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OPEN MEETING ITEM



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Executive Director

ARIZONA CORPORATION COMMISSION

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DATE: JULY 20, 2016
DOCKET NO.: E-04204A-15-0142

TO ALL PARTIES:

Enclosed please find the recommendation of Administrative Law Judge Jane L. Rodda. The recommendation has been filed in the form of an Opinion and Order on:

UNS ELECTRIC, INC.
(RATES)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by 4:00 p.m. on or before:

JULY 29, 2016

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

AUGUST 9 AND 10, 2016

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602) 542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

Arizona Corporation Commission

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1 **BEFORE THE ARIZONA CORPORATION COMMISSION**

2 **COMMISSIONERS**

3 DOUG LITTLE – Chairman
4 BOB STUMP
5 BOB BURNS
6 TOM FORESE
7 ANDY TOBIN

8 IN THE MATTER OF THE APPLICATION OF UNS
9 ELECTRIC, INC. FOR THE ESTABLISHMENT OF
10 JUST AND REASONABLE RATES AND
11 CHARGES DESIGNED TO REALIZE A
12 REASONABLE RATE OF RETURN ON THE FAIR
13 VALUE OF THE PROPERTIES OF UNS
14 ELECTRIC, INC. DEVOTED TO ITS OPERATIONS
15 THROUGHOUT THE STATE OF ARIZONA AND
16 FOR RELATED APPROVALS.

DOCKET NO. E-04204A-15-0142

DECISION NO. _____

OPINION AND ORDER

12 DATES OF HEARING: March 1, 3-4, 7-11, 14-18, 21, and 23, 2016
13 PLACE OF HEARING: Tucson, Arizona
14 PUBLIC COMMENT: March 22, 2016, Nogales, Arizona
15 March 31, 2016, Kingman, Arizona
16 March 31, and April 18, 2016, Lake Havasu, Arizona
17 ADMINISTRATIVE LAW JUDGE: Jane L. Rodda
18 IN ATTENDANCE Doug Little, Chairman (Hearing & Public Comment)
19 Bob Burns, Commissioner (Public Comment)
20 Tom Forese, Commissioner (Public Comment)
21 Andy Tobin, Commissioner (Public Comment)
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25 PINNACLE WEST CAPITAL CORPORATION, on
26 behalf of Arizona Public Service Company;
27 Mr. Court S. Rich and Ms. Loren Unger, ROSE LAW
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9 EARTHJUSTICE, on behalf of Vote Solar;

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11 Minerals Corporation and Arizonans for Electric Choice
and Competition;

12 Mr. Lawrence V. Robertson, Jr., on behalf of Noble
13 Americas Energy Solutions, L.L.C.;

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15 Ratepayer Alliance;

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17 Cooperative;

18 Mr. Garry D. Hays, LAW OFFICES OF GARRY D.
HAYS, P.C., on behalf of Arizona Solar Deployment
19 Alliance;

20 Mr. Tom Harris, on behalf of Arizona Solar Energy
Industries Association; and

21 Mr. Brian E. Smith and Ms. Bridget Humphrey, Staff
22 Attorneys, and Ms. Janice Alward, Chief Counsel, Legal
Division, on behalf of the Utilities Division of the
23 Arizona Corporation Commission.

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BY THE COMMISSION:

UNSE Electric, Inc. ("UNSE" or "Company") provides electric service to approximately 95,000 customers, of which 82,600 are residential, within Santa Cruz and Mohave Counties in Arizona.¹ On May 5, 2015, UNSE filed with the Arizona Corporation Commission ("Commission") an Application for a rate increase ("Application").

Intervention in this matter was granted to the Residential Utility Consumer Office ("RUCO"), Noble Americas Energy Solutions LLC ("Noble"), Nucor Corp. ("Nucor"), The Alliance for Solar Choice ("TASC"), Arizona Public Service Company ("APS"), Fresh Produce Association of the Americans ("FPAA"), Walmart Stores, Inc. ("Walmart"), Arizona Investment Council ("AIC"), Southwest Energy Efficiency Project ("SWEEP"), Western Resource Advocates ("WRA"), Vote Solar, Freeport Minerals Corporation ("Freeport") and Arizonans for Electric Choice and Competition (collectively "AECC"), Arizona Utility Ratepayer Alliance ("AURA"), Sulphur Springs Valley Electric Cooperative ("SSVEC"), Arizona Solar Deployment Alliance ("ASDA"), Arizona Solar Energy Industries Association ("AriSEA"), and Trico Electric Cooperative ("Trico").

The Application

UNSE's current rates were established as a result of a Settlement Agreement approved in Decision No. 74235 (December 31, 2013), based on a June 30, 2012 test year, and with rates effective January 1, 2014. The Company states that it filed the current Application due to increased costs associated with a substantial investment in plant since the last rate case, including in particular, the purchase of a 25 percent interest in the Gila River Power Plant #3 ("Gila River") for \$55 million, which alone increased the Company's Original Cost Rate Base ("OCRB") by 26 percent.² The Company states that the Gila River acquisition increased its non-fuel operating costs by approximately \$12 million per year, which was expected to be offset by lower purchased capacity and energy costs and a decline in base fuel rates of approximately \$12.3 million in 2015.

In addition to increased revenues needed to recover operating expenses, including its authorized return on equity, UNSE asserted that it needs an updated rate design to rectify the under-recovery of

¹ Post-Hearing Updated Schedule G-1 filed April 4, 2016 ("UNSE Final Schedules").

² Ex UNSE-1 at 3.

1 fixed costs due to declining retail energy sales and the fact that under current rates many of its fixed
2 costs are being recovered from volumetric per-kWh charges. UNSE's retail sales in the test year
3 declined nearly 8 percent since the last test year, which UNSE attributes to the closure of several large
4 customers since the last rate case, the effects of energy efficiency and distributed generation, and the
5 slow pace of economic recovery in its service territory.

6 In its Application, UNSE sought an increase in gross test year revenues of \$22.6 million.³ Its
7 proposed revenue requirement was based on a Fair Value Rate Base ("FVRB") of \$365.7 million,
8 which was the average of an OCRB of \$272 million and a Reconstruction Cost New Less Depreciation
9 ("RCND") Rate Base of \$439.4 million. To determine its cost of capital, UNSE employed its 2014
10 test year actual capital structure which was comprised of 52.83 percent equity and 47.17 percent debt,
11 with a cost of debt of 4.66 percent and proposed cost of equity of 10.35 percent. The Company
12 calculated a Weighted Average Cost of Capital ("WACC") of 7.67 percent. UNSE proposed a Fair
13 Value Rate of Return ("FVROR") of 6.22 percent, which assumed a return on its fair value increment
14 of 1.45 percent.⁴

15 In its Application, UNSE proposed to offset the \$22.6 million increase with a proposed \$14.9
16 million reduction in fuel costs and revenues due to its acquisition of Gila River, lower power market
17 costs, and adjustments to test year sales.⁵ UNSE also proposed that \$4.3 million in transmission costs
18 currently being recovered through its Transmission Cost Adjustor ("TCA") be recovered in base rates.
19 In addition, UNSE proposed a one-year credit to the Purchased Power and Fuel Adjustment Clause
20 ("PPFAC") to reflect the accrued savings as a result of the Accounting Order related to the acquisition
21 of Gila River (estimated at \$9.3 million).⁶ The combination of these proposals resulted in a revenue
22 decrease of approximately \$3.5 million, or 2.1 percent over test year adjusted retail revenue in the first
23 year, and an increase of approximately \$5.8 million, or 3.6 percent in year two.

24 The Company originally proposed a rate design that included: (1) increased basic service
25 charges for both residential and small commercial customers (from \$10 to \$20 for the Residential Class

26 ³ Id. at A-1.

27 ⁴ Id. at 1 and 6

⁵ Id. at 5.

28 ⁶ In Decision No. 74911 (January 22, 2015), the Commission authorized UNSE to defer the recovery of costs associated with its acquisition of the Gila River.

1 and from \$14.50 to \$30.00 for the Small General Service (“SGS”) Class); (2) eliminating the third
2 volumetric rate tier for residential customers; (3) an optional three-part rate structure for the Residential
3 and SGS Classes that included a monthly service charge, a demand component, and a volumetric
4 energy component; and (4) a mandatory three-part rate structure for partial requirements customers,
5 including new users of solar arrays and other distributed generation (“DG”) equipment.⁷

6 Additionally, to incentivize business development and retention in its service area, UNSE
7 proposed an Economic Development Rate (“EDR”) which would provide discounted electricity rates
8 to new or existing businesses that meet certain qualifications, such as job creation or minimum load
9 requirements. And in compliance with Decision No. 74689 (August 12, 2014) (approving the Fortis
10 Settlement Agreement) UNSE also submitted a pilot program for a “buy through” tariff that, if
11 approved, would be available to Large Power Service customers.⁸

12 UNSE also proposed to modify its net metering rider that would apply to net metered customers
13 who submitted applications for interconnection after June 1, 2015. Under UNSE’s proposal: (1) new
14 net metered customers⁹ would continue to receive a full retail rate offset for the energy they consume
15 from their DG system; (2) new net metered customers would pay the currently approved and applicable
16 retail rate for all energy delivered by UNSE, with applicable retail rates limited to the demand-based
17 rate options; and (3) new net metered customers would be compensated for any excess energy their DG
18 system produces and delivers to UNSE, with bill credits calculated using a new “Renewable Credit
19 Rate” (a rate that reflects the current cost of utility scale solar energy). New net metered customers
20 could carry over unused bill credits to future months if they exceed the amount of their current UNSE
21 bill.¹⁰

22 UNSE also proposed to modify its Purchased Power and Fuel Adjustment Clause (“PPFAC”)
23 to reflect a percentage basis allocation instead of a per kWh allocation, and to modify its Lost Fixed
24 Cost Recovery (“LFCR”) mechanism to include adding fixed generation costs and 100 percent of non-
25 generation demand charges (instead of 50 percent), as well as increasing the cap from 1 percent to 2

26 ⁷ Ex UNSE-1 at 8.

27 ⁸ UNSE does not support approval of a buy-through tariff.

28 ⁹ Under the Company’s proposal, “new” net metered customers would be those customers who submitted applications after June 1, 2015.

¹⁰ Ex UNSE-1 at 9.

1 percent.

2 Further, UNSE requested authority to defer 100 percent of the Arizona property taxes above or
3 below the test year level caused by changes in the composite property tax rate and changes in the Gila
4 River valuation methodology. It also requested authority to defer all costs associated with appealing
5 the Gila River property values, and to amortize the deferral balance over 3 years. Finally, the Company
6 proposed modifications to its Rules and Regulations and to its Tariff to modernize and clarify areas of
7 confusion.¹¹

8 **Overview of the Proceeding**

9 **Staff and Intervenor Direct Testimony**

10 In its November 6, 2015 Direct Testimony, Staff described a number of adjustments to rate base
11 and operating income, which resulted in a recommendation that UNSE be authorized a gross revenue
12 increase of \$18.1 million on an adjusted FVRB of \$353,896,000.¹² Staff's recommended revenue
13 increase was premised on using the Company's actual capital structure with a cost of equity of 9.5
14 percent, and a FVROR of 5.60 percent.¹³

15 In its Direct Rate Design Testimony filed on December 9, 2015, Staff recommended a
16 mandatory transition of the Residential and SGS Classes (including DG customers) to three-part
17 demand rates with a time of use ("TOU") component, in order to better and more accurately relate rates
18 to underlying costs.¹⁴ Staff did not recommended any changes to the current net metering tariffs.¹⁵

19 RUCO recommended various adjustments that resulted in a recommended gross revenue
20 increase of \$12.2 million, based on a Cost of Equity of 8.35 percent, and FVROR of 5.26 percent on
21 an adjusted FVRB of \$345,131,000.¹⁶

22 RUCO supported different rate options for DG and non-DG residential customers based on their
23 different usages of the grid. RUCO recommended keeping non-DG residential customers on traditional
24 two-part rates, and proposed three optional rates for residential solar DG customers, which would

25

26 ¹¹ Id. at 10.

27 ¹² Ex S-1 Mullinax Dir at DHM-2.

28 ¹³ Ex S-3 Abinah Dir at 12; Ex S-1 Mullinax Dir at DHM-2.

¹⁴ Ex Staff-5 Solganick Rate Dir at 3.

¹⁵ Ex S-16 Broderick Rate Dir at 11.

¹⁶ Ex RUCO-1 Michlik Dir at 4.

1 impact the current net metering scheme.¹⁷

2 Other than RUCO, Intervenors did not focus on the ultimate revenue requirement, although
3 TASC and Walmart provided testimony on the cost of capital. TASC recommended a hypothetical
4 capital structure of 50 percent debt and 50 percent equity and a Cost of Equity of 8.75 percent, and
5 Walmart recommended a Cost of Equity of no more than 9.5 percent based on the Company's actual
6 capital structure.¹⁸ SWEEP recommended incorporating \$5 million of energy efficiency costs in base
7 rates rather than recovered in the current adjustor mechanism, which would have affected the revenue
8 requirement, but not the bottom-line on ratepayers' bills.¹⁹

9 Intervenors, representing a wide array of interests, made a number of rate design
10 recommendations:

11 • TASC, Vote Solar, and AURA believed the Company's rate proposals were
12 discriminatory and would hinder the installation of solar DG. These intervenors objected to the
13 imposition of demand charges on residential DG customers or any changes to the net metering tariff.²⁰

14 • SWEEP objected to certain rate design changes such as increasing the basic customer
15 charge and eliminating the third rate tier which it believed would negatively impact energy efficiency
16 efforts.²¹

17 • WRA objected to treating DG and non-DG customers separately, objected to residential
18 demand charges and recommended a minimum bill to address low-usage customers.²²

19 • ACAA supported increasing eligibility for low-income discounts and advanced various
20 proposals to hold low-income customers harmless from the rate increase, opposing in particular
21 increased fixed charges.²³

22 • Large commercial and industrial customers, represented by Walmart and AECC/Noble,
23 in general supported the Company's Customer Cost of Service Study ("CCOSS") with some
24

25 ¹⁷ Ex RUCO-5 Huber Rate Dir at 13.

¹⁸ Ex TASC-22 Woolridge Dir at 4; Ex Walmart-1 Chriss at 9.

26 ¹⁹ Ex SWEEP-1 Schlegel Dir.

²⁰ Ex TASC 19 Fulmer Dir; Ex TASC-20 Fulmer Rate Dir; Ex AURA-4 Quinn Rate Dir; Ex Vote Solar-6 Kobor Dir.

27 ²¹ Ex SWEEP-2 Schlegel Rate Dir.

²² Ex WRA-1 Wilson Rate Dir at 2-3.

28 ²³ Ex ACAA-1 Zwick Dir; Ex ACAA-2 Zwick Rate Dir. UNSE's low income program is entitled "Customer Assistance Residential Energy Support" or "CARES".

modification, and advocated for a more equitable revenue allocation between the larger commercial customers who they assert are subsidizing the Residential and SGS Classes; they also supported the EDR and buy-through tariff proposals with modifications.²⁴ Nucor objected to the Company's methodology for determining demand charges, and recommended changes to the Large Power TOU rates and Interruptible Rider.²⁵ FPAA, representing the produce industry in Santa Cruz County, objected to the implementation of demand charges on its members.²⁶

• AIC, representing utility equity investors, and APS, a major electric utility in Arizona, supported the Company's proposal for residential demand charges and changes to net metering.²⁷

Company's Rebuttal Position

In Rebuttal Testimony filed on January 19, 2016, UNSE accepted some of Staff's adjustments as well as Staff's recommended revenue increase of \$18.5 million.²⁸ In accepting the lower revenue increase, the Company revised its revenue allocation, which reduced the amount of the decrease that had been proposed for the larger commercial and industrial classes.

The Company also accepted Staff's recommendation concerning mandatory demand charges for all residential and SGS customers, and proposed a plan that would transition to three-part rates by the spring of 2017.²⁹ Under UNSE's proposal, transitional rates that retained the current two-part rate design would remain in place until all residential and SGS customers were equipped with the smart meters necessary to implement demand rates, and several months of usage data could be collected.³⁰

UNSE stipulated that Staff's proposed three-part rate structure would eliminate the need to specifically address the current Net Metering policy if properly designed and implemented in a timely manner.³¹ Because not all parties supported the implementation of the three-part rates, UNSE continued to advocate that its net metering proposal be evaluated as part of this proceeding.³²

...

²⁴ Ex Walmart 4 Tillman Dir; Ex Walmart-2 Hendrix Dir; Ex AECC/Noble-1 Higgins Rate Dir;

²⁵ Ex NUCOR-1 Zarnikau Rate Dir.

²⁶ Ex FPAA-1 Jungmeyer Rate Dir; Ex FPAA-2 Simer Rate Dir.

²⁷ Ex AIC-C Hansen Rate Dir; AIC-A Yaquinto Rate Dir; Ex APS-6 Miessner Rate Dir.; Ex APS-3 Faruqui Rate Dir.

²⁸ Ex UNSE-12 Lewis Reb at 6.

²⁹ Ex UNSE-4 Hutchens Reb at 2.

³⁰ Ex UNSE-29 Dukes Reb at 11.

³¹ Ex UNSE-26 Tilghman Reb at 3.

³² Ex UNSE-4 Hutchens Reb at 12.

1 **Surrebuttal Positions**

2 In Surrebuttal Testimony filed on February 23, 2016, Staff made additional adjustments which
3 reduced Staff's recommended base rate increase to \$15.3 million, based on a FVROR of 5.63 percent,
4 and an adjusted FVRB of \$353,999,000.³³ Staff recommended a lower allocation of the revenue
5 increase to the Residential and SGS Classes than being proposed by the Company.³⁴

6 Staff supported the Company's three-part rate design proposal for the Residential and SGS
7 Classes, but proposed mitigation measures to protect customers who adopted DG prior to June 1, 2015.
8 Staff recommended keeping the existing Net Metering Tariffs.³⁵

9 RUCO made additional adjustments and calculated a gross revenue increase of \$17.205 million,
10 based on a Cost of Equity of 9.13 percent, FVROR of 5.48 percent, and an adjusted FVRB of \$353,755
11 million.³⁶ However, RUCO also stated that it would consider recommending Staff's Cost of Equity of
12 9.5 percent, if the overall revenue requirement was not greater than \$15.1 million.³⁷ RUCO continued
13 to advocate for its rate design options which distinguished between DG and non-DG residential
14 customers.³⁸

15 APS and AIC supported the Company's proposed three-part rate design for Residential and
16 SGS Classes and its proposed net metering modifications. TASC, Vote Solar, AURA, ACAA, SWEEP,
17 WRA opposed mandatory demand charges for residential ratepayers. FPAA opposed demand charges
18 being imposed on its members. The larger commercial and industrial customers, Walmart, Nucor and
19 AECC\Noble opposed Staff's recommended revenue allocation among the classes, the method for
20 determining demand charges, changes to the EDR, and supported the buy-through tariff.

21 **Company's Rejoinder Position**

22 In Rejoinder Testimony filed on February 29, 2016, UNSE agreed to accept a gross revenue
23 increase of \$15.1 million, as long it was is "provided with a reasonable opportunity to earn a 9.5 percent
24

25
26 ³³ Ex S-2 Mullinax Surr at Attachment DHM-1.

³⁴ Ex S-6 Solganick Surr at 5.

³⁵ Ex S-17 Broderick Surr.

³⁶ Ex RUCO-2 Michlik Surr at JMM-1

³⁷ Ex RUCO-4 Mease Surr at 21.

³⁸ Ex RUCO-6 Huber Surr.

1 return on equity.”³⁹ The Company continued to argue that its mandatory three-part rate design and
 2 proposed modifications to its Net Metering Tariff were appropriate and in the public interest to send
 3 the correct price signals.⁴⁰ The Company continued to argue that its Net Metering proposal can be
 4 approved without awaiting the outcome of the Value and Cost of Distributed Generation docket
 5 (“Value of DG docket”),⁴¹ although the Company also appeared willing to forego immediate net
 6 metering changes if its three-part rate proposal was adopted.⁴²

7 Public Comments

8 The Commission conducted Public Comment Meetings in Nogales, Lake Havasu and Kingman,
 9 and took public comments at the commencement of the hearing. The Commission has also received
 10 thousands of written letters and emails from members of the public, including many individuals and
 11 businesses located outside of UNSE’s service area, as it was widely perceived that the issues of three-
 12 part residential rates and changes in the net metering tariff had statewide implications. The vast
 13 majority of individuals making comments in this docket were either opposed to demand charges for
 14 residential customers, or to any changes in the net metering tariff, or both.

15 Company’s Post-Hearing Position

16 In its Initial Post-Hearing Brief filed on April 25, 2016, UNSE continued to propose a 9.5
 17 percent Cost of Equity and a gross revenue increase of \$15.1 million, but because it appeared that the
 18 transition to three-part rates for residential customers would not be as smooth as anticipated, the
 19 Company withdrew its support for mandatory demand charges for the Residential and SGS classes.⁴³
 20 Instead, as discussed herein, the Company offered a number of optional rates for non-DG residential
 21 customers, and mandatory three-part demand rates for DG customers, similar to its position in Direct
 22 Testimony. It continued to support revising its net metering tariff for new DG customers after June 1,

23
 24 ³⁹ Ex UNSE-13 Lewis RJ at 3. In Decision No. 75485 (March 10, 2016), the Commission modified the original accounting
 25 order that allowed deferral of the Gila River acquisition costs and benefits, and determined that it was in the public interest
 26 to offset the deferred costs and benefits to avoid a “yo-yo” effect from the PPFAC credit. As a result, UNSE now proposes
 to reduce expenses by \$3.1 million and flow the net benefits through the PPFAC. TEP, Staff and RUCO now agree that a
 \$15.1 million revenue increase is reasonable. UNSE Initial Brief at 11. UNSE reserves its right to contest the merits of the
 specific adjustments in a subsequent rate case.

27 ⁴⁰ Ex UNSE-5 Hutchens RJ.

⁴¹ Docket No. E-00000J-14-0023.

⁴² Ex UNSE-27 Tilghman RJ at 2.

⁴³ UNSE Initial Brief at 4.

1 2015.

2 Revenue Requirement

3 Rate Base

4 UNSE, RUCO and Staff were the only parties who made recommendations concerning rate
5 base adjustments. These parties have agreed for the purposes of this rate case that the Company's FVRB
6 should be \$354,001,000. This compares with the FVRB recommended by Staff and RUCO in
7 Surrebuttal Testimony of \$353.999 million and \$353.755 million, respectively,⁴⁴ and with the
8 Company's original proposed FVRB of \$355.729 million.⁴⁵

9 In pre-hearing testimony, the issues affecting rate base accounts involved a \$2.0 million
10 reduction related to deferred depreciation expense related to Gila River supported by Staff; a reduction
11 in Directors and Officers pre-paid insurance of \$16,778 recommended by Staff; and RUCO's
12 recommended adjustment for Net Operating Loss ("NOL") Carryforwards.⁴⁶

13 The parties' determined the Company's FVRB by weighing its OCRB and RCND Rate Base
14 50/50.

15	<u>Description</u>	<u>Adjusted OCRB</u> <u>(1,000s of Dollars)</u>	<u>Adjusted RCND</u> <u>(1,000s of Dollars)</u>
16	Gross Utility Plant in Service	\$664,701	\$1,169,067
17	Less Accumulated Depreciation	<u>296,961</u>	<u>561,911</u>
18	Net Utility Plant in Service	367,740	607,156
19	Citizens Acquisition Discount	(97,156)	(172,847)
20	LESS: Accum. Amort. Citizens Acq. Discount	<u>(36,098)</u>	<u>(69,682)</u>
21	Net Citizens Acquisition Discount	<u>(61,058)</u>	<u>(103,165)</u>
22	Total Net Utility Plant	<u>306,682</u>	<u>503,991</u>
23	Customer Advances for Construction	(3,833)	(4,268)
24	Customer Deposits	(4,428)	(4,428)
25	Other (ITC)	(422)	(422)

26
27 ⁴⁴ Ex S-2 Mullinax Surr at 2 and Ex RUCO-2 Michlik Surr at JMM-1.

