[730] Tr. at 2084-2087 (APS witness Bradley Albert); Tr. at 2186-2212 (TEP/UNSE witness David John Lewis); Tr. at 2225-2252 (TEP/UNSE witness Carmine Tilghman).

Staff urges the Commission to adopt both its proposed methodologies for use in rate cases.[731] Staff contends that both are consistent with much of the guidance provided by the Commissioners' letters to this docket, and that adoption of both methodologies would provide the Commission with maximum flexibility to address any rate design modifications necessary to respond to changes in the rooftop solar marketplace.[732]

Staff states that the determination of avoided cost can be a complicated undertaking, and asserts that the methodology adopted must include specificity, and must allow for calculation of avoided cost in a manner that can be accommodated in a rate case proceeding.[733] Staff believes that the use of both its proposed methodologies would give the Commission an important comparison point. Staff also believes that having both methodologies available would provide an important backstop in rate cases. Staff states that when its Resource Comparison Proxy methodology is used in conjunction with its traditional Avoided Cost methodology in rate cases, it will be informative to the Commission on its various value of solar determinations, and may be something that parties could agree on if a traditional avoided cost analysis becomes too difficult and time-consuming in the context of the rate case.[734]

2. Cost of Service Issues

Staff agrees with Commission findings in prior orders that there is a cost shift, but notes that issues were raised by Vote Solar and TASC regarding assumptions in APS's and TEP/UNSE's cost models that are appropriately addressed in this proceeding. Staff states that transparency issues with the utilities' COSS models, and their availability for use by other parties in future cases, are also appropriately addressed in this proceeding. Staff asserts that resolving model transparency issues now will permit easier assimilation and use in rate cases.[735]

3. Net Metering

Staff states that Arizona's NEM Rules were adopted when the rooftop solar industry was first emerging, and they provided an incentive for the growth and adoption of rooftop solar by utility

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[731] Staff Br. at 14; Staff Reply Br. at 1.
[732] Staff Reply Br. at 1.
[733] Staff Br. at 4.
[734] Staff Reply Br. at 2, 4.
[735] *Id.* at 2.

customers.[736] Staff states that Arizona, and many other states that adopted net metering, are faced with the issue of whether the same level of subsidies are necessary today, and whether net metering should continue to be a significant part of the value equation.[737] Staff contends that in addition to providing compensation to rooftop solar customers for their wholesale exports at a retail rate, NEM provides additional significant subsidies via its banking or crediting mechanisms.[738] For this reason, Staff recommends that net metering, and the banking of exports associated with net metering, should eventually be eliminated, and replaced with a mechanism for the direct purchase of exports.[739]

Currently, Staff explains, NEM provides for a 1-for-1 offset, which results in valuation of all rooftop solar exports at a utility's retail rate, regardless of the time of day, or time of year, that it is measured.[740] This results in situations in which rooftop solar energy can be exported during the winter, when wholesale prices are low, and the credit for that export can be used to offset energy provided by the utility during the summer, when wholesale prices are high.[741] Staff agrees with TEP/UNSE's witness Mr. Tilghman that the value of rooftop solar exports between October and May is not equivalent in value to the utility-provided energy the rooftop solar customer consumes during June through September.[742] Netting provides rooftop solar customers with a retail rate offset, and Staff explains that the duration period of the netting (which can be seasonal, monthly, daily, annual, or instantaneous) can skew the value of rooftop solar exports.[743] Staff believes it is clear that many entities leasing or selling rooftop solar systems to customers, and the customers themselves, consider the significant potential banking and netting effect on the price they will pay for energy when they consider the overall value the system will provide.[744] Staff notes that the typical rooftop solar installation exports on average one-third of its total production.[745]

Staff believes that in order to address some of the NEM issues and other cost shift issues, it is

[736] Staff Br. at 6, citing to Decision No. 70567.
[737] Staff Br. at 6.
[738] *Id.*
[739] *Id.*, citing to Exh. Staff-2, Direct Testimony of Howard Solganick, at 18.
[740] Staff Br. at 7.
[741] *Id.*, citing to Exh. TEP/UNSE-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 4-5.
[742] Staff Br. at 7, citing to Exh. TEP/UNSE-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 4-5.
[743] Staff Br. at 7.
[744] *Id.*
[745] *Id.*, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at 12.

necessary that the concept of net metering transition to a new, more simplified billing mechanism that allows the utility to purchase rooftop solar exports at an appropriate export rate set by the Commission.[746] Staff asserts that the appropriate place to consider the concepts of NEM banking and netting are either in a rulemaking proceeding or in each utility's rate case.[747]

4. Staff's Proposed Avoided Cost Methodology

a. Categories of Benefits and Costs

Staff's Proposed Avoided Cost Methodology would consider the following broad categories of benefits and costs:

1) Energy and System Losses;

2) Capacity (generation capacity, transmission and distribution capacity and distributed solar's installed capacity);

3) Grid Support Services (reactive supply and voltage control; regulation and frequency response; energy and generator imbalance; synchronized and supplemental operating reserves; scheduling, forecasting and system control and dispatch);

4) Financial Risk (fuel price hedge, and market price response);

5) Security Risk (reliability and resilience); Environmental (carbon emissions (CO_2); criteria air pollutants (SO_2, NO_2, PM); water and land; and Social (economic development (jobs and tax revenues)).[748]

b. Methodology for Considering the Benefits and Costs

Staff's Proposed Avoided Cost Methodology would consider the broad categories of benefits and costs as listed above, in the following manner:

1) avoided energy costs, along with appropriate losses based on an energy loss study performed by the utility which is specific to it and/or its interconnected systems;

2) avoided generating capacity with losses adjusted for geographic location using the demand loss study;

3) avoided transmission and distribution capacity costs, with adders for specific geographic areas where a demonstration is made that transmission lines or distribution feeders can be delayed due to solar DG in the area;

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746 Staff Br. at 7.

747 *Id.* at 7-8.

748 *Id.* at 14-15, citing to Exh. Staff -2, Direct Testimony of Staff witness Howard Solganick, at Exhibit HS-2.

4) environmental (would be analyzed, but typically not included because the environmental impacts are already considered in the IRP process); and

5) grid support services.[749]

Staff states that the consideration of benefits and costs can be done on either a short-term or a long-term basis as the Commission prefers.[750] Staff's witness testified that a short-term analysis is preferable, which would use forecasted data no longer than the period of time between a utility's rate cases, or approximately five years, before it would be updated again.[751] Staff states that if the Commission chooses to use long-term forecasts, more frequent updates could address the risk that the forecast will likely change, and lessen the risk of overpayment by non-DG customers.[752] Staff agrees with RUCO that only easily quantifiable costs and benefits should be examined, if the Commission chooses to use long-term forecasts.[753]

c. Avoided Energy Costs

Staff states that avoided energy costs are typically the most significant component of the avoided cost calculation, and that an adjustment for energy losses (due to local consumption) would be included based on an energy study. Staff states that APS's estimate is 7 percent over a year and 12 percent at the time of peak demand.[754]

d. Avoided Generation Capacity Costs

Staff states that determining the avoided generation capacity costs requires assumptions regarding (1) generation capacity additions that are reduced or delayed due to additional rooftop solar exports, and (2) the level of rooftop solar export capacity that is expected to contribute to the system peak.[755] Staff states that the second assumption is generally assessed using an ELCC (effective load carrying capacity) calculation, a method which reflects the capacity value of an intermittent

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[749] Staff Br. at 15, with citations throughout this list to Exh. Staff-2, Direct Testimony of Staff witness Howard Solganick, at 19, and Exhibit HS-2, pp. 7, 14, 15, and to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 5. Definitions of the terms considered in Staff's Proposed Avoided Cost methodology are found at those citations.
[750] Staff Br. at 16.
[751] Staff Reply Br. at 3, 12.
[752] *Id.*
[753] *Id.*
[754] Staff Br. at 16, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 16.
[755] Staff Br. at 16, citing to Exh. TEP/UNSE-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 13, and Vote Solar-7, Direct Testimony of Vote Solar witness Briana Kobor, at 31.

technology.[756] Staff states that battery storage is the only technology that reduces the intermittency of solar, and if used, would be included in the ELCC calculation.[757]

e. Avoided Transmission and Distribution Costs

Location-specific adders, and other adders, where value can be shown in certain geographic areas, are included in Staff's avoided cost calculation. For instance, a specific value adder would be appropriate if the deferral or elimination of transmission or distribution assets and/or costs can be demonstrated.[758] Staff states that this could be calculated based upon projections utilizing ELCC to determine when capacity is needed that can be offset.[759]

Staff believes that if enough rooftop solar can be aggregated at a specific location to make an incremental difference in feeder or substation enhancements, a value component could be recognized as an adder, based on ELCC calculations.[760]

f. Adders to Incentivize DG with Added System Value

Staff's methodology contemplates other adders for system attributes that may provide added value.

1) Geographic and West-Facing System Adders

Staff recommends that the Commission require use of a feeder-focused RFP process to identify geographic areas where additional rooftop solar may be of value, and notes that the RFP process could put a higher value on west-facing systems, which provide greater production during summer peaking hours.[761]

Staff states that the Commission could consider authorizing adders for west-facing facilities in specific geographic locations to encourage the development of west-facing facilities. Staff believes that geographic components should be treated as separate adders, and not accrue to all exports, because

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[756] Staff Br. at 16, citing to Exh. Staff -2, Direct Testimony of Staff witness Howard Solganick, at 18.
[757] Staff Br. at 16, citing to Exh. TEP/UNSE-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 13.
[758] Staff Br. at 16, citing to January 8, 2016 Correspondence to the Docket from Commissioner Forese, and to Exh. Staff - 2, Direct Testimony of Staff witness Howard Solganick, at 19-20; Staff Reply Br. at 3.
[759] Staff Br. at 16-17, citing to Exh. Staff -2, Direct Testimony of Staff witness Howard Solganick, at 13 and to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 5.
[760] Staff Br. at 17, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 5.
[761] Staff Br. at 17, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 20, and to Exh. TEP/UNSE-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 4.

transmission or distribution asset deferral is location specific.[762]

2) Renewable Energy Credits ("REC") Adder

Staff states that the Commission could consider an adder to recognize utility receipt of RECs when it purchases the customer's exports.[763]

3) Responsive System and Storage Adders

Staff states that widespread use of smart inverters with some centralized control may allow rooftop solar to provide control capabilities similar to utility-scale solar, and that adders would be appropriate to recognize the value of DG systems that can be controlled by the utility, to the extent it is dispatched to increase output during hours of system peak.[764]

Staff states that storage provides considerable value since it addresses intermittency concerns, and that the Commission may want to incent storage, to the extent it is dispatched to increase output during hours of system peak.[765]

4) Water

Staff states that the costs of water used in a utility's generation portfolio should already be reflected in the variable energy costs avoided from DG.[766] However, Staff states that concerns about future water shortages may be a policy issue for the Commission to consider.[767] Staff states that the Commission could recognize the fact that rooftop solar's water usage is lower on average, and could use an incentive mechanism for this in areas where there are concerns identified as to future water shortage.[768]

5) Adders for Added System Value May be Difficult to Demonstrate

Staff notes that until rooftop solar penetration is higher (either alone or combined with other technologies, the adders described in this section may be difficult to demonstrate in most areas.[769]

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[762] Staff Br. at 17, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 3; Staff Reply Br. at 3.
[763] Staff Br. at 17, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 20; Staff Reply Br. at 3.
[764] Staff Br. at 17, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 5, 12, 29; Staff Reply Br. at 3.
[765] Staff Br. at 18; Staff Reply Br. at 3.
[766] Staff Br. at 19.
[767] *Id.*, citing to Correspondence to the Docket filed on February 16, 2016 by Commissioner Burns.
[768] Staff Br. at 19; Staff Reply Br. at 3.
[769] Staff Br. at 19.

g. General Opposition to Including Environmental Benefits, Local Economic Development Benefits, Fuel Hedging Benefit, Reliability

Staff is generally opposed to including avoided environmental costs. Staff's witness explained that this is because avoided cost values kWh provided at costs the utility does not incur, and if a generating unit must meet a specific environmental compliance standard, (such as emissions or water usage), it has already incurred the associated cost to construct and operate the plant.[770] Staff states that only "if the environmental cost is identified in the IRP process and is not already included in utility costs and rates, and is based upon an emerging regulation or results in reductions in emission levels over and above required levels, should this be considered as an avoided cost.[771]

Staff believes that economic benefits should be considered qualitatively only, and opposes any adders for them. Staff states that such costs and benefits are very difficult to quantify, are not included in the ratemaking formula for existing generation and other facilities, and are not unique or incremental to DG.[772]

In regard to the fuel hedging value for rooftop solar advocated by TASC, RUCO, and Vote Solar, based on arguments that renewable generation reduces a utility's exposure to fossil fuel price volatility, Staff's witness states:

> I have seen little evidence that electric utility customers are demanding more reduction in long-term pricing volatility. In competitive supply states residential contracts appear to extend out a few years at most. Utility energy adjustment programs are generally annual or even shorter durations. Staff suggests electric customers do not value a partial fuel price hedge and one should not be applied.[773]

5. <u>Comments on Staff's Proposed Avoided Cost Methodology</u>

a. APS

APS states that it largely agrees with Staff's proposed avoided cost methodology, noting that its capacity savings were based on an ELCC assessment, which is the method APS uses to derive capacity value in the resource planning process.[774] APS is concerned with Staff's suggestion that forecasted capacity could be used in determining avoided cost, but states that with conditions, Staff's

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[770] Staff Br. at 18, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 12.
[771] Staff Br. at 18, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 4.
[772] Staff Br. at 18, citing to Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 20.
[773] Staff Br. at 18-19; Exh. Staff-3, Rebuttal Testimony of Staff witness Howard Solganick, at 14.
[774] APS Br. at 47.

avoided cost methodology would protect customers and would value exported energy in a transparent, verifiable, fair manner.[775] APS believes Staff's avoided cost methodology would accomplish those goals if the calculation of forecasted capacity savings is constrained to a limited time period no longer than the time between rate cases, and if the magnitude of capacity savings is based upon actual data derived from an ELCC analysis.[776]

b. TEP/UNSE

TEP/UNSE state that Staff's proposed avoided cost approach includes many elements they believe should be considered in determining a value of DG based on avoided cost.[777] They assert that the complexity of the methodology may provide a challenge to smaller utilities, and if applied in the context of a rate case, could overwhelm other important rate case issues.[778] They support Staff's position not to include elements that are not included in rates, such as environmental or economic benefits, fuel hedge values or grid reliability benefits.[779] TEP/UNSE state that Staff appears to acknowledge that "as available" energy from DG systems may provide no capacity value,[780] and agree with Staff's concept of using an ELLC analysis to identify any actual, real concrete and ongoing capacity savings from generation, transmission, or distribution before considering inclusion of any long-term avoided costs in valuing DG.[781] They assert, however, that given the nature of current rooftop solar installations, it is unlikely that rooftop solar provides an ELCC that should be compensated through a value of DG.[782] They disagree with Staff's suggestion that the utility's avoided cost could be could be considered a "floor" on the value of DG, asserting that since rooftop solar customers have no legal obligation to provide energy or capacity, short-term avoided cost is a reasonable valuation, consistent with PURPA.[783] TEP/UNSE assert that DG resources should be required to meet a significant burden of proof before any costs beyond short-term avoided cost savings

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[775] *Id.*
[776] APS Br. at 48
[777] TEP/UNSE Br. at 12-13.
[778] *Id.* at 13; TEP/UNSE Reply Br. at 3.
[779] TEP/UNSE Reply Br. at 2, referring to Staff Br. at 18-19.
[780] TEP/UNSE Br. at 10.
[781] TEP/UNSE Br. at 12-13; TEP/UNSE Reply Br. at 2, 7.
[782] TEP/UNSE Br. at 12-13.
[783] TEP/UNSE Br. at 10, referring to Tr. at 1309 (Staff witness Howard Solganick).

can be imposed on non-DG ratepayers.[784]

TEP/UNSE point out that Staff acknowledged that the many value and cost elements in its avoided cost methodology could be subject to litigation, resulting in a lengthy proceeding, and that it may not be easy to implement.[785] TEP/UNSE believe that an avoided cost determination for DG could be done more simply through a market proxy, which would also comport with PURPA.[786]

c. AIC

Of Staff's two proposals, AIC prefers Staff's Proposed Avoided Cost methodology because it better reflects the costs and cost saving resulting from DG of various types.[787]

d. Vote Solar

Vote Solar opposes Staff's preference to only analyze short-term avoided costs in its traditional avoided cost calculation.[788] Vote Solar argues that the methodology does not accurately value rooftop solar because it ignores significant future benefits.[789] Vote Solar is also critical of Staff's long-term avoided cost approach, because it omits the analysis of environmental, economic development, and grid security benefits that Vote Solar believes are necessary to properly value rooftop solar.[790]

e. TASC

With reservations, TASC is generally supportive of Staff's Proposed Avoided Cost methodology. According to TASC, unlike the utilities' and RUCO's avoided cost proposals, it would successfully analyze the costs and benefits of DG going forward, when future technologies, such as battery storage, will become part of the valuation equations.[791] Two issues impede TASC's full support of this methodology: (1) Staff's preference for a short-term time analysis as opposed to long-term; and (2) missing components which TASC believes should be included: environmental benefits, societal benefits, and fuel hedging cost benefits.[792]

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[784] TEP/UNSE Reply Br. at 2.
[785] TEP/UNSE Br. at 13, citing to Tr. at 1399-1400 (Staff witness Howard Solganick), and Tr. at 2324, 2327-2328 (Staff witness Thomas Broderick).
[786] TEP/UNSE Reply Br. at 1
[787] AIC Br. at 12.
[788] Vote Solar Reply Br. at 16.
[789] *Id.*
[790] *Id.*
[791] TASC Reply Br. at 20.
[792] *Id.* at 21-22.