⁴⁵ Application at Schedules A & B.

28 ⁴⁶ Ex RUCO-2 Michlik Surr at 304. RUCO withdrew its NOL adjustment based on UNSE providing additional Private Letter Rulings by the IRS on the topic.

1	Accumulated Deferred Inc. Taxes	(35,161)	(64,617)
2	Total Deductions	(43,844)	(73,735)
3	Allowance for Working Capital	7,455	7,454
4	Regulatory Assets	0	0
5	Regulatory Liabilities	0	0
6	Total Rate Base	\$270,293	\$437,710

7 No party to this proceeding objected to the FVRB finding agreed to by the Company, Staff and
8 RUCO. The record supports finding that a \$354,001,000 FVRB is fair and reasonable, and should be
9 adopted in this case.⁴⁷

10 Operating Revenue and Expenses

11 In their last rounds of pre-filed testimony, UNSE, RUCO and Staff proposed adjusted revenues
12 and operating expenses as follows (in 1,000s):⁴⁸

13		UNSE ⁴⁹	RUCO ⁵⁰	Staff ⁵¹
14	Adj TY Operating Revenues	\$156,717	\$158,714	\$156,717
15	Adj TY Operating Expenses	\$146,187	\$150,041	\$146,348
16	Adj TY Operating Income	\$10,530	\$8,673	\$10,369

17 Ultimately, UNSE agreed to revenue and operating expenses that resulted in Adjusted Test Year
18 Operating Revenues of \$156,717,000 and Adjusted Test Year Operating Expenses of \$146,187,000,
19 producing Adjusted Test Year Operating Income of \$10,530,000.⁵² For purposes of this rate case,
20 UNSE agreed to Staff's adjustments to Bad Debt Expense (\$132,000), Injuries and Damages
21 (\$320,000), Incentive Compensation (\$155,000), Directors and Officers Liability (\$20,000), Gila River
22 Deferred Costs (\$3,100,000), OATT (\$20,000) and Other (\$10,000), and to RUCO's adjustments for
23 Medical and Dental Insurance (\$181,000), Wellness Incentive Programs and Spot Awards (\$47,000),
24

25 ⁴⁷ $(\$270,293 + \$437,710) / 2 = \$354,001$.

26 ⁴⁸ No other parties submitted evidence on Operating Income except for SWEEP's proposal to include Energy Efficiency
Costs as part of Operating Expenses.

27 ⁴⁹ Ex UNSE-13 Lewis RJ at DBL-RJ-1.

27 ⁵⁰ Ex RUCO-2 Michlik Surr at JMM-8.

27 ⁵¹ Ex S-2 Mullinax Surr at Sch C.

28 ⁵² UNSE Final Schedules at C-1 and Ex UNSE-48.

1 EEI Dues (\$16,000), Rate Case Expense (\$17,000) and Other (\$1,000).⁵³

2 SWEEP recommended that the Commission move the recovery of Energy Efficiency program
3 costs (in this case, \$5 million) to base rates.⁵⁴ Under SWEEP's proposal, the demand side management
4 ("DSM") adjustor mechanism would remain intact and used as an adjustor to recover or refund any
5 energy efficiency funding amounts above or below the \$5 million being included in base rates.⁵⁵
6 SWEEP argues that it is unfair and illogical to single out only energy efficiency among the Company's
7 many energy resources on the customer's bill.⁵⁶ UNSE acknowledges that SWEEP's proposal has no
8 impact on customer bills, but believes that the DSM surcharge provides ratepayers with information
9 on the investments being made in energy efficiency programs.⁵⁷

10 **Resolution**

11 Although energy efficiency may be treated like other fuel resources in the integrated planning
12 process, we believe it is important to provide information about the benefits of energy efficiency and
13 the implications of using less energy. We believe that at this time, keeping the DSM adjustor as a
14 separate line item is the best course of action, especially given all of the other rate design issues and
15 changes that are being addressed in this proceeding. However, we do not rule out considering SWEEP's
16 proposal in a future rate case.

17 The compromise position for this rate case reached among the Company, RUCO and Staff is
18 reasonable. Thus, in the test year, we find that UNSE's adjusted Operating Income was \$10,530,000,
19 which resulted in a rate of return of 2.97 percent on its adjusted FVRB.

20 **Cost of Capital**

21 The Arizona Constitution requires the Commission to establish just and reasonable rates using
22 the fair value of the Company's property used to provide service.⁵⁸ Thus, the Commission needs to
23 determine a FVROR to apply to the FVRB. In recent years, the Commission has determined the

24 ⁵³ Ex UNSE-48.

25 ⁵⁴ Ex SWEEP-3 Schlegel Surr at 16.

26 ⁵⁵ Ex SWEEP-1 Schlegel Dir at 8-9; SWEEP/WRA/ACAA Reply Brief at 8.

27 ⁵⁶ SWEEP/WRA/ACAA Reply Brief at 8. ACAA is sympathetic to SWEEP's request, however customers on the CARES
rates are currently exempt from paying the DSM fee, so including this cost in base rates would raise low-income rates.
ACAA stated that this can be addressed through the CARES rate design by not including any DSM costs for low income
customers in the CARES rate, or through an adjustment of the CARES rates. SWEEP/WRA/ACAA Reply Brief at 10.

28 ⁵⁷ UNSE Initial Brief at 61.

⁵⁸ Ex RUCO-3 Mease Dir at 31; Ex UNSE-22 Bulkley Dir at 57.

1 FVROR by applying the market Return on Equity ("ROE") and the cost of debt to the Company's
 2 OCRB based on the percentage of equity and debt in the Company's capital structure. The Commission
 3 then applies a rate of return on the "fair value increment" which is the difference between the OCRB
 4 and the FVRB. The fair value increment represents the appreciation in the value of the assets to their
 5 current value due to inflation. The sum of the OCRB and the fair value increment is the total fair value
 6 of the utility's property. The FVROR is the sum of the returns on each of the components: (1) equity
 7 capital; (2) debt capital, and (3) the fair value increment, weighted by the percentage of each in the
 8 FVRB.

9 The parties making cost of equity recommendations in this case, except for TASC, recommend
 10 using the Company's actual capital structure to determine the weighted average cost of capital
 11 ("WACC"). At the end of the test year, UNSE's total capital consisted of 47.17 percent debt and 52.83
 12 percent equity.⁵⁹ The Company determined that the cost of debt is 4.66 percent, which no party
 13 disputes. TASC recommended using a hypothetical capital structure consisting of 50 percent equity
 14 and 50 percent debt.⁶⁰

15 UNSE

16 In its Direct Testimony, UNSE proposed a cost of equity of 10.35 percent based on Ms.
 17 Bulkley's proxy group analysis and application of the Constant Growth and Multi-stage forms of the
 18 Discounted Cash Flow ("DCF"), the Capital Asset Pricing Model ("CAPM") and the Risk Premium
 19 approach. Ms. Bulkely asserted that the range of returns on the fair value increment should be between
 20 the risk-free rate and the Cost of Equity, and ultimately concluded that the return on the fair value
 21 increment should be 1.5 percent, based on 50 percent of her estimated risk-free rate of 3.01 percent.⁶¹
 22 Based on these costs and percentages, UNSE proposed a FVROR of 6.22 percent.⁶²

23 In Rebuttal Testimony, the Company stated that it would not oppose using Staff's 9.5 percent
 24 cost of equity recommendations, and 0.5 percent return on the fair value increment, as long as the
 25 overall revenue increase and rate design provides UNSE with a reasonable opportunity to earn its

26 _____
 27 ⁵⁹ Ex UNSE-1 at Schedule D.

⁶⁰ Ex TASC-22 Woolridge Dir at 4.

⁶¹ Ex UNSE-22 Bulkley Dir at 60-62.

28 ⁶² Id. at 57-62.

1 ROE.⁶³

2 UNSE argues that the Commission should reject TASC's recommended hypothetical capital
3 structure and recommended cost of equity of 8.75 percent.⁶⁴ UNSE argues that a hypothetical capital
4 structure is used only when there is a significant variance from the proxy group. UNSE states that its
5 actual capital structure is similar to the proxy groups used to estimate the cost of capital by the various
6 cost of capital witnesses, and is comparable to the capital structure used in UNSE's last rate case. In
7 addition, UNSE asserts that utility management should be given some discretion in determining the
8 appropriate capital structure. UNSE's witness Grant testified that by having less debt in its capital
9 structure, UNSE has improved its access to credit and more favorable rates.⁶⁵ UNSE notes that when
10 it approved the Fortis merger, the Commission restricted UNSE's ability to pay dividends until equity
11 reached at least 50 percent. UNSE contends this indicates that the Commission considers 50 percent
12 equity to be a minimum target, not a specific target. UNSE asserts that its actual 52.8 percent equity is
13 only slightly higher than the minimum target and is a key component of maintaining the Company's
14 investment grade credit rating.⁶⁶

15 UNSE also disputes TASC's assertion that interest rates are falling. UNSE asserts that TASC
16 witness Woolridge's testimony shows that Moody's A rated and Baa rated utility bond rates are
17 increasing. In addition, UNSE asserts that credit spreads are increasing. By using a 4 percent risk free
18 rate in his CAPM analysis, when his data suggests a risk-free rate of approximately 2.75 percent, UNSE
19 claims that Mr. Woolridge acknowledges that rates will be increasing. In contrast, UNSE states that
20 the Cost of Equity agreed to by the Company, Staff, and RUCO of 9.5 percent is at the low end of the
21 authorized ROEs for Mr. Woolridge's proxy group.⁶⁷

22 RUCO

23 In Direct Testimony, RUCO originally recommended a Cost of Equity of 8.35 percent based
24 on its witness Mease's results from this DCF and CAPM models; a cost of debt of 4.66 percent, and
25 using the Company's actual capital structure. RUCO recommended that the Commission adopt a

26 ⁶³ Ex UNSE-23 Bulkley Reb at 79; UNSE Initial Brief at 16.

27 ⁶⁴ UNSE Initial Brief at 13-14.

28 ⁶⁵ Ex UNSE-9 Grant RB at 3.

⁶⁶ UNSE Initial Brief at 15.

⁶⁷ Ex UNSE-24 Bulkley RJ, Ex AEB-2. UNSE Reply Brief at 4.

1 WACC of 6.86 percent and a FVROR of 5.26 percent.⁶⁸ In Surrebuttal Testimony, Mr. Mease revised
 2 his recommendations to include a 9.13 percent cost of common equity, a 4.66 cost of debt, yielding a
 3 7.17 percent WACC and a FVROR of 5.48 percent.⁶⁹

4 At the hearing, RUCO agreed to adopt Staff's 9.5 percent cost of equity and 0.50 percent fair
 5 value increment.⁷⁰

6 **Staff**

7 Staff recommended a 9.5 percent Cost of Equity and a 0.5 percent rate of return on the fair
 8 value increment based on the findings in UNSE's last rate case.⁷¹ Staff also recommended that the
 9 Commission approve the capital structure proposed by the Company. Staff's recommendations resulted
 10 in a WACC of 7.22 percent, and a rate of return on the fair value increment of 0.5 percent, and a
 11 FVROR of 5.63 percent.⁷²

12 **Walmart**

13 Walmart asserted that the 10.35 percent ROE proposed by the Company was too high, and that
 14 the Commission should not approve a ROE higher than the currently approved ROE of 9.5 percent.⁷³

15 Walmart's witness Chriss acknowledged that Walmart could also accept the 9.5 percent cost of
 16 equity as agreed by UNSE, RUCO and Staff.⁷⁴

17 **TASC**

18 TASC was the only party which provided evidence on the issue of the cost of equity that did
 19 not agree to accept a 9.5 percent cost of equity for the purposes of this rate case. TASC argues the
 20 proposed 9.5 percent cost of equity does not recognize financial improvements since the last rate case,
 21 such as UNSE's improved bond rating, from Baa3 to A3, and receipt of over \$100 million in equity
 22 capital, which should have the effect of lowering the cost of equity.⁷⁵

23

24 ⁶⁸ Ex RUCO-3 Mease Dir at ii.

25 ⁶⁹ Ex RUCO-4 Mease Surr at ii. Mr. Mease appears to calculate a weighted average cost of capital of 7.17 percent, but
 utilizes 7.02 percent in his calculation of FVROR. Given RUCO's acceptance of Staff's recommended cost of equity and
 FVROR, we do not attempt to reconcile the discrepancy.

26 ⁷⁰ RUCO Initial Brief at 1.

27 ⁷¹ Ex Staff-3 Abinah Dir at 2.

28 ⁷² Ex S-2 Mullinax Surr at DHM-1(Schedule D).

⁷³ Ex Walmart-1 at 4; Tr. at 782.

⁷⁴ Tr. at 782.

⁷⁵ TASC Initial Brief at 37-38.

1 TASC did not discuss the capital structure or FVROR in its post-hearing briefs, but in Direct
 2 Testimony, Mr. Woolridge proposed using a hypothetical capital structure comprised of 50 percent
 3 equity and 50 percent debt, in order to better match the capitalization of the proxy group.⁷⁶ Mr.
 4 Woolridge did not address the calculation of the FVROR.

5 TASC supports a cost of equity of 8.75 percent.⁷⁷ Its witness Woolridge utilized the DCF and
 6 CAPM in his analysis of UNSE's cost of equity. Mr. Woolridge's DCF analyses indicated ROEs of 8.7
 7 and 9.0 percent, and his CAPM results were 8.1 percent and 8.3 percent. As a check on his result, he
 8 compared his results to the returns on equity of similar publicly held electric utilities as well as the
 9 proxy group used by UNSE's witness.

10 TASC criticizes Staff's use of the cost of equity utilized in the last rate case, because that return
 11 was the result of a settlement and not based on empirical analysis, and relies on outdated data that does
 12 not account for current market conditions.⁷⁸ TASC also criticizes UNSE's recommended ROE of 10.35
 13 percent, which is almost 100 basis points over the Cost of Equity awarded in the last rate case, even
 14 though the Company has decreased its credit risk and interest rates remain at historic lows.⁷⁹ TASC
 15 believes that the UNSE witness "grossly" inflated the GDP growth rates and long-term projected 30-
 16 Year Treasury yield, and used an unrealistic overall stock market return which results in inflating her
 17 risk premium calculations.⁸⁰

18 TASC also criticizes Ms. Bulkley's presentation of the ROE returns for 2012-2016 by lumping
 19 them into one chart that masks the recent trend that authorized rates of return have declined since
 20 2012.⁸¹ TASC argues that in determining a cost of equity, the Commission must look at the company's
 21 individual circumstances. According to TASC, investor risk is key to the authorized rate of return
 22 calculation and therefore UNSE's equity infusion from Fortis reduced investor risk and justifies a
 23 downward adjustment of the cost of equity from the Company's last rate case.⁸²

24 ...

25 ⁷⁶ Ex TASC-22 Woolridge Dir at 4.

26 ⁷⁷ Id. at 26-27.

27 ⁷⁸ TASC Initial Brief at 38-39.

28 ⁷⁹ UNSE Initial Brief at 39.

⁸⁰ TASC Initial Brief at 39-40.

⁸¹ TASC Reply Brief at 17-18.

⁸² Id. at 18.

Resolution – Cost of Capital

Only TASC specifically disputes utilizing a Cost of Equity of 9.5 percent, recommending instead a Cost of Equity of 8.75 percent. The estimates for the Cost of Equity in this proceeding range from 8.75 percent by TASC to UNSE's 10.35 percent.⁸³ The agreed 9.5 percent is within the range and supported by the evidence. Although UNSE's financial metrics, such as its bond rating and capitalization, have improved since its last rate case due to the financial support of its parent Fortis, interest rates are rising, and UNSE faces significant risks from challenging economic conditions in its service area, declining energy sales, and a current rate design that requires substantial modification in order to comply with traditional principles of cost causation. A Cost of Equity of 9.5 percent is not unreasonable in this case.

UNSE did not provide a calculation of the FVROR or a direct calculation of the \$15.1 million agreed revenue increase. Based on a Cost of Equity of 9.5 percent, cost of debt of 4.66 percent, and a return on the fair value increment of 0.5 percent, we calculate a FVROR of 5.63 percent.⁸⁴ Under the totality of circumstances in this case, a FVROR of 5.63 percent is reasonable.

Resolution – Authorized Revenue Increase

Based on the findings of FVRB and FVROR, we authorize a non-fuel revenue increase of \$15,100,000, a 9.6 percent increase over adjusted test year revenues, as illustrated below:⁸⁵

Adjusted Fair Value Rate Base	\$354,001,000
Adjusted Operating Income	\$10,530,000
Current Rate of Return	2.97%
Required Operating Income	\$19,930,000
Required Rate of Return	5.63%
Operating Income Deficiency	\$9,400,000
Gross Revenue Conversion Factor	1.6070

⁸³ TASC 8.75 percent, RUCO 9.13 percent, Staff 9.5 percent, Walmart 9.5 percent and UNSE 10.35 percent.

⁸⁴ UNSE's Final Schedule A-1 does not reconcile with the updated Schedule D-1 (Cost of Capital), appears to utilize an erroneous FVROR of 3.95 percent, and does not indicate how the utility calculated a \$15.1 million revenue increase.

⁸⁵ We are not able to precisely reconcile a 9.5 percent Cost of Equity and rate of return on the fair value increment with the requested increase of \$15,100,000. We find, however, that in this case, the deviation is de minimus, and does not alter the ultimate conclusion that a revenue increase of \$15.1 million is supported by the record.

1 Increase in Gross Revenue Requirement

\$15,105,800

2 No party objected to the proposed \$15.1 million revenue increase. An increase of \$15,100,000
3 comports with the lowest of the range of recommendations advanced by parties in this proceeding who
4 addressed the revenue increase.

5 Revenue Allocation

6 UNSE

7 One of the goals in this rate case has been to achieve a better alignment of revenue recovery
8 and cost causation. UNSE's CCOSS indicates that the large commercial and industrial classes are
9 subsidizing the Residential and SGS Classes.⁸⁶ The CCOSS shows that despite a positive return for the
10 Company as a whole, the Residential Class had a negative return and the SGS Class return was lower
11 than the Company average, while the medium/large general service class and the Large Power Service
12 ("LPS") Class contributed returns many times the Company average, at 17.55 percent and 31.48
13 percent, respectively.⁸⁷ Another way to show the current inter-class subsidies looks at the unitized rates
14 or return ("UROR") for each class.⁸⁸ Under current rates the Residential Class has UROR of -0.13, the
15 SGS Class has an UROR of 0.33, the MGS/LGS Class has a UROR of 3.51 and the LPS Class has a
16 UROR of 6.04.⁸⁹

17 UNSE proposed an allocation of the revenue increase that does not match the results of its
18 CCOSS in that it does not achieve a UROR of 1.0 for each class. Rather, in the interest of gradualism
19 UNSE proposed to take a step that would reduce, but not eliminate, the subsidy from the large
20 commercial classes to the Residential Class. Of the \$15.1 million revenue increase, UNSE would
21 allocate \$14,136,082 (93.6 percent) to the Residential Class; \$1,528,313 (10.1 percent) to the SGS
22 Class; a decrease of \$83,000 (0.5 percent) to the Interruptible Power Service Class; an increase of
23

24 ⁸⁶ Ex UNSE-33 Jones RJ at 4.

25 ⁸⁷ UNSE Final Schedules at G-1. Updated Schedule G does not reconcile precisely with the book values used to determine
26 the revenue increase. UNSE indicates that the difference is due to a difference in billed revenues with booked revenues.
27 This also affects the ability to compare Staff's Ex-18 (showing results of various allocation strategies) which is based on
28 the CCOSS with the authorized increase.

⁸⁸ A common method to measure the degree of inter-class subsidy paid or received by a particular customer class is the
measurement of UROR, or relative rate of return. A UROR of less than 1 indicates that a class is receiving a subsidy and
a UROR above 1 indicates that a class is paying a subsidy. Ex S-5 Solganick Rate Design Dir at 21, Ex Walmart-4 Tillman
Dir at 6; Tr. at 2795-96.

⁸⁹ Ex S-18.

1 \$286,000 (1.9 percent) to the MGS Class; a decrease of \$131,000 (0.86 percent) to the LGS Class; a
 2 decrease of \$759,000, (5.0 percent) to the LPS Class; and an increase of \$53,000 (0.35 percent) to the
 3 Lighting Class.⁹⁰

4 UNSE asserts that Staff's proposal, which allocates less of the increase to the Residential Class,
 5 would require a larger "jump to parity" in the next rate case than proposed in this case, and that the
 6 Company's allocation would make a "two rate case jump" more fair, reasonable, and attainable.
 7 Ultimately, however, UNSE acknowledges that the revenue allocation is a policy decision for the
 8 Commission which must decide what level of cross-subsidization is appropriate and how quickly it
 9 would like to achieve a more equitable allocation of costs.⁹¹

10 Staff

11 Staff acknowledges that the Residential Class is currently being subsidized by the commercial
 12 classes. However, Staff claims that in order to bring the Residential Class to parity with the other
 13 classes would require the Residential Class receiving 127.6 percent of the total increase; and that to
 14 bring the SGS class to parity would require a class increase of 15.7 percent.⁹² Given the magnitude of
 15 these percentages, Staff proposes a gradual transition toward the long-term goal of parity.⁹³ According
 16 to Staff, the relative size of each class limits the degree to which the Commission can increase cost
 17 allocations in a single rate case. When determining class revenue allocations, Staff believes that the
 18 Commission should consider each class' relative position to other classes, economic conditions for
 19 consumers, the business climate and past cost allocation practices.

20 Staff considered various methodologies of allocating the revenue requirement among the rate
 21 classes, and ultimately recommends increasing the Residential and SGS Classes by 50 percent of the
 22 amount needed to reach parity, and increasing all other classes by an equal 10.1 percent.⁹⁴ Thus, Staff
 23 would have the Commission move the Residential Class half way to bringing it to conformity with the
 24 actual cost of service, with a goal to eliminate inter-class subsidies by the Company's next rate case.⁹⁵

25

26 ⁹⁰ UNSE Final Schedules at A-1.

27 ⁹¹ UNSE Initial Brief at 17; UNSE Reply Brief at 4-5.

28 ⁹² Ex S-18.

⁹³ Staff Initial Brief at 8-9.

⁹⁴ Staff Initial Brief at 9; Staff Reply Brief at 7-8.

⁹⁵ Tr. at 2792; Staff Reply Brief at 7.

Specifically, Staff would allocate \$9,658,500 (64.0 percent) of the \$15,100,000 revenue increase to the Residential Class; \$1,183,250 (7.8 percent) to the SGS Class; \$3,710,667 (24.6 percent) to the MGS/LGS Class; and \$509,647 (3.4 percent) to the LPS Class.⁹⁶ Under Staff's recommendation, the Residential Class would have a UROR of 0.07, the SGS Class would have a UROR of 0.31, the MGS/LGS Class would have a UROR of 3.10, and the LPS Class would have a UROR of 5.34.⁹⁷

Staff does not oppose AECC/Noble's proposed funding mechanism for the buy-through tariff, but does not oppose the formula as a way to allocate the revenue increase.⁹⁸ Staff states that by allocating revenue based on the originally proposed \$22.6 million increase, and then reducing the amount by half of the \$7.5 million difference between the \$22.6 million and the ultimately agreed-to \$15.1 million, merely changes the bottom line allocation percentages. Staff believes that the traditional methodology, as used by Staff and the Company, is simpler, more direct, and accomplishes the same goal.

RUCO

RUCO agrees with Staff's position on allocating the revenue increase in this proceeding. RUCO notes that both Staff and the Company have proposals for moving rates closer to the cost of service, but Staff's proposal is a less aggressive transition.⁹⁹

Walmart

Walmart argues that the Commission should attempt to eliminate subsidies between customer classes in order to send proper price signals and drive efficient use of system resources.¹⁰⁰ Walmart asserts that subsidies tend to perpetuate themselves by encouraging inefficient use of system resources and skew customer's evaluation of alternative supply options and energy efficiency efforts.¹⁰¹ Walmart states that Staff's proposal to increase the Residential and SGS classes by 50 percent of the amount needed to reach parity in UROR, still allocates 24.6 percent of the incremental base revenue increase

⁹⁶ Ex S-18. The remaining \$37,522 of the increase, or 0.2 percent, is allocated to the Lighting Class. Ex S-18 updates Solganick's Direct Testimony, Ex S-5 at Ex HS-4, to reflect the revised revenue increase of \$15.1 million. It is the best illustration of various allocation options, but was prepared prior to the updated Final Schedules and does not precisely conform to the updated CCOSS.

⁹⁷ Ex S-18.

⁹⁸ Staff Reply Brief at 7-8.

⁹⁹ RUCO Reply Brief at 12.

¹⁰⁰ Walmart Initial Brief at 2.

¹⁰¹ Ex Walmart-5 Tillman at 8.

1 to the medium and large general service classes, and 3.4 percent to the large power class, and results
 2 in total inter-class subsidies of about \$10.8 million.¹⁰² Walmart notes that Staff's proposal only moves
 3 the UROR for the medium and large general service class slightly, from 3.51 to 3.10, and the UROR
 4 for the LPS Class from 6.04 to 5.34.

5 Walmart recommends that the Commission adopt a revenue allocation that moves the
 6 residential class 67.7 percent of the way to a UROR of 1.0.¹⁰³ This position would result in
 7 approximately \$1.25 million less in revenue being recovered from the Residential Class than under the
 8 Company's proposed revenue allocation, but limits the revenue increases of the subsidizing classes to
 9 about 1 percent.¹⁰⁴ Under this proposal, the Residential Class UROR moves to 0.38, the SGS Class
 10 UROR moves to 0.54, the Medium/Large GS Class UROR moves to 2.39 and the LPS Class UROR
 11 moves to 4.13.¹⁰⁵ Walmart argues that decreasing subsidies to a greater degree in this proceeding will
 12 make the complete elimination of the inter-class subsidies in the next rate case more attainable.¹⁰⁶

13 AECC/Noble¹⁰⁷

14 AECC and Noble ("AECC/Noble") assert that the rate allocation proposed by UNSE in its
 15 Direct Testimony continues considerable inter-class subsidies, but is a step in the right direction of
 16 achieving a better alignment of class revenue and class cost of service. However, AECC/Noble assert
 17 that UNSE's latest proposal, that applies the entire \$7.5 million reduction in the requested revenue
 18 requirement to the benefit of the Residential and SGS Classes, and to the detriment of the larger
 19 customer classes, and is a step backwards.¹⁰⁸

20 AECC/Noble propose a different approach to revenue allocation than taken by the Company
 21 and Staff, by factoring in fuel cost reductions, which they assert result in additional cross-subsidies.¹⁰⁹
 22 These intervenors assert that their proposed allocation methodology more closely aligns rates for the
 23 different customer classes with their cost of service, while adhering to the principle of "gradualism"

24
 25 ¹⁰² Walmart Initial Brief at 3; Ex S-18; Tr. at 2800

¹⁰³ Walmart Initial Brief at 4.

¹⁰⁴ Ex S-18.

¹⁰⁵ Id.

¹⁰⁶ Walmart Initial Brief at 4.

¹⁰⁷ These parties both sponsored the testimony of Kevin Higgins and filed joint briefs.

¹⁰⁸ AECC/Noble Initial Brief at 16.

¹⁰⁹ Id. at 15-18.

1 when compared to either the UNSE or Staff proposals. A major component of their proposal is the
2 implementation of a “buy-through” program that would allow large customers an opportunity to
3 purchase generation from third-party providers, without, they claim, harming the Company or its
4 ratepayers. They state that the primary driver of their overall rate spread and buy-through proposal is
5 not only to attract new or expanding businesses, but to help UNSE keep existing customers which will
6 create jobs and support further economic development.¹¹⁰

7 AECC/Noble assert that the most equitable division of the \$7.5 million revenue reduction in
8 revenue is to apportion 50 percent to the subsidy-paying classes and 50 percent to the subsidy-receiving
9 classes. Under this approach, the reduced revenue requirement results in an overall increase of 10.4
10 percent for Residential Class and 9.5 percent for SGS Class; a net decrease of 2.7 percent for the
11 MGS/LGS Classes; and a 3.0 percent net decrease for the LPS Class.¹¹¹ Although the MGS, LGS and
12 LPS classes would receive a rate decrease, they would still be subsidizing the subsidy-receiving
13 classes.¹¹²

14 AECC/Noble argue that Staff’s proposed revenue allocation is even worse than UNSE’s, and
15 would result in an inter-class cross-subsidy of nearly \$11.9 million.¹¹³ They argue that Staff’s proposal
16 to set increases to selected classes to half of what is required to attain parity without linking it to other
17 measurements such as the system average increase, or the relationship to the increase levied on the
18 subsidy-paying classes, is arbitrary and unreasonable. They assert that the inequity of Staff’s position
19 is illustrated by the fact that the MGS and LGS customers warrant a non-fuel rate reduction of 8.85
20 percent to attain parity, but wind up with a non-fuel revenue increase of 10.12 percent.

21 Furthermore, AECC/Noble assert that Staff’s revenue allocation is incomplete and does not
22 focus on the full bill impact on customers due to factors such as the Gila River acquisition, the reduction
23 in base fuel costs and the absorption of the Transmission Cost Adjustor. According to AECC/Noble,
24 when these factors are considered, the net impact on the subsidy-receiving classes are dramatically
25

26 ¹¹⁰ Id. at 1-3.

27 ¹¹¹ Id. at 4-5.

28 ¹¹² Id. at 5-6.

¹¹³ AECC/Noble Initial Brief at 17, Ex AECC/Noble -2 Higgins Surr at 7. In the Company’s direct case, the subsidy-paying classes provided approximately \$9 million in subsidies to the subsidy-receiving classes. AECC/Noble Reply Brief at 2.

1 lower than the impacts of the non-fuel increases upon which Staff focuses.¹¹⁴

2 AECC/Noble assert that the URORs under the Company's and Staff's positions show a large
3 disparity between the Residential/SGS and large commercial and industrial customer classes, and that
4 neither proposal results in "fair and equitable rates for all customer classes under sound Cost-of-Service
5 and Rate Design principles."¹¹⁵ They urge that if the Commission is inclined to adopt either the
6 Company's or Staff's allocation proposals, then the buy-through proposal becomes essential to retain
7 existing large commercial and industrial customers.¹¹⁶

8 **Nucor**

9 Nucor is a member of the LPS industrial class. Nucor concurs with the Company's expressed
10 goal to reduce inter-class subsidies. Nucor believes, however, that the revenue allocations proposed by
11 the Company and Staff do not move in the right direction, and actually make the situation worse.¹¹⁷
12 Noting that the CCROSS shows that currently the LPS class is providing a return of 27.95 percent, and
13 thus provides a significant subsidy to other rates classes, Nucor argues that the LPS rates should be
14 reduced, or at least not increased.¹¹⁸ Nucor states it could support the Company's revenue allocation as
15 expressed in Direct Testimony, provided the Company commits to further reducing such subsidies in
16 subsequent rate cases.

17 Nucor strongly opposes Staff's recommendation to apply a rate increase to the LPS class.¹¹⁹
18 Nucor also opposes the Company's revised revenue allocation as presented in its Rejoinder Testimony,
19 because it would result in a 1.12 percent increase, and exacerbate the existing rate subsidy between the
20 industrial and residential rate classes.¹²⁰ Nucor notes that even though the Company's requested overall
21 revenue requirement decreased from \$22.3 million to \$15.1 million, the subsidy-paying customer
22 classes are worse off in the Company's Rejoinder position.

23 Nucor notes that the Company's witnesses agree that energy rates can be a factor in whether
24 industrial users locate in the UNSE's territory and that attracting large, high load-factor customers is

25 ¹¹⁴ AECC/Noble Initial Brief at 18 and Exhibit 3, Ex AECC/Noble-2 Higgins Surr, Table KCH-SR-4.

26 ¹¹⁵ AECC/Noble Solutions Reply Brief at 5, citing Ex UNSE-31 Jones Dir at 8.

27 ¹¹⁶ AECC/Noble Solutions Reply Brief at 2-4.

28 ¹¹⁷ Nucor Reply Brief at 4-6.

¹¹⁸ Ex UNSE-31 Jones Dir at 24.

¹¹⁹ Nucor Initial Brief at 13.

¹²⁰ Id. at 13.

one of the goals of the Company-proposed EDR.¹²¹ Nucor argues that it is important to keep rates paid by the industrial energy customers as low as possible in order to maintain a viable business climate in the current difficult economy in UNSE's service area.

Nucor recommends the bill impacts to LPS and LPS-TOU be no higher than the values in the Company's original filing, which when including the fuel impact, increase the LPS-TOU customers 0.17 percent, and decrease the LPS customers -0.44 percent.¹²² Nucor states it would not oppose the Revenue Allocation proposed by AECC/Noble's witness Higgins because it takes a meaningful step toward reducing inter-class subsidies.¹²³

Resolution – Revenue Allocation

While no party objects to the overall base rate revenue increase of \$15.1 million, there is little agreement on how to allocate the increase among the various rate classes. The problem of allocation is exacerbated by the current rate structure that has perpetuated significant inter-class subsidies for many years. Allocating less to one class requires increasing the allocation to another. In determining how to distribute the increase, we have to consider, at a minimum, the total amount of the increase, the relative size of the various classes, how aggressively the goal of parity (or closer parity) should be pursued, economic conditions in the service territory, and principles of equity and fairness. The parties' recommended allocations are illustrated below:

Customer Class	Current Adjusted TY Revenue ¹²⁴ (000's)	UNSE ¹²⁵ (000's)	Staff/ RUCO ¹²⁶ (000's)	AECC/Noble ¹²⁷ (000's)	Walmart ¹²⁸ (000's)
Residential	\$79,482	\$14,135	\$9,659	\$17,419	\$12,884
SGS	\$12,673	\$1,528	\$1,184	\$2,089	\$1,578
Med/Large GS	\$56,615	\$72	\$3,711	-\$2,518	\$556
LPS	\$7,467	-\$759	\$510	-\$1,080	\$76

¹²¹ Nucor Initial Brief at 16-17, citing Tr. at 2635-37 and 287-88, 292-94, and Ex UNSE-28 Dukes Dir at 31.

¹²² Ex UNSE- 31 Jones Dir at Exhibit CAJ-2. Nucor believes these values should actually be reduced since they are based on the higher revenue requirement in the Application.

¹²³ Nucor Initial Brief at 18.

¹²⁴ UNSE Final Schedules G-1.

¹²⁵ UNSE Final Schedules A-1. Schedule A-1 does not reconcile with Schedule G.

¹²⁶ Ex S-18.

¹²⁷ Ex AECC/Noble 4.

¹²⁸ Ex S-18.

1	Lighting	\$550	\$53	\$37	\$28	\$6
2	Sub Total	\$156,787	\$15,029	\$15,101	\$15,938	\$15,100
3	Rider-14 Reserve				-\$908	
4	Total	\$156,787			\$15,030	

5 Although most parties expressing an opinion seem to agree with Staff's proposal to reach parity
6 over two rate cases, we reserve judgement on that specific goal at this time. We believe it will be
7 important to assess conditions at the time of the next rate case to determine if parity can, or should, be
8 achieved at that time. After careful consideration of all these factors, we find that significant progress
9 toward parity among the classes is achievable, while giving appropriate consideration to all of the other
10 factors. To reserve an option of reaching parity in the next rate case, we believe that Staff's proposal
11 to move the Residential and SGS Classes 50 percent of the way to parity may not go far enough. We
12 find that being slightly more aggressive than Staff's proposal will make the next step more attainable,
13 as well as being more favorable to the subsidy-paying classes. Given the substantial size of the overall
14 increase, however, we do not believe it is reasonable, or complies with principles of gradualism, to
15 allocate as much of the increase to the Residential Class as urged by the large commercial and industrial
16 users.

17 We recognize that the larger commercial and industrial users on UNSE's system are suffering
18 through slow economic times, the same as the residential and SGS customers. The larger users have
19 subsidized the Residential and SGS Classes for many years, and while some subsidization can be in
20 the public interest, the subsidies for UNSE have become excessive, and it is time that the Commission
21 take action to move to a more equitable allocation of revenue. To provide electric rates that more
22 closely reflect the cost of service would assist these large electricity users, who are also employers, to
23 be more competitive. Unfortunately, because of the relative sizes of the various classes and the large
24 leap needed to achieve parity, to move as far as the large commercial and industrial classes urge would
25 not be reasonable as the impact on the Residential Class would be too great. Consequently, we adopt
26 an allocation that would move the Residential and SGS Classes 60 percent of the way to an UROR of
27
28

1.0, and allocate the remaining revenue increase evenly among the MGS, LGS and Lighting Classes.¹²⁹

	Total (000's)	Residential Service (000's)	Small General (000's)	Medium/Large General (000's)	LPS (000's)	Lighting (000's)
Incremental Revenue	\$15,099	\$11,590	\$1,420	\$1,821	\$250	\$18
UROR	1.00	0.25	0.45	2.68	4.62	0.74
% Incr. compared to revenue from Current Sales	9.96%	14.6%	11.2%	3.2%	3.3%	3.3%
% of the Total Increase	100.0%	76.8%	9.4%	12.1%	1.7%	0.1%

We note that our approved allocation results in a 14.6 percent increase for the Residential Class, which is four times the increase allocated to the LGS and LPS Classes. We find the allocation of the revenue increase approved herein is in the public interest as it strikes a fair and reasonable balance of the competing interests.

Rate Design

Residential and Small General Service

UNSE

UNSE argues that its current residential rate design is flawed and antiquated because it collects a large amount of fixed costs through volumetric rates. UNSE supports Staff's proposal to implement a three-part rate design for all residential and small general service customers, however, after hearing the public comments in this docket, the Company is concerned that there is a high degree of customer confusion and misunderstanding concerning three-part rates, and that it will take much longer than the Company had originally anticipated to inform and educate customers about how three-part rates work and how ratepayers can manage their demand and achieve savings on their electric bills.¹³⁰ As a result, UNSE requests that the Commission adopt rate structures for non-DG residential and SGS customers that are similar to what the Company originally proposed in its Application.

UNSE proposed a monthly basic service charge under all rate options of \$15 for residential customers. Under each of the two-part residential options, the volumetric energy rate would be

¹²⁹ Based on Ex S-18.

¹³⁰ UNSE Initial Brief at 4.

1 comprised of two tiers, 0 to 400 kilowatt hours (kWh), and over 400 kWh. UNSE's proposed three-
 2 part rate has a single tier for all energy consumption. For the SGS Class, the monthly service charge
 3 for all rate options is \$25, and under the two-part options, the volumetric energy rates would be
 4 comprised of three tiers, 0 to 400 kWh, 401-7,500 kWhs, and over 7,500 kWhs. The on-peak hours
 5 under the Residential TOU options would run from 2-8 p.m. in the summer and 5-9 a.m. and 5-9 p.m.
 6 in winter.¹³¹ UNSE's proposed options for non-DG Residential and SGS customers follows.¹³²

7 A basic two-part rate:

8 Residential Service	Current Rates	Proposed Rates
9 Basic Service Charge	\$10.00	\$15.00
10 Energy Charge 0-400 kWh	\$0.019300	\$0.031500
11 Energy Charge 401-1,000 kWh	\$0.034350	\$0.046160
12 Energy Charge all additional kWhs	\$0.038599	\$0.048160
13 Base Power Supply Charge all kWhs	\$0.064510	\$0.055254
14 PPFAC	(\$0.022139)	(\$0.00000)

15 A two-part time-of-use ("TOU") rate:

16 Residential Service TOU	Current Rates	Proposed Rates
17 Basic Service Charge	\$11.50	\$15.00
18 Energy Charge 0-400 kWh	\$0.030350	0.031500
19 Energy Charge 401-1,000 kWh	\$0.030350	0.046160
20 Energy Charge all additional kWhs	\$0.030350	0.046160
21 Base Power Supply Charge summer on-peak all kWhs	\$0.129605	0.111001
22 Base Power Supply Charge summer off-peak all kWhs	\$0.039606	0.042800
23 Base Power Supply Charge winter on-peak all kWhs	\$0.129605	0.091550
24 Base Power Supply Charge winter off-peak all kWhs	\$0.031385	0.038568
25 PPFAC	(\$0.002139)	0.000000

27 ¹³¹ Ex UNSE-31 Jones Dir at CAJ-3 sheet 102-1. UNSE's rate schedules attached to its Initial Brief do not indicate the on-
 28 peak hours.

¹³² UNSE Initial Brief at Ex 1, based on UNSE's proposed revenue allocation.

1 A two-part super-peak TOU rate for residential customers:

2 Residential Service TOU Super Peak	Current Rates	Proposed Rates
3 Basic Service Charge	\$11.50	\$15.00
4 Energy Charge 0-400 kWh	0.025000	0.031500
5 Energy Charge all additional kWhs	0.035000	0.036160
6 Base Power Supply Charge summer on-peak all kWhs	0.170000	0.159790
7 Base Power Supply Charge summer off-peak all kWhs	0.039800	0.040810
8 Base Power Supply Charge winter on-peak all kWhs	0.150000	0.159790
9 Base Power Supply Charge winter off-peak all kWhs	0.038700	0.040810
10 PPFAC	(\$0.002139)	0.000000

11
12 A three-part rate that includes a monthly basic service charge, a demand charge and a volumetric energy
13 charge:

14 Residential Service - Demand	Current Rates	Proposed Rates
15 Basic Service Charge	N/A	\$15.00
16 Demand Charge 0-7 kW, per kW	N/A	\$5.50
17 Demand Charge >7kW, per kW	N/A	\$7.50
18 Energy Charge (kWhs)	N/A	\$0.013800
19 Base Power Supply Charge Summer on-peak all kWhs	N/A	\$0.055254
20 PPFAC	N/A	(\$0.000000)

21 And a three-part TOU rate that includes a monthly basic service charge, a demand charge and on- and
22 off-peak energy charges:

23 Residential Service Demand TOU	Current Rates	Proposed Rates
24 Basic Service Charge	N/A	\$15.00
25 Demand Charge 0-7 kW, per kW	N/A	\$5.50
26 Demand Charge >7kW, per kW	N/A	\$7.50
27 Energy Charge (kWhs)	N/A	0.013800
28 Base Power Supply Charge summer on-peak all kWhs	N/A	0.111001

1	Base Power Supply Charge summer off-peak all kWhs	N/A	0.042800
2	Base Power Supply Charge winter on-peak all kWhs	N/A	0.091550
3	Base Power Supply Charge winter off-peak all kWhs	N/A	0.038568
4	PPFAC	N/A	0.000000

5 UNSE proposed four options for the SGS Class:

6 A basic two-part rate:

7	Small General Service	Current Rates	Proposed Rates
8	Basic Service Charge	\$10.00	\$15.00
9	Energy Charge 0-400 kWh	\$0.019300	\$0.031500
10	Energy Charge 401-7,500 kWh	\$0.034350	\$0.046160
11	Energy Charge > 7,500 kWh	\$0.038599	\$0.048160
12	Base Power Supply Charge all kWhs	\$0.064510	\$0.055254
13	PPFAC	(\$0.022139)	(\$0.000000)

14 A two-part time-of-use ("TOU") rate;

15	Small General Service TOU	Current Rates	Proposed Rates
16	Basic Service Charge	\$16.50	\$25.00
17	Energy Charge 0-400 kWh	0.030176	0.033780
18	Energy Charge 401-7,500 kWh	0.043176	0.044650
19	Energy Charge > 7,500 kWhs	0.076042	0.079650
20	Base Power Supply Charge summer on-peak all kWhs	0.129605	0.109800
21	Base Power Supply Charge summer off-peak all kWhs	0.039605	0.045800
22	Base Power Supply Charge winter on-peak all kWhs	0.129605	0.108800
23	Base Power Supply Charge winter off-peak all kWhs	0.031385	0.040036
24	PPFAC	(\$0.002139)	0.000000

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A three-part rate that includes a monthly basic service charge, a demand charge and a volumetric energy charge:

Small General Service - Demand	Current Rates	Proposed Rates
Basic Service Charge	N/A	\$25.00
Demand Charge 0-7 kW, per kW	N/A	\$6.50
Demand Charge >7kW, per kW	N/A	\$8.50
Energy Charge (kWhs)	N/A	0.015340
Base Power Supply Charge Summer on-peak all kWhs	N/A	0.053290
PPFAC	N/A	(\$0.00000)

And a three-part TOU rate that includes a monthly basic service charge, a demand charge and on- and off-peak energy charges:

Small General Service	Current Rates	Proposed Rates
Basic Service Charge	N/A	\$25.00
Demand Charge 0-7 kW, per kW	N/A	\$6.50
Demand Charge >7kW, per kW	N/A	\$8.50
Energy Charge (kWhs)	N/A	0.015340
Base Power Supply Charge summer on-peak all kWhs	N/A	0.109800
Base Power Supply Charge summer off-peak all kWhs	N/A	0.045800
Base Power Supply Charge winter on-peak all kWhs	N/A	0.108800
Base Power Supply Charge winter off-peak all kWhs	N/A	0.040036
PPFAC	N/A	0.000000

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UNSE calculated the following bill impacts based on its revenue allocations and proposed rate elements.¹³³

Current Rates			
Customer Size	Billing kWh	Billing kW	Monthly Bill
Small	330	1.7	\$37.33
Medium	664	3.1	\$68.96
Large	1,144	5.2	\$116.53
XLarge	2,162	9.2	\$220.37
Mean	830	3.8	\$85.16
Proposed 2-part Rates			
Customer Size	Monthly Bill	\$ Change	% Change
Small	\$43.63	\$6.29	15.9%
Medium	\$76.48	\$7.52	10.96%
Large	\$125.15	\$8.63	7.4%
XLarge	\$228.39	\$8.02	3.6%
Mean	\$89.96	\$8.10	9.5%
Proposed 3-part Rates			
Customer Size	Monthly Bill	\$ Change	% Change
Small	\$47.13	\$9.80	26.2%
Medium	\$77.90	\$8.94	13.0%
Large	\$122.60	\$6.07	5.2%
XLarge	\$219.30	-\$1.07	-0.5%
Mean	\$93.18	\$8.02	9.4%

Thus, under the two-part rates, the average residential user, consuming 830 kWh /month would see a bill increase of \$8.10, or 9.5 percent, if they select the two-part rates, and an \$8.02, or 9.4 percent increase, under the optional three-part rates. A small consumer, using 330 kWh/ month would see a bill

¹³³ UNSE Opening Brief at Ex 2.

1 increase of \$6.29, or 15.9 percent, under the two-part option and an increase of \$9.80, or 26.2 percent,
2 under the three-part option. Under either rate option, \$5.00 of the increase would be due to the proposed
3 increase in the monthly customer charge. Thus, for the small user, 79 percent of the increase under the
4 two-part rate is due to the customer charge.