Based on TASC's position that a DG system must be valued over its useful life, because a short-term, "snapshot" analysis cannot properly value a DG system's actual benefits, TASC disagrees with Staff's assertion that the methodology can accurately value DG if it is performed on a short-term basis.[793] TASC asserts that only performing the avoided cost valuation over a 20 year plus period of time would enable DG to be "treated like a resource and evaluated in the same manner that utilities consider the acquisition of other long-term resources."[794]

In regard to TASC's second reservation regarding Staff's Proposed Avoided Cost methodology, TASC asserts that there is no justification for excluding environmental benefits due to an inability to quantify those benefits today, and a party should be able to present evidence in a rate case to demonstrate the existence of such a benefit in the future.[795] TASC points to Staff's acknowledgement that environmental costs could be considered an avoided cost if identified in a utility's IRP.[796]

TASC contends that adders reflecting societal benefits of DG, (water savings, carbon reduction, air pollution reduction, and local economic benefits), which do not directly impact utility rates, but that are conferred on all citizens, should be included in Staff's Avoided Cost methodology.[797] TASC asserts that they should also be looked at from a policy perspective in promoting clean energy, because according to TASC, if the compensation for DG exports is set too low, the societal benefits will never accrue, which would be counter-productive to the Commission's goals of promoting a healthy market for DG.[798]

TASC argues that fuel hedging costs should not have been excluded from Staff's valuation methodology. TASC asserts that fuel hedging costs are quantifiable, asserting that according to APS in its 2012 IRP, renewable resources "provide mitigation against the inherent price volatility risks associated with a natural-gas dominated energy mix."[799] TASC asserts that fuel hedging costs are part of the avoided cost of natural gas attributable to DG, and can therefore be quantified.[800]

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[793] *Id.* at 20.
[794] *Id.* at 20-21.
[795] *Id.* at 21.
[796] *Id.*, referring to Staff Br. at 18.
[797] TASC Reply Br. at 21. A description of these benefit categories as proposed by TASC is set forth above, in the section describing TASC's proposed Long-Term Avoided Cost methodology.
[798] TASC Reply Br. at 21.
[799] *Id.* at 22, citing to Exh. TASC-26, Direct Testimony of TASC witness R. Thomas Beach, at Exhibit 2, p. 17, n. 16.
[800] TASC Reply Br. at 22. TASC cited to Docket No. E-01345A-13-0248, "Technical Conferences on DG and NEM."

f. RUCO

RUCO's most recent recommendation supports either of the methodologies Staff proposes for adoption in this proceeding.[801] RUCO believes that Staff capably presented a long-term avoided cost methodology that is similar to how energy efficiency is treated with the societal cost test.[802] RUCO states that its step-down proposal could be used as an implementation option in addition to either of Staff's proposed methodologies.[803]

6. Staff's Responses to Comments on its Avoided Cost Methodology

Staff responded to TEP/UNSE's comment regarding the complexity of Staff's Avoided Cost methodology, and that the complexity could overwhelm issues in a rate case, and might provide a challenge for smaller utilities with limited resources. Staff states that while it is true that traditional avoided cost studies can be very complex and time-consuming, they have been undertaken many times before in both short-term and long-term formats, and there are accepted methodologies for both.[804] Staff states that there are completed analyses in the record of this proceeding that the Commission could use if it so wishes. Staff states that the geographic adder approach presented in the testimony of its witness relies in part upon already-developed utility analyses and long-term planning methodologies that look at upgrades to distribution and transmission.[805]

Staff states that its witness Director Broderick acknowledged at the hearing that Staff's proposed Resource Comparison Proxy methodology would probably be a simpler method of producing a reliable proxy for avoided cost, and for that reason it may be a more appropriate method initially.

7. Staff's Proposed Resource Comparison Proxy Methodology

Staff states that its Resource Comparison Proxy methodology is a reliable avoided cost proxy representing the actual average avoided cost of the utilities' provision of solar generation to their customers.[806] Staff devised its Resource Comparison Proxy methodology to determine avoided cost by using the weighted average of utility-owned solar facilities and PPAs of each individual utility.[807]

[801] RUCO's June 22, 2016 Responsive Comments.
[802] *Id.*
[803] RUCO Br. at 14.
[804] Staff Reply Br. at 9.
[805] *Id.*
[806] Staff Br. at 22, citing to Tr. at 2332-2333 (Staff witness Thomas Broderick).
[807] Staff Br. at 19, citing to Tr. at 2332-2333 (Staff witness Thomas Broderick).

a. Components

During the course of the hearing, at the end of April, 2016, Staff requested and received a significant amount of information from APS and TEP/UNSE related to all of their utility-owned grid scale solar PV facilities, and all their PPAs for solar PV facilities.[808] The information included the effective date, when the specific generating project began producing energy, the term of the PPA, pricing information related to the PPA, the type of renewable technology, copies of each of the actual contracts, and the actual purchase power agreements.[809]

Staff requested in its Data Request 3.6 to APS, that APS build a spreadsheet that could combine the cost and pricing information for all the solar projects, both utility-owned and PPAs, and then calculate a weighted average overall price or cost for all the solar projects.[810] APS provided the active spreadsheet in Excel with the formula to each party.[811] Staff states that currently the spreadsheet is set up to only allow an analysis up to five years, but at the hearing, APS agreed to modify the spreadsheet to allow for consideration of facilities or PPAs spanning a period of time greater than five years.[812]

Staff describes the spreadsheet and its functions as follows:

> The spreadsheet allowed for variance in terms of which projects to include, how far back to go in the analysis i.e., whether the analysis should be limited to a certain number of years, the ability to have the cost represented on either a levelized or non-levelized basis, inclusion or exclusion of Arizona's production tax credit applicable to the first 10 years that the project is in service as well as other variables. At a high level, the response to Staff Data Request 3.6 was intended to provide a per kilowatt hour cost that blends all of APS's grid scale PV facilities. The spreadsheet also has weighting factors built in where the analyst can put more weight on more recent projects or can assign more weight to a larger project that produces more energy.
>
> The levelized versus non-levelized function allows the analyst to see the variance that would result from year to year if a non-levelized annual cost was preferred. Some of the variance may be due to PPAs which contain an escalator over time. Utility owned PV facilities, on the other hand, are going to reflect a higher cost at the beginning of the life of the project because the revenue requirement is higher at the beginning and declines over time as the project is depreciated. In general if you were to use a levelized cost, it is likely to be lower than the yearly or non-levelized cost because the in-service dates of the various facilities or agreements are more recent, so the revenue requirements

[808] Staff Br. at 19, referring to Exh. Staff-4 and Tr. at 1314-1318.
[809] Staff Br. at 19-20.
[810] *Id.* at 20, referring to Tr. at 2086 (APS witness Bradley Albert).
[811] Tr. at 2088 (APS witness Bradley Albert).
[812] Staff Br. at 20, fn. 119.

are still higher than the average over the life of the facility.

Staff Br. at 20 (citations to Tr. 2088-2103 (APS witness Bradley Albert) omitted).

Staff supports the use of a spreadsheet such as that developed by APS for use in rate cases for this methodology.[813] The spreadsheet allows parties to apply different weights to different factors, to include only those projects a party believes is appropriate, and allows for any adjustment to the result that the Commission may deem appropriate.[814]

b. Results for APS

In response to Staff's Data Requests for information from 2008 forward, APS provided cost per kWh information for the utility-scale projects it owns, and for its current PPAs.[815] Staff states that APS's analysis of both owned facilities and PPAs included identification of the year in which the projects came on line, or the "vintage."[816] The vintage information indicates a decrease in costs per kWh from projects of earlier vintage to more recently completed projects.[817] The owned projects included in APS's analysis were Hyder, Hyder 2, Cotton Center, Paloma, Chino Valley, Foothills, Gila Bend, Luke AFB, Desert Star, and Red Rock.[818] APS also provided analysis for six current PPAs.

For PPAs, the weighted average cost is 11.3 cents/kW.[819] The weighted average cost of APS's company-owned and PPA resources considered together is 10.9 cents/kWh.[820] Staff states that the vintage data also suggest that as APS adds new solar facilities to its portfolio, whether through PPAs or utility-owned facilities, the weighted average price per kWh will decline.[821]

c. Results for TEP/UNSE

TEP/UNSE also performed an analysis of its solar generation resources, both utility-owned and PPAs, and calculated a weighted average of the costs of those resources.[822] Staff states that TEP/UNSE provided a similar set of analyses as APS.[823] The owned projects included in TEP/UNSE's

[813] Staff Reply Br. at 5.
[814] *Id.*
[815] Staff Br. at 21.
[816] *Id.*
[817] *Id.*
[818] *Id.*
[819] *Id.*
[820] *Id.*
[821] *Id.*
[822] *Id.*
[823] *Id.*

analysis included Fort Huachuca, Rio Rico, Prairie Fire, La Senita, UASTP1, UASTPII, Springerville 1.8, and White Mountain.[824]

Staff states that the analysis shows, based on a production weighted average of the entire spectrum of project vintages of company-owned projects, a cost of approximately 13.3 cents/kWh. [825] For PPAs, the weighted average cost is 10.6 cents/kW.[826] The weighted average cost of company-owned and PPA resources considered together is 11.1 cents/kWh.[827]

Staff believes that its Resource Comparison Proxy methodology is a good alternative to TEP/UNSE's PPA Proxy methodology, which proposes use of the most recent utility scale renewable energy purchased power agreement for either TEP or UNSE, and to APS's Grid-Scale Adjusted methodology, which also relies upon recent PPAs, RFPs, or PPAs entered into by other western based electric utilities.[828]

8. Comments on Staff's Proposed Resource Comparison Proxy Methodology

a. APS

APS states that Staff's weighted blending proposal could produce an objective and transparent per kWh price valuation for exported energy, because it is based on actual data that is verifiable and transparent, and that APS could support it.[829] APS believes that to be comprehensive, Staff's Resource Comparison Proxy methodology should include the following factors:

> 1) a graduated weighting system that places a greater emphasis on more recent announced or executed grid-scale solar prices;
>
> 2) a rolling blended average of no more than five years, where in each subsequent year, the oldest year of data in that period would roll out of the calculation;
>
> 3) refreshing the analysis each year to capture the most current available data and ensure that the price used in the calculation reflects current market conditions;
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> 4) utilizing data and pricing for photovoltaic solar panels, [that] excludes other types of solar technologies (e.g., concentrated solar or solar thermal

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[824] *Id.*
[825] *Id.*
[826] *Id.*
[827] *Id.*
[828] *Id.* at 22.
[829] APS Br. at 49.

projects);

5) in the event that the utility does not have any projects of recent vintage (for example – within the previous year), the methodology could consider utilizing pricing data from available industry sources for grid-scale solar PV projects with priority placed on projects within the state of Arizona to the extent available; and

6) adjusting to recognize the value differences between grid-scale and the export portion of rooftop solar. This adjustment to recognize valuation differences such as generation capacity value and energy losses is more fully discussed in the direct testimony of Mr. Albert.[830]

b. TEP/UNSE

TEP/UNSE disagree with the use of utility-owned solar facilities costs as a proxy for rooftop solar.[831] TEP/UNSE note that the vintage of the PPAs or utility facilities that would be used as a proxy is unknown, and that it is uncertain how the methodology would apply to utilities who have no PPA or utility-owned grid-scale solar facilities.[832]

TEP/UNSE believe that a recent grid-tied PPA is an appropriate proxy for the value of DG exports. However, they believe that Staff's proposal to use utility-owned solar facilities in addition to PPAs overreaches, because it would use a weighted average of all such resources, with no limitation on vintage.[833] They contend that this would overcompensate DG exports due to the steep decline in the cost of solar capacity.[834] They argue that using older PPAs would reflect outdated PPA costs, which would result in non-DG customers overpaying for excess DG energy, and would allow a rooftop solar customer installing a DG system now to benefit from out-of-date pricing for PPAs entered into years ago.[835] TEP/UNSE are opposed to pricing DG exports for new rooftop solar customers based on out-of-date PV pricing or older PPAs that were signed in order to meet a Commission REST requirement, and note that at the time its pre-2014 PPAs were signed, residential customers were still receiving upfront incentives to install rooftop solar PV systems.[836]

TEP/UNSE assert that updating the value over time to reflect evolving PPA pricing, as Staff

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[830] *Id.*, citing to Exh. S-5 (public responses to Staff's Third Set of Data Requests to APS).
[831] TEP/UNSE Reply Br. at 3.
[832] TEP/UNSE Br. at 13.
[833] TEP/UNSE Reply Br. at 3.
[834] *Id.*
[835] TEP/UNSE Br. at 13-14.
[836] TEP/UNSE Reply Br. at 3.

indicated could be done, would create economic uncertainty for DG customers, and grandfathering issues.[837] Therefore, TEP/UNSE believe that using a current PPA price that is locked in for a period of time to be a more sustainable approach, and state that UNSE has proposed to lock in, for a period of time, the PPA proxy price at the time of interconnection as the value for DG exports.[838]

TEP/UNSE expressed concerns in regard to Staff's proposal to use a weighted average of the per-kWh cost of utility owned grid-scale solar PV to set a proxy rate. They have the same concerns regarding the vintage of the facilities as they expressed for using older PPAs.[839] In addition, they point to operational differences, such as the fact that utilities control the output of systems they own to provide voltage stabilization or other system benefits, which results in lowering the actual kWh produced, thereby skewing the per kWh cost, even though the system benefits from the curtailments.[840]

TEP/UNSE disagree with Staff's position that reconsideration of the concepts of banking and netting DG exports should take place in a rate case or rulemaking.[841] They assert that the concept of value of DG necessarily requires no banking of DG exports, and that if parties believe that DG exports are worth either more or less than bundled retail rates, that the exports cannot be netted or banked.[842]

c. GCSECA

GCSECA believes that no single methodology will address each utility's unique circumstances, and agrees with Staff that the appropriate method for valuing DG should be utility-specific.[843] GCSECA points out that Staff acknowledged that different utility characteristics may warrant different approaches.[844] GCSECA believes that Staff's various adders, including the nodal approach to calculating a transmission or distribution adder should be rejected because they would require additional data gathering, analysis, and review that would impose economic and operational hardships on the Cooperatives.[845]

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[837] TEP/UNSE Br. at 14.
[838] *Id.* TEP/UNSE did not indicate the period of time.
[839] TEP/UNSE Br. at 14.
[840] *Id.*; TEP/UNSE Reply Br. at 3, referring to Tr. at 2226, 2247-2248 (TEP/UNSE witness Carmine Tilghman).
[841] TEP/UNSE Reply Br. at 2, referring to Staff Br. at 7-8.
[842] TEP/UNSE Reply Br. at 2.
[843] GCSECA Br. at 5.
[844] *Id.*, citing to Exh. S-3, Rebuttal Testimony of Staff witness Howard Solganick, at 18, Tr. at 1402-1403 (Staff witness Howard Solganick), and Tr. at 2352-2353 (Staff witness Thomas Broderick).
[845] GCSECA Br. at 5, fn. 5.

d. AIC

AIC asserts that Staff's Resource Comparison Proxy methodology does not comport with sound public policy, because it does not provide customers with the benefit of using more efficient marginal cost prices.[846] AIC argues that by blending and averaging historical prices of a utility's solar facilities, the methodology asks current customers to pay more for rooftop solar today because older technology was more expensive.[847] AIC points out that according to TEP/UNSE witness Mr. Tilghman, PPA prices have dropped from 14 cents/kWh ten years ago to as low as 4 cents/kWh in the past year.[848] AIC believes that paying today's rooftop solar customers a rate that includes a portion of the higher costs from older PPAs and utility-owned grid scale projects would be unjust and inequitable because it would deprive current non-DG customers of the benefit of innovation and cost-effectiveness.[849]

e. Vote Solar

Vote Solar contends that Staff's Resource Comparison Proxy methodology is flawed for the same reasons the utilities' methodologies on which it is based are flawed.[850] However, Vote Solar states that despite this "fatal flaw," it is a marked improvement on the utilities' methodologies, because it would reduce the variability of the export rate that would result from using a single utility-scale solar PPA to set the export rate.[851] Vote Solar believes Staff's Resource Comparison Proxy methodology would also reduce the potential for a utility to strategically select low-priced PPAs to minimize the export rate.[852]

Vote Solar contends that Staff's attempts to improve the proposed utility-scale methodologies are unsuccessful and cannot address the fundamental problems with using utility-scale pricing as a proxy for the value of DG solar.[853] Vote Solar believes that the fact that the value of DG solar could vary widely depending on which utility-scale PPAs are used and the parameters employed demonstrates the arbitrary nature of the methodology, and shows that utility-scale solar PPAs are not

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[846] AIC Br. at 12, citing to Tr. at 871 (TEP/UNSE witness Edwin Overcast).
[847] *Id.*
[848] AIC Br. at 12, citing to Tr. at 623 (TEP/UNSE witness Carmine Tilghman).
[849] *Id.*
[850] Vote Solar Reply Br. at 16.
[851] *Id.*
[852] *Id.* at 16-17.
[853] Vote Solar Br. at 32.

a reasonable proxy.[854] Vote Solar asserts that the differing results of TEP/UNSE's utility-scale benchmarking methodology (5.84 cents/kWh) and Staff's Resource Comparison Proxy methodology (a range from 10.6 cents/kWh to 13.3 cents/kWh), demonstrate that using a utility-scale benchmarking methodology is an arbitrary way to "value" rooftop solar.[855]

Vote Solar contends that the actual value of rooftop solar is relatively stable and objective, and does not fluctuate.[856] Vote Solar contends that the net value of a rooftop system's exports do not change based on the price a utility paid for its most recent PPA, or some subset of historical PPAs.[857] However, Vote Solar states that if the Commission were to endorse a utility-scale proxy approach despite the flaws, Staff's Resource Comparison Proxy methodology is superior to the utilities' methodologies.[858]

f. TASC

TASC asserts that Staff's Resource Comparison Proxy methodology must be rejected for the following reasons:

1) it uses utility-scale solar as a proxy for rooftop solar exports;

2) if the value of rooftop solar increases in the future, for example due to the introduction of rooftop solar with battery storage, the methodology could not accommodate the increased value;

3) it would lead to lengthy disputes over what the weighted average should be, including:

   a) which utilities to include in the weighted average;

   b) what timeframe the analysis should look back to;

   c) whether or not to include certain PPA escalators in the average;

   d) whether the analysis should be done with a levelized or non-levelized function;

   e) whether to include or exclude certain production tax credits;

   f) whether to use only PPAs or utility-owned assets in the proxy, since they produce different average costs; and

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[854] *Id.*
[855] Vote Solar Reply Br. at 17.
[856] *Id.*
[857] Vote Solar Br. at 33.
[858] *Id.*

g) what ratio of the proxies to be used in the weighted average (i.e., 40 percent PPA and 60 percent utility-scale vs. 50/50, etc.); and

4) due to the weighting process, the methodology could make the export compensation rate subject to abrupt drops, and such regulatory uncertainty would make it very difficult for potential rooftop solar customers to make an informed investment decision.[859]

g. RUCO

RUCO believes that Staff's proposal offers a viable alternative to using either TEP/UNSE's PPA Proxy methodology or APS's Grid-Scale Adjusted methodology alone.[860] RUCO believes that its step-down proposal could be used as an implementation plan in addition to either of Staff's proposed methodologies.[861]

9. <u>Staff's Responses to Comments on its Proposed Resource Comparison Proxy Methodology</u>

a. APS

In response to APS's first suggestion for inclusion of a weighting system that places greater emphasis on more recent grid-scale prices, Staff states that the spreadsheet would allow this.[862]

Staff states that APS's second suggestion, that older data be rolled out of the equation every five years, would be unworkable.[863] Staff states that its proposal is for updates to be made in the utility's subsequent rate cases, and that rolling older data out every five years would provide too much uncertainty and variability in the value of solar proxy and the export rate from year to year.[864]

Staff disagrees with APS's third suggestion, to require annual updates of the calculation between rate cases, would also provide too much uncertainty and variability in the value of solar proxy and the export rate from year to year.[865]

In response to APS's fourth suggestion, to use data and pricing for solar PV panels only, Staff states that its methodology considers the universe of solar utility-scale PPA or owned facilities initially, with a subsequent evaluation made as to whether a particular project should be included or not, and

[859] TASC Reply Br. at 23.
[860] RUCO Br. at 13-14.
[861] *Id.* at 14.
[862] Staff Reply Br. at 5.
[863] *Id.*
[864] *Id.*
[865] *Id.* at 5-6.

that Staff continues to support that approach.[866]

Staff agrees with APS's fifth point, that it may be appropriate to consider pricing data from other industry sources, to the extent that the proxy is appropriate, if in subsequent rate cases, the utility has no projects or PPAs of its own to rely on.[867]

Staff is not opposed to APS's sixth suggestion, that adjustments be used which would recognize the value differences between rooftop solar and grid-scale solar, but states that if this methodology is to be used long-term, adjustments to reflect various geographic adders attributable to rooftop solar, if appropriate, should also be reflected.[868]

b. TEP/UNSE and AIC

Staff responds to arguments by TEP/UNSE and AIC that using older PPAs and grid-scale facilities would result in a higher export rate, and result in overpayment by non-DG customers. Staff states that when new projects are added, earlier projects drop out of the equation, and this will likely reduce the export rate.[869] In addition, Staff states, the methodology allows for heavier weighting to be applied to projects and PPAs of more recent vintage.[870] Staff states that use of a single PPA is risky because while it might result in a lower export rate, it may not be representative of a utility's avoided cost.[871] Staff points out that there are many factors that make one PPA different from another, and that the most recent PPA may not be representative of a utility's avoided cost.[872]

In response to TEP/UNSE's argument that export rate changes that would result with the addition of new PPAs would create uncertainty and grandfathering issues, Staff states that it sees no difference between Staff's proposal and TEP/UNSE's in this regard.[873] Under both proposals, rates would be locked in for a period of time, and Staff's proposal would keep rates in place until the utility's next rate case.[874] Staff disputes that this would create uncertainty.[875]

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[866] *Id.* at 6.
[867] *Id.*
[868] *Id.*
[869] *Id.*
[870] *Id.*
[871] *Id.*
[872] *Id.*
[873] Staff Reply Br. at 7.
[874] *Id.*
[875] *Id.*

c. Vote Solar and TASC

Staff responds to arguments by Vote Solar and TASC that the value established would be "arbitrary" because it could vary dramatically depending on which utility-scale PPA is used and the parameters employed. Staff disagrees, asserting that the Resource Comparison Proxy methodology is based upon the electric utility's actual costs for the last five years, (or whatever time period the Commission selects), and includes the actual PPA prices and revenue requirements of utility-owned grid-scale facilities.[876] Staff states that the variables incorporated in the spreadsheet allow for differences in weighting and selection criteria and other variables, to ensure that a representative cost per kWh is produced.[877] Staff asserts that in the end, the Resource Comparison Proxy methodology produces an accurate and reliable indication of the utility's costs associated with its solar PPAs and its owned solar generating facilities.[878]

Staff also responds to arguments by Vote Solar and TASC that grid-scale facilities are not interchangeable with rooftop solar, and therefore they cannot be used as proxies for one another. Staff believes that this criticism, which would apply to all of the grid-scale proposals offered, is misplaced, because grid-scale solar PPAs or utility-owned solar facilities are the cost that would typically be avoided, since they are the most likely to be used in place of solar DG.[879] Staff points to testimony by TASC witness Mr. Beach, who stated that an apples-to-apples comparison was possible if you subtract the long-run marginal costs associated with transmission, since rooftop solar is located on-site.[880]

IV. <u>POSITIONS OF PARTIES NOT PROPOSING A SPECIFIC METHODOLOGY</u>

A. GCSECA

1. <u>GCSECA's Position</u>

GCSECA, on behalf of its electric distribution cooperative members[881] (collectively, "Cooperatives") does not propose a particular methodology for evaluating the value of DG or for

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[876] *Id.*
[877] *Id.*
[878] *Id.*
[879] *Id.*
[880] *Id.*, citing to Tr. at 1969 (TASC witness R. Thomas Beach).
[881] GCSECA's electric distribution cooperative members include Dixie Escalante Rural Electric Association, Inc.; Duncan Valley Electric Cooperative, Inc.; Garkane Energy Cooperative, Inc.; Graham County Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc.

conducting a general cost/benefit analysis of DG.[882] Instead, GCSECA urges the Commission to adopt policies and guidelines that are consistent with standard ratemaking principles and flexible enough to account for each utility's unique characteristics, including structure and purpose as well as diversity in customers, geography, power sources, load, and growth potential.[883] GCSECA believes that no single methodology will address each utility's unique circumstances, and that this is especially true for the Cooperatives, as compared to larger, investor-owned, integrated utilities.[884]

GCSECA believes that the ratemaking standard of using actual, known and measurable data should be applied to a determination of the costs and benefits of DG.[885] GCSECA argues that alleged social or indirect benefits are difficult, if not impossible, to quantify in a ratemaking sense, and for that reason should not be included in the calculation of the rate for excess DG generation.[886] Because forecasts are based on inherently unknowable assumptions, GCSECA is opposed to their use to quantify the costs and benefits of DG. In addition, GCSECA states that incorporating long-term benefits into rates would create an inequitable mismatch by paying today for a benefit that will not be received until the distant future, if at all.[887]

GCSECA contends that the same rules should apply to the ratemaking formula for DG generation as applies to non-DG generation. GCSECA argues that because social or indirect benefits such as environmental benefits, job creation and avoided water consumption are not included in the ratesetting analysis for non-DG generation, neither should they be included in the ratesetting analysis for DG generation.[888]

GCSECA urges the Commission to adopt a simple methodology for calculating the rate that the Cooperatives pay for excess DG. GCSECA believes that the methodology should be based on the Cooperatives' true avoided costs.[889] GCSECA states that the only costs avoided by DG power are fuel and energy, because the Cooperatives do not provide their own generation, but receive their power

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[882] GCSECA Br. at 2.
[883] *Id.* at 1.
[884] *Id.* at 4-5.
[885] *Id.* at 2.
[886] *Id.* at 1, 2.
[887] *Id.* at 2.
[888] *Id.*
[889] GCSECA Br. at 3.

pursuant to wholesale contracts that contain fixed charges for generation capacity.[890] GCSECA states that as a result, any reduction in the Cooperatives' capacity requirements does not reduce their generation capacity costs.[891] GCSECA contends that DG does not reduce its distribution costs either, and instead, may result in the need for more distribution expenditures.[892]

GCSECA contends that while proliferation of DG in the future could possibly result in cost savings or other benefits, those benefits are not currently known, measureable or quantifiable, and should therefore not be included in the calculation of the rate the Cooperatives pay for excess generation.[893]

GCSECA takes issue with TASC's and Vote Solar's claims that no cost shift due to DG exists,[894] and its arguments in that regard appear in the sections of this Decision further below that outline TASC's and Vote Solar's proposals, and the parties' responses thereto.

GCSECA believes that just as determining the appropriate valuation methodology is utility-specific, so is the issue of rate design and finding the best solution to the cost shift.[895] GCSECA states that transition to a three-part rate with a demand charge requires capital investment in metering capability and billing system upgrades, in addition to customer outreach and education, and the transition for many of its member Cooperatives would be expensive and time-consuming.[896] GCSECA urges the Commission to adopt a flexible approach for the Cooperatives to addressing the cost shift - one that takes into account the Cooperatives' unique situations as small rural non-profit cooperatives that serve some of the most economically challenged areas of the state.[897] GCSECA submits that there are other viable options to Staff's proposal for a transition to a three-part rate with a demand charge, such as increasing fixed costs, developing separate rate classes for DG customers, and revising net metering tariffs for new DG customers.

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890 *Id.*, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 10, and Tr. at 1039-1040 (GCSECA witness David Hedrick).

891 GCSECA Br. at 3, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 10, and Tr. 1403-1404 (Staff witness Howard Solganick).

892 GCSECA Br. at 3, citing to Exh. GCSECA-1, Direct Testimony of GCSECA witness David Hedrick, at 11.

893 GCSECA Br. at 3.

894 *Id.* at 7.

895 *Id.*

896 *Id.*

897 *Id.*

2. Responses to GCSECA's Position

a. TASC

TASC disagrees with GCSECA's position that any methodology adopted applicable to the Cooperatives should only include avoided fuel and energy costs.[898] TASC opposes the adoption in this docket of a separate methodologies for the Cooperatives than for other utilities, and asserts that it would be appropriate to evaluate the costs and benefits of rooftop solar in Cooperative rate cases with the aid of the record in this docket.[899]

b. Staff

Staff agrees with GCSECA that the Cooperatives are different in important respects from the other utilities participating in this proceeding. Staff believes that given the differences, and that many of the Cooperatives serve rural areas and have higher costs in general, any methodology the Commission adopts should allow for the unique circumstances of the Cooperatives to be taken into account.[900]

B. IBEW Locals

1. IBEW Locals' Position

The IBEW Locals state that they intervened in this matter to insure the safety and well-being of its members, and the equitable treatment of all public utility patrons.[901] IBEW Locals assert that assessment of the value and cost of DG affects its members because the bidirectional flow of electricity required for DG interconnections creates new safety hazards for its members working on the lines, and the imbalance in cost sharing for DG use of the grid between DG and non-DG customers jeopardizes job stability for utility workers and reduces utility's ability to provide a safe and efficient workplace.[902] In addition to backfeed issues for electrical workers, IBEW Locals state that rooftop solar can create multiple new hazards for firefighting personnel.[903] The IBEW Locals contend that preventing such hazards is not free, and that any valuation of solar DG should include such costs.[904] The IBEW Locals

[898] TASC Reply Br. at 25.
[899] *Id.*
[900] Staff Reply Br. at 14.
[901] IBEW Locals Br. at 2.
[902] *Id.*
[903] IBEW Locals Br. at 4, citing to Tr. at 1901 (TASC witness R. Thomas Beach).
[904] IBEW Locals Br. at 4.

assert that in assessing the value and cost of DG in this docket, the Commission should place the interests of the IBEW Locals' members on par with the interests of utility patrons, pursuant to Article 15, § 3 of the Arizona Constitution.[905]

The IBEW Locals assert that solar DG does not reduce the distribution costs of providing utility service, because the energy produced is intermittent, and the size of the facilities required to serve rooftop solar customers is exactly the same as for non-DG customers.[906] The IBEW Locals further argue that the cost shift from solar DG customers to non-DG customers has become a cost shift from affluent families to low-income families, because solar DG is not available to those living in apartments or multi-unit low-income housing, or those living in single-family homes but not possessing a credit score and the means necessary to lease a rooftop solar unit.[907] The IBEW Locals assert that there are also negative impacts on rural electric utility customers who are incurring higher distribution and fixed costs due to DG interconnections on their utilities' systems.[908] The IBEW Locals argue that the Commission lacks the authority to subsidize private, unregulated companies at the expense of and to the detriment of ratepayers; that such subsidization is inherently unjust; and that incorporating societal and non-economic benefits, which are unquantifiable and unknown, into rates will exacerbate the problem.[909]

C. AIC

1. Overview

AIC advocates the elimination of all subsidies, including those embedded in existing rate design and those caused by the retail export credit paid under current net metering policies.[910] AIC asserts that there is no public policy rationale to existing subsidies to rooftop solar customers, and that any value of rooftop solar determined in this proceeding should result in a level playing field for all technologies, and recognize the basic cost of service principle that customers should pay for the services they use.[911] AIC acknowledges that it is a policy decision for the Commission whether to

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[905] *Id.* at 2.
[906] *Id.* at 4-5, citing to Exh. IBEW-2, Rebuttal Testimony of IBEW Locals witness Scott Northrup, at 6.
[907] IBEW Local Br. at 6.
[908] *Id.*
[909] IBEW Locals Reply Br. at 2-3.
[910] AIC Br. at 3-11.
[911] *Id.* at 3.

continue to subsidize the rooftop solar industry, but argues that if subsidies are to be continued, they should be made open and transparent so that customers know what they are paying.[912]

AIC states that the only method for valuing rooftop solar exports that is likely to result in a figure that exceeds the utility rate, thereby retaining the current profitability margin for the rooftop solar industry, is one based on a long-term outlook that includes subjective and speculative inputs.[913] AIC asserts that any such method is guaranteed to produce a flawed result that would justify paying rooftop solar customers (and through them, the rooftop solar industry), a rate that exceeds the savings to all other customers in the long run.[914]

AIC believes that Arizona's advanced energy future depends on the rooftop solar industry itself evolving, along with the evolution of rate design, pricing signals, and technologies.[915] AIC argues that in the past, the rooftop solar industry has innovated its business model to survive the termination of up-front incentives, which were also intended to spur deployment. AIC believes that eliminating the net metering subsidy will create real competition in the solar distribution generation market, thus spurring development of new business models and technologies, all to the benefit of all utility customers.[916]

AIC urges the Commission to establish a regulatory regime that applies broadly not to just rooftop solar, but to all emerging technologies, and will support utilities' attempts to incorporate those technologies into the grid with fair regard to all utility customers.[917] AIC asserts that such a regime should acknowledge that customers using rooftop solar and other behind-the-meter technologies are sufficiently different from other customers to justify their inclusion in a separate customer class for cost of service purposes; that rate design should reflect how customers use the grid; and that customers who export energy from all types of distributed generation should be compensated for savings (demonstrated through tangible evidence) that they bring to other utility customers.[918]

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[912] AIC Reply Br. at 4.
[913] *Id.*
[914] *Id.*
[915] AIC Br. at 2-3.
[916] AIC Reply Br. at 4, citing to Tr. at 1010 (APS witness Ashley Brown).
[917] AIC Reply Br. at 12.
[918] *Id.*

2. Avoided Cost for Exports

AIC believes that whatever method the Commission decides to use to value solar, it should apply only to rooftop solar exports, and not self-consumption, as agreed by all parties participating in this proceeding, with the exception of RUCO.[919] AIC advocates setting the rooftop solar export rate based on transparent, reliable, and cost-based data.[920] AIC believes that the export rate should be based on the utility's short-term avoided costs (primarily fuel costs, O&M expenses, and line losses), and should be calculated on a time-of-use or specific hourly basis to the extent practical, as opposed to a monthly basis.[921] AIC contends that this type of compensation is transparent, fair and sustainable for all stakeholders.[922]

3. Subsidies in Rate Design and Retail Export Credit

AIC asserts that the evidence in this proceeding demonstrates that under today's two-part rates, coupled with existing net metering policies, there is a shifting of costs that is giving rooftop solar customers a "free ride on the utility system."[923] AIC asserts that APS's and TEP's cost studies demonstrate that the cost to serve a rooftop solar customer is higher than the cost to serve the average residential customer, and that rooftop solar customers pay significantly less than that cost.[924] AIC contends that the evidence in this proceeding shows that rooftop solar customers in APS's service territory on a two-part rate pay 36 percent of the cost to serve them, and those on APS's three-part rate schedule ECT-2 pay 72 percent of the cost to serve them.[925] AIC asserts that the amount of costs currently avoided per APS rooftop solar customer on a two-part rate is $804 annually, with the total annual amount over $580 million.[926]

AIC asserts that the current net metering policy of month to month banking of credits for rooftop solar exports, which allows the ability to carry over unused credits, exacerbates the effect of rate design

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[919] AIC Reply Br. at 2.
[920] *Id.* at 5.
[921] AIC Br. at 10, citing to Tr. at 509 (AIC witness Michael O'Sheasy), and Tr. at 1854 (TASC witness R. Thomas Beach).
[922] AIC Br. at 11.
[923] *Id.* at 3, citing to Tr. at 845 (TEP/UNSE witness Edwin Overcast).
[924] AIC Br. at 4, citing generally to Exh. APS-1, Direct Testimony of APS witness Leland Snook, Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, and Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast.
[925] AIC Br. at 4, citing to Tr. at 103 (APS witness Leland Snook).
[926] AIC Br. at 4, citing to Tr. at 116 (APS witness Leland Snook). AIC refers to this amount as a cost shift. These figures do not reflect the portion of these costs that APS is currently recovering through its LFCR.

inequities for rooftop solar customers.[927] AIC contends that the policy allowing such "banking" has promoted overproduction of rooftop solar energy in non-summer months in order to "bank" enough retail credit "to get through the summer months without having to pay for the energy generated and delivered by the utility that was consumed by the customer."[928] AIC states that this banking leads to rooftop solar customers not paying their fair share of energy costs, because energy generated during non-summer, low energy-cost months is not as valuable to the utility system as the energy delivered in summer, high energy-cost months.[929]

4. Rooftop Solar Customers as Partial Requirements Customers

AIC argues that the cost studies presented by APS and TEP/UNSE in this case demonstrate that rooftop solar customers and the average residential customer have sufficiently different usage patterns to justify treatment of rooftop solar customers as a separate rate class.[930] AIC argues that as a matter of law, it is not discriminatory to treat customers who are not similarly situation dissimilarly, but rather that customer classification is a routine part of allocating costs to cost-causers during the ratemaking process.[931] AIC asserts that a separate classification for rooftop solar customers is called for, because no other type of customer exports energy to the grid.[932] In addition, AIC points out that rooftop solar customers' differing usage patterns are due not to an overall reduction in energy usage, such as occurs with customers who adopt energy efficiency measures, but are due instead to major differences in the load pattern of rooftop solar customers.[933] AIC asserts that while energy efficiency customers typically reduce their overall energy consumption by 5-10 percent, rooftop solar customers have a 70 percent reduction in energy usage, but only during certain periods of the day, and they may have sudden and dramatic increases to their demand requirements.[934]

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[927] AIC Br. at 5; AIC Reply Br. at 3.
[928] AIC Br. at 5, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 5.
[929] AIC Br. at 5, citing to Exh. TEP-1, Direct Testimony of TEP/UNSE witness Carmine Tilghman, at 5, and Exh. TEP-3, Direct Testimony of TEP/UNSE witness Edwin Overcast, at 13.
[930] AIC Br. at 5-7; AIC Reply Br. at 2.
[931] AIC Reply Br. at 11.
[932] *Id.*
[933] AIC Br. at 7.
[934] *Id.*, referring to Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 25.

5. Demand Rates

AIC contends that the best and most efficient way to eliminate cross-subsidization of rooftop solar customers by other customers is to implement demand rates, with an energy charge set at the utility's avoided cost.[935] AIC believes that proper cost recovery from all customers can be accomplished through implementation of a three-part, cost-based rate structure comprised of: (1) a customer charge, which includes charges for billing, metering, and maintaining a minimum sized system; (2) a demand charge, which includes charges for the impact to the utility system due to fluctuations in a customer's individual demand; and (3) an energy charge, which is the cost of the energy delivered (or may include additional fixed costs if the demand charge was set too low).[936]

AIC believes that a three-part demand rate automatically sends proper price signals, and aligns better with cost causation than current two-part rates (which lack a demand charge).[937] AIC advocates the use of accurate price signals based on actual cost and cost causation, because accurate price signals minimize subsidization and require customers to pay their "fair share."[938] Better price signals, according to AIC, would allow all customers to manage demand as well as consumption, and would incent the rooftop solar market to invest in new technologies to benefit both the electric system and customers.[939] AIC contends that rates not based on costs raise questions of fundamental fairness and long run sustainability, and are more likely to result in cost shifting.[940] AIC argues that if the Commission wishes to continue to subsidize rooftop solar, it should do so in a clear and transparent manner, and not continue to cloak subsidies in rate design.[941]

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[935] AIC Br. at 10.
[936] AIC Br. at 8, citing to Tr. at 1415-1416 (Staff witness Howard Solganick).
[937] AIC Br. at 8.
[938] *Id.* at 9, citing to Exh. AIC-1, Direct Testimony of AIC witness Michael O'Sheasy, at 6.
[939] AIC Br. at 8, citing to Exh. APS-1, Direct Testimony of APS witness Leland Snook, at 24, and Tr. at 1009 (APS witness Ashley Brown).
[940] AIC Br. at 10, citing to Tr. at 525 (AIC witness Michael O'Sheasy), and Tr. at 1341 (Staff witness Howard Solganick).
[941] AIC Br. at 10.