5 In this case, some parties criticized UNSE's use of the minimum system method to determine
6 the basic customer charge because they claim it includes charges that are not appropriately recovered
7 in the customer charge. UNSE argues, however, that the previous method to determine the monthly
8 customer charge, the basic service method, does not use accurate cost causation assumptions or
9 information, greatly underestimates the unavoidable fixed system costs needed to serve a customer,
10 and also ignores the increasingly diverse use of the grid that makes recovery of fixed costs through
11 volumetric rates inequitable.¹³⁴

12 UNSE presented evidence that the fixed monthly cost to serve the average residential customer
13 is approximately \$55.¹³⁵ UNSE notes that by increasing its residential basic service charge from \$10 to
14 \$15, it would still be recovering \$40 per month through volumetric charges.¹³⁶ UNSE disputes concerns
15 that increasing the basic service charge will reduce incentives to conserve energy because the
16 volumetric rate, the driver for conservation, will also be increased, to provide "plenty" of incentive to
17 conserve.

18 Some parties have criticized the proposal to eliminate the third volumetric tier because it would
19 reduce the incentive for customers to adopt DG or Energy Efficiency ("EE"). UNSE argues that the
20 third residential volumetric tier is a significant source of intra-class cross-subsidization and has
21 contributed to the Company's inability to earn its authorized revenue requirement.¹³⁷ UNSE believes
22 that the record is clear that eliminating the third tier better aligns rate design with cost-causation and
23 reduces the excess recovery of fixed costs from those customers whose usage is in the third tier.
24 Moreover, UNSE states the volumetric rate in its proposed second tier is almost the same as the rate in
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27 ¹³⁴ UNSE Reply Brief at 6; Ex UNSE-35 Overcast RJ at 10.

¹³⁵ UNSE Reply Brief at 6; Ex UNSE-32 Jones Dir at 41.

¹³⁶ UNSE Reply Brief at 6.

28 ¹³⁷ UNSE Reply Brief at 7; Ex UNSE-31 Jones Dir at 42.

1 the current third tier, so customers will have the same incentive to conserve.¹³⁸ UNSE also believes
 2 that three-tiered rates are confusing, and not helpful, to customers who don't understand why they have
 3 to pay higher rates when they use more energy in the summer.¹³⁹

4 UNSE argues that the record supports finding that DG customers are substantially different than
 5 non-DG customers, and to allow them to take service under any of the two-part rates would exacerbate
 6 the cost shift from DG customers to Non-DG customers.¹⁴⁰ According to UNSE, DG customers use the
 7 grid constantly, either producing their own energy and pushing the excess energy back into the grid, or
 8 using it to receive electricity when their DG systems are not producing.¹⁴¹ UNSE asserts that DG
 9 customers place additional costs on the grid due to additional maintenance costs from reverse flow
 10 caused by excess energy, and increased ancillary services such as load balancing, frequency support,
 11 voltage support, spinning reserves and non-spinning reserves needed due to the intermittent nature of
 12 solar DG and the utility's inability to monitor and control the solar DG systems.¹⁴² Moreover, UNSE
 13 states, the intermittent nature of DG resources requires utilities to incur generation costs to address that
 14 intermittency. Furthermore, UNSE asserts that DG customers do not reduce the demand on the grid,
 15 and the Company must be prepared to meet DG customer demand at a moment's notice if their systems
 16 production slows or stops. In addition, UNSE claims that DG customers can cost more to serve due to
 17 increased reserve requirements, VAR requirements and reduced life of voltage devices.¹⁴³

18 UNSE argues that solar DG customers are not like other low usage customers who have a low
 19 steady predictable load, regardless of weather or time of day. According to UNSE, the DG customer
 20 uses the grid constantly either taking electricity or pushing it back, and if a cloud affects their
 21 production, the utility must be ready to provide instantaneous service. In addition, UNSE claims that
 22 vacant homes don't all become occupied at the same time, but all DG homes in a neighborhood might
 23 need energy at the same moment when a cloud passes by or the sun sets.¹⁴⁴

24
 25 ¹³⁸ UNSE Initial Brief at Exhibit 1. The current third tier rate for usage over 1,000 kWh/month is \$3.8408 cents/kWh; the
 proposed second tier rate for usage greater than 401 kWhs per month is \$4.86160/kWh for residential service.

26 ¹³⁹ Tr. at 669-70, 2715, 2755-56

¹⁴⁰ UNSE Initial Brief at 24.

¹⁴¹ Ex UNSE-25 Tilghman Dir at 4-6.

¹⁴² Id. at 4-6.

¹⁴³ Ex UNSE-34 Overcast Reb. At 26-27.

¹⁴⁴ UNSE Initial Brief at 26-27.

UNSE asserts vacant or seasonal homes pay a customer charge that helps cover minimum system costs, and their low power usage places minimal demands on the grid. UNSE asserts that many of the costs that solar DG impose on the system are demand-related costs, which justifies placing them on three-part rates. UNSE explains that two-part rates rely on energy charges to recover fixed costs, and are designed to recover costs based on the average consumption levels of full-requirements customers.¹⁴⁵ A three-part rate is appropriate for DG customers because they don't use as much energy, but impose similar demands as full-requirements customers.¹⁴⁶ UNSE states that it is not seeking to recover more fixed costs from DG customers than from non-DG customers, but attempting to have DG customers cover their fair share of the costs they impose on the grid. Given their different cost causation and load characteristics, UNSE argues that limiting them to certain rates is appropriate and not discriminatory.¹⁴⁷

The Company states that mandatory three-part rates for DG customer will reduce, but not eliminate, the cost shift on non-DG customers.¹⁴⁸ The Company's analysis shows that under two-part volumetric rates, and in conjunction with current net metering practices, DG customers avoid paying their fair share of grid costs, and are being subsidized by the 98 percent of customers without DG by an average of more than \$642 per year for a 7kW solar PV system.¹⁴⁹ UNSE argues that even if solar DG customers represent only 2 percent of its residential customers, it is a growing number, and the problem of recovering a fair share of fixed costs from these customers' needs to be addressed before the problem gets worse, and while grandfathering the current DG customers is manageable.¹⁵⁰

The Company argues that its proposed mandatory three-part rates for DG customers are not unduly confusing or burdensome, especially after an adequate transition period and customer education.¹⁵¹ UNSE asserts that the solar advocates raise several concerns about demand rates, but do

¹⁴⁵ Ex UNSE-28 Dukes Dir at 28.

¹⁴⁶ Tr. at 2919-30.

¹⁴⁷ UNSE Initial Brief at 27; Ex UNSE-34 Overcast Reb at 14-27.

¹⁴⁸ As discussed in detail below, the Company also proposes to modify its net metering tariff to (1) eliminate the "banking" of excess energy produced by a DG system to offset future energy usage and (2) compensate DG customers for exported energy at the Renewable Credit Rate ("RCR"). The RCR would be equivalent to the rate paid for utility scale solar resources under the most recent purchased power agreement entered into by UNSE's sister company, TEP.

¹⁴⁹ Ex UNSE-34 Overcast Reb at 15-19.

¹⁵⁰ UNSE Reply Brief at 8-9.

¹⁵¹ Id. at 11.

1 not offer specific solutions to the challenges created by DG and other issues regarding inequitable and
2 inadequate recovery of fixed costs of the grid. UNSE states that the solar advocates previously argued
3 that the cost shift UNSE is seeking to rectify must be addressed in a rate case, but now that UNSE has
4 filed a rate case these same solar advocates now urge the Commission to delay addressing the cost shift
5 until the Company's next rate case. UNSE believes the desire to wait conflicts with the solar advocates'
6 insistence that all DG customers be grandfathered onto the current rate design and net metering tariff.¹⁵²
7 Furthermore, UNSE asserts TASC and Vote Solar are vague about which aspects of the rates should
8 be grandfathered under their proposals.

9 UNSE appreciates RUCO's attempt at proposing rate designs to address the DG differences,
10 but believes that RUCO's proposals are either too complicated as compared to the Company's three-
11 part rates, or do not sufficiently remedy the fixed cost recovery issues created by DG customers.¹⁵³
12 UNSE also criticizes the minimum bill and TOU proposals for not being sufficiently detailed to be
13 adopted here and for not solving the fundamental fixed cost recovery issue because they perpetuate the
14 volumetric recovery of fixed costs.

15 If the Commission desires to offer an option for DG customers in addition to three-part rates,
16 UNSE recommends its two-part TOU rates, coupled with the elimination of banking for DG customers,
17 and the implementation of an additional charge to cover the fixed costs of the second meter required
18 of DG customers. Pursuant to the CCOSS, the fixed costs of a meter total \$6.95, comprised of: (1) the
19 meter (\$1.58); (2) billing and collection (\$4.37) (for DG production meters, the Company has costs of
20 offsetting production from consumption and calculating credits); and (3) meter reading (\$1.00).¹⁵⁴ The
21 Company argues that based on the CCOSS and evidence in this docket, the extra meter costs can be
22 assessed pursuant to Section 2305 of the Net Metering Rules (A.A.C. R14-2-2305).¹⁵⁵ UNSE states
23 that the second meter creates fixed costs caused solely by DG customers, which arguably would be
24 partly covered by a demand charge for DG customers. Thus, UNSE proposes that should the
25 Commission desire a two-part rate option for DG customers, the DG customers would have a choice

26 ¹⁵² Id. at 9.

27 ¹⁵³ Id. at 12.

28 ¹⁵⁴ UNSE Final Schedules at G-6-1, Sheet 1 of 1.

¹⁵⁵ Section 2305 provides that net metering charges shall be assessed on a non-discriminatory basis and the costs must be supported with cost of service studies and benefit/cost analyses.

1 between: (1) the two-part TOU rate plus the \$6.95/month charge or (2) one of the two three-part rate
2 options. Under any option, UNSE argues, all kWh banking of excess DG system output should be
3 eliminated.¹⁵⁶

4 **Staff**

5 Staff continues to believe that a mandatory three-part rate design with a monthly customer
6 charge, a demand component, and a volumetric energy charge is a viable and reasonable solution to
7 the recovery of fixed costs and the mitigation of cross subsidies. However, without the full support of
8 UNSE, Staff does not believe that mandatory three-part rates would be successful. Staff also continues
9 to believe that it is not appropriate to distinguish between DG and non-DG customers in designing rates
10 and that any rate design adopted should be applicable to all residential and SGS customers.

11 Staff recommends adopting one of several alternative rate designs, with the choices including
12 voluntary TOU and demand charge options. One of Staff's options would be a two-part rate for
13 residential and SGS customers, with the elimination of the third volumetric tier, and a fixed customer
14 charge of \$15/month for residential and \$25/month for SGS. Staff believes the larger customer charges
15 under this option would improve revenue stability and greater recovery of fixed costs, and that the
16 continuation of a two-part rate design would enable the Commission to ascertain the outcome of the
17 Value of DG docket.¹⁵⁷ In the interim, Staff suggests, UNSE could create educational and
18 informational programs to prepare for a transition to three-part rates sometime in the future.

19 Staff believes that offering a voluntary three-part rate that includes a demand charge may be
20 helpful to give the Company and ratepayers experience with residential demand charges. Staff suggests
21 that under this proposal the basic service charge could be less than under the two-part rate option in
22 order to provide an incentive for voluntary customer migration. Staff believes that with this option,
23 the Company should develop a customer information and education program to help customers
24 determine whether they could benefit from voluntarily subscribing to a demand rate. In addition, Staff
25 recommends that the Company develop a bill format to illustrate each customer's monthly (and twelve
26 months) demand (both on-peak and off-peak) in order to educate customers about demand rates even

27 _____
28 ¹⁵⁶ See Net Metering Section below for the Net Metering proposals.

¹⁵⁷ Staff Reply Brief at 3.

1 if the customer hasn't selected a demand rate. Staff believes that even if mandatory demand rates are
2 not approved in this case, it would be wise to prepare customers for an eventual transition in the future.

3 Staff would also support a rate design like that it is proposing in the pending SSVEC rate case
4 (Docket No. E-01575-15-0312).¹⁵⁸ Under this proposal, the customer service charge increases each
5 year contemporaneously with decreases in the energy charge. Staff states that this rate scheme would
6 not only more accurately recover fixed costs through the service availability charge, but would also
7 lessen rate shock because of the reduction of the volumetric charge.¹⁵⁹

8 Staff would also support continuing with the Company's existing two-part rate design with
9 three tiers. Staff states that it would prefer eliminating the third volumetric tier, but notes that the
10 existing three tiers have been operating for some time.¹⁶⁰

11 Because many of RUCO's proposed rate options would require changes to net metering, and
12 Staff recommends waiting for the conclusion of the pending Value of DG docket before altering net
13 metering tariffs, Staff does not support RUCO's proposals at this time.¹⁶¹ Staff acknowledges that a
14 minimum bill option, as proposed by some, would make recovery of fixed costs more certain, but does
15 so at the expense of eliminating customer ability to respond to price signals and not encouraging
16 conservation.¹⁶² Staff's witness Solganick also believes that a minimum bill is a public relations
17 challenge.¹⁶³

18 Using Staff's proposed revenue allocation, the impacts of moving from current rates to Staff's
19 proposed two-part transition rates are illustrated below:¹⁶⁴

Customer Size	Billing kWh	Current Bill	New Bill	\$ Change	% Change
Small	330	\$37.33	\$41.32	\$3.98	10.78%
Medium	664	\$68.97	\$70.59	\$1.64	2.4%

24 ¹⁵⁸ Tr. at 3597. Staff Reply Brief at 4.

25 ¹⁵⁹ Staff notes that the SSVEC proposal distinguishes between DG and Non-DG customers and sets a cut-off date that
26 determines whether the new rate schedule applies. Staff does not support a separate rate schedule for DG customers,
irrespective of the date of installation. The SSVEC plan also calls for a change in net metering. Staff opposes any change
in net metering until a decision is issued in the pending Value of DG Docket. Staff Reply Brief at 4.

27 ¹⁶⁰ Staff Reply Brief at 4.

¹⁶¹ Staff Reply Brief at 6. See RUCO Initial Brief at 11, 13-15.

¹⁶² Staff Reply Brief at 4.

¹⁶³ Staff Reply Brief at 6.

28 ¹⁶⁴ Late-filed Staff Revised Schedule H-4.

1	Large	1,144	\$116.53	\$116.28	\$(0.25)	-0.2%
2	XLarge	2,162	\$220.37	\$226.08	\$5.71	2.6%
3	Mean	830	\$85.16	\$85.45	\$0.29	0.3%

4 The impacts of moving from Staff's transition rates to Staff's proposed three-part rates differ by season
5 as shown below:

Winter ¹⁶⁵					
Customer Size	Billing kWh	Transition Rate Bill	New Bill	\$ Change	% Change
Small	294	\$38.45	\$40.34	\$1.89	4.92%
Medium	560	\$61.26	\$61.93	\$0.67	1.09%
Large	914	\$93.03	\$90.14	(\$2.89)	-3.11%
XLarge	1,653	\$171.17	\$146.90	(\$23.27)	-13.60%
Winter Ave	669	\$71.08	\$70.75	(\$0.33)	-0.47%

Summer ¹⁶⁶					
Customer Size	Billing kWh	Transition Rate Bill	New Bill	\$ Change	% Change
Small	386	\$45.78	\$50.56	\$4.78	10.44%
Medium	813	\$83.97	\$87.82	\$3.85	4.59%
Large	1,395	\$143.35	\$137.68	(\$5.67)	-3.96%
XLarge	2,472	\$259.40	\$228.13	(\$31.27)	-12.05%
Summer Ave	983	\$99.25	\$102.50	\$3.25	3.27%

23 Staff recommended keeping the Rate Design portion of this docket open to address any
24 unintended consequences from the new rate design.¹⁶⁷ Staff stated that it wants the ability to address
25 any discrepancies between estimated and actual kW demands.

26
27 ¹⁶⁵ The difference in the current bill is due to different season seasonal averages

¹⁶⁶ The difference in the current bill is due to different season seasonal averages

28 ¹⁶⁷ Staff Initial Brief at 14. Staff did not revisit this recommendation after UNSE withdrew its mandatory residential demand charges. We presume, given the multitude of new rate options, that Staff has not changed its position.

1 APS

2 APS is an electric utility that provides service to 1.2 million retail and wholesale customers
3 throughout Arizona. APS firmly believes that the record in this proceeding establishes that demand
4 rates are a fair and equitable rate design that is superior to the two-part volumetric rates traditionally
5 employed for residential customers, and specifically, that universal demand rates are appropriate in the
6 UNSE service territory.¹⁶⁸ APS asserts that three-part rates reduce intra-class subsidies, better track
7 cost of service, improve the efficient use of the grid and encourage new behind-the-meter technologies.
8 Furthermore, APS asserts that even if universal demand rates are not ultimately adopted for UNSE in
9 this case, it does not mean that demand rates are inappropriate, especially for rooftop solar customers,
10 or that universal demand charges should not be implemented in other utility service territories.¹⁶⁹

11 APS has had optional residential demand rates for thirty years, with more than 117,000
12 customers choosing to participate in a three-part demand rate with a TOU feature. APS provided
13 evidence that its customers have been able to respond to demand rates to their advantage.¹⁷⁰ An APS
14 analysis of 1,000 customers who had recently switched from a two-part TOU rate to a demand rate
15 with a TOU feature, found that 60 percent saved on their demand and energy, on average saving
16 between 2-3 percent on monthly demand, and that those customers who actively managed their demand
17 achieved demand savings of 10-20 percent.

18 Moreover, APS argues there is substantial evidence in the record to support treating solar
19 rooftop customers as a separate rate class.¹⁷¹ APS points to RUCO's witness Huber's testimony that at
20 times solar customers' demand can spike randomly which requires the utility to react quickly to procure
21 energy in the spot market to meet the intermittent demand. Mr. Huber testified that it is prudent to treat
22 solar customers differently because no other utility customers have the same profile or use the grid in
23 the same fashion. In addition, APS believes rooftop solar customers' ability to export electrons onto
24 the distribution system distinguishes them from energy efficiency efforts.¹⁷²

25 ¹⁶⁸ APS Reply Brief at 1-2.

26 ¹⁶⁹ On June 1, 2016, APS filed its rate case which includes a proposal for residential demand charges. See Docket No. E-01345A-16-0036.

27 ¹⁷⁰ APS Reply Brief at 2-3.

28 ¹⁷¹ Id. at 3.

¹⁷² APS Reply Brief at 3-4, Tr. at 2267 and 2274; Ex UNSE - 34 Overcast Reb at 14-20 and Ex UNSE-26 Tilghman Reb at 19.

AIC

AIC agrees that public policy favors transitioning all residential customers to a three-part demand rate sooner rather than later in order to provide an equitable solution to fixed cost recovery and to reduce cross-subsidization issues.¹⁷³ AIC supports mandatory residential demand rates because they eliminate customer and technology biases inherent in the current rate structure, and move toward a rate design that is “neutral, agnostic, and unbiased toward technology and lifestyle choices of customers.”¹⁷⁴ AIC claims the public interest requires that rate design must allow the utility the opportunity to recover its investment in the power grid while also allowing customers who choose to install cost-effective behind-the-meter technologies the opportunity to save money. AIC argues that the current two-part rate design, with fixed costs recovered in volumetric charges, do not meet that standard. AIC denies that a demand charge is a fixed charge, but rather recovers fixed costs through a per kW rate, and incentivizes customers to smooth their load and become more efficient for the utility to serve.

AIC criticizes TASC and Vote Solar for their characterization of UNSE’s revenue problem as one of a slow economy, loss of major customers, snowbirds and vacant homes. AIC argues that TASC and Vote Solar miss the point that the Company’s proposals are not about declining revenue generally, but rather the specific issue of under-recovery of fixed costs and the corresponding cost shift associated with an outdated rate design. AIC asserts that regardless of how the Company’s sales are doing, the current two-part residential rates do not adequately reflect cost causation and thereby allow certain customers to avoid paying their fair share of fixed costs.¹⁷⁵

Citing the use of demand charges in the commercial sector and APS’s decades of voluntary residential demand charges, AIC asserts that three-part demand rates are not a wild experiment that will result in unintended consequences, but a proven effective tool for linking rates to the actual cost of service.¹⁷⁶ AIC notes that recent advances in metering technology allows use of demand rates in the residential market, which means that it is no longer necessary to be restricted to the less efficient two-part rates. AIC charges that opponents of residential demand charges do not explain why taking

¹⁷³ AIC Reply Brief at 3.

¹⁷⁴ AIC Initial Brief at 2-5; AIC Reply Brief at 8. After the Company withdrew its proposal for mandatory universal residential demand rates, AIC did not change its support for such rates.

¹⁷⁵ AIC Reply Brief at 4-5.

¹⁷⁶ Id. at 5-10.

1 advantage of technological advances and modernizing residential rates is inappropriate.

2 AIC asserts that a demand charge that reflects the cost of service is neither volatile nor
3 unmanageable, and that intervenor concerns that customers will need to “perfectly manage” their
4 demand to avoid volatile charges are overstated.¹⁷⁷ According to AIC, these demand rates were
5 designed to avoid bill fluctuations and allow for customer flexibility by using a one hour interval and
6 only measuring demand during an on-peak period (as compared to the typical 15 minute interval for
7 commercial customers). AIC believes that customers can manage their electricity use on a demand rate,
8 just like they do on TOU rates, but demand rates will also provide customers “with another way to save
9 money on their electricity bill.”¹⁷⁸ AIC explains that on a two-part rate, customers only save by
10 reducing total consumption, but on a three-part rate customers save both by reducing total consumption
11 and reducing maximum demand. Citing APS’ witness Faruqui’s testimony and APS’s experience with
12 demand charges, AIC claims there is no reason to think that customers are not able to respond to the
13 demand charge signal such that the demand charge will act as a fixed charge.¹⁷⁹

14 According to AIC, TASC is concerned that demand charges will impact customers’ lifestyle
15 choices, but AIC claims that TASC and Vote Solar fail to explain why rates should not affect lifestyle
16 choices when those choices affect the cost to serve.¹⁸⁰ In response to intervenor claims that DG
17 customers may have greater difficulty anticipating their demand because of weather, AIC counters that
18 this is exactly why demand charges are appropriate and necessary, since fluctuating and uncertain DG
19 demand places a higher burden on the grid relative to their lower energy consumption, which results in
20 non-DG customers bearing the costs of the fixed charges in their volumetric energy charges. AIC
21 asserts that demand charges will shift some, but not all, of the cost of DG customer demand back to the
22 DG customer.¹⁸¹

23 AIC states further that demand charges will not disproportionately impact low-income
24 customers, as demand charges are agnostic to income or even monthly consumption. AIC notes that
25 low-income customers are not low usage customers by default, and there is no empirical evidence that

26 ¹⁷⁷ Id. at 7-8.

27 ¹⁷⁸ AIC Reply Brief at 8, Ex APS-4 Faruqui Surr at 13.

27 ¹⁷⁹ AIC Initial Brief at 14; Ex APS-4 Faruqui Surr at 7 & 9-10; Ex APS-3 Faruqui Dir at 15.

28 ¹⁸⁰ AIC Reply Brief at 8.

¹⁸¹ Id. at 9.

1 shows that low income customers will fare worse overall under a three-part rate, or won't have the
2 same opportunities to save by reducing maximum demand and/or reducing consumption as other
3 customers. AIC claims that the arguments that low income customers will be adversely affected by
4 demand charges ignore the additional \$17 flat discount being proposed for CARES customers.¹⁸² AIC
5 asserts that the cross-subsidies inherent in the two-part rates disproportionately disadvantage low
6 income customers because these customers are less likely to be able to afford to invest in DG systems
7 and thus are paying subsidies in their rates to those higher income customers able to invest in DG.