V. CONCLUSIONS

A. Overview

The parties all agree that rooftop solar exports should be valued based on an avoided cost methodology. Beyond that, the parties' proposals and positions on an appropriate methodology for the valuation of DG are varied. APS and TEP/UNSE each presented COSS models that they proposed be used to determine the costs to serve rooftop solar customers. Those COSS models were a subject of debate as well, regarding not only substantive issues, but also procedural issues.

APS advocates adoption of one of two value of DG proposals: APS's Proposed Short-Term Avoided Cost methodology, which would base compensation for rooftop solar exports on the price for short-term solar energy at the Palo Verde Hub; and APS's Proposed Grid-Scale Adjusted methodology, which would base compensation for rooftop solar exports on a recent PPA for utility-scale solar, adjusted to account for operational differences between utility-scale solar and rooftop solar.

TEP/UNSE advocates adoption of one of two value of DG proposals: TEP/UNSE's Proposed PPA Proxy, which would base compensation for rooftop solar exports on the price of its most recent PPA for grid-scale solar, and TEP/UNSE's Proposed CCOS methodology, which is a comparative costing analysis, based on two separate cost of service studies, one of which assumes no rooftop solar ("Utah model").

Vote Solar, TASC, RUCO, and Staff all propose adoption of avoided cost methodologies based on multi-factor valuation methods to determine a value of DG for consideration in determining how rooftop solar customers are compensated for their exports. Vote Solar and TASC propose that the methodology consider all of a broad range of benefit/cost categories. RUCO proposes that the methodology not examine difficult to determine and de minimus benefit/cost categories, or controversial economic and societal cost or benefit categories. Staff proposes that the methodology not examine societal benefits; that it examine, but probably not include environmental benefits; and that it include various adders to incentivize desirable system attributes DG can offer.

Vote Solar, TASC and RUCO all advocate for an analysis that includes a long-term, 20 to 30 year forecasting view. Staff prefers a short-term, 5 year forecasting view, but states that its avoided cost proposal could accommodate a long-term analysis. In the event a long-term forecasting view is adopted, Staff proposes that only easily quantifiable long-term costs and benefits should be included in the analysis, in order to minimize the potential for overpayment by non-DG customers.

In addition to Staff's Avoided Cost methodology, Staff proposes adoption of Staff's Resource Comparison Proxy ("RCP") methodology. Staff's Resource Comparison Proxy methodology would determine a weighted average cost of each individual utility's PPAs and utility-owned grid-scale facilities. Staff advocates that both its proposed methodologies be adopted for use in rate cases to determine a value of DG for consideration in determining how rooftop solar customers are compensated for their exports.

RUCO advocates that an initial rate be set for all rooftop solar production, both self-consumed and exported, using a long-term, 20 to 30 year cost/benefit analysis that incorporates only easily quantifiable long-term costs and benefits, to which a declining, adjustable step-down mechanism be applied for the compensation of rooftop solar exports. RUCO is the sole party advocating that rooftop solar customers also be allowed to choose to pay for their self-consumed production at the same level as their export compensation.

GCSECA and AIC participated in the hearing, presented testimony through witnesses, and filed briefs. They proposed no studies of their own, but support adoption of a market based or cost based methodology. GCSECA advocates that the Cooperatives, due to their unique situations, be afforded flexibility in valuation and rate design solutions in order to avoid economic and operational hardships.

B. Recommendations of the Parties

The specific recommendations of the parties as provided in their briefs are as follows:

1. APS

APS requests that the Commission make the following factual findings and conclusions, based on the evidence in this proceeding:

a. Rooftop solar customers are partial requirements customers and should be placed in their own separate class of customers;

b. APS's proposed cost of service methodology – through which i) costs are allocated using rooftop solar customers' entire load; and ii) rooftop solar customers are fully credited for the verifiable energy and capacity benefits they supply to the grid – is appropriate and reasonable;

c. The amount paid for energy exported to the grid from rooftop solar should be based on market or cost-based data;

d. Either APS's Short-term Avoided Cost or Grid-Scale Adjusted value of solar methodologies should be used to determine the amount paid for energy exported to the grid from rooftop solar; and

e. Rates should be based on a COSS; long-term forecasts should not be used to set rates or establish the amount paid for energy exported to the grid from rooftop solar.[942]

2. TEP/UNSE

TEP/UNSE request:

a. that the Commission adopt one of its proposed methodologies to value rooftop solar, and believe that for efficiency's sake, its PPA Proxy methodology is the most feasible approach and will be the least controversial to apply;

b. that the PPA proxy reflect recent PPAs that accurately reflect the current cost of PV systems, not of older, costlier systems;

c. that it be made clear that any valuation methodology does not include banking or netting of DG energy at retail rates;

d. that to the extent the Commission includes societal and forward-looking benefits, that the benefits be separately identified from the utility's cost of service, be paid outside of avoided cost payments, and be recovered through a separate charge on customers' bills; and

e. that the Commission commence a rulemaking to review and amend the current Net Metering Rules to track the outcome of this docket.[943]

3. Vote Solar

Vote Solar makes the following recommendations:

a. Direct the utilities to conduct a value of solar analysis using Vote Solar's proposed long-term benefit and cost methodology.[944]

b. Reject the cost of service evidence provided by APS and TEP/UNSE in this proceeding. Vote Solar requests that the Commission find them irrelevant to the value of solar analysis, find that they suffer from significant methodological flaws, and find that they suffer from transparency issues.[945]

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[942] APS Br. at 2.
[943] TEP/UNSE Br. at 15; TEP/UNSE Reply Br. at 2, 5.
[944] Vote Solar Reply Br. at 41; Vote Solar Reply Br. at 26.
[945] *Id.*

4. TASC

TASC recommends that the Commission take the following actions:

a. Require use of a framework that incorporates a methodology premised on the long-term avoided costs of DG;

b. Place no weight on the cost of service studies provided in this docket;

c. Require use of a methodology that analyzes and accounts for the non-economic and societal benefits the Commission determines are created via the adoption of DG;

d. Reject proposals to set compensation rates premised on a proxy rate set by utility-scale solar rates;

e. Keep current Net Metering Rules in place;

f. Reject the creation of a new class for residential DG customers;

g. Regardless of any action taken in this docket, recognize the right of all DG customers that have submitted interconnection applications for DG systems prior to any final Order issued in any rate case where changes to net metering or rate design are considered be fully grandfathered and continue to utilize currently-implemented rate design and net metering, and be subject to currently-existing rules and regulations impacting DG; and

h. Issue an Order acknowledging that any action taken herein is advisory or informational only and the specific elements of any methodology utilized in future rate cases will be subject to review in each individual rate case and that the ultimate applicability of any value determined in a rate case can be acknowledged in rates in various ways to be determined separately in each utility rate case.[946]

5. RUCO

RUCO recommends that the Commission:

a. Adopt a 20 year long-term, but conservative (due to future uncertainties), avoided cost methodology which:

   1) Does not include hard to determine and de minimus cost/benefit categories, and

   2) Does not include controversial economic and societal cost/benefit categories;

b. Allow whichever methodology ultimately adopted to be applied to both self-consumed rooftop solar and rooftop solar exports, as the Commission in individual rate cases sees

[946] TASC Br. at 27-28; TASC Reply Br. at 25-26.

fit; and

c. Regardless of the methodology adopted, allow room for a declining step down mechanism that can be easily adjusted based on locational value, technology advances, REST compliance, and solar cost trends.[947]

6. <u>Staff</u>

Staff recommends that the Commission:

d. Adopt both of Staff's proposed methodologies for use in future electric utility rate cases to inform the Commission's decision-making in those cases on related policy and ratemaking issues,[948] because adoption of both its methodologies for consideration in rate cases would give the Commission maximum flexibility to address the issues in a fair and balanced manner.[949]

e. Recognize the concept of gradualism when adopting methodologies.[950] Staff asserts that it is critical that the Commission's move away from the current framework be accomplished in a gradual manner.[951] Staff states that RUCO described the concept well, saying the methodology should not be a "blunt instrument designed to cut off the subsidy all at once . . . but a common sense, gradual, proposal which is sensitive to the solar business model while at the same time addressing the changing DG market."[952]

f. Allow for the unique circumstances of the Cooperatives to be taken into account when adopting methodologies.[953]

g. Provide specificity with respect to the methodology adopted, including the list of inputs, and whether they are to be calculated on a short-term, long-term, or something in between a short- and long-term basis; and identifying any appropriate adders or adjustments to the methodology.[954]

h. Adopt the following guidelines for the adopted methodology, in order to facilitate timely processing within a rate case. Staff requests that the methodology be:

1) Transparent: all inputs, assumptions and calculations should be clearly described and explained;

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[947] RUCO Reply Br. at 1-2.
[948] Staff Br. at 33; Staff Reply Br. at 1-2.
[949] Staff Reply Br. at 15.
[950] *Id.*
[951] *Id.*
[952] *Id.*, citing to RUCO Br. at 38.
[953] Staff Reply Br. at 14.
[954] *Id.* at 16.

2) Accessible: i.e., the cost-benefit calculation should be made available to the public in the form of an electronic spreadsheet that is published on the Commission's website; and

3) Flexible: to allow for the ability to change inputs and assumptions used in the calculation which are likely to change over time.[955]

i. Require utilities to provide any underlying data of the utilities that the methodology relies upon to be made available immediately for pending rate cases, or within 30 days of the filing of a rate case.

j. Require the adopted methodology/methodologies adopted by the Commission to have spreadsheets with links between inputs and outputs which are available to all parties. Staff recommends that in the event this will take time to accomplish, the party whose methodology was adopted should be required to perform the analysis within the required time period, and make all assumptions and inputs of its analysis available to others.[956]

k. Hold an evidentiary hearing, after allowing a specified period of time for parties to develop their positions based upon use of the methodologies specified by the Commission. Staff believes that if the methodologies are made available as Staff recommends, and the utility has provided the necessary inputs, the parties should be able to develop their positions within 30-45 days. Staff states that if the evidentiary hearing for a rate case has not been held yet, the value of DG issue could be incorporated into that hearing. Staff does not recommend at this time that the Commission require, as recommended by Vote Solar, the utilities to retain an independent third-party to conduct the analysis, but if the Commission decides to enlist the services of a third party, Staff recommends that the third party be required to perform its work within the timeframes Staff recommends for the utilities.

l. Specify any follow-up proceedings that may be necessary, and the timing of any of those follow-up proceedings.

m. Reject requests that the issue of whether rooftop solar customers should be treated as a separate class for rate design purposes be determined in this proceeding.

7. GCSECA

GCSECA asserts that the following findings are supported by the record, are just and reasonable, and in the public interest:

a. The appropriate method for valuing DG and determining the rate to be paid for excess DG generation is a utility-specific question;

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[955] *Id.*, referring to Exh. RUCO-2, Direct Testimony of RUCO witness Lon Huber, at 8.
[956] Staff Reply Br. at 16.

b. Rates should be set based on actual, known, measurable, and quantifiable data, not long-term forecasts or speculative benefits;

c. The appropriate rate for the Cooperatives to pay for excess DG generation is their true avoided costs, which are limited to their avoided wholesale energy and fuel costs; and

d. The Cooperatives should be afforded flexibility to develop rate design solutions to the cost shift caused by DG and should not be required to comply with any one-size-fits-all requirements that would impose economic and operational hardships.[957]

8. IBEW

The IBEW Locals request:

a. that the Commission "adopt a methodology that does not continue the subsidization of rooftop solar companies and only attributes value and cost to tangible, measureable benefits,"[958] and clearly separates the utilities' cost of service from societal or forward-looking benefits.[959]

b. that the DG-related costs of distribution, line losses, and protecting against increased safety hazards be considered, and that equity, safety, and the well-being of the IBEW Locals' membership be taken into account.[960]

9. AIC

AIC requests that the Commission conclude that:

a. subsidies should be eliminated from rate design and net metering;

b. rooftop solar customers are more expensive to serve than the average residential customer;

c. the characteristics of rooftop solar customers are sufficiently distinct to make them a distinct rate class for cost of service purposes;

d. subsidies and the current cost shift can be mitigated by changes to residential rate design (such as a three-part demand rate);

e. the method for valuing exported rooftop solar should be cost-based; and

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957 GCSECA Br. at 1.
958 IBEW Locals Reply Br. at 4.
959 IBEW Locals Br. at 7.
960 *Id.*

f. a utility's short-term avoided cost, calculated on an hourly or time of use basis, should be used to set the rate for rooftop solar exports in the utilities' next rate cases.[961]

C. Establishing a Value of DG Methodology in This Proceeding

1. TASC's Request

TASC contends that establishing a binding value of solar methodology would go beyond the scope of this proceeding as set forth in the public notice of the hearing.[962] TASC asserts that the Commission should instead "indicate that it would prefer that the long-term avoided cost methodology be further vetted in each utility rate case as it will result in an accurate assessment of the actual value of DG and further promote optimal DG policy."[963]

Specifically, TASC requests, as set forth above, that the Commission "[I]ssue an Order acknowledging that any action taken herein is advisory or informational only and the specific elements of any methodology utilized in future rate cases will be subject to review in each individual rate case and that the ultimate applicability of any value determined in a rate case can be acknowledged in rates in various ways to be determined separately in each utility rate case."[964]

TASC contends that "[c]alls for a decision that binds future dockets or sets forth guidelines or procedures that must be adhered to in the future are asking the Commission to promulgate or amend administrative rules by improper means and must be rejected."[965] TASC claims that there was no indication of the potential for a methodology to be established in this proceeding for use in other dockets, and that the notice made no indication that the outcome of this proceeding would be binding or conclusive in future rate cases.[966] TASC asserts that a rulemaking would be required to adopt a methodology to be used in every subsequent rate case as the sole determining factor for valuing solar, and that the Commission is limited in this proceeding to the issuance of a policy statement, or the use of the evidence gathered in this docket to bear on a future rulemaking.[967]

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961 AIC Br. at 23; AIC Reply Br. at 3, 12.
962 *Id.* at 23-24.
963 TASC Reply Br. at 4.
964 TASC Br. at 27-28; TASC Reply Br. at 25-26.
965 TASC Br. at 3.
966 *Id.*
967 TASC Br. at 26-27.

2. APS's Response

APS contends that TASC's position is contrary to the public notice provided of this proceeding, contrary to good public policy, not supported by relevant law, and is an effort to preserve the current structure of cross-subsidization of rooftop solar customers by customers without rooftop solar.[968] Citing to the procedural background which culminated in the generic proceeding leading to this Decision, and to the record in this proceeding regarding cross-subsidization of rooftop solar, APS asserts that more delay will harm customers and waste resources.[969] APS contends that "TASC has had every opportunity to introduce evidence on every aspect of DG, rooftop solar, net metering, the cost shift, and related cost of service issues," there is no credible reason to delay further, and the time to act is now.[970]

APS asserts that the public notice provided in this proceeding was broad enough to encompass any outcome the Commission finds appropriate. In APS's opinion, the notice's reference to future proceedings for all public service companies provided notice that the Commission intended to create a methodology that would be broadly applicable, and permits the facts found in this generic proceeding to be binding in future utility rate cases.[971] APS argues that establishing a methodology in this proceeding is a ratemaking function that falls outside the rulemaking process of the APA.[972] APS points out that the Commission's plenary power over rates is not conferred by the legislature, which created the APA, but is directly granted by the Arizona Constitution.[973] APS contends that subject to due process, the Commission may act either through a general rulemaking or through orders specific to each public service corporation, as required by the situation, and is not subject to the legislature's oversight.[974] APS argues that flexibility in the accomplishment of regulatory goals is important, and that a rigid requirement for a rulemaking:

> would make the administrative process inflexible and incapable of dealing with many of the specialized problems which arise. (Citation omitted). Not every principle

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[968] APS Reply Br. at 12-15.
[969] *Id.* at 14-15.
[970] *Id.* at 15.
[971] APS Reply Br. at 13.
[972] *Id.* at 13-14.
[973] *Id.* at 14.
[974] *Id.* at 13-14, citing to *Phelps Dodge Corp. v Arizona Elec. Power Co-Op., 207 Ariz. 95 (Ct. App. 2004).*

> essential to the effective administration of a statute can or should be cast immediately into the mold of a general rule. Some principles must await their own development, while others must be adjusted to meet particular, unforeseeable situations. In performing its important functions in these respects, therefore, an administrative agency must be equipped to act either by general rule or by individual order. To insist upon one form of action to the exclusion of the other is to exalt form over necessity.[975]

3. AIC's Response

AIC argues that the Commission's intent in this proceeding is to approve a methodology to be used in future rate dockets, and not to provide only an advisory framework, as TASC advocates.[976] AIC contends that the Decision in this proceeding should reach some conclusion and provide certainty for the parties going forward.[977]

4. Staff's Response

Staff disagrees with TASC's argument that the Commission may not use methodologies adopted in this proceeding in a rate case without first either concluding a ratemaking proceeding or adopting a policy statement. Staff recommends that the Commission reject that argument.[978] Staff states that while this proceeding could be the predecessor to a rulemaking proceeding, this does not mean that the Commission must wait until the conclusion of that rulemaking proceeding to act in each of the electric utility rate cases as TASC appears to suggest.[979]

Staff states that the whole purpose of this proceeding is to adopt methodologies to determine both the value and cost of rooftop solar.[980] Staff disagrees with TASC's assertions that any value of DG framework the Commission adopts in this proceeding must be treated as advisory, and cannot be binding on future rate cases.[981] Staff states that TASC and the solar advocates have been arguing for some time that the Commission cannot make any changes to rooftop solar rate design without first performing a value of DG study; and now that the Commission has engaged in this lengthy proceeding to determine the value of DG methodology, TASC appears to be saying that the Commission cannot now use the results of this proceeding in any case without first (1) revisiting all the issues again in the

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[975] APS Reply Br. at 13, citing *Arizona Corporation Comm'n v. Palm Springs Utility Co., Inc.* 24 Ariz. App. 124, 129 (1975).
[976] AIC Reply Br. at 2.
[977] *Id.* at 3.
[978] Staff Reply Br. at 2, 18-19.
[979] *Id.* at 19.
[980] Staff Reply Br. at 18.
[981] *Id.*

rate case itself, or (2) completing a rulemaking, or (3) issuing an advisory statement.[982] Staff states that TASC's assertions regarding whether the Commission has authority to act on the issues in this generic docket are unsupported, in that the Commission is not limited to acting through its rulemaking proceedings or policy statements.[983]

5. Resolution

We agree with Staff that the purpose of this proceeding is to adopt methodologies to determine the value and cost of rooftop DG. The record in this proceeding is the culmination of years of argument and debate on this issue, and TASC has been afforded ample due process and a full opportunity to present any and all evidence it wished to have considered. It is time to provide certainty and a path forward to resolve disputes surrounding the successful integration of DG with the utility's electrical systems in an economic and fair manner. We believe that the determinations we make in this proceeding provide that path.

There is no doubt that the Commission may act through Orders as well as rulemakings, and TASC's request to delay the determinations we make herein are simply not reasonable or supportable. Moreover, the notice that was required of all the utility providers in this proceeding was more than sufficient to encompass the scope of this docket and the findings made herein.