8 Additionally, AIC rejects the argument that residential demand rates will kill the solar
9 industry.¹⁸³ AIC claims that the evidence shows that solar DG customers can save on their bills both
10 by avoiding the energy charge and by moderating their demand and smoothing their load, and AIC
11 argues that there is no logical reason why the solar industry cannot market their products given the
12 continued savings potential. Furthermore, AIC argues that the Commission's ratemaking obligation is
13 to balance the interests of the utility and its customers in a manner that serves the public interest and
14 not to prop up the economic well-being of a single industry.¹⁸⁴ AIC argues that ultimately, demand
15 charges will have a positive long-term effect on the solar industry because removing misaligned
16 subsidies that artificially inflate the cost of DG solar will allow market forces to spur innovation to the
17 benefit of consumers.¹⁸⁵

18 AIC argues that the proposed alternatives to the three-part rates, such as minimum bills, TOU
19 and RUCO's optional rates, do not effectively address the fundamental flaws in the current rate design,
20 nor achieve the key public policy objectives as well as the three-part rate design because the price signals
21 they send are not as closely related to costs.¹⁸⁶ Under the minimum bill concept, customers would be
22 charged the greater of the minimum bill amount or their bill under the standard two-part rates. AIC
23 argues that the minimum bill does not reflect customer demand costs and would apply to all customers
24

25 ¹⁸² AIC Reply Brief at 10. UNSE's current proposed CARES discount is \$16.

26 ¹⁸³ AIC Initial Brief at 11-14.

27 ¹⁸⁴ Id. at 12.

28 ¹⁸⁵ AIC Initial Brief at 13. AIC points to the testimony of Vote Solar witness Kobor who argued that demand charges should not be implemented because "enabling technologies" that could help customers manage demand are uncommon, costly and not widely adopted. Ex Vote Solar-6 Kobor Dir at 35. AIC asserts that demand charges might incentivize the development of these technologies.

¹⁸⁶ AIC Initial Brief at 5-10.

1 regardless of their usage, demand, or load factor, and would perpetuate the current problems with intra-
 2 customer cost-shifting. AIC believes that the lack of correlation would continue to misalign price
 3 signals and customer behavior, would not reward reductions in demand or improvements in load factor,
 4 and would be “highly unfriendly” to new technologies. AIC believes that in order to assist in the
 5 recovery of fixed costs, the minimum bill would need to be higher than any benchmark being proposed
 6 by its proponents in this case.¹⁸⁷

7 AIC supports including a TOU component as part of the three-part rates design, but claims that
 8 TOU energy rates, by themselves, are not a viable alternative because they do not adequately reflect
 9 infrastructure and capacity costs that vary over time or with consumption.¹⁸⁸ AIC submits that a TOU
 10 energy rate without a demand component does nothing to resolve the problem associated with
 11 recovering demand-related costs through energy charges because DG and other low load factor
 12 customers will continue to pay less than their fair share of demand-related costs.¹⁸⁹ Furthermore, AIC
 13 claims, TOU rates to not provide incentive for customers to reduce their demand.

14 AIC also asserts that RUCO’s rate design proposals discussed during the hearing do not address
 15 the fundamental flaw with existing rates because they perpetuate the two-part rate option.¹⁹⁰ According
 16 to AIC, both RUCO’s “Non-Export Option” and “RPS Bill Credit” would allow DG customers to
 17 choose any of the Company’s traditional two-part rates, but under two-part rates DG customers avoid
 18 paying their fair share of demand-related costs. Citing the testimony of its witness Hansen, who
 19 compared the costs of the “RPS Bill Credit” option and the “Advanced DG TOU” option for customers
 20 who use no DG, and those to receive at least 50 percent of their energy needs from DG and actively
 21

22 ¹⁸⁷ Ex APS-7 Miessner Surr at 11. APS’s witness Miessner estimates the minimum bill would need to be in the range of
 \$30 for small homes, \$70 for medium-sized homes and \$150 for large homes. *Id.* at 14.

23 ¹⁸⁸ Ex APS-7 Miessner Surr at 15-16.

24 ¹⁸⁹ AIC Initial Brief at 8, citing Ex APS-7 Miessner Surr at 16 and Ex AIC-D Hansen Surr at 8.

¹⁹⁰ At the hearing, RUCO supported treating DG customers as a separate class and advanced three options for DG customers:

- (1) The “non-Export Option” under which DG customers could select any of the Company’s standard rates but would not be allowed to export power to the grid;
- (2) The “Advanced DG TOU Option” under which DG customers would pay a three-part rate consisting of a minimum bill, a flat base energy rate (\$0.084/kWh), a peak-hours demand charge (\$19.50/kWh incurred between 2 and 8 p.m.), and could export power to the grid and receive credit dependent upon whether the customer exchanges Renewable Energy Credits (“REC”) with the Company; and
- (3) The “RPS Bill Credit Option” under which DG customers could select any of the Company’s standard rates and receive a credit that is based on the amount of renewable capacity added over time (starting at \$0.11/kWh). But customers must exchange RECs with the Company.

1 manage demand, shows that the Advanced DG TOU Option would increase customers' bills between
 2 19 to 290 percent under each scenario.¹⁹¹ Consequently, AIC concludes virtually no DG customer
 3 would select the "Advanced DG TOU," which leaves only the "RPS Bill Credit" option, and no
 4 effective customer choice. AIC believes that RUCO's additional options, as explained in its post-
 5 hearing brief, are too late to be sufficiently analyzed and do not address the cost-shift nor incentivize
 6 innovation of behind-the-meter technologies as well as the three-part rates endorsed by Staff.¹⁹²

7 AIC argues that demand charges should be implemented before DG penetration grows. AIC
 8 believes that a voluntary opt-in demand pilot would not operate the same as a universal mandatory
 9 residential demand rate and thus would not provide additional useful information that cannot already
 10 be gleaned from APS's experience with a voluntary demand rate program. AIC states that by the time
 11 the new rates go into service, UNSE will have access to about nine months of usage data that customers
 12 can utilize to adjust their behaviors. AIC alleges that delay will hurt everyone as more and more people
 13 will be making the decision to go solar based on "broken" two-part rates, which will make the "fix"
 14 harder in the future.¹⁹³

15 AIC agrees with Staff and APS that customers are capable of understanding demand rates and
 16 that UNSE's proposed customer education program is sufficient.¹⁹⁴ Even so, AIC supports Staff and
 17 the Company's position that the transition period to three-part rates should be flexible to that the
 18 Company can educate customers and overcome misconceptions about the proposed rate design.

19 RUCO

20 RUCO argues that a universal three-part rate is not warranted, and that the Company has not
 21 met its burden of demonstrating that the proposed three-part residential rates are just and reasonable.¹⁹⁵
 22 RUCO firmly believes that the DG partial requirements customers should be their own rate sub-class.¹⁹⁶
 23 RUCO states that it appreciates the Company's post-hearing position to return to its opening position,
 24 however, RUCO is concerned that the partial requirements customers are only given one rate option
 25

26 ¹⁹¹ Ex AIC-D Hansen Surr at 14-16; AIC Reply Brief at 9.

27 ¹⁹² AIC Reply Brief at 11.

28 ¹⁹³ Id. at 11-12.

¹⁹⁴ Id. at 12.

¹⁹⁵ RUCO Initial Brief at 3-4.

¹⁹⁶ RUCO Reply Brief at 1.

1 under the Company's latest proposal.

2 RUCO asserts that rate discrimination does not require that every customer in the rate class be
3 subject to the same rates as long as there are distinguishing characteristics.¹⁹⁷ RUCO argues that the
4 record shows that partial requirement DG and full requirements customers are not similarly situated,
5 and a solution that would impact only 2 percent of the Company's residential ratepayers is preferable
6 to affecting every customer.¹⁹⁸

7 Although UNSE is close to having the smart meters in place to implement three-part rates for
8 all residential customers, RUCO states that the Company has not collected sufficient data on customer
9 usage to design appropriate universal three-part rates.¹⁹⁹ RUCO notes that the Company expects to
10 have the infrastructure to measure demand installed for all customers by the end of 2016, but that is
11 not soon enough to collect the data needed to inform the decision making in this rate case.²⁰⁰ RUCO
12 believes that the lack of data is of particular concern in light of the extraordinary amount of opposition
13 to the three-part rate proposal from the public at large.²⁰¹

14 RUCO argues that the demand charge discussed at the hearing is not properly designed because
15 it does not distinguish between the seasonality of the utility's costs—as a high electricity demand in
16 January would cost a ratepayer the same as a high electricity demand in August. Because the utility's
17 system costs differ during these times, having the same rate sends the wrong price signal to the
18 customer.²⁰² RUCO states a primary reason for implementing three-part rates is to recover the costs
19 driven by demand which varies significantly based on the season and time of day.

20 RUCO is also concerned that the Company has no history or experience offering a three-part
21 rate to residential ratepayers and has not yet developed customer tools to help ratepayers manage their
22 demand. RUCO believes this lack of experience raises doubt about the Company's ability to implement
23 such an ambitious plan. RUCO suggests that it may be better to offer an optional three-part rate in order
24 to start developing the data, experience, and infrastructure needed to consider universal implementation

25 ¹⁹⁷ RUCO Initial Brief at 5, citing A.R.S. §40-334 and *Town of Wickenburg v. Sabin*, 68 Ariz. 75 (1948). RUCO notes that
26 distinctions are made all the time between ratepayers in the same Class, citing the low income tariffs.

¹⁹⁸ RUCO Initial Brief at 6.

¹⁹⁹ Id. at 7-8.

²⁰⁰ Id. at 7.

²⁰¹ Id. at 8.

28 ²⁰² RUCO Initial Brief at 9. The Company's post-hearing demand charges do not have a seasonality feature either.

1 in three-part rates in the future.

2 RUCO proposes several rate options for the partial requirements DG customers:²⁰³

3 (1) Non-Export Option. Under this option, DG customers can choose any of the Company's
4 traditional rates offered for full requirement customers, but are not allowed to export any excess power
5 generated to the grid. However, RUCO is open to allowing exports at the Market Cost Comparable
6 Convention Generation ("MCCCG") rate.

7 (2) Advanced DG TOU Option. This option is a three-part rate, with a minimum bill and a
8 TOU demand rate during the summer. The rate includes a minimum bill (not a fixed charge), volumetric
9 rates, and a demand charge component. The export rate for excess power to the grid for customers who
10 exchange renewable energy credits ("RECs") is 8.5 cents per kWh (\$.085/kWh), equal to the self-
11 consumption rate. For those DG customers who do not exchange RECs, the export rate is the MCCCG
12 rate.

13 (3) RPS Bill Credit Option. Under this option, customers can select any of the Company's
14 traditional rates; the credit rate for new DG customers decreases over time as the Company's portfolio
15 of renewable capacity increases. The credit rate would start at 11 cents per kWh and go no lower than
16 the MCCCG rate. The reductions are based on pre-determined tranches in order to provide certainty
17 to the ratepayers choosing this option. RUCO states that the bill credit would be applied every month
18 and be fixed for 20 years from the date the system was installed to assure certainty for new DG
19 adopting customers.

20 If mandatory three-part rates are not adopted, RUCO proposed four additional rate options:²⁰⁴

21 (1) Traditional Two Part Rates with a Market Based Export Option. In the event the Non-
22 Export option above is not found to be appropriate, this option would be available for all residential
23 ratepayers. For DG customers with a PV system that produces less than 25 percent of their annual
24 load, full net metering would be preserved for generation exports. For partial requirement DG
25 customers who produce more than 25 percent of their annual load, generation exports would be
26 compensated at a market-based rate, calculated at the average wholesale price for that month.

27 ²⁰³ RUCO Initial Brief at 11.

28 ²⁰⁴ Id. at 13-15.

1 Compensation for excess power would be paid monthly, with no banking. RUCO asserts that the
 2 lower than MCCCCG generation export rate, for the partial requirement DG customer who produces
 3 more than 25 percent of their annual load, is justified because it is more than offset by the rate for self-
 4 consumed generation.²⁰⁵

Residential Service	Current	UNSE Proposed	RUCO Recommended
Customer Charge	\$10.00	\$15.00	\$12.50
Energy Charge 1 st 400 kWh	\$0.019300	\$0.030100	\$0.028600
Energy Charge 401-1,000 kWhs	\$0.034350	\$0.040100	\$0.051000
Energy Charge all add'l kWhs	\$0.038499	\$0.058100	\$0.057300
Base Power Supply Charge all kWhs	\$0.061700	\$0.055090	\$0.055090
PPFAC	(\$0.003488)	Varies	Varies

13 (2) Three-Part Rate Option. RUCO proposes an optional three-part rate that would be
 14 available to all residential ratepayers and includes a \$12.50 customer fixed charge. Full net metering
 15 would be preserved under this option and the rate includes a tiered TOU demand charge, with the on-
 16 peak summer demand charge over 30 percent higher than the on-peak winter demand charge. The
 17 demand charge includes two tiers, one below 4 kW and one above 4 kW. RUCO believes this option
 18 sends a better cost-based price signal than Staff's three-part rate proposal which maintains the same
 19 demand charge with no tiers or price differential for seasons. In the future, RUCO would like to see
 20 even more seasonality built into the rate design.

Three-Part Residential TOU	Current	UNSE Proposed	RUCO Recommended
Customer Charge	N/A	\$15.00	\$12.50
Demand Charge			
0-4 KW Summer	N/A	\$5.00	\$4.00
>4 kW Summer	N/A	\$5.00	\$12.00

27
 28 ²⁰⁵ RUCO Initial Brief at 13-14 and Attachment A. Note: UNSE and RUCO support differing allocations of the revenue increase and thus, their rates cannot be directly compared with precision.

0-4 kW Winter	N/A	\$5.00	\$4.00
>4 Winter	N/A	\$5.00	\$8.00
Summer On-peak, kWh	N/A	\$0.105800	\$0.124450
Summer Off-peak, kWh	N/A	\$0.042830	\$0.045000
Winter On-peak, kWh	N/A	\$0.086300	\$0.064400
Winter Off-peak, kWh	N/A	\$0.038610	\$0.035000
Base Power Supply Charge, all kWhs	N/A	\$0.015340	\$0.013300
PPFAC			
Summer On-peak, kWh	N/A	Varies	Varies
Summer Off-peak, kWh	N/A	Varies	Varies
Winter On-peak, kWh	N/A	Varies	Varies
Winter Off-peak, kWh	N/A	Varies	Varies

(3) Volumetric TOU Option. RUCO proposed this option in response to the solar industry's expressed desire for rate options other than a universal three-part rate. This optional volumetric TOU rate would be available to all residential ratepayers. Under this option, full net metering is preserved, but in order to address the fixed cost recovery issue, the fixed charge is increased to \$19.00. RUCO believes that this option makes a sizeable contribution to reducing the cost shift.²⁰⁶

Residential Volumetric TOU Option	Current	UNSE Proposed	RUCO Recommended
Customer Charge	N/A	N/A	\$19.00
Base Power Supply Charge, all kWhs	N/A	N/A	\$0.035040
Summer On-peak, kWh	N/A	N/A	\$0.145000
Summer Off-peak, kWh	N/A	N/A	\$0.032500
Winter On-peak, kWh	N/A	N/A	\$0.105000
Winter Off-peak, kWh	N/A	N/A	\$0.013300
PPFAC			

²⁰⁶ RUCO Initial Brief at 14-15.

1	Summer On-peak, kWh	N/A	N/A	Varies
2	Summer Off-peak, kWh	N/A	N/A	Varies
3	Winter On-peak, kWh	N/A	N/A	Varies
4	Winter Off-peak, kWh	N/A	N/A	Varies

5
6 (4) Full Requirement Customer TOU Option. This option would be available only to full
7 requirements customers and includes a \$12.50 customer fixed charge. RUCO states it was built based
8 on the Company's existing residential TOU rate and seeks to improve the low participation rate by
9 offering a shorter window for on-peak, and two tiers instead of three, to alleviate some of the
10 Company's concerns. On-peak summer hours are reduced from six hours to three (4-7 p.m. instead of
11 2-8 p.m.) and winter peak is from 6-9 a.m. and 6-9 p.m. (rather than the current four hours each). RUCO
12 believes that a simpler offering, including a TOU rate with a shorter on-peak period will simplify
13 customer communications, boost enrollment, and increase overall effectiveness.²⁰⁷

14	Full Requirement Residential TOU Option, all kWhs	Current	UNSE Proposed	RUCO Recommended
15	Customer Charge	N/A	N/A	\$12.50
16	Energy Charge 1 st 400 kWhs	N/A	N/A	\$0.034000
17	Energy Charge, all add'l kWhs	N/A	N/A	\$0.050000
18	Base Power Supply Charge, all kWhs			
19	Summer On-peak, kWh	N/A	N/A	\$0.150000
20	Summer Off-peak, kWh	N/A	N/A	\$0.045000
21	Winter On-peak, kWh	N/A	N/A	\$0.090000
22	Winter Off-peak, kWh	N/A	N/A	\$0.035000
23	Base Power Supply Charge, all kWhs	N/A	N/A	\$0.040000
24	PPFAC			
25	Summer On-peak, kWh (4-7 p.m.)	N/A	N/A	Varies
26	Summer Off-peak, kWh	N/A	N/A	Varies

27
28 ²⁰⁷ RUCO's Initial Brief at 15. See RUCO Reply Brief at 8-10.

Winter On-peak, kWh (6-9 a.m. and p.m.)	N/A	N/A	Varies
Winter Off-peak, kWh	N/A	N/A	Varies

RUCO states that evaluating its proposals as standalone rates does not provide the full picture of the interworking of all the rates. RUCO disagrees with criticisms of its proposals on the grounds that they reach behind the meter. RUCO argues that partial requirements solar DG customers use the grid for backup services, voltage and frequency regulation, in-rush current, spinning and non-spinning reserves and other ancillary services, the costs of which are being borne primarily by full-requirements customers, such that what happens behind the meter is very much the business of all residential ratepayers and highly relevant to designing appropriate rates.²⁰⁸ In any case, RUCO states its “Non-Export” rate option does not look behind the meter.

In response to criticism that the Non-Export option does not capture any benefits of exporting excess generation to the grid, RUCO explains that is why it modified this option to pay for exported energy at a market-based rate.²⁰⁹

RUCO notes that the solar advocates criticize its “Advanced DG TOU” rate because it contains a demand charge component; and because the proposed \$.085/kWh rate was not based on the actual value of solar.²¹⁰ RUCO responds that the Advanced DG TOU rate is optional and available to all residential customers, so the partial and full requirements customers are treated the same. RUCO asserts that its recommended market rate was a good faith attempt to capture the value of solar and is only 1 cent/kWh lower than the TASC sponsored calculation using the same benefit categories. RUCO argues that its proposals are a step in the right direction and waiting for the completion of the Value of DG docket is not an option for this case.²¹¹

RUCO also rejects claims that changing a rate would prevent partial requirement customers

²⁰⁸ RUCO Reply Brief at 3.

²⁰⁹ RUCO Reply Brief at 4. RUCO states that its modified Non-Export Option preserves benefits of the exported energy for residential ratepayers, and while the original non-export option treated partial and full requirement customers the same, the modified rates would not.

²¹⁰ RUCO Reply Brief at 4.

²¹¹ Id. at 5.

1 from self-consuming their own generated power.²¹² RUCO believes that to make such arguments
 2 appear calculated to stir solar supporters to action and are not productive. RUCO argues that having
 3 the ability to change the accounting method for compensating exported power is central to developing
 4 fair and reasonable rates.

5 RUCO believes that its RPS Bill Credit option would be the most popular initially. Under this
 6 option, the credit rate starts at or near the current retail rate and decreases over time based on the
 7 Company's REST compliance. RUCO claims that this option provides a window of time for solar
 8 companies to be profitable, while providing time to develop a technology offering to maximize the
 9 potential sales to customers on the other rate option. Contrary to claims that this option could cause
 10 customers to lose money on their DG investments, RUCO states this rate actually provides stability
 11 because the credit rate will be known by all parties at the time of installation and will be locked in for
 12 that customer for 20 years, which RUCO believes is a benefit to the solar industry because it solves the
 13 need for future grandfathering. RUCO states that the RPS Bill Credit could be modified by the
 14 Commission to serve as a "glide path" for compensating energy exports and the Commission could use
 15 the RPS Bill Credit framework to increase or decrease the current retail rate, to meet the future credit
 16 rate set by the value of solar methodology.²¹³

17 RUCO reiterates that it firmly believes that rate options designed specifically for partial
 18 requirement customers that address unique issues presented by these customers is the preferred option.
 19 However, if the Commission determines as a matter of policy that partial and full requirement
 20 customers should be treated the same, RUCO proposes the following optional rates available to all
 21 residential customers:

22 1. Residential Service

- 23 • Hourly net credit export rate at 6 cents/kWh. This creates the same blended rate as
- 24 the advanced DG rate and the volumetric TOU proposed by RUCO.
- 25 • Banking is modified to an hourly net credit export rate based on hourly
- 26 consumption/production that is paid monthly.

27 _____
 28 ²¹² RUCO Reply Brief at 6, *citing* Vote Solar Initial Brief at 44.

²¹³ RUCO Reply Brief at 7.

- A grid access charge, similar to that of APS, may be prudent

2. Residential Three-part TOU

- Customers on this rate keep the current form of banking and net metering.

3. Residential Volumetric Two-part TOU

- Customers on this rate keep the current form of banking and net metering.

RUCO also provides an option only available to Energy Efficiency participants. To qualify for this rate, a customer must be enrolled in a pre-programmed thermostat of demand side management ("DSM") energy efficiency program offered by the Company. This rate features a 3 hour peak window.²¹⁴

RUCO proposes that DG customers who had an application submitted prior to the date of a final order in this case, should be fully grandfathered with existing rates and net metering compensation. RUCO continues to support a fixed charge of \$12.50. The Residential Volumetric Two-part TOU rate carries with it a \$19 fixed charge.

For partial requirement customers on the standard Residential Service, the current banking mechanism would be modified from a kWh-for-kWh exchange, with excess power rolling forward to future months to an hourly net credit export rate based on hourly consumption/production that is paid monthly. However, RUCO proposes that if it is found to be true that there are tax implications using this method, solar DG customers would have two other rate options to choose from. RUCO claims that banking of excess energy by residential solar DG customers is the exact problem this rate case is trying to solve, and must be addressed. RUCO asserts that the TOU structure reduces the need to end banking at this juncture, however, the switch could still take place on RUCO's TOU rates with little to no impact on the economics of solar adopters.

RUCO contends that DG customers have additional costs that non-DG customers do not. DG customers in the Company's territory have two meters. RUCO believes this cost should be paid by the DG customer. Based on the CCOSS, RUCO recommends implementing a \$6.95/month metering charge for DG customer with a link to RECs.

²¹⁴ Id. at 8-12.

1 TASC

2 In its Initial Brief, TASC argued extensively that the proposed mandatory residential demand
 3 charges are not in the public interest because they are unprecedented, volatile, punitive, confusing, and
 4 the specific proposal was rushed and its implementation was not well thought out.²¹⁵ In addition, TASC
 5 asserted that the docket lacks significant or substantive analyses, with no studies done to determine the
 6 amount of peak demand to be shifted or comparing impacts between potential TOU rates and demand
 7 rates in UNSE's territory. Furthermore, TASC argues that at the time of the hearing, there was no
 8 proof-of-revenue analysis presented for the three-part rate design.²¹⁶ TASC also criticized the
 9 Company's inability to show that it had an effective game plan for educating customers about demand
 10 charges or tools in place to assist ratepayers in managing their demand.²¹⁷ TASC argued that demand
 11 charges are volatile and burdensome and require an extreme level of diligence to avoid substantial bill
 12 impacts if a consumer experiences even one hour with greater-than-normal demand for that month.
 13 TASC asserts that the proposed peak hours (6 hours per day in summer and 8 hours per day in winter,
 14 excluding weekends and holidays) impose an "unconscionable" burden on ratepayers each month.²¹⁸
 15 TASC also claims that demand charges are particularly difficult for solar customers to manage because
 16 of the unpredictability of the weather. Moreover, TASC argued that the demand charges do not even
 17 solve UNSE's real problem of declining retail sales.²¹⁹

18 TASC argues that UNSE's post-hearing position, that would have demand charges apply only
 19 to DG solar customers, unreasonably discriminates against DG customers, violates procedural and
 20 substantive due process, and would render DG solar uneconomical.²²⁰ TASC argues that the
 21 combination of the post-hearing changes to rate design and the net metering tariff prevents TASC and
 22 other intervenors from formally examining any evidence of projected bill impacts, any new cost of
 23 service information justifying the newest proposal, and any proposed educational programs for the new
 24 demand rates. TASC argues that UNSE continues to fail to meet its burden to support its proposed rate

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 26 ²¹⁵ TASC Initial Brief at 12-22.