D. COSS

1. COSS Models

APS and TEP/UNSE made efforts in this proceeding to adapt the traditional cost of service methodology to the current regulatory need to determine the costs to serve DG customers. It is important to determine these costs correctly. Once a utility's revenue requirement is determined, the actual costs to serve customers are a very important consideration when choosing an appropriate and fair rate design, based on principles of cost causation, that will result in just and reasonable rates for all customers.

APS and TEP/UNSE made the inputs and assumptions they used available to the parties, but unfortunately, due to proprietary issues with the COSS models the utilities used in this proceeding, the

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[982] *Id.*
[983] *Id.*

parties were unable to use the models to prepare their cases. The parties were not able to operate the models as they are designed to be used, to show how differing inputs under differing scenarios would affect a determination of costs. While parties were able to conduct a review of the inputs and assumptions that the utilities chose to use with the models, they were not able to make differing inputs or assumptions using the same data, for purposes of showing any comparisons.

Based on the available information provided by the utilities, Vote Solar and TASC made several substantive objections to the methodologies the utilities employed in their cost studies, primarily in regard to the allocations of costs and system benefits to rooftop solar customers relating to transmission, distribution, and generation capacity, and in regard to revenue allocations. Vote Solar and TASC believe that APS's cost study was skewed by APS's decision to allocate costs to rooftop solar customers based on their total load, including load served on-site by their self-generation, instead of allocating costs based only on their delivered load, and disputed the justifications APS offered for doing so. Vote Solar and TASC found fault with the incongruence between TEP/UNSE's use of actual 2015 historical test year revenues, but use of projected costs to serve customers based on the revenue increase it is requesting in its pending rate case. Vote Solar and TASC also contend that both of the utilities' cost studies understated the revenues received from rooftop solar customers because they subtracted the compensation paid for solar exports from the overall revenues received from solar customers for their electricity purchases.

We recognize the differences of opinion among the parties on these disputed issues. However, absent an ability to review and compare the alternate scenarios with varied inputs and assumptions that all the parties would have been able to present with a fully functional model, we are left with a record that does not support approval of a specific COSS methodology in this proceeding. Even if there had been an ability to examine differing scenarios in this proceeding, it would not have precluded the necessity of conducting cost studies in each individual utility rate case. Because each utility's system is unique, and each rate case for each utility is different, based on a different historical test year, the inputs and assumptions in cost of service studies will differ in every rate case. It will be of utmost importance in upcoming electric utility rate cases for all parties to be on equal footing with regard to the ability to use the cost of service model to illustrate their positions.

Vote Solar advocates for the appointment of an independent third-party to conduct COSS and value of DG analyses in rate cases, and points to the transparency issues that arose in this proceeding as justification for taking such a measure. At this juncture, we agree with Staff that such a requirement is not necessary. However, we will adopt RUCO's and Staff's recommendations in regard to requirements for full transparency of all models used in electric utility rate cases.

2. Rooftop Solar Customers as Partial Requirements Customers

APS requests a finding in this proceeding that rooftop solar customers are partial requirements customers and should be placed in their own separate class of customers. APS argues that it would be consistent with COSS principles to do so, because rooftop solar customers, as a sub-class of their current classification, differ significantly in regard to service, load, and cost characteristics. AIC similarly requests a finding that rooftop solar customers are sufficiently distinct to make them a separate rate class for cost of service purposes. AIC argues that the cost studies presented by APS and TEP/UNSE in this proceeding demonstrate that rooftop solar customers and the average residential customer have sufficiently different usage patterns to justify treatment as a separate class.

It is undisputed that rooftop solar customers are different from the average residential customer in that they supply a portion of their own energy needs and are thus partial requirements customers. In addition, rooftop solar customers export power to the grid. Vote Solar argues, however, that these differences alone do not justify disparate treatment of customers. Vote Solar argues that in order to avoid unconstitutional discriminatory rate treatment, it must be determined that differences between the average solar customer and the average non-solar customer result in meaningful impacts that would justify singling out solar customers for differential rate treatment.

Staff argues that the issue of a separate rate class is not part of the methodology for determining either the cost or the value of solar, but is instead a rate design issue that should be examined in the context of each utility's rate case, along with other rate design issues involving rooftop solar customers. Staff states that rate design issues have an impact on the level of cost shift between DG and non-DG customers, and asserts that this proceeding is not the appropriate docket for adoption of changes to a utility's rate design, including the issue of whether rooftop solar customers should be treated as a separate class for rate design purposes.

We agree with APS that the appropriate test for the formation of a subclass of customers for purposes of rate design is whether a sub-group of customers is sufficiently different from the sub-group's current classification in regard to service, load, or cost characteristics to place that sub-group into a separate class. The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers. The ratemaking implications of this separate class treatment are to be determined in each utility's rate case supported by a fully vetted cost of service analysis.

E. Net Metering

TEP/UNSE recommend that the Commission commence a rulemaking to review and amend the current Net Metering Rules to track the outcome of this docket. TEP/UNSE also request that any valuation methodology adopted not include banking or netting of DG energy at retail rates. Staff also recommends that net metering, and the banking of exports associated with net metering, should eventually be eliminated, and replaced with a mechanism for the direct purchase of exports. TASC requests that the Net Metering Rules be kept in place.

The record in this proceeding supports TEP/UNSE's and Staff's recommendations. Now that the value of DG methodology has been established in this proceeding for use in utility rate cases, we expect to establish, in those utility rate cases, a more precise framework for the fair and appropriate compensation of DG customers for their exports than the framework established by the Net Metering Rules in 2008. Once a customer with a DG system is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer. Any requests for waivers of the Net Metering Rules will be considered in utilities' rate cases.

We will instruct Staff to file, within 60 days following the date that the Commission has issued a Decision in the pending APS rate case, a Staff Report with recommendations regarding a rulemaking process to enable the Commission to review and amend the current Net Metering Rules to comport with the changes in circumstances since their adoption. We direct Staff to include in the Staff Report recommendations that take into account any waivers to the Net Metering Rules that may have been granted or denied in the currently pending rate cases for UNSE, TEP, and APS.

F. Value of DG Methodology

1. Analysis of DG Exports

The methodologies proposed in this proceeding contemplate an analysis of rooftop solar exports, with the exception of RUCO's recommendation to analyze all the production of rooftop solar systems. RUCO asserts that the Commission should address both self-consumption and the export rate in this docket, contending that there are costs and benefits associated with self-consumption as well as exports, and there is no justification for valuing them separately.

Vote Solar agrees that self-use of rooftop solar provides significant benefits, but believes focusing on exports is the better approach because the utility should not "look behind the meter" based on a customer's technology choices. Vote Solar strongly believes in a customer's right to self-consume energy generated behind the meter through its own investment.

Like Vote Solar, Staff believes that what a customer chooses to do behind the meter regarding its energy needs is the customer's concern, and that the customer's right to reduce its load by the installation of a DG meter is no different from the customer's right to reduce load by conservation, insulation, high efficiency appliances, or storage. In addition, Staff states that it views the export rate more in the nature of a wholesale rate, and not a retail rate, which would apply to self-consumption.

For the reasons voiced by Vote Solar and Staff, the methodology we adopt will be used for the purpose of ascertaining the appropriate level of compensation to be paid to rooftop solar customers for their exported energy, and not for the purpose of determining a monetary value of the energy a DG customer consumes on site.

2. Methodology

The participating parties to this proceeding exhibited a great deal of professionalism and determination in an effort to achieve a workable and reasonable solution to the highly contested issues that gave rise to the evidentiary hearing in this generic proceeding. The weight of those efforts is second only to the weight of the issues themselves, and the Commission is appreciative of all the hours spent in the furtherance of finding the best way forward, especially including those hours spent in attempting to negotiate a settlement.

After a careful and extensive review of the proposals presented, we find that adoption of Staff's Avoided Cost methodology, with a short-term forecasting view limited to five years to approximately reflect the time that elapses between utility rate cases, in conjunction with Staff's Resource Comparison Proxy methodology, with a five-year rolling average (based on projects with in-service dates within the last five years), will provide the strongest and most flexible tool to inform our determinations in rate cases regarding the appropriate level of compensation for rooftop solar exports. Adoption of both these methodologies will provide a path for a gradual transition away from the current net metering model to one that better reflects the value of DG. While none of the parties would likely whole-heartedly agree with the Commission's adoption of any methodology proposed by any other party, there was general agreement on some of the elements of both of Staff's proposed methodologies. We believe that our adoption of Staff's methodologies for establishing the value of DG in each company's rate cases is the best and most reasonable option available in the record of this proceeding. However, in the view of the Commission's desire to provide for a gradual transition to the DG export rate concept, the Resource Comparison Proxy methodology shall be implemented as a means to guide DG export rate compensation within currently pending electric utility rate cases. The reduction to the compensation rate under the RCP methodology shall not exceed 10 percent annually. The Resource Comparison Proxy is the appropriate valuation methodology to utilize for pending electric utility rate cases because doing so will afford parties the necessary time to further develop the implementation parameters of Staff's alternative five-year Avoided Cost methodology. Once a five-year Avoided Cost methodology is finalized, the Commission will have the flexibility to utilize either the Avoided Cost methodology or Resource Comparison Proxy methodology (or a combination of both) in setting a formula for setting the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate.

We adopt Staff's Avoided Cost proposal using a shorter, five year forecast of avoided costs, rather than a longer, 20 to 30 year forecast as recommended by TASC, Vote Solar, and RUCO. We believe that a 20 to 30 year forecast would incorporate inherently speculative data based on factors that could be easily manipulated. There was agreement, including from Vote Solar and TASC, that Staff's Avoided Cost methodology's use of an ELCC assessment, which is used in utility IRPs, provides a way to successfully and reasonably identify and analyze the costs and capacity savings from generation, transmission and distribution resulting from rooftop solar exports. While the parties did not express the same level of general agreement on Staff's Resource Comparison Proxy methodology, RUCO and Vote Solar agreed that it was an improvement on the proxy methodologies proposed by the utilities, both of which were based on one recent PPA. RUCO expressed general support for either of Staff's proposals, and APS stated that it could support Staff's Resource Comparison Proxy methodology because it could produce an objective valuation for exports based on verifiable actual data.

We also believe that the concurrent adoption of Staff's alternative Resource Comparison Proxy methodology, with a five-year rolling average, represents a reasonable compromise to the utilities' proposals to use a proxy based on a single PPA for valuing DG. Moreover, use of utility scale solar obligations represents the most reliable and objective proxy for rooftop solar by diminishing concerns that societal and environmental factors, as well as other externalities, should be included in the equation. Not only does Staff's methodology provide for a gradual transition for the rooftop solar model, but it reflects a utility's actual, ongoing contractual obligations for purchasing utility-scale solar generation. The adoption of a rolling five year average of utility-scale solar PPAs is likely to gradually reduce the cost to utilities of purchasing rooftop solar energy over time, as older contracts are removed from the proxy analysis and newer, lower-cost, PPAs are included in the mix of solar contracts analyzed in the proxy group.

a) Staff's Avoided Cost Methodology with Five-Year Forecasting

Vote Solar and TASC expressed reservations with Staff's Avoided Cost methodology regarding (1) the use of a short-term forecasting analysis as opposed to the longer, 20 to 30 year forecasts they recommended in order to align with the expected production life of rooftop solar systems; and (2) components they would like to see included in the analysis, such as environmental benefits, societal benefits, and fuel hedging benefits. RUCO also advocated for a long-term forecasting analysis, but not for the inclusion of additional components in the analysis.

The fact that rooftop solar systems have an expected life of 20 to 30 years does not require the forecasting of benefits to span that time period in order for the long-term benefits to be recognized, as long as the value of DG analysis is repeated in utility rate cases as Staff's methodology contemplates.

Contrary to the concerns expressed by Vote Solar and TASC, future changes in the value of DG will not be lost due to short-term forecasts, because the value will be re-assessed in each rate case as time goes on, in order to inform the Commission's determination on setting an appropriate compensation rate for exports. Setting a formula in each rate case for use in annual updates to the export rate provides a concrete answer to the need for gradualism, an issue that RUCO sought to address in its proposal that a graduated step-down mechanism be developed, following the one-time setting of an initial compensation rate informed by a long-term cost/benefit analysis. Staff's Avoided Cost methodology with a five-year forecasting timeframe provides the flexibility required to adjust the analysis to changed circumstances that may increase or decrease the value that DG provides to the utilities' systems and thereby to their customers. In addition to re-assessment of the value of DG in each rate case with the inputs updated annually, Staff's proposed methodology includes the concept of adders which can be used to recognize or incent development of desirable DG attributes such as active smart inverters and west-facing solar DG.

Staff's Avoided Cost methodology will consider environmental benefits and costs, but will not duplicate them in the analysis if they are already considered in the IRP process and in operating costs. As Staff's witness explained, avoided cost values kWhs provided at costs the utility does not incur, and if a generating unit must meet a specific environmental compliance standard (such as emissions or water usage), it has already incurred the associated cost to construct and operate the plant. We agree with the parties who argued that quantifying the societal and economic development benefits of DG in an avoided cost forecast, as proposed by Vote Solar and TASC, is a speculative endeavor that has no place in ratemaking.

We do not believe it is appropriate to include fuel hedging cost benefits in the valuation analysis. The testimony of Staff's witness Mr. Solganick is compelling on this point, when he states that electric utility customers are not demanding more reduction in long-term pricing volatility, as evidenced by current utility fuel adjuster programs of one year or shorter duration, and by residential contracts that extend out a few years at most in states with retail electric competition.

b) Staff's Resource Comparison Proxy Methodology with a Five Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years) and credit for avoided transmission, distribution, and line losses

As TASC pointed out in its comments on Staff's Resource Comparison Proxy methodology, there are several factors that the methodology considers, each of which may be a subject of disagreement when the model is used. TEP/UNSE and AIC's arguments against the model's use of older PPAs illustrates TASC's point. TASC and Vote Solar also claim that the model could produce varying values depending on the weighting of the PPAs and utility-owned solar projects, and that the result of the methodology would therefore be arbitrary.

We disagree with claims that the results of the methodology would be arbitrary. As Staff states, the methodology is based on the utility's actual costs for the last five years, and includes the actual PPA prices and revenue requirements of utility owned grid-scale solar facilities. While the parties have points of disagreement based on their interests over how best to value DG, the spreadsheet that was developed by APS at Staff's request and direction, and described at the hearing by APS's witness Mr. Albert, will provide the parties a means of communicating and litigating their disagreements using a common, transparent tool that is available to all. The spreadsheet will allow the parties to apply different weights to different factors, to include only those projects a party believes appropriate, and will allow for any adjustment to the result that the Commission may deem appropriate. Because the model will be made available to parties within 30 days of the filing of a rate case, the parties will have sufficient time to develop their case for presentation in testimony.

RUCO expressed concern that the Resource Comparison Proxy methodology may not reflect market changes over time. However, as Staff explained, also in response to concerns raised by TEP/UNSE and AIC, because the methodology drops earlier projects out of the calculation as new projects are added, the weighted average will decline over time when utilities add newer, and presumably lower-cost, solar resources.

There were also concerns raised in regard to the possibility of dramatic changes in the export rate and resulting uncertainty. However, to allow the export rate developed using this methodology to change gradually, it will be updated annually after it is initially set in a rate case proceeding or separate rate design phase. At the time that the initial DG export rate is set, a Plan of Administration that provides the mechanism for annual modifications to that initial rate also will be adopted. The annual updates accomplished between rate cases should be formulaic exercises where the Resource Comparison Proxy Methodology and the Avoided Cost Methodology established in the rate case is updated; however the reduction to the compensation rate under the RCP methodology shall not exceed ten percent per year. The updated data and model should be provided to Staff by the relevant utility for review; a hearing is not contemplated.

Staff is in agreement with APS's suggestion in its comments that "if projects of recent vintage are not available for the utility, use of pricing data from available industry sources for grid-scale solar PV projects should be utilized with priority given to projects in Arizona to the extent available." We adopt this addition to Staff's Resource Comparison Proxy methodology, and believe it may prove useful in analyses of the value of DG in rate cases for smaller utilities with no recent grid-scale projects or PPAs to serve as suitable proxies. In order to be an accurate proxy, however, we do believe that DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt herein will require that avoided transmission, distribution capacity and line losses be considered in the analysis. In order for the comparison between central station solar and DG to be meaningful and accurate, these key differences must be addressed and included in the Resource Comparison Proxy analysis that will occur in the rate cases.

We agree with Staff that in the end, with input from all parties, Staff's Resource Comparison Proxy methodology can produce an accurate and reliable indication of utilities' costs associated with its solar generation facilities, including both PPAs and utility-owned facilities.

G. Other Issues

1. Implementation

a. For currently pending electric utility rate cases, the utility shall provide the underlying data of the utility that the Resource Comparison Proxy methodology relies upon to Staff pursuant to a procedural order to be issued in those rate cases. For electric utility rate cases not currently pending before the Commission, the data for the selected valuation methodology will be provided to Staff within 30 days of a sufficiency finding.

As we stated above, once the Five-Year Avoided Cost methodology is finalized, the

Commission will have the flexibility to utilize either the Avoided Cost methodology or Resource Comparison Proxy methodology (or a combination of both) in setting a formula for setting the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate. Therefore, once the Five-Year Avoided Cost methodology is finalized, electric utilities shall provide to Staff, within 30 days of a sufficiency finding in its rate case, the underlying data for both the Resource Comparison Proxy methodology and the Five-Year Avoided Cost methodology.

b. For the Avoided Cost Methodology with Five-Year Forecasting, Staff shall use the matrix attached to this Decision as Exhibit A to evaluate specific eligible costs and value of energy, capacity, and other services delivered to the grid by DG (of all types) over a five-year horizon, during each electric utility's rate case, in order to inform a determination on an appropriate level of compensation to be paid to DG customers for their exports to the grid.[984]

c. For the Resource Comparison Proxy Methodology with a Five Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years), Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case. If projects of recent vintage are not available for the utility, Staff shall use pricing data from available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available. DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt herein will require that avoided transmission, distribution capacity and line losses be considered in the analysis.

d. The Commission may use either the Avoided Cost Methodology or Resource Comparison Proxy Methodology or a combination of both in determining the formula for setting the value of DG. The formula setting the assumptions and weighting of the two methodologies is to be determined in each utility's individual rate case or separate rate design phase. The formula should only be changed within a rate case to allow parties an opportunity to scrutinize the assumptions and

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[984] Exhibit A is a copy of Exhibit HS-3 to Exh. Staff-2, Direct Testimony of Staff witness Howard Solganick. Definitions of terms applicable to Exhibit A are found in Exh. Staff-2, Direct Testimony of Staff witness Howard Solganick, at 11-12.

weighting of the methodologies. However, once the formula has been set, the inputs to the formula should be updated annually to provide for more measured adjustments. We believe that this will reduce the risk of dramatic changes to customers and the solar industry and is consistent with our interest in rate gradualism.

e. At the time that the initial DG export rate is set, a Plan of Administration that provides the mechanism for annual modifications to that initial rate also will be adopted.

f. The value of DG methodologies we adopt shall be:

1) Transparent: all inputs, assumptions and calculations shall be clearly described and explained;

2) Accessible: i.e., the value of DG methodology cost-benefit calculation shall be made available to the public in the form of an electronic spreadsheet that is published on the Commission's website; and

3) Flexible: to allow for the ability to change inputs and assumptions used in the calculation which are likely to change over time.

g. These initial evidentiary proceedings will not be the forum to re-litigate any issue decided in this proceeding. Instead, they will resolve any open questions regarding how the valuation methodologies adopted in this decision will be implemented for each utility. These issues should be limited to utility-specific issues, such as the cost incurred for grid scale facilities in relation to the Resource Comparison Proxy Methodology, and the costs forecasted to be avoided over the next five years in relation to the Avoided Cost Methodology.

h. We are mindful of the Commission's limited resources and the burden created on Staff and the Hearing Division by having evidentiary proceedings within evidentiary proceedings. We are also concerned about the potential delay created by having multiple evidentiary proceedings and are aware of our obligations to comply with our well-established rate case time clock rules. Therefore, we believe that if a separate evidentiary hearing proceeding on the value of DG is necessary, the scope must be reasonably limited to take into consideration the outcomes already decided in this Decision, including use of Staff's Avoided Cost methodology and Staff's Resource Comparison Proxy Methodology or a combination of the two. These separate evidentiary proceedings should not be taken as opportunities for parties to collaterally attack the outcomes established in this Decision.

i. The methodologies shall have spreadsheets with links between inputs and outputs which are available to all parties.

j. Within 90 days of receipt of the underlying data provided by the utility, Staff shall:

1) Perform the analysis; and

2) Make all assumptions and inputs of its analysis available to others.

k. The cost of service study models used by the utilities shall be:

1) Transparent: all inputs, assumptions and calculations shall be clearly described and explained;

2) Accessible: have electronic spreadsheets with links between inputs and outputs made available to all parties; and

3) Flexible: to allow for the ability to change inputs and assumptions used in the calculation.