²¹⁶ Id. at 15.

²¹⁷ Id. at 15-16.

²¹⁸ TASC Initial Brief at 18. The proposed peak hours were 2-8 p.m. in summer and 5-9 a.m. and 5-9 p.m. in winter.

²¹⁹ TASC Initial Brief at 19-20.

²²⁰ TASC Reply Brief at 1.

1 design. Consequently, TASC believes the most reasonable approach is to deny any requested rate
2 design changes to residential, small commercial, and DG customers. TASC recommends that if the
3 Commission desires to explore new rate designs, it should order the Company to propose pilot rates,
4 which would allow the Company to experiment with rates, educational materials and needed customer
5 support, and to seek implementation of new rate designs in its next rate case.

6 In order to treat DG customers differently than its non-DG customers, TASC argues that UNSE
7 has the burden to demonstrate that differential treatment is just, reasonable, and nondiscriminatory, and
8 must also conduct solar-specific cost-of-service studies using actual data and benefit/cost analyses to
9 prove disparate treatment is warranted.

10 TASC observes that DG customers have never been subject to the demand charges, and have
11 no greater understanding of three-part rates or ability to control their demand than their non-DG
12 counterparts. TASC asserts that the demand charge volatility stems from the fact that demand charges
13 will be based on brief snapshots of time for each ratepayer's monthly usage, and argues that one-hour
14 with higher than usual demand could result in higher bills.²²¹ TASC argues that it is unfair and unjust
15 to adopt a rate design that could see a residential customer's diligent electricity usage wiped out by one
16 hour in the month. TASC asserts that under UNSE's proposal, a DG customer will have to constantly
17 be aware of simultaneous use of appliances, but will not have access to real-time information to aid
18 them.²²² TASC argues that in addition to the volatility and burdensome nature of demand charges, a
19 DG customer must also take into account the unpredictability of the weather on a daily basis. As a
20 result, TASC believes DG customers would face an impossible challenge to manage their loads. TASC
21 believes the evidence shows that adapting to demand charges would be problematic for all customers,
22 but even more so for DG customers because of the volatility of their load due to weather.²²³

23 TASC argues that under Commission Rules, in order to impose higher charges on DG
24 customers than all other customers with similar load characteristics, or customers in the same rate class
25 as the DG customer would qualify for if not participating in net metering, UNSE carries the burden of
26 proof and must support the differential treatment with "cost of service studies and benefit/cost

27 ²²¹ TASC Reply Briefs at 4-5, citing Tr. at 361.

28 ²²² TASC Reply Brief at 4.

²²³ Id. at 5.

1 analyses.”²²⁴ TASC asserts that UNSE has failed to submit the requisite studies or analyses needed to
2 support differential treatment of DG customers. TASC also asserts that the Company provided no
3 evidence to support its claim that DG causes considerable challenges to the grid, and could not identify
4 a single cost that the Company has incurred as a result of the implementation of DG systems.²²⁵

5 TASC asserts that UNSE has focused on DG as causing “cost shifts,” but ignores that the actual
6 cause of its declining revenue can be traced to the recent loss of its largest commercial customer, a high
7 number of “snowbirds” that visit seasonally, the growing number of vacant homes, and the lagging
8 economy in its service territory.²²⁶ According to TASC, the evidence shows that 75 percent of the
9 Company’s decline in retail sales is due to the loss of industrial and mining customers, and 19 percent
10 is due to sluggish economic conditions. TASC states that DG customers account for only 6 percent of
11 the total sales decline,²²⁷ such that singling out DG customers does not even address the problem that
12 UNSE claims that it is trying to solve.

13 TASC argues that in changing its rate proposals and proposing four different proposals over the
14 course of this proceeding, UNSE has violated the intervenors’ procedural due process right to notice
15 and to be heard.²²⁸ Further, TASC claims that UNSE’s actions have deprived the public and all
16 intervenors of substantive due process because the timing of UNSE’s latest rate proposal deprives
17 intervenors the opportunity to present witnesses and evidence bearing on the proposal, or even time to
18 assess the proposals.

19 Vote Solar

20 Vote Solar opposes mandatory demand charges for residential consumers and the Company’s
21 proposed changes to net metering as expressed at the hearing, as well as the proposed increase in the
22 monthly customer charge, and elimination of the upper residential tier.²²⁹ Vote Solar recommends that
23 the Commission consider TOU rates and a minimum bill concept in order to address the issues caused
24 by low-usage customers.

25
26 ²²⁴ TASC Reply Brief at 6, citing A.A.C. R14-2-2305.

27 ²²⁵ TASC Reply Brief at 6-7.

28 ²²⁶ Id. at 7.

²²⁷ Id. at 8.

²²⁸ TASC Reply Brief at 14-16; *Iphaar v. Indus Com’n of Arizona*, 171 Ariz. 423, 426 (App. 1992).

²²⁹ Vote Solar Initial Brief at 55-56.

1 Vote Solar argues that UNSE's post-hearing rate proposals that single out solar customers are
 2 discriminatory and violate the law. Vote Solar also asserts that the proposals are unnecessary,
 3 duplicative and unjust as UNSE's solar customers are a negligible cause of declining sales, costs shifts
 4 and grid impacts. Vote Solar believes minimum bills and time-of-use rates are better options to address
 5 UNSE's concerns. If the Commission were to adopt UNSE's proposals for solar customers, Vote Solar
 6 insists it is essential to grandfather all existing customers as of the decision date.²³⁰

7 One of the justifications for singling out solar customer is the alleged cost shift and need to
 8 improve fixed cost recovery, but Vote Solar states the evidence shows that solar customers are a
 9 negligible cause of these problems compared to customers without solar. Vote Solar calculated that the
 10 Company's approximate 1,800 residential net metering customers comprise only 2 percent of the total
 11 residential customers, that DG is only responsible for 6 percent of the decline in retail sales, and
 12 responsible for only 3 percent of the decline in usage-per-customer.²³¹ Thus, Vote Solar asserts it would
 13 be unjust and discriminatory to single out the minority of customers for "punitive rate treatment" while
 14 allowing the customers who actually cause the majority of the problem to avoid these rates. Vote Solar
 15 argues that UNSE has failed to substantiate the claim that DG causes numerous grid impacts and that
 16 those parties claiming that DG and net metering create huge subsidies have not quantified the alleged
 17 "huge subsidies" or how DG actually impacts UNSE.

18 Vote Solar argues that UNSE's proposed demand charges would discriminate against new solar
 19 customers, violate prohibitions in the Arizona Constitution and Commission Rules against
 20 discriminatory rate treatment, and that none of UNSE's most recent arguments for singling out rooftop
 21 solar for separate treatment and demand charges have merit. According to Vote Solar, UNSE has
 22 claimed there are several differences between DG Solar and Non-DG customers including that they
 23 use the grid differently and create costs by exporting power; and they are different than other low-usage
 24 customers as their demand can spike suddenly due to the weather. Vote Solar responds by arguing that:
 25 (1) UNSE fails to recognize the benefits of solar DG such as avoided energy costs, avoided generation
 26 costs, and avoided transmission and distribution costs; (2) the low percentage of solar DG means that

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 28 ²³⁰ Id. at 1.

²³¹ Ex UNSE-3 Hutchens Dir at 5; Ex Vote Solar-6 Kobor Dir at 9 & 12.

1 any operational differences in contributions to lost fixed cost recovery are negligible; and (3) UNSE
2 must stand ready to serve seasonal and newly occupied vacant homes as well as solar customers. Vote
3 Solar states that 66 percent of UNSE's residential bills do not fully recover fixed costs, and with solar
4 customer bills accounting for just 2 percent of the bills causing a cost shift, it is unjust and
5 discriminatory to single out these customers.

6 Vote Solar also asserts that RUCO's claim that solar customers are different than other
7 customers, which justifies different rate treatment, is arbitrary, unjust and discriminatory. Vote Solar
8 claims that merely listing how one type of customer differs from another doesn't automatically justify
9 disparate rate treatment, as there are a wide variety of customer types such as rural versus urban,
10 apartment dwellers versus single family homes, those with central air conditioning versus those
11 without, that are not placed in separate rate classes.²³²

12 Vote Solar asserts that UNSE's demand charge proposal for DG solar remains fatally flawed
13 because: (1) there is no evidence that residential customers can effectively respond to a demand charge;
14 (2) the demand charge would cause significant bill increases to low-usage customers; and (3) the
15 demand charge would not accurately reflect cost causation.²³³ Vote Solar states there is nothing about
16 solar customers that allows them to respond to demand charges any better than other residential
17 customers, and every argument against mandatory demand charges made to date in this case remains
18 applicable if only solar customers are required to pay the charges.²³⁴ Vote Solar criticizes RUCO for
19 supporting a mandatory demand charge for solar customers at the same time it highlights why the
20 demand charge is poorly designed. Vote Solar also criticizes AIC for claiming that a demand charge
21 will not act like a fixed charge, when UNSE's own witness Overcast has characterized demand charges
22 as fixed charges in a recent article.²³⁵ Vote Solar notes that the findings of APS' witness Faruqui about
23 customers' abilities to respond to demand charges involved optional charges. Similarly, Vote Solar
24 states that APS' and AIC's claims that APS has had residential demand charges for years resulting in
25 customer savings involve optional rates. Finally, Vote Solar asserts that it is unclear how UNSE would

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27 ²³² Vote Solar Reply Brief at 6.

²³³ Vote Solar Initial Brief at 26-34 and Reply Brief at 7-9.

²³⁴ Vote Solar Reply Brief at 7.

28 ²³⁵ Vote Solar Reply Brief at 7-8, Tr. at 1485.

1 provide safeguards, education and mitigation measures to transition customers to the new demand rates.

2 AURA

3 In its Initial Brief, AURA argued that because the three-part rate design was not raised until
 4 Staff proposed it in Direct Testimony, there has been insufficient time to fairly consider this radical
 5 rate redesign. Thus, AURA claimed that not only did the timing of the proposals create due process
 6 concerns concerning adequate notice and time to prepare, UNSE failed to submit sufficient evidence
 7 to allow the Commission to evaluate the effect of the cost shifts. AURA argued that to fairly evaluate
 8 a rate redesign of this magnitude, UNSE needs to collect and analyze at least one year of customer data
 9 from its new meters. In addition, AURA asserted UNSE needs to develop and submit a comprehensive
 10 customer education proposal. Thus, AURA generally recommended that UNSE utilize its transmission
 11 rate design until its next rate case. Alternatively, AURA recommended a second phase of this case to
 12 evaluate rate design.²³⁶

13 After UNSE withdrew its proposal of mandatory residential three-part rates, and assuming the
 14 Commission does not require mandatory three-part rates for residential customers, AURA
 15 recommends: (1) UNSE's rebuttal two-part rate design ("transition" rate) as the permanent rate design
 16 as it best tracks costs to serve residential customers; (2) the customer charge be set at RUCO's proposed
 17 \$12.26 with any reduction in revenues spread over the usage charges; and (3) given the pendency of
 18 the Value of DG docket, consideration of any changes to net metering be deferred to UNSE's next rate
 19 case.²³⁷

20 AURA's Reply Brief did not specifically address UNSE's post-hearing modifications to its
 21 residential rate design that would treat DG and non-DG customers differently, but AURA is on record
 22 as opposing the singling out of solar customers for demand charges. AURA criticizes UNSE for
 23 singling out residential DG customers without performing a cost-of-service study to determine if they
 24 actually have different characteristics. AURA provided the testimony of Mr. Alston who opines that

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 26 ²³⁶ AURA Initial Brief at 1-2. AURA had three recommendations in its Initial Brief: (1) to reject the residential rate proposal
 27 in favor of the transition rates; (2) alternatively, split the proceeding into two phases with phase one determining the revenue
 28 requirement and two-part rates, with phase 2 considering three-part rates after UNSE has collected at least a year's worth
 of data; and (3) if the Commission adopts UNSE's three-part rates, to hold customers harmless during an 18 month transition
 period.

²³⁷ AURA Reply Brief at 2.

1 UNSE's original rate design for DG customers was so severe that it would eliminate the economic
 2 benefits of installing residential solar systems and would be more difficult for customers to understand
 3 than TOU rates.²³⁸ AURA asserted that UNSE provided virtually no empirical data to support its rate
 4 design. Furthermore, AURA's witness Rubin compared the UNSE rate designs and concluded that the
 5 rebuttal position two-part rate design more equitably recovers costs and reduces intra-class
 6 subsidization.²³⁹

7 AriSEIA

8 AriSEIA believes that mandatory demand charges are inappropriate for residential service in
 9 general, and for the UNSE service territory in particular. AriSEIA states that the implementation of
 10 residential demand charges in this case would be a live social experiment with far-reaching
 11 consequences and a difficult path back in case of failure.²⁴⁰ AriSEIA asserts that as an alternative to
 12 demand charges, TOU tariffs should be considered, as TOU rates have been shown to be effective in
 13 reducing peak loads. AriSEIA also advocates customer choice and seems to support giving ratepayers
 14 a choice between two-part TOU and three-part demand rates.

15 SWEEP/WRA/ACAA

16 When UNSE was proposing mandatory demand charges for residential customers,
 17 SWEEP/WRA/ACAA²⁴¹ focused on the disparate bill impacts the proposal (demand charges plus an
 18 increased customer charge) was expected to have on moderate and lower usage customers. SWEEP's
 19 analysis indicates that for consumers using 687 kWhs per month the overall increase would be 14
 20 percent; but for those using 340 kWhs/month the increase would be 26.7 percent, and for those using
 21 109 kWhs/month the increase would be 34.2 percent.²⁴² They assert that demand charges for lower
 22 usage customers are going to appear like fixed charges to these customers to the extent that the
 23 customers cannot reduce demand. These intervenors argued that UNSE's claim that it is currently not
 24 recovering its fixed costs because per-customer usage is declining does not warrant the extreme

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 26 ²³⁸ AURA Initial Brief at 5-6.

²³⁹ Id. at 9-11.

²⁴⁰ AriSEIA Initial Brief at 8. AriSEIA did not file a Reply Brief.

²⁴¹ These parties are represented by the same counsel and filed joint briefs.

²⁴² SWEEP/WRA/ACAA Initial Brief at 5. The dollar increase would be \$9.65 for those using 687 kWhs, \$9.97 for those using 340 kWhs, and \$6.57 for those using 109 kWhs.

1 reaction of imposing demand charges on residential users, and that it is premature to say that the
2 Company could not recover its costs of service based on traditional volumetric charges.²⁴³

3 SWEEP/WRA/ACAA argue that the Commission should reject increases to any fixed charges
4 or the establishment of new ones, such as a demand charge.²⁴⁴ According to these parties, increasing
5 either the customer charge, or imposing a demand charge, will reduce volumetric rates which gives
6 customers less control over their bills and reduces the incentive to lessen consumption. These parties
7 argue there is no justification to increase the basic customer charge, and deviating from the basic
8 customer method of determining this charge allows the Company to move as many costs as possible
9 out of volumetric rates and into a fixed charge.²⁴⁵ SWEEP/WRA/ACAA believe that the Commission
10 has historically used the "basic customer method" for determining the basic service charge, which
11 involves determining those costs associated with customer service and which vary with the number of
12 customers, regardless of power usage, such as meters and service line drops.²⁴⁶ They assert that the
13 customer fixed charge should not include grid related costs of transmission and distribution plant which
14 are driven by customer usage and demand. They note that the calculations of three parties in this
15 proceeding have determined that the customer charge should not be increased, with two of the three
16 recommending a reduction.²⁴⁷

17 After the Company's withdrawal of its proposed universal mandatory residential demand
18 charges, SWEEP/WRA/ACAA note that the proposed fifty percent increase in the customer charge,
19 from \$10 to \$15, would still have a large impact on lower-usage customers, many of whom, according
20 to these parties, are low income. They note that customers would see an annual \$60 increase in their
21 bills without even turning on a single light. They suggest that the simplest and most appropriate way
22

23
24 ²⁴³ SWEEP/WRA/ACAA believe it worth noting that in 2015, UNSE's actual return on equity was 7.4 percent, which
25 although below the authorized rate of return, the original revenue request would have resulted in over a 12 percent rate of
26 return on equity in 2015 using only volumetric charges for residential customers (reduced to 10.8 percent under the reduced
27 agreed revenue requirement). Tr. at 508 and 522. SWEEP/WRA/ACAA Initial Brief at 7.

28 ²⁴⁴ In their Reply Brief, SWEEP/WRA/ACA consider the universal residential three-part rate proposal to be moot.

²⁴⁵ SWEEP/WRA/ACAA Initial Brief at 10.

²⁴⁶ SWEEP/WRA/ACAA state that this method is consistent with principles established by Professor Bonbright in his
Principles of Public Utility Rates. SWEEP/WRA/ACAA Initial Brief at 9.

²⁴⁷ SWEEP calculated the customer costs would be \$4.32, Vote Solar calculated the costs at \$7.50, and RUCO recommended
the current charge should not be increased. Ex SWEEP- 3 Schlegel Surr at 3; Ex Vote Solar-6 Kobor Dir at 61; and Ex
RUCO-6 Huber Surr at 24.

1 to assist lower income customers is to reject the increase in the basic service charge.²⁴⁸

2 SWEEP/WRA/ACAA assert that the rationale for imposing demand charges on larger
3 commercial customers, who have predictable loads, does not necessarily apply to residential customers
4 who have more variety in their usage patterns. Relying on AURA's witness Rubin's analysis, these
5 parties argue that the record supports a finding that volumetric rates do a better job of recovering the
6 costs of service than the demand rates.²⁴⁹ They argue that demand charges will cause confusion and
7 will not provide residential customers a real opportunity to save on their bills.²⁵⁰

8 SWEEP is a public interest organization that is dedicated to advancing energy efficiency as a
9 means to promote customer benefits, economic prosperity, and environmental protection in Arizona
10 and five other states. Specifically (and independent of WRA and ACAA), SWEEP recommends: (1)
11 the customer charge be reduced to \$4.32; (2) rejecting mandatory residential demand charges; (3)
12 denying the three-part rate design as proposed based on insufficient data to develop appropriate rates;
13 (4) if three-part rates are adopted, the Commission should ensure consistency with system coincident
14 peak demand; (5) UNSE should use TOU rates as an effective alternative to three-part rates; (6) if
15 residential demand charges are adopted, the Company must provide information and effective tools for
16 customers; (7) retaining tiered rates for residential customers to discourage wasteful energy use; (8)
17 recovering energy efficiency costs in base rates rather than in an adjustor mechanism because energy
18 efficiency is an important part of UNSE's energy resource portfolio; (9) treating all energy resources
19 equitably in terms of disclosure and transparency on customer bills;²⁵¹ and (10) modifying the cost-
20 effectiveness test for energy efficiency.²⁵²

21 WRA is a nonprofit organization that states it protects the West's land, air and water through
22 conservation programs, including Clean Energy. WRA recommends: (1) not approving separate rate
23 structure for non-DG and solar DG customers; (2) denying demand charges for residential customers

24 ²⁴⁸ SWEEP/WRA/ACAA Reply Brief at 3.

25 ²⁴⁹ SWEEP/WRA/ACAA Initial Brief at 13, citing Ex AURA-1 Rubin Surr at 17.

26 ²⁵⁰ SWEEP/WRA/ACAA Initial Brief at 14-19. They assert that the idea that customers only have to remember to run their
27 appliances one at a time is overly simplistic, as the same amount of demand will be created by running the appliances one
28 after another during the same hour peak period.

²⁵¹ SWEEP believes the bill should be simplified with fewer cost categories with supplemental information on costs and
energy resources provided on the web and via quarterly bill inserts or other communications to avoid singling out energy
efficiency for inequitable or selective treatment.

²⁵² SWEEP/WRA/ACAA Initial Brief at 17-15.

1 as they are difficult to understand, will act like fixed charges, and will likely increase bills for low
 2 income customers; (3) considering a minimum bill to recover a portion of fixed costs not otherwise
 3 recovered from very low usage customers; (4) implementing TOU rates for all residential customers to
 4 send price signals about the cost of generation; and (5) retaining the current customer charge of \$10.²⁵³

5 Specifically concerning the Company's latest proposal with five rate options for residential
 6 customers, SWEEP/WRA/ACAA recommend that the Commission reject the proposal to eliminate the
 7 three-tiered structure and instead approve the transition rates proposed by the Company with a \$10
 8 basic service charge.²⁵⁴ SWEEP/WRA/ACAA assert that the three-tiered rate structure promotes
 9 energy conservation and elimination of waste, and that its elimination would have high usage customers
 10 paying proportionately less, and low usage customers proportionately more.²⁵⁵ ACAA is against
 11 removing the third tier because it would disproportionately affect low-income customers since 75
 12 percent of the CARES customers use less than 1,000 kWh, compared to 69 percent of the customers
 13 on the RES-01 tariff. ACAA states that eliminating the third tier would redistribute these costs among
 14 the low-use customers who are already doing everything they can to conserve to keep their bills low.

15 SWEEP/WRA/ACAA generally support rate options as long as customers are provided
 16 sufficient information to make informed choices and given adequate tools to implement the choices.
 17 Thus, they assert that any TOU or three-part rate option must be accompanied by education and
 18 information materials. These intervenors support TOU rates, but do not support the Company's
 19 specific proposed TOU rates because the summer on-peak of 2:00 p.m. to 8:00 p.m. and the two four
 20 hour winter peak periods are too long.²⁵⁶ They assert that the on-peak periods should only be three
 21 hours long so that customers can adjust their schedules and energy use.²⁵⁷ They propose the following
 22 residential TOU rates with a \$10 basic service charge, and shorter on-peak periods (summer on-peak
 23 4-7 p.m.; winter on-peak 6-9 a.m. and p.m.) and a three-tier energy charge.²⁵⁸

24
 25 ²⁵³ Id. at 25-30.

26 ²⁵⁴ Ex UNSE-33 Jones RJ, CAJ-RJ-2 Sch H-3at 1.

27 ²⁵⁵ SWEEP/WRA/ACAA provide an alternative residential rate schedule if the Commission does not elect to adopt the
 transitional rates. SWEEP/WRA/ACAA Reply Brief at 6.

28 ²⁵⁶ SWEEP/WRA/ACAA Reply Brief at 6.

²⁵⁷ Citing RUCO's Initial Closing Brief at 15 ("More simplified offerings, including a TOU rate with a shorter on-peak
 period, will simplify customer communications, boost enrollment, and insure overall effectiveness.")

²⁵⁸ Based on the Company's revenue requirement.