Within 45 days of Staff's receipts of the underlying data Staff shall file a request for a procedural order setting a procedural schedule for evidentiary hearing. For rate cases presently set for hearing but that have not yet been heard the evidentiary proceeding shall be incorporated into the existing proceeding in a manner to be determined by the ALJ.

2. <u>Grandfathering</u>

TASC requests a finding that any changes in net metering framework or valuation that the Commission adopts, now or in the future, should apply only to DG customers who sign up for new DG interconnection after the effective date of any Order issued in the utility rate case or rulemaking docket where such changes are ultimately implemented. TASC asserts that rooftop solar customers, who have in good faith made long-term and substantial investments in reliance on the existence of net metering and the current rate design, should not be penalized by policy changes in those two areas.[985] TASC believes that the Commission set a precedent in this regard when it issued Decision No. 74202 in 2013, and requests that the Commission act accordingly in the future.[986]

Generally, grandfathering decisions should be made in the context of a rate case. However, we recognize that net metering and certain elements of rate design work together to a certain degree to

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[985] TASC Br. at 28; TASC Reply Br. at 26.
[986] *Id.*

create benefits for DG customers. The value of DG methodology that we adopt in this proceeding may lead to a change, however gradual, in the compensation rate for solar exports that will be set in pending utility rate cases. Therefore, it is important to make clear that for the first utility rate case in which the value of DG methodology we adopt in this proceeding will be used, our default policy is that the new export compensation rate set in that case, as well as any changes to DG-related rate design, should generally apply only to DG systems that interconnect to a utility's distribution system after the effective date of the Decision issued in that utility rate case. Unless unique circumstances warrant different results, our default policy for existing DG customers shall be that DG systems that interconnect to a utility's distribution system before the effective date of the decision issued in that utility rate case should be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date a DG system is interconnected. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG.

We also take this opportunity to clarify that this default policy is not intended to shield customers with DG systems from generally applicable rate design changes, such as changes for the basic service charge. It is, instead, intended to preserve the expectations that customers with DG systems may have relied upon when they chose to adopt DG technology. We further wish to clarify that our grandfathering concepts are intended to apply to the location where DG equipment is located, as opposed to any specific customer. For example, if a customer with a grandfathered DG system moves to a different home, that customer forfeits his grandfathered status. A customer who moves into a home that has a grandfathered DG system may "inherit" that grandfathered status.

A DG system that interconnects to a utility's distribution system after a DG export rate is set for that utility shall be placed on the DG export rate effective at the time of the interconnection for a period of ten years.

3. <u>Cooperatives</u>

GCSECA requests that the Cooperatives be afforded flexibility to develop rate design solutions to cost shifts resulting from DG integration, and that the Cooperatives not be required to comply with any one-size-fits-all requirements that would impose economic and operational hardships. As Staff states, the Cooperatives are different in important respects from the other utilities participating in this proceeding. The value of DG methodologies adopted herein represent our preference for how the value of DG should be assessed and export compensation rates set. However, it may be appropriate to use other methodologies or modified versions of the methodologies adopted herein that address the Cooperatives' unique circumstances. The appropriate method for determining DG compensation rates for the cooperatives should be determined on a case by case basis. The Commission has long recognized that the electric cooperatives are quite different than investor owned utilities. They are owned by their members (i.e., their customers) and managed by locally elected boards. Additionally, their service areas are highly rural which can alter their cost profile significantly relative to the investor owned utilities. Because of these differences, we believe the regulation of the cooperatives by this Commission can be significantly streamlined relative to the investor owned utilities. We have taken significant steps in this direction in the past but recognize that there is further work to do. To recognize this we instruct Staff, led by a Commission appointed by the Commission Chairman, to form a working group in conjunction with GCSECA and other parties to develop recommendations for policy and/or rule changes intended to streamline the regulatory process for the cooperatives. It is the intent of this Commission that a workshop be convened for this purpose. Staff shall report back on the status of these efforts by July 1, 2017.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

Procedural History

1. On December 3, 2013, the Arizona Corporation Commission ("Commission") issued Decision No. 74022. Among other things, Decision No. 74022 ordered that this generic docket be opened on net metering issues, and that workshops would be held with all stakeholders to help inform future Commission policy on the value that distributed generation installations bring to the grid.

2. On January 24, 2014, this generic docket was opened.

3. On January 27, 2014, Staff filed a memorandum in this docket, listing categories of DG

values and costs, and requesting that interested parties provide written comments as to their relevance and significance. Staff also solicited recommendations on other DG-related issues, and solicited substantive comments regarding the process and methodology for assigning monetary values to DG costs and values.

4. From February 14 through August 7, 2014, several entities filed comments.

5. On February 14, 2014, TASC filed an Application for Leave to Intervene.

6. On February 18, 2014, Clean Power filed a Motion to Intervene.

7. On February 27, 2014, Freeport Minerals and AECC jointly filed an Application for Leave to Intervene.

8. On March 10, 2014, a Procedural Order was issued granting intervention to TASC, Clean Power, Freeport Minerals, and AECC.

9. On March 12, 2014, Commissioner Bob Stump filed correspondence.

10. On April 10, 2014, Commissioner Bob Stump filed correspondence.

11. On May 7, 2014, Commissioner Susan Bitter Smith filed correspondence.

12. On May 7, and June 20, 2014, workshops were held in this docket as Special Open Meetings of the Commission.

13. On July 14, 2014, Commissioner Bob Stump filed correspondence.

14. On October 20, 2015, at its regularly scheduled Open Meeting, in considering Docket No. E-01345A-13-0248, the Commission ordered that an evidentiary hearing on the value and cost of DG be held in this generic docket.

15. On October 23, 2015, ASDA filed a Motion to Intervene.

16. On October 28, 2015, by Procedural Order, a procedural conference was scheduled to be held on November 4, 2015.

17. On November 2, 2015, Vote Solar filed a Petition for Leave to Intervene.

18. On November 2, 2015, AURA and APS each filed a Motion to Intervene.

19. On November 3, 2015, SSVEC filed an Application for Leave to Intervene, and AIC filed a Motion to Intervene.

20. On November 4, 2015, the procedural conference convened as scheduled. Counsel for APS, SSVEC, TASC, Freeport Minerals, AECC, AURA, RUCO, WRA, Vote Solar, AIC, TEP, UNSE, and Staff entered appearances and discussed procedural issues related to the evidentiary hearing. A deadline for filing written comments on procedural issues was set for November 13, 2015.

21. On November 4, 2015, RUCO filed an Application to Intervene.

22. On November 6, 2015, TEP and UNSE jointly filed an Application for Leave to Intervene.

23. On November 13, 2015, GCSECA[987] filed its Motion to Intervene.

24. On November 13, 2015, written comments on procedural issues were filed by APS, TEP/UNSE, GCSECA, AIC, TASC, Vote Solar, AURA, RUCO, and Staff.

25. On November 16, 2015, the Alliance filed an Application for Leave to Intervene.

26. On November 19, 2015, WRA filed a Petition for Leave to Intervene.

27. On November 24, 2015, Staff filed supplemental written comments.

28. On November 24, 2015, Clean Power filed a Notice of Consent to Email Service.

29. On November 25, 2015, PORA filed a Consent to Email Service.

30. On December 3, 2015, following consideration of the oral and written comments received in this docket regarding procedural issues related to the evidentiary hearing to be held in this docket, a Procedural Order was issued governing procedural matters. The Procedural Order set the hearing to commence on April 18, 2016, and set associated public notice requirements and testimony filing deadlines.[988] In consideration of the purpose and subject of the evidentiary hearing in this docket, the Procedural Order joined all Arizona jurisdictional electric utilities as parties to this proceeding. The Procedural Order granted intervention to ASDA, Vote Solar, AURA, AIC, RUCO, GCSECA, ACPA, Western Resource, and the Energy Freedom Coalition of America ("EFCA"), and approved Consents

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[987] GCSECA's members include DVEC, GCEC, NEC, MEC, SSVEC, and Trico.

[988] In pertinent part, the form of public notice set forth in the Procedural Order stated:

> The Arizona Corporation Commission ("Commission") will hold a generic evidentiary hearing to investigate the cost to serve customers with distributed generation, and the value of distributed generation, in Docket No. E-00000J-14-0023. The hearing is intended to produce a factual record that will be available for the Commission to use in future proceedings for all Arizona electric public service corporations. You are receiving notice of the hearing because its outcome may impact you as a customer.

to Email Service completed by RUCO, AURA, Staff, AIC, TASC, Freeport Minerals, AECC, and Clean Power.

31. On December 4, 2015, a Procedural Order was issued rescinding the erroneous grant of intervention to EFCA, which had not requested intervention in this docket.

32. On December 9, 2015, Commissioner Susan Bitter Smith's office filed a copy of an email letter received from MEC, and on that same date, the Hearing Division provided a copy of the email to all parties. The letter stated that MEC had no issues before the Commission concerning NM and DG; MEC could not describe to its members why it is a party; and MEC had no data or analysis to present. MEC objected to being required to provide notice to its customers as required by the December 13, 2015 Procedural Order, on the grounds of the costs of mailing and addressing potential customer confusion, and requested that it be excluded from this proceeding.

33. On December 14, 2015, GCSECA filed its Objection and Request for Clarification Re December 3, 2015 Procedural Order. In its filing, GCSECA reiterated its position set forth in its November 13, 2015 written comments. GCSECA stated its objection to the joinder of all Arizona jurisdictional utilities as parties to this docket, and to the requirement that the utilities mail notice of the hearing to all their customers. GCSECA argued that AEPCO has no retail customers, therefore had no direct interest in the topics of DG or NM, and should therefore should be removed as a party and relieved of obligations imposed by the December 3, 2015 Procedural Order. GCSECA requested clarification regarding whether and to what extent the record and findings in this docket would be binding on future ratemaking proceedings.

34. On December 15, 2015, Commissioner Susan Bitter Smith's office filed a copy of an email received from DVEC.

35. On December 15, 2015, Staff filed a Request for Procedural Conference, requesting that a procedural conference be convened to discuss the issues raised in MEC's and GCSECA's filings.

36. On December 16, 2015, Staff filed a Request for Procedural Order. Staff stated that it had conferred with counsel for MEC and GCSECA, and believed that with further discussion, the parties could possibly reach a satisfactory resolution to the issues raised. Staff continued to support the requirement that customers of all electric companies regulated by the Commission receive notice

of this proceeding. However, in recognition of concerns regarding the associated costs, Staff recommended that the public notice deadline be suspended until parties had an opportunity to suggest feasible customer notice deadlines. Staff further stated support for providing the cooperatives an opportunity to draft and submit their own form of notice for consideration. Staff stated that it viewed the parties' level of participation, beyond responding to data requests, to be subject to their discretion, and that the December 13, 2015 Procedural Order's deadlines for prefiling proposals and exhibits did not require any entity to make such filings.

37. On December 17, 2015, the Hearing Division provided a copy to all parties of the December 15, 2015, email from DVEC filed in the docket by Commissioner Susan Bitter Smith's office.

38. On December 17, 2015, NEC filed a copy of a letter to Commissioner Susan Bitter Smith. The letter stated that NEC's Board instructed that the letter be sent requesting that NEC: 1) not be joined as a party to this proceeding; 2) not be required to send the ordered form of notice; and 3) not be required to send notice to all its members. The letter stated that NEC supported the Commission's decision to examine the cost and value of DG, and would gladly share its general thoughts either directly or through GCSECA during voluntary workshops. The letter stated that NEC requested rate adjustments in 2011 and 2014, and was currently considering another filing in 2016. The letter stated that NEC had neither the time nor the financial ability to actively participate in this proceeding, and asked that NEC be excluded.

39. On December 17, 2015, GCSECA filed a Response to Staff's December 16, 2015 Request for Procedural Order. GCSECA joined in Staff's request for the suspension of the December 30, 2015 deadline for parties to mail public notice. GCSECA proposed that its member cooperatives be afforded flexibility to select the appropriate delivery method for notice based on their individual operational and financial situations, such as sending bill inserts, publishing in their newsletters, or publishing in newspapers of general circulation in their service territories. GCSECA proposed that the deadline for completing notice be set for January 30, 2016, and proposed an alternative form of notice for its members to provide. GCSECA renewed its objection regarding joinder of all jurisdictional electric utilities to this proceeding.

40. On December 17, 2015, TEP/UNSE filed a Response to Staff's Request for Procedural Order, stating that in order to comply with the December 3, 2015 Procedural Order notice requirements, they had commenced mailing bill inserts for some customers as soon as possible, and had arranged for direct mail to the remaining customers for which bill inserts would not be possible under the current deadline time constraints. TEP/UNSE expressed support for Staff's request for a suspension of the notice compliance deadline, because an extension of the deadline would provide TEP and UNSE an opportunity to provide all customers the notice by bill insert, by January 10, 2016, at a significant cost reduction compared to their planned partial direct mailing.

41. On December 18, 2015, AEPCO filed a copy of its letter to Commissioner Susan Bitter Smith. AEPCO stated that as a generation cooperative, it had neither retail customers nor a net metering program, and did not believe it is a necessary or relevant party to this docket.

42. On December 18, 2015, Vote Solar filed a Consent to Email Service.

43. On December 21, 2015, one consumer comment was filed expressing opposition to an alternate fee schedule for net metering customers.

44. On December 22, 2015, Commissioner Doug Little filed a letter outlining his views regarding the purpose of the evidentiary hearing, expected outcomes of the process, and parties' participation. Commissioner Little's letter also enumerated some specific issues/questions he believed should be addressed by participating parties.

45. On December 22, 2015, MWE and Ajo filed their Proof of Mailing and Comments Regarding December 3, 2015 Procedural Order. MWE and Ajo stated that they had no objection to GCSECA's request to extend the deadline to provide notice, or to the submission of an alternative form of notice to GCSECA member customers, but that they opposed any requirement that they make a second mailing providing any alternative form of notice to their customers, due to the additional costs they would incur. MWE and Ajo expressed agreement with Staff that no entity should be required to submit any cost of service or value of solar study, or make any filing in this proceeding. MWE and AIC stated that neither utility had the resources to submit any such studies by the deadlines set by the December 3, 2015 Procedural Order; that neither utility intended to take an active role in the

proceeding; that neither utility currently had a general rate case before the Commission; and that neither utility intended to file a general rate case in 2016.

46. On December 23, 2015, counsel for Vote Solar and WRA filed a Notice of Change of Address.

47. On December 23, 2015, a Procedural Order was issued extending the December 31, 2015 public notice requirement deadline set by the December 3, 2015 Procedural Order to February 1, 2016; extending the intervention deadline to February 19, 2016; widening the acceptable means of providing public notice; and indicating that utilities could include their own individual introductory paragraphs preceding the prescribed form of public notice.

48. On December 28, 2015, CEC filed a copy of a letter to Commissioner Susan Bitter Smith requesting to be excused from participation in this docket, including public notice requirements.

49. The Commission's December 29, 2015 Staff Open Meeting Agenda included Agenda Item 1, "Docket No. E-00000J-14-0023 - Commission discussion, consideration, and possible vote concerning the requirements included in the December 3, 2015 Procedural Order that all Arizona jurisdictional electric utilities be joined as parties to this docket and that all Arizona jurisdictional electric utilities mail notice to their customers." The Commission discussed the item and took no vote.

50. On January 6, 2015, Commissioner Doug Little's office filed a copy of a document used as a reference in his December 22, 2015 letter to the docket.

51. On January 8, 2015, Commissioner Tom Forese filed a letter to the docket expressing his concerns, and requesting that parties work to develop "win-win" methodologies and solutions.

52. On January 8, 2015, Trico filed its Certificate of Mailing and Affidavit of Publication.

53. On January 11, 2016, Patricia Ferré and Nancy Baer each filed a Motion to Intervene.

54. On January 19, 2016, TEP/UNSE filed a Notice of Filing Certificate of Mailing.

55. On January 21, 2016, GCEC filed a Proof of Public Notice of Hearing.

56. On January 21, 2016, DVEC filed an Affidavit/Certification of Customer Notice.

57. On January 22, 2016, APS filed a Proof of Publication.

58. On January 25, 2016, a Procedural Order was issued granting intervention to Patricia Ferré and Nancy Baer.

59. On January 26, 2016, SSVEC filed a Notice of Consent to Email Service.

60. On January 26, 2016, AriSEIA filed an Application to Intervene.

61. On January 28, 2016, Garkane filed an Affidavit/Certification of Public Notice and Notice of Change of Firm Affiliation.

62. On January 29, 2016, IBEW Locals filed a Motion to Intervene.

63. On February 1, 2016, Navopache and MEC each filed a Certification of Compliance with Public Notice Requirements.

64. On February 1, 2016, Lewis M. Levenson filed a Motion to Intervene.

65. On February 1, 2016, Susan Pitcairn and Richard Pitcairn filed a joint Motion to Intervene.

66. On February 2, 2016, pursuant to Arizona Supreme Court Rule 39, Timothy Hogan filed a Motion to Associate Counsel *Pro Hac Vice* to associate Chinyere Ashley Osuala as counsel for Vote Solar.

67. On February 5, 2016, CEC filed a Notice of Filing Certificate of Mailing.

68. On February 8, 2016, Commissioner Bob Burns filed a letter to the docket requesting that the parties file testimony regarding the impact of rooftop solar and other distributed generation on water use, discussed in the context of developing a methodology for the value and cost of distributed generation.

69. On February 9, 2016, TEP filed a Consent to Email Service.

70. On February 9, 2016, SSVEC filed a Notice of Filing Additional Affidavits of Publication.

71. On February 9, 2016, Dixie-Escalante filed its Declaration of Mailing.

72. On February 16, 2016, a Procedural Order was issued granting intervention to AriSEIA, IBEW Locals, Lewis M. Levenson, Susan Pitcairn, and Richard Pitcairn.

73. On February 19, 2016, Commissioner Bob Stump filed a letter to the docket listing policy considerations and questions intended to inform both cost of service and value of solar considerations within the context of the evidentiary hearing.

74. On February 25, 2016, direct testimony in this matter was filed by APS, TEP/UNSE, SSVEC, GCSECA, IBEW Locals, AIC, TASC, Vote Solar, RUCO, and Staff.

75. On February 29, 2016, Patricia Ferré filed a Motion for Procedural Order Taking Official Judicial Notice of Filings in Generic Docket Nos. E-00000C-11-0328 and E-01345A-13-0069.

76. On February 29, 2016, AriSEIA filed a Notice of Change of Representative, to which was attached a copy of a Board Resolution dated February 11, 2016. The Board Resolution designated AriSEIA's President and Chairman as its official representative in all matters before the Commission, and appointed Tom Harris as its President and Chairman.

77. On February 29, 2016, ARISEIA filed a Consent to Email Service.

78. On March 8, 2016, Southwest Energy Efficiency Project ("SWEEP") filed comments.

79. On March 8, 2016, Ms. Ferré filed comments.

80. On March 24, 2016, a Procedural Order was issued granting AriSEIA's Consent to Email Service.

81. On March 29, 2016, APS filed summaries of the direct testimony of its witnesses.

82. On April 7, 2016, rebuttal testimony in this matter was filed by APS, TEP/UNSE, the IBEW Locals, AIC, TASC, Vote Solar, RUCO, and Staff.

83. On April 11, 2016, Patricia Ferré filed a Disability Request.

84. On April 14, 2016, Patricia Ferré filed the pre-filed direct testimony of her witness Elizabeth A. Kelley.

85. The hearing on this matter commenced on April 18, 2016.

86. On April 20, 2016, Staff posed questions to APS's witness Bradley J. Albert in regard to his prefiled rebuttal testimony (Hearing Exhibit APS-6).

87. On April 21, 2016, APS docketed a Notice of Filing email communication with Utilities International, the owner of APS's cost of service software.

88. On April 22, 2016, as discussed during the hearing on April 20, 2016, during cross-examination of APS witness Bradley Albert,[989] Staff submitted requests in writing to APS, TEP, and

[989] Tr. 465-471.

UNSE for additional information regarding their proposed methodologies. Staff's request to APS was issued as Staff's Third Set of Data Requests, and Staff's request to TEP/UNSE was issued as Staff's Second Set of Data Requests. Staff's Third Set of Data Requests to APS was admitted into evidence as Hearing Exhibit S-4.

89. On May 5, 2016, TASC filed a Notice of Filing Errata of Direct Testimonies of R. Thomas Beach and William A. Monsen.

90. On May 6, 2016, the hearing on this matter was recessed until June 8, 2016 at 9:30 a.m. Prior to the recess, APS and TEP/UNSE agreed to make witnesses available on that date for the sole purpose of providing testimony regarding the information to be provided in response to Staff's Hearing Data Requests. At the hearing, parties agreed that they could file written responses to the information to be provided in response to Staff's Hearing Data Requests, or alternatively, that they would have an opportunity to present a witness to testify in response. The continuation hearing date and due date for responses was set for June 13, 2016. A schedule for filing closing briefs was also set, with Initial Closing Briefs due on or before June 20, 2016, and Reply Closing Briefs due on or before July 8, 2016.

91. On May 6, 2016, as discussed during the hearing, APS filed a Form of Protective Order for the parties to utilize in order to facilitate the exchange of confidential information in response to Staff's Hearing Data Requests.

92. On May 6, 2016, Patricia Ferré filed a document titled "Testimony of Patricia Ferré, Intervener."

93. On May 10, 2016, the Hearing Division issued the Protective Order as filed on May 6, 2016.

94. On May 12, 2016, APS filed a Request to Amend Protective Order, indicating that there were errors in the May 6, 2016 Form of Protective Order. Both a redlined and a clean version of APS's proposed amended Form of Protective Order were attached to the Request. APS requested the issuance of an amended Protective Order, but indicated that to avoid delay, it had begun providing documents under the Protective Order issued May 10, 2016.

95. On May 12, 2016, Staff filed a Motion for Procedural Order, requesting the issuance of a Procedural Order adding an additional hearing date to those dates set during the hearing on May 6, 2016.

96. On May 12, 2016, Patricia Ferré filed a Notice of Errata.

97. On May 13, 2016, TEP and UNS filed Exhibits A and B of the Protective Order for Michael Patten, Dallas J. Dukes, and David Lewis.

98. On May 18, 2016, AIC filed Exhibits A and B of the Protective Order for Meghan H. Grabel.

99. On May 20, 2016, TEP and UNS filed Exhibits A and B of the Protective Order for Bradley S. Carroll and Carmine Tilghman.

100. On May 23, 2016, a Procedural Order was issued with the requested amended Protective Order to supersede the previously issued Protective Order. The Procedural Order also modified the Procedural Schedule for the continuation of the hearing, adding an additional hearing day and extending the briefing schedule accordingly.

101. On May 24, 2016, APS filed a copy of a letter addressed to Chairman Little and signed by several individuals.

102. On May 25, 2016, Garkane filed Exhibits A and B of the Protective Order for Jennifer A. Cranston.

103. On June 1, 2016, APS filed Exhibits A and B of the Protective Order for Thomas Loquvam, Raymond Heyman, Bradley Albert, and Paul Smith.

104. On June 8, 2016, APS filed Exhibits A and B of the Protective Order for Hannah Dolski.

105. On June 8, 2016, the hearing reconvened. Witnesses for APS and TEP/UNSE testified regarding their respective responses to Staff's Third Set of Data Requests to APS and Staff's Second Set of Data Requests to TEP/UNSE. Pursuant to Staff's request, certain exhibits related to those data responses were admitted to the record of this proceeding. Witnesses for RUCO and Staff provided oral responsive testimony.

106. On June 13, 2016, Vote Solar filed the Supplemental Responsive Testimony of Briana Kobor.

107. On June 13, 2016, Commissioner Stump filed a letter in the docket.

108. On June 13, 2016, at the close of the hearing, the June 13, 2016 deadline for the filing of written responses set by the May 23, 2016 Procedural Order was extended to June 22, 2016. In addition, the deadlines for filing Initial Closing Briefs and Reply Closing Briefs were extended to June 30 and July 8, 2016, respectively.

109. On June 20, 2016, IBEW Locals filed their Initial Closing Brief.

110. On June 22, 2016, RUCO filed its Responsive Comments in response to the testimony and exhibits presented at hearing on June 8, 9, and 13, 2016.

111. On June 22, 2016, TASC filed the Responsive Supplemental Testimony of R. Thomas Beach, responding to the testimony and exhibits presented at hearing on June 8, 9, and 13, 2016.

112. On June 23, 2016, APS, TEP/UNSE and Staff filed a Joint Request for Extension of Briefing Schedule. APS, TEP/UNSE and Staff requested an extension of the deadlines for filing Initial Closing Briefs and Reply Closing Briefs from June 30 and July 8, 2016, respectively, to July 7 and July 25, 2016. The Joint Request indicated that Vote Solar had requested that the proposed July 25, 2016 deadline for the Reply Closing Brief be extended to July 29, 2016 instead, due to counsel's timing conflict with another matter. The Joint Request alternatively proposed that if the Reply Closing Brief deadline were extended as requested by Vote Solar, the Initial Closing Brief deadline also be extended by four days.

113. On June 27, 2016, by Procedural Order, the deadlines for filing Initial Closing Briefs and Reply Closing Briefs were extended to July 11 and July 29, 2016.

114. On June 30, 2016, Freeport Minerals and AECC filed Notice that they would not be filing an Initial Opening Brief.

115. On July 6, 2016, Staff filed a Notice of Settlement Discussions.

116. On July 8, 2016, TASC filed Exhibits A and B of the Protective Order for Elijah Gilfenbaum.

117. On July 8, 2016, Staff filed a Request for Extension of Time, seeking an extension from July 11, 2016, until July 20, 2016, to file its Initial Closing Brief.

118. On July 11, 2016, TEP and UNS filed Notice of Filing Late-Filed Exhibits.

119. On July 11, 2016, GCSECA filed its Initial Closing Brief.

120. On July 11, 2016, a Procedural Order was issued extending the deadline for filing Initial Closing Briefs to July 20, 2016, and the deadline for filing Reply Closing Briefs to August 5, 2016.

121. On July 15, 2016, SSVEC filed a Notice indicating that it would not be filing an Initial Closing Brief.

122. On July 20, 2016, Initial Closing Briefs were filed by APS, TEP/UNSE, AIC, TASC, Vote Solar, and RUCO.

123. On July 21, 2016, Staff filed a Notice indicating that it would be filing its Initial Closing Brief on that date, and that it was not filed the day prior due to computer problems resulting in lost data. Counsel for Staff indicated that while the other parties had filed their Initial Closing Briefs on the previous day, Staff had not viewed or used the Initial Closing Briefs filed by the other parties in preparing its own brief.

124. On July 21, 2016, Staff filed its Initial Closing Brief.

125. On July 29, 2016, Freeport Minerals filed a Notice indicating that it would not be filing a Reply Closing Brief.

126. On August 2, 2016, Staff filed a Notice of Workshop to be held in Docket No. E-000005-16-0257 (Reducing System Peak Demand Costs) to be held on August 4, 2016 beginning at 9:00 A.M. at the Arizona Legislature in House Hearing Room No. 4, noticed as a Special Open Meeting of the Commission.

127. On August 2, 2016, the City of Tucson filed a copy of a Resolution adopted by the Mayor and Council of the City of Tucson.

128. On August 5, 2016, Reply Closing Briefs were filed by APS, TEP/UNSE, IBEW Locals, AIC, TASC, Vote Solar, RUCO, and Staff.

129. On August 8, 2016, Staff filed a Notice of Errata.

130. Numerous public comments have been filed in this docket.

Determinations

131. Net metering, and the banking of DG exports associated with net metering, should eventually be eliminated and replaced with a mechanism for the direct purchase by utilities of DG

exports. Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer.

132. The value of DG exports should be used to inform compensation rates to be paid to DG customers for their exports.

133. There is a need for a valuation of DG methodology that will provide a gradual transition away from the current net metering model for compensating DG exports, toward compensation of DG exports that reflects the actual value of DG.

134. Valuation of DG exports should be based on an avoided cost methodology.

135. Long-term forecasts should not be used to establish the value of DG, due to the risk of inclusion of speculative benefits and costs.

136. Environmental benefits and costs of DG should be considered in an avoided cost forecast, but should not be duplicated if they are already considered in the IRP process and in operating costs.

137. Quantifying the societal and economic development benefits of DG in an avoided cost forecast is speculative and inappropriate for ratemaking purposes.

138. It is inappropriate at this time to include fuel hedging costs in a value of DG avoided cost forecast.

139. A five year forecast of the benefits and costs of DG for purposes of valuation of DG exports is reasonable if the valuation is re-assessed in each electric utility rate case and the inputs are updated annually.

140. Use of utility-scale solar obligations represents the most reliable and objective avoided cost proxy for rooftop solar and diminishes concerns for the inclusion of societal and environmental factors and other externalities in valuing solar DG exports.

141. A five year rolling weighted average of a utility's solar PPAs and utility-owned solar generating resources used as a proxy for purposes of valuation of solar DG exports is reasonable if the valuation is re-assessed in each electric utility rate case and the inputs are updated annually and the additional benefits of avoided transmission and distribution capacity and avoided line losses are added

into the weighted average.

142. A re-assessment of the value of DG formula in each electric utility rate case with annual updates to the formula inputs in order to inform compensation rates to be paid for DG exports ensures a gradual transition from the current net metering compensation model to compensation that reflects the actual value of DG.

143. A re-assessment of the value of DG formula in each electric utility rate case with annual updates to the formula inputs in order to inform compensation rates to be paid for DG exports precludes the need for the implementation of a separate step-down mechanism.

144. The best and most reasonable option available in the record of this proceeding for the valuation of DG is the adoption of both Staff's Avoided Cost methodology, with a short-term forecasting view limited to five years to approximately reflect the time that elapses between utility rate cases, and Staff's Resource Comparison Proxy methodology, with a five-year rolling average (based on projects with in-service dates within the last five years), as modified to account for the added benefits of DG including avoided transmission and distribution capacity and avoided line losses. Adoption of both these alternative methodologies to be used in utility rate cases on a going-forward basis will provide a path for a gradual transition away from the current net metering model to one that better reflects the value of DG.

145. For the Avoided Cost Methodology with Five-Year Forecasting, Staff shall use the matrix attached to this Decision as Exhibit A to evaluate specific eligible costs and value of energy, capacity, and other services delivered to the grid by DG (of all types) over a five-year horizon, during each electric utility's rate case, in order to inform a determination on an appropriate level of compensation to be paid to DG customers for their exports to the grid. The methodology will have electronic spreadsheets with links between inputs and outputs, allow for the ability to change inputs and assumptions used in the calculation, and will include a clear description and explanation of all inputs, assumptions, and calculations. These items will be made available to all parties. The development of the electronic spreadsheet and its implementation will occur within the next three years in anticipation of the next cycle of rate cases.

146. For the Resource Comparison Proxy Methodology with a Five Year Rolling Average

(Based on Projects and PPAs with In-Service Dates within the Last Five Years), Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case. If projects of recent vintage are not available for the utility, Staff shall use pricing data from available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available. The Resource Comparison Proxy spreadsheet described in this Decision shall also calculate the additional benefits of avoided transmission and distribution capacity and avoided line losses and those additional benefits should be added to Resource Comparison Proxy Methodology analysis. The methodology will have electronic spreadsheets with links between inputs and outputs, allow for the ability to change inputs and assumptions used in the calculation, and will include a clear description and explanation of all inputs, assumptions, and calculations. These items will be made available to all parties.

147. For currently pending electric utility rate cases, the utility shall provide the underlying data of the utility that the Resource Comparison Proxy methodology relies upon to Staff pursuant to a procedural order to be issued in those rate cases.

148. For electric utility rate cases not currently pending before the Commission, the data for the selected valuation methodology will be provided to Staff within 30 days of a sufficiency finding. As stated herein, once the Five-Year Avoided Cost methodology is finalized, the Commission will have the flexibility to utilize either the Avoided Cost methodology or Resource Comparison Proxy methodology (or a combination of both) in setting a formula for setting the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate. Therefore, once the Five-Year Avoided Cost methodology is finalized, electric utilities shall provide to Staff, within 30 days of a sufficiency finding in their rate cases, the underlying data for both the Resource Comparison Proxy methodology and the Five-Year Avoided Cost methodology.

149. It is inappropriate for utility scale assets that are related to solar + storage to be included in the calculation of the Resource Comparison Proxy methodology. Including these assets could deter utilities from entering into prospective PPA agreements for such resources based on the recognized higher pricing and accompanying compensation rates attributable to such arrangements. A party can

argue for the inclusion of such PPAs as long as the added value of the storage component is appropriately excluded from the analysis. Similarly, PPAs related to solar arrays that are primarily for R&D purposes should also be excluded from the analysis.

150. More generally, nothing we adopt herein is intended to limit the Commission from adopting any policies regarding energy storage at a future date.

151. The Commission may use either the Avoided Cost Methodology (when available) or Resource Comparison Proxy Methodology or a combination of both in determining the formula for setting the value of DG. The formula setting the assumptions and weighting of the two methodologies is to be determined in each utility's individual rate case or separate rate design phase. The formula should only be changed within a rate case to allow parties an opportunity to scrutinize the assumptions and weighting of the methodologies. However, once the formula has been set, the inputs to the formula should be updated annually to provide for more measured adjustments. We believe that this will reduce the risk of dramatic changes to customers and the solar industry and is consistent with our interest in rate gradualism.

152. At the time that the formula is set, a plan of administration that will address the procedural mechanisms for the annual modifications to the initial export rate will also be adopted.

153. Within 90 days of receipt of the underlying data provided by the utility, Staff shall:

1) Perform the analysis;
2) Make all assumptions and inputs of its analysis publicly available in the form of an electronic spreadsheet that is published on the Commission's website, with a clear description and explanation of all inputs, assumptions and calculations.

154. Within 45 days of Staff's receipts of the underlying data Staff shall file a request for a procedural order setting a procedural schedule for evidentiary hearing. For rate cases presently set for hearing but that have not yet been heard the evidentiary proceeding shall be incorporated into the existing proceeding in a manner to be determined by the ALJ.

155. These initial evidentiary hearings will not be the forum to re-litigate any issue decided in this proceeding. Instead, they will resolve any open questions regarding how the valuation methodologies adopted in this decision will be implemented for each utility. These issues should be

limited to utility-specific issues, such as the cost incurred for grid scale facilities in relation to the Resource Comparison Proxy Methodology, and the costs forecasted to be avoided over the next five years in relation to the Avoided Cost Methodology.

156. We are mindful of the Commission's limited resources and the burden created on Staff and the Hearing Division by having evidentiary proceedings within evidentiary proceedings. We are also concerned about the potential delay created by having multiple evidentiary proceedings and are aware of our obligations to comply with our well-established rate case time clock rules. Therefore, we believe that if a separate evidentiary hearing proceeding on the value of DG is necessary, the scope must be reasonably limited to take into consideration the outcomes already decided in this Decision, including use of Staff's Avoided Cost Methodology and Staff's Resource Comparison Proxy Methodology or a combination of the two. These separate evidentiary proceedings should not be taken as opportunities for parties to collaterally attack the outcomes established in this Decision.

157. The record does not support approval of a specific COSS methodology in this proceeding.

158. Rooftop solar DG customers are partial requirements customers who export power to the grid.

159. Rooftop solar customers are a separate class of customers. The ratemaking implications of this separate class treatment are to be determined in each utility's rate case supported by a fully vetted cost of service analysis.

160. Utilities will be directed to submit cost of service studies in rate cases, both pending cases and in future rate cases, which are based on models with spreadsheets containing links between inputs and outputs which are available to all parties. The cost of service study models used by the utilities shall be:

1) Transparent: all inputs, assumptions and calculations shall be clearly described and explained;

2) Accessible: have electronic spreadsheets with links between inputs and outputs made available to all parties; and

3) Flexible: to allow for the ability to change inputs and assumptions used in the

calculation.

161. Generally, grandfathering decisions should be made in the context of a rate case. However, we recognize that net metering and certain elements of rate design work together to a certain degree to create benefits for DG customers. The value of DG methodology that we adopt in this proceeding may lead to a change, however gradual, in the compensation rate for solar exports that will be set in pending utility rate cases. Therefore, it is important to make clear that for the first utility rate case in which the value of DG methodology we adopt in this proceeding will be used, our default policy is that the new export compensation rate set in that case, as well as any changes to DG-related rate design, should generally apply only to DG systems that interconnect to a utility's distribution system after the effective date of the Decision issued in that utility rate case. Unless unique circumstances warrant different results, our default policy for existing DG customers shall be that DG systems that interconnect to a utility's distribution system before the effective date of the decision issued in that utility rate case should be considered to be fully grandfathered and continue to utilize currently implemented DG-related rate design and net metering for a period of 20 years from the date a DG system is interconnected. Existing customers with DG systems will be subject to currently-existing rules and regulations impacting DG. We also take this opportunity to clarify that this default policy is not intended to shield customers with DG systems from generally applicable rate design changes, such as changes to the basic service charge. It is, instead, intended to preserve the expectations that customers with DG systems may have relied upon when they chose to adopt DG technology. We further wish to clarify that our grandfathering concepts are intended to apply to the location where DG equipment is located, as opposed to any specific customer. For example, if a customer with a grandfathered DG system moves to a different home, that customer forfeits his grandfathered status. A customer who moves into a home that has a grandfathered DG system may "inherit" that grandfathered status.