1	Basic Service Charge	\$10	
2	Energy Delivery		Tier Limit
3	0-400 kWh	\$0.034000	400
4	401-1,000 kWh	\$0.050000	1,000
5	Over 1,000 kWh	\$0.063000	
6	Base Power	Summer	Winter
7	On-Peak	\$0.150000	\$0.090000
8	Off-Peak	\$0.043500	\$0.043100
9	PPFAC	0.0000%	

10 **Analysis and Resolution – Residential and SGS Rate Design**

11 We find the following from Bonbright's Principles of Public Utility Rates to be particularly
 12 relevant as we consider the myriad rate design proposals in this proceeding:

13 The administration of *any* standard or system of rate making has consequences,
 14 some of which are costly or otherwise harmful; and these consequences may
 15 warrant the rejection of one system in favor of some other system admittedly less
 16 efficient in the performance of its recognized economic functions. Thus an
 17 elaborate structure of rates designed to make scientific allowance for the relative
 18 cost of different kinds of service may possibly be rejected in favor of a simpler
 structure more readily understood by consumers and less expensive to administer.
 And thus a system of rate regulation that would come closest to assuring a company
 of its continued ability to earn a capital-attracting rate of return may be rejected in
 favor of an alternative system that runs less danger of removing incentives to
 managerial efficiency. The art of rate making is an art of wise compromise.²⁵⁹

19 Utilities have traditionally used two-part volumetric rates, consisting of a fixed customer
 20 charge, and an energy charge based on kWhs sold, to recover the costs of serving residential customers.
 21 Until fairly recently, the load characteristics of residential customers were relatively homogeneous,
 22 such that the simple two-part rates, designed based on average consumption assumptions, did an
 23 adequate job of recovering the costs of service. The short-coming of two-part rates is that if customers
 24 use fewer kWhs, for whatever reason, including energy efficiency products, a desire to protect the
 25 environment, or to save money, these rates do not recover all of the costs of service. The Commission
 26 recognized this effect when energy efficiency and DSM programs were approved by enacting the
 27

28 ²⁵⁹ Bonbright, James C., Principles of Public Utility Rates. New York, Columbia University Press, 1961, p. 37-38.

1 LFCR, which was intended to compensate the Company for the lost revenues associated with EE and
2 DG. The LFCR collects these costs by means of a per kWh charge. Thus, residential customers pay
3 more when sales decline. Low usage customers do not pay as much through the LFCR as others
4 because the LFCR is based on kWh consumption.

5 Some parties in the this case have argued for the implementation of three-part residential rates,
6 comprised of a fixed customer charge, a demand charge, and a volumetric energy charge, in order to
7 better align cost recovery and cost causation. As they were recommended in this case, a demand charge
8 would be incurred based on the highest one hour KW use during peak periods. Because the demand
9 charge would recover some of the fixed costs associated with investment in capacity formerly being
10 recovered in the energy charge, the energy charge portion of the rate is reduced. UNSE attempted to
11 design the three-part rates in this case such that they would be revenue neutral, in that the customer
12 using the average number of kWh's annually would see the same total bill for the month, but the
13 revenues would be recovered partly from a new demand charge in addition to the basic customer charge
14 and the energy charge.

15 Until recently, the technology to implement three-part rates for the residential class has not been
16 widely available. UNSE, however, expects to have smart meters, able to measure demand, installed
17 for all of its residential customers by the fall of 2016. We do not disagree with those who have argued
18 in this case that a three-part rate design can better align revenue recovery with cost causation. However,
19 the devil is in the details.

20 Demand charges, although used for many years in a commercial context, are a new concept for
21 most residential customers. APS has had a voluntary residential demand charge for many years, which
22 for certain customers, generally with high usage, has worked well, allowing them to save money. In
23 order for customers to understand how demand charges work and how they can manage their energy
24 consumption to save money, or at least not incur a bill increase, requires education and tools available
25 to monitor their load. Although the necessary meters that can measure demand are close to being
26 ubiquitous in UNSE's service areas, an education plan has not been formalized, nor have tools for
27 managing load been made available.

28 Thus, we concur with those parties who argue that this is not the time for this utility to require

1 all residential and SGS customers to transition to mandatory three-part rates. The public distrust or
2 antipathy to the proposal has convinced the Company and the Commission that any transition to three-
3 part rates will require a massive public education effort before we can say with any degree of certainty
4 that mandatory residential demand rates in UNSE's service territory are in the public interest. This does
5 not mean that another utility, under different circumstances, cannot make a convincing argument that
6 mandatory residential demand charges can be in the public interest. Our decision in this case applies
7 only to UNSE at this point in time.

8 Even though we do not approve mandatory residential or SGS demand rates, we believe that
9 the time is ripe for a more modern rate design. Before turning to mandatory three-part residential rates,
10 however, we find that the better, more tempered, path to modernity is to move as many customers as
11 possible to TOU rates, while also promoting other rate options, including an optional three-part rate
12 for the Residential and SGS Classes. Appropriately designed TOU rates should allow better recovery
13 of costs, and send the correct signals about the cost of service and encourage customers to shift their
14 loads to off-peak times. By shaving the peak, the utility and its ratepayers can save on investments in
15 generation, transmission and capacity.

16 In general, we find that the various options offered by UNSE in its Initial Brief (a two-part rate,
17 TOU, Super Peak TOU, three-part rate, and three-part TOU), modified to reflect the revenue allocations
18 approved herein and other adjustments discussed below, are reasonable. In order to move as many
19 residential and SGS customers as possible to TOU rates, we believe that the TOU option should be the
20 default residential rate for existing as well as new customers. However, because we do not yet have
21 rate proposals that reflect the conclusions of this Order, and because transitioning to default TOU rates
22 will take planning and education, there must be a transition period.

23 Thus, we authorize a traditional two-part rate structure (including UNSE's proposed two-tier
24 proposal for the energy charges) for a transition period of at least six months before residential
25 customers will be placed on the TOU options. During the transition period, UNSE shall compile and
26 submit a transition plan for review by Staff and RUCO (and any other interested party to this docket)
27 and Commission approval. The transition plan shall include the proposed transition date, and specific
28 educational materials to inform customers about TOU rates and how they can manage their bills under

1 TOU rates. Ratepayers should be allowed to opt out of the TOU option, and select any of the other rate
2 options. Because TOU rates will be a new experience for the vast majority of UNSE residential
3 customers, they should include shorter peak hours (3-7 p.m. in the summer, and 6-9 a.m. and 6-9 p.m.
4 in winter) than UNSE has proposed. Furthermore, with the increased volumetric rates during the peak
5 hours, it is reasonable to be more gradual with the increase in the monthly customer charge. We find
6 that a 30 percent increase, from \$10 to \$13 per month is reasonable in this case.

7 Accordingly, we are authorizing the continuance of the traditional two-part volumetric rate
8 design, with a \$13 basic customer charge for the Residential Class and \$20 for the SGS Class, as a
9 transition to universal default TOU rates. These rates shall be effective on the first day of the month
10 after they are filed, and remain in effect until the Commission authorizes the transition to TOU as the
11 default according to a transition plan. Then, as directed herein, UNSE shall file a proposed two-part
12 TOU rate, a two-part super-peak TOU rate, a three-part rate and a three-part TOU rate for the
13 Residential Class, and a two-part TOU rate and three-part rate, and three-part TOU rate for the SGS
14 Class.

15 In addition, UNSE shall file a transition plan, under which all Residential and SGS customers
16 will be transitioned to the two-part TOU rate. The plan shall provide educational materials and time
17 frame for the transfer. Residential and SGS customers shall have the opportunity to opt into any of the
18 residential or SGS rates. In order to encourage as many customers as possible to remain on the TOU
19 rates, the basic customer charge for the available two-part volumetric rates shall be increased to \$15,
20 with the energy charges adjusted accordingly in order to be revenue neutral.

21 Because we adopt a different revenue allocation than either Staff or the Company, and are
22 modifying their proposed monthly customer charge from \$15 to \$13 per month, until UNSE files new
23 rate schedules and proof of revenue that conform to our authorizations herein, we cannot provide an
24 exact bill impact analysis. However, as the allocation to the Residential Class we adopt is more than
25 Staff's proposal and less than the Company's proposal, the bill impacts under the transition rates are
26 expected to fall between the estimates provided by those parties. Thus, factoring in our approved
27 revenue allocation to the Residential Class and a lower monthly customer charge which places a higher
28 percentage of the increase in the commodity charges than proposed, we estimate that under the

1 transition two-part rates, an average residential customer using 830 kWhs a month would see a monthly
2 bill of approximately \$87.52, an increase of \$2.36, or 2.7 percent, over current rates. The ultimate TOU
3 and optional demand rate options adopted after the transition period will be designed on a revenue
4 neutral basis such that the revenue collected from the Residential Class will not be changed, but
5 individual customers will experience different impacts based on their usage patterns.

6 The appropriate rate design and effective date of any new rate design affecting DG Residential
7 and SGS customers will be discussed in the Net Metering Section of this Decision.

8 CARES

9 UNSE

10 UNSE proposes a single fixed discount of \$16 per month for CARES customers and a single
11 fixed discount of \$28 per month for CARES-Medical customers. Under UNSE's proposal, CARES
12 customers will take service under the residential tariffs and the discounts will be applied to the bills.
13 UNSE states that the proposed discounts are based on bill impacts and designed to provide a similar
14 bill discount as the CARES customers currently receive. UNSE also proposes to keep the CARES-
15 Medical rate frozen.²⁶⁰ UNSE states that the CARES discounts will result in an overall subsidy of
16 approximately \$1.3 million, which is approximately twice the existing subsidy. The revenue lost from
17 the CARES discount is recovered in the rates of the Residential Class. Under this scheme, CARES
18 customers will no longer need a special rate, which UNSE asserts will give these customers experience
19 with standard rates. UNSE believes that this approach is simpler and easier to understand than the
20 current structure and should provide for a smoother transition to standard rates when economic
21 situations improve for these customers.²⁶¹

22 The Company opposes increasing CARES eligibility from 150 percent to 200 percent of the
23 federal poverty level because it would increase the cost of the program which would be passed on to
24 other residential customers.²⁶²

25 ACAA requested that 10 percent of the Warm Spirits funds be provided to the agencies that
26

27 ²⁶⁰ UNSE Initial Brief at 59.

28 ²⁶¹ Id. at 60.

²⁶² Id.

1 distribute the funds to cover the costs of program delivery. UNSE agrees to provide such funding.²⁶³
 2 ACAA requested that the Company add information to its disconnection notice that notifies customers
 3 about agencies providing bill assistance in their area, weatherization agencies, and the CARES
 4 discount. UNSE agrees to incorporate such information as part of an upcoming bill re-design project.²⁶⁴
 5 ACAA also requests that the Company streamline the CARES enrollment process by automatically
 6 enrolling customers who are already enrolled in other low income assistance programs and by
 7 increasing certain training for the Company's customer service representatives. UNSE believes that the
 8 proposals "are worth further study."²⁶⁵

9 UNSE disagrees that the Fortis settlement agreement requires "holding low income customers
 10 harmless" from rate increases, but rather commits UNSE to "support . . . low income assistance
 11 programs at or above the current levels."²⁶⁶ UNSE states that the proposed CARES discount that more
 12 than doubles the assistance provided to CARES customers clearly meets the intent of the Fortis
 13 Settlement.

14 In addition, UNSE disagrees that CARES customers should be treated differently than other
 15 customers with respect to deposits, and that all customers should fund Commission-mandated energy
 16 efficiency programs through the DSM surcharges. UNSE states there is no prohibition on low income
 17 customers participating in energy efficiency programs.

18 Staff

19 Staff supports UNSE's extended CARES plan which increases the monthly discount for
 20 qualifying CARES customers and CARES medical customers.²⁶⁷ Staff notes that the increased
 21 discounts will cost \$1.3 million and would take effect upon the implementation of the three-part rates,
 22 and are intended to offset the proposed expected rate increases in this case.²⁶⁸ Staff believes the discount
 23 would be transparent under the Company's proposal. Staff sates further that it commits to monitor the
 24 CARES program during the final phase of rate design.

25 ²⁶³ Ex UNSE-20 Smith Reb at 5.

26 ²⁶⁴ UNSE Initial Brief at 61, Ex UNSE-20 Smith Reb at 7.

²⁶⁵ UNSE Reply Brief at 36.

27 ²⁶⁶ Id.

²⁶⁷ Staff Initial Brief at 17. Staff refers to a \$17 discount, but the proposal in UNSE's updated schedules is \$16.

28 ²⁶⁸ Staff Initial Brief at 17. Staff made its statement before UNSE withdrew the demand charge proposal of all residential customers. Staff did not address the CARES program in relation to UNSE's revised rate proposals.

1 ACAA

2 ACAA is a nonprofit agency that works with organizations and individuals to develop and
 3 implement strategies to address and ultimately eliminate poverty across Arizona. ACAA provided
 4 information and recommends: (1) low income households in UNSE's service territory are in a
 5 vulnerable state as the poverty levels in Mohave and Santa Cruz Counties are higher than the statewide
 6 average and any additional increase in electric rates will exacerbate the existing hardship for these
 7 households; (2) participation in UNSE's CARES program is under-subscribed based on ACAA
 8 estimates and UNSE needs to take steps to improve outreach and streamline the application process;²⁶⁹
 9 (3) the CARES rate should ensure that CARES customers are held harmless; (4) CARES customers
 10 should be held harmless from UNSE's proposed deposit rule which would allow the Company to
 11 collect deposits more frequently;²⁷⁰ (5) CARES eligibility should be expanded up to 200 percent of the
 12 Federal Poverty Guideline; and (6) the current exclusion of the DSM surcharge for CARES customers
 13 should be maintained.²⁷¹

14 ACAA recommends that if the Company's modified rate proposal is selected, the CARES rate
 15 will need to be enlarged in order to provide a similar level of protection to low-income customers.
 16 According to ACAA, the two-part CARES rate proposed by the Company in its Initial Brief results in
 17 an 11 percent increase for the CARES customer class, and in order to hold the CARES class harmless,
 18 the CARES discount would need to be \$23/month instead of the \$16/month proposed by UNSE. ACAA
 19 states that the CARES-Medical discount could remain at \$28/month.²⁷²

20 ACAA does not believe that Staff's proposal to "monitor the CARES program during the final
 21 rate design development" is clear.²⁷³ ACAA recommends at a minimum, such monitoring should
 22 include enrollment, bill impacts and total revenue collected, comparing actual results to expectations.
 23 ACAA states there must be tools available to increase assistance to CARES customers in the event

24 ²⁶⁹ ACAA supports auto-enrollment in the CARES program and states that based on the experience of SRP, ACAA
 25 anticipates an increase in participation of approximately 3.4 percent, or 210 customers. SWEEP/WRA/ACAA Reply Brief
 at 10.

26 ²⁷⁰ ACAA appreciates that UNSE incorporated several of ACAA's suggestions into its proposal, such as maintaining the
 27 deferred payment plan length at six months, modifying the termination notice to include contact information to bill
 assistance, and providing a program delivery budget for agencies distributing Warm Spirit funds.

27 ²⁷¹ SWEEP.WRA/ACAA Initial Brief at 30-35.

28 ²⁷² SWEEP/WRA/ACAA Reply Brief at 9.

²⁷³ Id.

1 adverse impacts from any changes in rates are greater than expected.²⁷⁴

2 ACAA requests a separate CARES rate instead of the proposed discount off the standard
3 residential rate. ACAA supports RUCO's CARES rate (a monthly fixed charge of \$6.13).²⁷⁵ ACAA
4 believes that the RUCO proposal does the best job of protecting low-income customers. However,
5 ACAA would modify the CARES program such that in lieu of the current CARES discount (percentage
6 based on usage, with a flat discount for customers over 1,000 kWh) there be a flat discount of \$12 per
7 month for CARES customers and \$24 per month for CARES-Medical customers.²⁷⁶ ACA also agrees
8 with RUCO's suggestion that CARES customers remain on a separate rate structure, as they have
9 unique needs and concerns.

10 **Analysis and Resolution – CARES**

11 Lagging economic opportunities in the areas of the state served by UNSE have resulted in a
12 population that is particularly susceptible to rising costs of living. The Fortis merger Decision requires
13 UNSE to support low income programs at or above levels at the time of that Decision. In this case,
14 UNSE proposed a low income budget of \$1.3 million, which is an increase over the last rate case, and
15 intended to maintain the current discount to CARES customers, and which we believe meets the
16 obligation in the Fortis merger Decision. We find that the Company's proposed funding of the CARES
17 program is reasonable. Any increase in the low income program, either by expanded eligibility, or
18 greater discounts, is borne by the remainder of residential ratepayers. Given the amount of the
19 authorized rate increase on the residential class, we do not believe that it is prudent to further burden
20 the residential class. Further, considering the revenue allocations authorized herein, UNSE must
21 determine the appropriate discount for the CARES customers, and such discount must reflect the
22 greater of a budget of \$1.3 million or an amount necessary to maintain the current level of discount
23 received by CARES customers.

24 ACAA argues that the CARES class should continue to be exempt from the DSM surcharge,
25 while UNSE argues the charge should apply because the CARES class is eligible to benefit from DSM

26 ²⁷⁴ Id. at 8.

27 ²⁷⁵ RUCO Initial Brief at Attachment A.

28 ²⁷⁶ SWEEP/WRA/ACAA Reply Brief at 8. ACAA notes that the Company proposed a flat discount to decrease the administrative burden of CARES. ACAA references a \$12 discount for the CARES discount, however, the Company is currently proposing a \$16 discount for CARES and \$28 for CARES-Medical. UNSE Initial Brief at Exhibit 1.

1 programs. Because they are currently exempt from the charge, CARES customers in essence receive
 2 an additional discount on their bills. Thus, when UNSE calculates the appropriate discount under the
 3 new rates approved herein, it should include the current DSM discount as part of the calculation and
 4 adjust the overall discount accordingly. Under this approach it would be appropriate to assess the DSM
 5 surcharge to CARES customers.

6 ACAA believes that a separate CARES rate, as opposed to a discount on regular residential
 7 rates, best serves the needs and concerns of the low income customers. It is not clear, however, which
 8 needs and concerns are not served under a discount if the end result is a bill that is approximately the
 9 same. We find that the Company's proposal is reasonable and promotes transparency.

10 We are disappointed by the low participation in the CARES program vis-a-vis the apparent
 11 need in the community. Thus, we believe that ACAA's suggestion to streamline enrollment through an
 12 automatic process when customers seek other financial assistance has merit. The Company should
 13 investigate how to implement such automatic enrollment. If such program is not implemented before
 14 UNSE's next rate case, the Company should address why an automated or streamlined process could
 15 not be implemented, or was not cost effective, in its next rate application and provide supporting direct
 16 testimony.

17 ACAA also opposes the proposed change to the Company's deposit rules. The Company
 18 proposes the following language regarding residential deposits:

19 4.3. Residential Customers – The Company may require a residential Customer to
 20 establish or reestablish a deposit if the Customer becomes ~~became~~ delinquent in the
 21 payment of ~~three (3)~~ two (2) or more bills ~~within a twelve (1) consecutive month period,~~
 22 or has been disconnected from service during the last twelve (12) months, ~~or the~~
 23 ~~Company has a reasonable belief that the Customer is not credit worthy on a rating from~~
 24 ~~a credit agency utilized by the Company.~~²⁷⁷

25 The use of the permissive “may” gives the Company flexibility in the operation of this
 26 provision. Ms. Smith testified that the Company considers the individual circumstances of its
 27

28 ²⁷⁷ UNSE Initial Brief at Exhibit 3, Section 3(B)(3)

1 customers in designing repayment plans in the case of delinquencies.²⁷⁸ The change gives the Company
 2 more flexibility in dealing with delinquencies and to gain more control over bad debt expense. It does
 3 not appear that the change from three to two months will have a substantial effect on low income
 4 ratepayers. We find the proposed language reasonable.

5 Rate Design - Large Commercial and Large Power Service

6 UNSE

7 UNSE states that in this rate case it seeks to modernize its rate structure to more closely match
 8 revenue recovery with cost of service. As part of this effort, the Company proposes to redesign the
 9 current LGS and LPS tariffs to more appropriately recover fixed costs in the fixed portion of rates.
 10 Thus, UNSE proposes to increase the basic service charges for the non-residential classes to be closer
 11 to levels indicated by the CCOSS.

12 The Company proposed to create a new MGS Class that will contain most of existing LGS
 13 customers because the current LGS class contains a wide range of customer load sizes. The design for
 14 the new MGS rate is proposed to be the same as the current and new LGS rates, with a 75 percent
 15 ratchet. The new LGS rates will not be changed, except that the rates will be recalculated to blend about
 16 10 of the largest former LGS customers and about 7 of the former LPS customers (those who take LPS
 17 service at less than 69kV-distribution level voltage). UNSE agreed with Staff's recommended
 18 modification to these rates.²⁷⁹ The LPS Class will not undergo a rate design change, but will only be
 19 available to customers taking service at greater or equal to 69 kV.²⁸⁰ The Company accepted Staff's
 20 suggested modifications to the LPS tariff.²⁸¹

21 UNSE seeks to freeze enrollment in the current Interruptible Power Service ("IPS") rate. The
 22 provisions of the tariff will be unchanged for those customers currently being served under this rate,
 23 with the rates increased to reflect the authorized revenue and allocations in this case.²⁸² In its place,
 24 UNSE proposed an interruptible rider similar to that approved for TEP.²⁸³ UNSE states this will result

25 ²⁷⁸ Tr. at 632 & 638; Ex UNSE-21 Smith RJ at 6; Ex UNSE-20 Smith Reb at 4.

26 ²⁷⁹ UNSE Initial Brief at 37; Ex S-5 Solganick Rate Dir at 36.

²⁸⁰ UNSE Initial Brief at 37.

²⁸¹ Ex S-5 Solganick Rate Dir at 36.

27 ²⁸² UNSE Initial Brief at 38. Pursuant to the Settlement agreement approved in Decision No. 74235, UNSE was required to
 evaluate options to redesign its IPS Tariff.

28 ²⁸³ Ex UNSE-31 Jones Dir at CAJ-3, Rider R-12 Interruptible Service.

1 in a rate that is more cost-based, can be offered in a manner more consistent with TEP, and allow for a
 2 more consistent application of the rate.²⁸⁴ The rider provides for a customer to pay standard tariff rates,
 3 but allows the customer to designate a portion of their load as interruptible and receive a credit on their
 4 bill for the amount of capacity offered. UNSE states that this results in a more cost-based credit for
 5 the real value of interruptible capacity in the year it is offered and protects the remaining customers.²⁸⁵

6 UNSE proposed several changes to its service fees, to which Staff made several
 7 recommendations that are acceptable to the Company.²⁸⁶ UNSE requests that the Commission approve
 8 the service fees recommended by Staff.²⁸⁷

9 In UNSE's last rate case it proposed a 100 percent demand ratchet for large and medium general
 10 services customers, but settled for a 75 percent ratchet. Decision No. 74235 approved the demand
 11 ratchet in an effort to stabilize demand revenue and more closely align cost recovery with the cost
 12 causer.²⁸⁸ In this case, UNSE seeks to continue the 75 percent demand ratchet for the medium and large
 13 general services customers. UNSE explains that the demand ratchet looks at the "maximum demand
 14 used for billing purposes in the preceding 11 months, and will apply if the demand that month is 75
 15 percent of that level or lower." When the ratchet applies, the demand charge is set at the 75 percent
 16 level, and thus, UNSE states operates as a type of minimum demand charge, but allows the customer
 17 to reduce that minimum charge by reducing maximum demand during the rolling 11 month period.
 18 UNSE claims that the alternative to a ratchet is to assign the costs to other customers or to create a
 19 seasonal rate that recovers the costs with higher charges.²⁸⁹ UNSE is not proposing any changes to the
 20 methodology for demand charges to the LPS class approved in the last rate case.

21 The Company states that it evaluated Nucor's proposal to use the 4 coincident peak ("4CP")
 22 method, but continues to believe that industrial demand rates should combine costs based on both the

23
 24 ²⁸⁴ Rider-12 is available to customers taking service over 1,000 kW (either TOU or non-TOU) and willing to subscribe to
 at least 500 kW at a contiguous facility.

25 ²⁸⁵ Ex S-5 Solganick Rate Dir at 41. Staff accepted the Company's proposed new Interruptible Rider-12 and has not opposed
 freezing the current IPS rate. Staff recommends the existing IPS tariff be eliminated in the Company's next rate case, which
 26 the Company agrees to propose in its next rate case.

27 ²⁸⁶ UNSE Initial Brief at 39, Ex S-5 Solganick Rate Dir at 46-47; Ex UNSE-32 Jones Reb at 22.

28 ²⁸⁷ Ex UNSE-31 Jones Dir at 69-73 and Exhibit CAJ-3; Ex S-5 Solganick Rate Dir at 46-47; Ex UNSE-32 Jones Reb at
 22; UNSE Initial Brief at 39.