162. A DG system that interconnects to a utility's distribution system after a DG export rate is set for that utility shall be placed on the DG export rate effective at the time of the interconnection for a period of ten (10) years.

163. While we refrain from commenting on the appropriateness of any particular rate design

as part of this proceeding, the Commission is committed to modifying residential rate design in a manner that mitigates the recognized cost shift caused by rooftop solar customers' self-consumption.

164. The Cooperatives should be afforded flexibility to develop rate design solutions to the cost shift caused by DG and should not be required to comply with any one-size-fits-all requirements that would impose economic and operational hardships. The value of DG methodologies adopted herein represent our preference for how the value of DG should be assessed and export compensation rates set for the Cooperatives. However, it may be appropriate to use other methodologies or modified versions of the methodologies adopted herein that address the Cooperatives' unique circumstances. The appropriate method for determining DG compensation rates for the Cooperatives should be determined on a case by case basis.

165. The Commission has long recognized that the Electric Cooperatives are quite different than investor owned utilities. They are owned by their members (i.e., their customers) and managed by locally elected boards. Additionally, their service areas are highly rural which can alter their cost profile significantly relative to the investor owned utilities. Because of these differences, we believe the regulation of the Cooperatives by this Commission can be significantly streamlined relative to the investor owned utilities. We have taken significant steps in this direction in the past but recognize that there is further work to do. To recognize this we instruct Staff, led by a Commissioner appointed by the Commission Chairman, to form a working group in conjunction with GCSECA and other parties to develop recommendations for policy and/or rule changes intended to streamline the regulatory process for the Cooperatives. It is the intent of this Commission that a workshop be convened for this purpose. Staff shall report back on the status of these efforts by July 1, 2017.

CONCLUSIONS OF LAW

1. Pursuant to Article 3, Section 15 of the Arizona Constitution, the Commission has jurisdiction over the Arizona jurisdictional utilities who are parties to this generic proceeding.

2. Notice of this proceeding was provided in accordance with law.

3. It is just and reasonable and in the public interest to adopt the methodologies for calculating the value of DG exports set forth herein for use in electric utility rate cases before the Commission.

ORDER

IT IS THEREFORE ORDERED that the Commission adopts adopt the methodologies for calculating the value of DG exports set forth and described herein for use in electric utility rate cases before the Commission.

IT IS FURTHER ORDERED that Staff shall promptly undertake all steps necessary to develop the electronic spreadsheet described herein for the Avoided Cost Methodology with Five-Year Forecasting, within a timeframe that will allow its implementation to occur no later than December 31, 2019.

IT IS FURTHER ORDERED that: (i) for currently pending electric utility rate cases, the utility shall provide the underlying data of the utility that the Resource Comparison Proxy methodology relies upon to Staff pursuant to a procedural order to be issued in those rate cases and (ii) for electric utility rate cases not currently pending before the Commission, the data for the selected valuation methodology will be provided to Staff within 30 days of a sufficiency finding. As stated herein, once the Five-Year Avoided Cost methodology is finalized, the Commission will have the flexibility to utilize either the Avoided Cost methodology or Resource Comparison Proxy methodology (or a combination of both) in setting a formula for setting the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate. Therefore, once the Five-Year Avoided Cost methodology is finalized, electric utilities shall provide to Staff, within 30 days of a sufficiency finding in their rate cases, the underlying data for both the Resource Comparison Proxy methodology and the Five-Year Avoided Cost methodology.

IT IS FURTHER ORDERED that these initial evidentiary hearings will not be the forum to re-litigate any issue decided in this proceeding. Instead, they will resolve any open questions regarding how the valuation methodologies adopted in this decision will be implemented for each utility. These issues shall be limited to utility-specific issues, such as the cost incurred for grid scale facilities in relation to the Resource Comparison Proxy Methodology, and the costs forecasted to be avoided over the next five years in relation to the Avoided Cost Methodology.

IT IS FURTHER ORDERED that Staff shall follow the procedural requirements set forth herein regarding use of the methodologies for calculating the value of DG exports set forth and described herein for use in electric utility rate cases before the Commission.

IT IS FURTHER ORDERED that for currently pending electric utility rate cases, the Hearing Division shall promptly issue any necessary Procedural Orders regarding the incorporation of the Resource Comparison Proxy methodology into the existing proceedings.

IT IS FURTHER ORDERED that for electric utility rate cases not currently pending before the Commission, within 45 days of Staff's receipt of the required underlying data from the utility, Staff shall file a request for a procedural order setting a procedural schedule for evidentiary hearing.

IT IS FURTHER ORDERED that rooftop solar customers shall be treated as a separate class of customers for the reasons set forth herein. The ratemaking implications of this separate class treatment shall be determined in each utility's rate case, supported by a fully vetted cost of service analysis.

IT IS FURTHER ORDERED that electric utilities shall submit cost of service studies in rate cases, both pending cases and in future rate cases, which are based on models with spreadsheets containing links between inputs and outputs which are available to all parties. The cost of service study models used by the utilities shall be:

1) Transparent: all inputs, assumptions and calculations shall be clearly described and explained;

2) Accessible: have electronic spreadsheets with links between inputs and outputs made available to all parties; and

3) Flexible: to allow for the ability to change inputs and assumptions used in the calculation.

IT IS FURTHER ORDERED that for the first utility rate case in which the value of DG methodology we adopt in this proceeding will be used, including pending cases, the new export compensation rate set in that case, as well as any changes to rate design, will apply only to DG customers who sign up for new DG interconnection after the effective date of the Decision issued in that utility rate case. Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will be no further netting or banking of exported DG kWh for that customer. Unless unique circumstances warrant different results, our default policy for existing DG customers shall be that DG systems that interconnect to a utility's distribution system before the effective date of the Decision issued in that utility rate case will be considered to be fully grandfathered and continue to utilize currently-implemented rate design and net metering, and will be subject to currently-existing rules and regulations impacting DG for a period of twenty years from the date a DG system is interconnected.

IT IS FURTHER ORDERED that the default grandfathering policy set forth in the prior Ordering Paragraph shall apply to the location where DG equipment is located, and not to any specific customer. If a customer with a grandfathered DG system moves to a different home, that customer will no longer enjoy a grandfathered status. However, a customer who moves into a home that has a grandfathered DG system may "inherit" the grandfathered status attached to that DG system.

IT IS FURTHER ORDERED that the default grandfathering policy set forth in the prior Ordering Paragraphs shall not apply to generally applicable rate design changes, such as changes to the basic service charge.

IT IS FURTHER ORDERED that a DG system that interconnects to a utility's distribution system after a DG export rate is set for that utility shall be placed on the DG export rate effective at the time of the interconnection for a period of ten years.

IT IS FURTHER ORDERED that Staff shall file, within 60 days following the date that the Commission has issued a Decision in the pending Arizona Public Service Company rate case, a Staff Report with recommendations regarding a rulemaking process to enable the Commission to review and amend the current Net Metering Rules to comport with the changes in circumstances since their adoption. Staff shall include in the Staff Report recommendations that take into account any waivers to the Net Metering Rules that may have been granted or denied in the currently pending rate cases for UNS Electric, Inc., Tucson Electric Power Company and Arizona Public Service Company.

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IT IS FURTHER ORDERED that the Cooperatives should be afforded flexibility to develop rate design solutions to the cost shift caused by DG and should not be required to comply with any one-size-fits-all requirements that would impose economic and operational hardships. The value of DG methodologies adopted herein represent our preference for how the value of DG should be assessed and export compensation rates set for the Cooperatives. However, it may be appropriate to use other methodologies or modified versions of the methodologies adopted herein that address the Cooperatives' unique circumstances. The appropriate method for determining DG compensation rates for the Cooperatives shall be determined on a case by case basis.

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IT IS FURTHER ORDERED that Staff, led by a Commissioner appointed by the Commission Chairman, shall form a working group in conjunction with GCSECA and other parties to develop recommendations for policy and/or rule changes intended to streamline the regulatory process for the Cooperatives; shall convene a workshop be convened for this purpose; and shall report back on the status of these efforts by July 1, 2017.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN LITTLE	COMMISSIONER STUMP

COMMISSIONER FORESE	COMMISSIONER TOBIN	COMMISSIONER BURNS

IN WITNESS WHEREOF, I, JODI A. JERICH, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 3rd day of January 201~~6~~7

JODI A. JERICH
EXECUTIVE DIRECTOR

DISSENT ____________________

DISSENT ____________________

TJ/rt

COMMISSIONERS
DOUG LITTLE - Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

ARIZONA CORPORATION COMMISSION

BOB BURNS
COMMISSIONER

Direct Line: (602) 542-3682
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January 3, 2016

RE: Dissent in the Value and Cost of Distributed Generation, Docket No.: E-00000J-14-0023

Dear Commissioners, Stakeholders and Parties:

I could not support this decision because the overall result does not get to where I need it to be. Having supported the net metering compromise of 2013, I had high hopes that the parties could achieve real compromise based on their observable movements toward middle ground. In my view, this decision comes close but does not accomplish that goal.

We should have included all costs and benefits in the Avoided Cost Methodology. This inclusion would be for qualitative purposes only, and if the benefits/costs were to become quantifiable in the future, then their values would be included at that time. Just because a benefit is speculative at this point in time does not mean we should automatically conclude that its value is zero, especially when individual homeowners are undertaking financial risks by investing tens of thousands of dollars of their own money to install rooftop solar systems that provide benefits to all ratepayers. The present monopoly model provides a guaranteed, significant return on and of investment to monopoly investors who install new generation. The current utility model does not provide for a similar return for individual homeowners who install rooftop solar, and it seems to me that we should consider all potential benefits when individuals are making personal financial investments that provide benefits to all ratepayers. If the currently unquantifiable values become quantifiable at a future time, they could be included in the export rate. What harm is there in having as much information as possible on the table?

Moreover, future solar customers should have their solar export rate grandfathered for 20 years, not 10 years, just like what was approved for existing solar customers. I find the solar installers' comments, especially AriSEIA's—an Arizona-based group that represents over 40 local, Arizona-based businesses—compelling on this point.

Some of the amendments adopted would be more appropriately addressed in rate cases or rulemakings, not in this proceeding. For example, the issue of whether solar customers are partial requirements customers who should be part of a separate rate class should be decided in a rate case proceeding. The decision to prohibit solar customers from banking unused kWh is contemplated in the net metering rules, and the appropriate place for its resolution should be in that rulemaking proceeding.

I am also concerned about the "settlement" that was reached during the 40 minute afternoon break amongst some of the parties regarding Tobin Proposed Amendment No. 12. It appeared to me that some of the parties had compromised on tweaks to the amendment, although they had not included other, including solar, parties in the discussion. By the time the proposed tweaks came to the Commission for consideration, the issues and discussion had already been framed, and it was an uphill battle for the other parties who had been excluded from those break-time discussions.

Thus, I regrettably must dissent.

Sincerely,

Robert L. Burns
Commissioner

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

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Exhibit HS-3
Page 1 of 6

Value of Distributed Generation					
DG Type		Generation			
DG Characteristics & Capabilities		Off Grid	No Export	Responsive	Non-Responsive
Energy					
On-Peak		Not Applicable	Not Applicable	Avoided Cost	Avoided Cost
Off-Peak				Avoided Cost	Avoided Cost
Losses-Energy				Avoided Cost	Avoided Cost
Emergency (shortage)				Time Specific Avoided Cost	
Low Load (Excess generation)				Time Specific Payment	
Capacity					
Generation					
	Emergency			Outage Prevention Value	
	Long-term			ELCC	ELCC
	Short-term				
	Losses			Proportional to ELCC	Proportional to ELCC
Transmission					
	Emergency			Outage Prevention Value	
	Long-term			Proportional to ELCC	Proportional to ELCC
	Short-term			Specific Location Only	Specific Location Only
	Losses			Proportional to ELCC	Proportional to ELCC
Distribution					
	Emergency			Outage Prevention Value	
	Long-term			Proportional to ELCC	Proportional to ELCC
	Short-term			Specific Location Only	Specific Location Only
	Losses			Proportional to ELCC	Proportional to ELCC
Reactive				Value	
Frequency Regulation				Value	
Energy Imbalance				Maybe If Aggregated	
Operating Reserves				Maybe If Aggregated	
Scheduling/Forecasting					
Risk					
Fuel Price Hedge					
Market Price Response				Yes	Yes
Environmental					
Carbon				Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX				In Avoided Cost	In Avoided Cost
Water				In Avoided Cost	In Avoided Cost
Land				In Avoided Cost	In Avoided Cost
Social					
Customer					
Meter & Reading		100%		Increased Cost	Increased Cost
Service Drop		100%			
Billing		100%		Increased Cost	Increased Cost
Customer Service		100%		Increased Cost	Increased Cost
Interconnection		No Cost	No Cost	One Time Cost	One Time Cost

Exhibit HS-3
Page 2 of 6

Value of Distributed Generation			Load Shifting		Storage-Energy	
DG Type	DG Characteristics & Capabilities		Responsive	Non-Responsive	Responsive	Non-Responsive
Energy						
	On-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
	Off-Peak		Cost or Value	Cost	Both	Retail Purchase
	Losses-Energy		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
	Emergency (shortage)		Time Specific Avoided Cost		Time Specific Avoided Cost	
	Low Load (Excess generation)		Time Specific Payment		Time Specific Payment	
Capacity						
	Generation					
		Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
		Long-term	ELCC	ELCC	ELCC	ELCC
		Short-term				
		Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Transmission					
		Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
		Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
		Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
		Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Distribution					
		Emergency	Ltd Outage Prevention Value		Ltd Outage Prevention Value	
		Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
		Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
		Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Reactive		Ltd Value		Ltd Value	
	Frequency Regulation					
	Energy Imbalance					
	Operating Reserves					
	Scheduling/Forecasting					
Risk						
	Fuel Price Hedge					
	Market Price Response		Yes	Yes	Yes	Yes
Environmental						
	Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost
	NOX SOX		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
	Water		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
	Land		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social						
Customer						
	Meter & Reading		Increased Cost	Increased Cost	Increased Cost	Increased Cost
	Service Drop					
	Billing		Increased Cost	Increased Cost	Increased Cost	Increased Cost
	Customer Service		Increased Cost	Increased Cost	Increased Cost	Increased Cost
	Interconnection		One Time Cost	One Time Cost	One Time Cost	One Time Cost

Exhibit HS-3
Page 3 of 6

Value of Distributed Generation					
DG Type	Solar				
DG Characteristics & Capabilities	Fixed Axis			Tracking	
	South	West	Responsive	Responsive	Non-Responsive
Energy					
On-Peak	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Off-Peak	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Losses-Energy	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Emergency (shortage)					
Low Load (Excess generation)					
Capacity					
Generation					
Emergency					
Long-term	ELCC	ELCC	ELCC	ELCC	ELCC
Short-term					
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Transmission					
Emergency			Outage Prevention Value	Outage Prevention Value	
Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Distribution					
Emergency			Outage Prevention Value	Outage Prevention Value	
Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Reactive			Value	Value	
Frequency Regulation			Maybe If Aggregated	Maybe If Aggregated	
Energy Imbalance			Maybe If Aggregated	Maybe If Aggregated	
Operating Reserves					
Scheduling/Forecasting					
Risk					
Fuel Price Hedge	Yes	Yes	Yes	Yes	Yes
Market Price Response	Yes	Yes	Yes	Yes	Yes
Environmental					
Carbon	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Water	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Land	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social					
Customer					
Meter & Reading	Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Service Drop					
Billing	Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Customer Service	Increased Cost	Increased Cost	Increased Cost	Increased Cost	Increased Cost
Interconnection	One Time Cost	One Time Cost	One Time Cost	One Time Cost	One Time Cost

Exhibit HS-3
Page 4 of 6

Value of Distributed Generation			
DG Type		Wind	
DG Characteristics & Capabilities		Responsive	Non-Responsive
Energy			
On-Peak		Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost
Emergency (shortage)			
Low Load (Excess generation)		Time Specific Payment	
Capacity			
Generation			
	Emergency		
	Long-term	ELCC	ELCC
	Short-term		
	Losses	Proportional to ELCC	Proportional to ELCC
Transmission			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Distribution			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Reactive		Value	
Frequency Regulation		Maybe If Aggregated	
Energy Imbalance			
Operating Reserves			
Scheduling/Forecasting			
Risk			
Fuel Price Hedge		Yes	Yes
Market Price Response		Yes	Yes
Environmental			
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost
Social			
Customer			
Meter & Reading		Increased Cost	Increased Cost
Service Drop			
Billing		Increased Cost	Increased Cost
Customer Service		Increased Cost	Increased Cost
Interconnection		One Time Cost	One Time Cost

Value of Distributed Generation		Increased Conservation	Increased Insulation
DG Type			
DG Characteristics & Capabilities			
Energy			
On-Peak		Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost
Emergency (shortage)			
Low Load (Excess generation)			
Capacity			
Generation			
	Emergency		
	Long-term	ELCC	ELCC
	Short-term		
	Losses	Proportional to ELCC	Proportional to ELCC
Transmission			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Distribution			
	Emergency		
	Long-term	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC
Reactive			
Frequency Regulation			
Energy Imbalance			
Operating Reserves			
Scheduling/Forecasting			
Risk			
Fuel Price Hedge		Yes	Yes
Market Price Response		Yes	Yes
Environmental			
Carbon		Maybe In Avoided Cost	Maybe In Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost
Social			
Customer			
Meter & Reading			
Service Drop			
Billing			
Customer Service			
Interconnection		No Cost	No Cost

Value of Distributed Generation DG Type DG Characteristics & Capabilities		Efficent Appliances		Efficient HVAC	
		Responsive	Non-Responsive	Responsive	Non-Responsive
Energy					
On-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Off-Peak		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Losses-Energy		Avoided Cost	Avoided Cost	Avoided Cost	Avoided Cost
Emergency (shortage)					
Low Load (Excess generation)		Time Specific Payment		Time Specific Payment	
Capacity					
Generation					
	Emergency				
	Long-term	ELCC	ELCC	ELCC	ELCC
	Short-term				
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Transmission					
	Emergency				
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Distribution					
	Emergency				
	Long-term	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
	Short-term	Specific Location Only	Specific Location Only	Specific Location Only	Specific Location Only
	Losses	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC	Proportional to ELCC
Reactive					
Frequency Regulation					
Energy Imbalance					
Operating Reserves					
Scheduling/Forecasting					
Risk					
Fuel Price Hedge		Yes	Yes	Yes	Yes
Market Price Response		Yes	Yes	Yes	Yes
Environmental					
Carbon		Maybe in Avoided Cost	Maybe in Avoided Cost	Maybe in Avoided Cost	Maybe in Avoided Cost
NOX SOX		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Water		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Land		In Avoided Cost	In Avoided Cost	In Avoided Cost	In Avoided Cost
Social					
Customer					
Meter & Reading					
Service Drop					
Billing					
Customer Service					
Interconnection		No Cost	No Cost	No Cost	No Cost