²⁸⁸ Decision No. 74235 at 22-23.

²⁸⁹ UNSE Initial Brief at 40.

1 system's non-coincident peak and coincident peak. UNSE states that it has proposed to reduce the
2 differential between on-peak and off-peak rates to better reflect the difference between the marginal
3 cost of energy purchased on-peak versus off-peak. The Company states that it does not incur a
4 substantial difference in the marginal cost of such purchases, and Nucor's TOU rate proposal ignores
5 the actual differential between the marginal costs. UNSE asserts the current off-peak energy rate is
6 basically the same as the current marginal cost of energy and, as a result, there was no contribution to
7 the Company's margin from LPS TOU off-peak energy sales.²⁹⁰ UNSE states that Nucor's proposal
8 would allow Nucor to pay less than the marginal cost of energy during off-peak periods and push such
9 recovery onto other customers.²⁹¹ UNSE also asserts that Nucor's proposal to modify the Interruptible
10 Rider would benefit Nucor, but not provide any material benefits for the Company and its other
11 customers.

12 UNSE asserts that it is sympathetic to the issues raised by FPAA and has tried to work with the
13 organization to find solutions to the demand ratchet applied to its class of service. UNSE states,
14 however, that FPAA is mistaken that its members do not contribute to the Company's system peak, as
15 the FPAA group peak is in June, which is the same as the typical system peak in the Santa Cruz area.
16 Given this fact, UNSE finds it hard to justify giving an intra-class subsidy to FPAA members when
17 their load characteristics are similar to other customers in the class.²⁹² UNSE states that each of FPAA's
18 offered solutions (to treat it as a separate class, offer economic incentives, eliminate the ratchet) would
19 result in a cost shift to other customers.

20 UNSE states that it has worked with FPAA to design a seasonable rate that would allow FPAA
21 members to save money based on their characterization of their consumption patterns. The Company
22 analyzed a number of scenarios including: (1) no demand ratchet with a high summer kW charge and
23 a lower winter kW charge; (2) a kW ratchet that is calculated strictly on summer kW demand; and (3)
24 a higher kW charge that focused strictly on the peak months of June, July and August. UNSE states
25 that when these options are applied to the actual usage of the FPAA member accounts, only a few of
26 those accounts would realize some savings, and that based on historical usage habits, most of the

27 ²⁹⁰ UNSE Initial Brief at 37, Tr. at 2616-18 and 2620-23.

28 ²⁹¹ UNSE Reply Brief at 28.

²⁹² Id. at 28-29.

1 produce accounts would have experienced an increase as the result of these rate designs.²⁹³

2 UNSE suggests that if the Commission makes a policy decision to offer a non-cost based rate
3 option to address FPAA's concerns, the Company could create a second MGS rate tariff that would
4 reflect an increased basic service charge (from \$100 to \$150 for those who opt in). The customers
5 would also receive a credit equal to 50 percent of the standard MGS kW rate multiplied by the amount
6 that measured kW is less than the ratchet demand for the summer months (May-Oct). UNSE states
7 that of the 55 produce customers identified on the MGS standard rate, 32 of them could save an average
8 of approximately \$1,600/year with this proposal. The total savings realized by the MGS class is
9 estimated at \$300,000/year, which the Company proposes should then be collected from other
10 customers through the PPFAC.²⁹⁴

11 **Nucor**

12 Nucor operates a steel mill facility in Kingman that produces coil rebar and wire rod products.
13 Nucor states that for electric arc furnace-based steel mills, electricity is a very important input and is
14 typically one of the highest variable costs in steel production. To stay economically viable in a
15 competitive world market, Nucor schedules its operations, when feasible, during UNSE's off-peak
16 periods. Nucor purchases most of its electricity through UNSE's Large Power Service Time of Use
17 (LPS-TOU) tariff.²⁹⁵

18 Nucor asserts that the demand charge applicable to large industrial energy consumers should
19 be based on a customer's contribution to system peak demand, in other words, that within the LPS rate
20 class, customers should pay their share of the demand-related costs allocated to the LPS class based on
21 each customer's contribution to the Company's coincident peaks in the four summer months (June,
22 July, August and September) of the previous year (aka the "four coincident peak method" or "4CP").
23 In addition, Nucor recommends that the current differential between on-peak charges and off-peak
24 energy charges in the LPS-TOU tariff should be maintained, and the Interruptible Rider should be
25 redesigned to be available to all industrial energy consumers regardless of when they operate.

26 Nucor raised the same issue of the demand charge calculation in the Company's last rate case.

27 ²⁹³ UNSE Initial Brief at 43.

28 ²⁹⁴ Id.

²⁹⁵ Nucor Initial Brief at 2.

1 At that time, the Commission did not adjust the demand charge, but the Settlement Agreement
 2 approved in the last rate case contained a directive to UNSE to evaluate the impact of switching to a
 3 4CP method of determining an industrial customer's demand, although UNSE was not required to
 4 endorse such switch.²⁹⁶ Nucor states the Company presented the required evaluation, but did not
 5 propose any meaningful changes to the method used to calculate industrial customers' demand charges.

6 UNSE proposed the following demand charge calculation for an LPS-TOU customer:

- 7 1. The greatest measured 15 minute interval demand read of the meter during the on-peak
- 8 hours of the billing period;
- 9 2. One-half of the greatest measured 15 minutes interval demand read of the meter during the
- 10 off-peak hours of the billing period;
- 11 3. The greater of (1) or (2) above during the preceding 11 months; or
- 12 4. The contract capacity or 500 kW, whichever is greater.

13 Nucor submits that there is no dispute that capacity-related or demand-related costs, are directly related
 14 to investment in generation and transmission capacity to meet the system peak demand.²⁹⁷ Nucor argues
 15 that UNSE's proposed demand charge calculation, however, has nothing to do with LPS-TOU
 16 customers' contribution to the system peak. Thus, Nucor argues that UNSE's proposed demand charges
 17 for industrial users do not reflect cost causation and are not just and reasonable.

18 Nucor argues that the UNSE proposed criteria represent an inaccurate price signal for LPS-
 19 TOU customers and contribute to significant intra-class subsidies. First, Nucor argues the on-peak
 20 period in the first criterion is too broad, as it encompasses 3,096 on-peak hours in the summer and an
 21 additional 3,024 winter hours, when system demand is not very high.²⁹⁸ Nucor argues that if an LPS
 22 customer's individual demand peaked in one of the on-peak hours of low system demand, the resultant
 23 charge would be a poor measure of that customer's contribution to the system peak.

24 Nucor asserts that the second criterion, based on one-half of the highest hourly use by the
 25 customer during the off-peak period, is arbitrary and not based on the consumer's contribution to the
 26 system peak. Nucor claims that UNSE could not explain how this criterion was connected to the
 27 Company's ratemaking principles.²⁹⁹ Nucor argues that a non-coincident peak demand measurement
 28 is not a useful or accurate basis for calculating an industrial TOU customer's contribution to system

²⁹⁶ Decision No. 74235 (December 31, 2013) Exhibit A at 15.2/

²⁹⁷ Nucor Initial Brief at 5.

²⁹⁸ Ex Nucor-1 Zarnikau Dir at 12-13.

²⁹⁹ Tr. at 2611-13 and Tr. at 2658-59.

1 cost.³⁰⁰ Nucor explains that because industrial customers, who are served at transmission voltage, do
 2 not cause distribution level investment, it is not appropriate to recover costs based on non-coincident
 3 peak demand.

4 Nucor states the third criterion is a “ratchet,” and although it is not uncommon for utilities to
 5 use demand ratchets to achieve stability in their collection of revenues, the ratchet should be based on
 6 justifiable and accurate methods of calculating a customer’s contribution to system peak. Nucor argues
 7 that since neither of the first two criteria are good measurements of demand-related cost causation,
 8 neither is the ratchet.³⁰¹

9 Nucor suggests that the fourth criterion should be eliminated because according to the
 10 Company, no customers have a contract capacity, and it is not clear how a simple “500 kW minimum”
 11 reflects a customer’s contribution to the system peak.³⁰²

12 Nucor recommends using the industrial customer’s contribution to the coincident peak in the
 13 four summer months as a proxy for its contribution to system peak. Alternatively, Nucor proposed that
 14 a customer’s contribution to the “top 20 hours” of highest demand in the previous year could be used.
 15 Nucor states that its proposed change will not affect how costs are allocated among rate classes and
 16 would only improve how costs are recovered from the customers within the class, which is a significant
 17 step toward reducing intra-class subsidies.³⁰³

18 In its Initial Brief, UNSE stated that Nucor’s suggested changes to its LPS tariff structure are
 19 unnecessary and inappropriate, and modifying the demand rate and off-peak prices would simply shift
 20 more costs to other customer classes or would increase other parts of Nucor’s bill. Based on these
 21 statements, Nucor believes that UNSE may not understand Nucor’s proposal.³⁰⁴ First, Nucor explains,
 22 its proposal is designed to reduce intra-class subsidies within the LPS and LPS-TOU class, and would
 23 not shift costs to other customer classes, but only align prices within the LPS rate class. Nucor claims
 24 it has demonstrated, without dispute, that its proposed change to a 4CP-based demand charge would

25 ³⁰⁰ Nucor submits that for a distribution level customer, there may be some merit to using a non-coincident peak demand
 26 measurement to design a demand charge, as these customers cause distribution-related costs related to the customer’s
 maximum demand, regardless of when that maximum occurs. Nucor Initial Brief at 10.

27 ³⁰¹ Nucor Initial Brief at 10.

27 ³⁰² Ex Nucor-1 Zarnikau Dir at 13-14.

27 ³⁰³ Nucor Initial Brief at 11.

28 ³⁰⁴ Nucor Reply Brief at 2-4.

1 reduce the intra-class subsidies within the LPS rate class by properly aligning demand charges with
2 cost causation. Nucor states that it currently subsidizes other customers within the LPS class because
3 Nucor consumes relatively little energy during on-peak periods and thus has little impact on the utility's
4 need for generation and transmission capacity.

5 Second, Nucor believes that the Company's argument that redesign of the demand charge could
6 increase other parts of Nucor's bill is inaccurate because Nucor's proposal only affects the recovery of
7 demand-related costs among the LPS and LPS-TOU class. Nucor states that the Company appears to
8 suggest that it could move demand-related costs so they might be recovered through other charges (e.g.
9 energy or customer charges). Nucor strongly opposes any such reclassification or shifting of costs, and
10 states that it would be absurd, and completely contrary to cost-causation ratemaking, to argue that
11 demand related fixed costs should be collected through an energy or customer charge.

12 In addition to redesigning the demand charge, Nucor also recommends that the Company
13 improve and clarify the LPS-TOU tariff, the proposed Interruptible Rider, and the proposed Economic
14 Development Rider. Nucor advocates keeping the current differential between the on-peak energy
15 charges and the off-peak energy charges in the LPS-TOU tariff. Currently, the LPS-TOU Power Supply
16 Charge, Base Power price during on-peak periods in the summer is \$0.12358 per kWh, and the price
17 in off-peak periods is \$0.09338 per kWh—a ratio of 5 to 1. During the winter, the current charges are
18 \$0.093880 per kWh during the on-peak period and \$0.022105 per kWh during the off-peak period,
19 resulting in a ratio of roughly 4.25 to 1. UNSE proposes the summer Power Supply Charge Base Power
20 price to be \$0.125220 per kWh on-peak and \$0.033410 per kWh off-peak, a differential of 3.7 to 1.
21 The proposed winter charges are \$0.09211 on-peak and \$0.030410 off-peak, resulting in a differential
22 of about 3 to 1.³⁰⁵ Nucor notes that UNSE is proposing to increase the off-peak charges, while keeping
23 the on-peak charges close to the existing charges. Nucor states the reduction in the difference between
24 on and off peak will reduce the incentive for customers on this tariff to move consumption to off-peak
25 periods. Nucor argues that the Company has not provided adequate justification for reducing the LPS-
26 TOU on-peak/off-peak charge ratio.

27
28 ³⁰⁵ Using rates in UNSE Initial Brief at Exhibit 1.

1 Nucor also recommends that the Interruptible Rider be redesigned so that it is available to all
2 industrial customers, regardless of when they operate.³⁰⁶ Nucor considers the proposed Interruptible
3 Rider (R-12) to be a step in the right direction, but believes that it will be of limited value to UNSE's
4 system. Nucor states that it (and maybe other industrial users) have loads which could be interrupted
5 during emergencies at the utility's request, but that these loads are not always available "around the
6 clock" as defined under the Rider R-12. Nucor suggests that a potentially more effective program would
7 be a "peak rebate program" under which industrial customers would be notified by the utility when a
8 load reduction would be valuable to maintain reliability or for economic reasons. This would allow
9 industrial customers an opportunity to voluntarily reduce load in return for a payment or bill credit.
10 Under Nucor's proposal, participation in this option would be limited to customers not otherwise
11 interruptible, and there would be no obligation on the customer to participate in the requested reduction.
12 Nucor proposes that compensation should be based on an even split of the savings between the utility
13 and the participating load, with the savings being the cost avoided by the customer's action.³⁰⁷
14 Alternatively, Nucor suggests the Rider R-12 could be modified to allow for participation from
15 industrial customers that operate on shifts or predominately during off-peak period, with the
16 compensation adjusted appropriately.³⁰⁸

17 **Fresh Produce Association of the Americas**

18 FPAA members comprise the bulk of the produce industry in Nogales, Arizona, and the
19 evidence indicates their operations are an important economic driver in Santa Cruz, County.³⁰⁹ FPAA
20 intervened in this proceeding because after UNSE's last rate case, many of its members experienced
21 significantly higher electric bills as the result of the application of newly implemented demand ratchets.
22 FPAA opposes UNSE's request for an additional rate increase on the newly proposed Medium General
23 Service Class, and asks that the Commission consider FPAA members' unique load profiles as it
24 evaluates the proposed rate design in this matter.

25
26 ³⁰⁶ Nucor Initial Brief at 20.

27 ³⁰⁷ Id. at 21.

28 ³⁰⁸ Nucor witness Zarnikau testified that a customer with a largely predetermined fixed schedule could provide the Company with expected load information on specific days/times and the Company could adjust a bill credit according to the value of the interruptibility of the load. Ex Nucor-1 Zarnikau Dir at 23-29.

³⁰⁹ Ex FPAA-1 Jungmeyer Dir at 5-6.

1 In the last rate case, in addition to a 9 percent increase, the Commission approved a new LGS³¹⁰
2 tariff that included a ratcheted demand provision that would adjust the monthly billing demand to the
3 maximum of either the monthly metered demand or 75 percent of the greatest demand in the preceding
4 11 months. That rate was approved as part of a settlement agreement, and prior to that Decision, UNSE
5 had not used a demand ratchet to recover fixed costs from its large commercial customers. FPAA states
6 that being unfamiliar with demand ratchets and not suspecting the impact it would have on FPAA
7 members, FPAA did not intervene in the last rate case.³¹¹ FPAA states that since the rates approved in
8 Decision No. 74235 went into effect on January 1, 2014, many FPAA customers have experienced a
9 rate impact of 20 to 30 percent due to the demand ratchet. FPPA estimates that the proposed increases
10 in UNSE's non-fuel rate components (the basic service charge, the demand charge and energy delivery
11 charges) will result in an additional rate increase of at least 2-5 percent for the typical FPAA member.³¹²

12 FPAA asserts that the demand ratchet imposed on the LGS and MGS classes is unfair and
13 punitive to counter-seasonal, low-load factor customers. FPAA asserts that demand charges should
14 reflect a customer's contribution to the overall system peak. FPAA provided testimony that it claims
15 shows that its members generally do not contribute to UNSE's overall system peak demand the same
16 way as the rest of the businesses in the MGS/LGS class. FPAA members provide refrigeration services
17 primarily from October through June, and the facilities go almost dormant from July through
18 September, such that the overall demand of the industry has high peaks in the winter and valleys in the
19 summer.³¹³ Thus, FPAA alleges that its members do not contribute to UNSE's peak like other members
20 of its class, and when it is charged with the same demand ratchet formulas as the rest of the members
21 of its class, it asserts that it subsidizes the rest of the class during the summer.³¹⁴

22 FPAA argues that its members' load characteristics are unique to UNSE's system and warrant
23 unique rate treatment. FPAA notes that in Texas, there is a minimum load-factor threshold for
24

25
26 ³¹⁰ At that time FPPA members would be considered part of the large general services class. The medium general services
class was created in the current proceeding.

27 ³¹¹ FPAA Initial Brief at 2.

28 ³¹² Id.

³¹³ Tr. at 3005-3007.

³¹⁴ FPAA Initial Brief at 6.

1 industries such as the seasonal produce industry, below which demand ratchets cannot be applied.³¹⁵
 2 FPAA believes there is no reason why a similar approach could not work in Arizona. In addition, FPAA
 3 asserts that demand ratchets discourage investment in energy conservation technologies, such as large
 4 solar distributed generation installations, because counter-seasonable users aren't able to offset high
 5 winter usage with the excess solar generation in the summer, because the credits are swept or reset in
 6 the fall when operations are starting to ramp up, and the ratchet causes an FPAA member to feel the
 7 effect of one month of high demand for the entire year.³¹⁶

8 FPAA does not believe that UNSE's expressed concerns, that removal of the demand ratchet
 9 for FPAA members would cause unfair shifts onto other customers, are valid, because FPAA claims
 10 that it is already cross-subsidizing other members of the LGS class by paying disproportionately higher
 11 bills during July, August and September. FPAA asserts that a demand ratchet may be appropriate for
 12 class members who contribute to the utility's peak periods, but not for FPAA members who do not.³¹⁷

13 FPAA does not believe that UNSE's proposal in its Initial Brief of an optional MGS rate under
 14 which customers would "receive a credit equal to 50 percent of the standard MGS kW rate multiplied
 15 by the amount that measured kW is less than the ratchet demand for the summer months," goes far
 16 enough to reverse the negative effects of the ratchet on these customers.³¹⁸ FPAA believes that UNSE
 17 can recover its fixed costs without a ratchet and cites the experience of APS which does not apply a
 18 ratchet to customers the size of FPAA members.³¹⁹

19 **Analysis and Resolution – Large Commercial and Industrial Rate Design**

20 Besides the revenue allocation concerns discussed earlier, the issues raised by the large and
 21 industrial customers regarding UNSE's proposed rate design included Nucor's objection to the
 22 determination of demand charges as applied to the LPS-TOU Class, and FPAA's objection to the
 23 calculation of demand charges applied to its members in the MGS.

24

25 ³¹⁵ The Texas Public Utilities Commission ruled that "the unique characteristics of seasonal agricultural customers"
 26 warranted an exemption to the establishment of generic ratcheted distribution charges for these customers, and allowed for
 rates to be designed to recover distribution charges without the use of a demand ratchet. Texas PUC Order No. 40, Docket
 No. 22344. FPAA Replay Brief at 2.

27 ³¹⁶ FPAA Initial Brief at 8-9.

28 ³¹⁷ FPAA Reply Brief at 3.

³¹⁸ Id.

³¹⁹ Id. at 4.

1 UNSE used a modification of the Average and Excess Demand Method to prepare its
2 CCOSS.³²⁰ Nucor argues that the determination of demand charges as they relate to the LPS-TOU
3 Class should be based on the industrial customers' contribution to the system peak demand, which
4 occurs in the four summer months (the 4CP months).

5 Under the Average and Excess Demand Method of a class cost of service analysis, the average
6 demand for each customer class is calculated by dividing the total class annual energy (KWh)
7 consumption by the number of hours in the year (8,760). In other words, class average demand
8 represents the level of demand that would be placed on the system if all customers within a class used
9 energy at a constant rate for all hours throughout the year for a 100 percent load factor. The system
10 average demand is calculated as the aggregate of the individual class average demands. The system
11 excess demand is defined as the system coincidental peak, the highest hourly demand in the year, less
12 the system average demand. The system excess demand is allocated to the classes to determine the
13 excess demand for each class. In the generic version of the Average and Excess Demand Method, the
14 proportion of the system excess demand allocated to each class, i.e., class excess demand, is calculated
15 as the excess of non-coincident peak hourly demand over the average hourly demand for the class
16 divided by the aggregate of the excesses of non-coincident hourly demands over the average hourly
17 demands for all classes. UNS used a modified version of the Average and Excess Demand Method
18 that allocates the system excess demand to the customer classes using the 4-CP method, a method that
19 was widely accepted by other parties in this case.³²¹

20 The purpose of demand ratchets is to provide for more uniform revenue collections throughout
21 the year, and stabilize revenue recovery, as customers are not able to shift load from a high cost billing
22 period to a lower cost billing period. Demand ratchets may not be equitable for customers that do not
23 have significant energy use during the system peak months, or whose peak consumption occurs during
24 off-peak hours. Ratchets can send incorrect pricing signals by redirecting cost recovery away from the
25 periods in which the cost is incurred.

26 Nucor does not seem to object to the use of a ratchet, but believes that the proposed ratchet in

27 ³²⁰ Ex UNSE-31 Jones Dir at 25.

28 ³²¹ Nucor argues that the determination of demand charges as they relate to the LPS-TOU Class should be based on the industrial's contribution to the system peak demand, which occurs in the four summer months (the 4CP months).

1 this case does not reflect Nucor's contribution to UNSE's system peak as measured by the 4CP method.
 2 Nucor may be correct, as neither the peak measured during the on-peak or off-peak in the current or
 3 prior 11 months necessarily aligns with the Average/4CP method used to allocate costs in the CCOSS.
 4 Under UNSE's proposal, the ratchet that determines the billed demand units could be based on one-
 5 half of Nucor's peak demand during off-peak hours in a month not included in the 4-CP calculation 11
 6 months prior. UNSE's proposed rate design for the LPS class does not seem to provide a good matching
 7 of cost causation and revenue recovery. An improvement that would better match the average and
 8 excess CCOSS costs allocations would be to calculate the demand charge as the greater of:

- 9 1. The mean average of the greatest measured 15 minute interval demands read of the meter
 10 during the on-peak hours of each of the 4-CP months;³²² or
- 11 2. One-half of the greatest measured 15 minute interval demand read of the meter during the
 12 billing period.³²³

13 The first criteria would better align the ratchet with the excess component of the CCOSS and
 14 the second criteria better aligns the ratchet with the average component of the average and excess/4CP
 15 CCOSS. UNSE arbitrarily chose a 50 percent factor to apply to the second criteria, and we do not alter
 16 this component, but note that it is an example of rates that might not align with the cost of service.³²⁴
 17 Nucor's proposal to use the customer's contribution to the coincident peak in four summer months to
 18 determine demand charges is too simplistic. Under this proposal, the Company may under-recover
 19 demand-related costs from customers who either normally place demands on the system during off-
 20 peak times or can shift load to off-peak times. Customers that cause the peak should fund the cost of
 21 peaking facilities, but customers that have average demands at various times throughout the year should
 22 participate in funding the facilities required to provide average demand, even if those customers
 23 contribute only nominally to the system hourly peak demand. Thus, UNSE should revise its LPS
 24 demand formula as set forth above. The fourth criteria, referencing the greater of contract capacity or

25

26 ³²² This compares to UNSE's proposal of "the greatest measured 15 minute interval demand read of the meter during the
 on-peak hours of the billing period."

27 ³²³ This compares to UNSE's proposal of "one-half of the greatest measured 15 minutes interval demand read of the meter
 during the off-peak hours of the billing period."

28 ³²⁴ The purpose of the 50 percent factor is intended to provide a "break" to those customers who create demand during the
 off-peak. Tr. at 2612-13.

1 500 kW, does not affect any current UNSE customer. The 500kW appears to reflect a minimum
2 demand. We do not object to the provision.

3 We do not find that the evidence in this case supports Nucor's position that the difference
4 between on-peak and off-peak energy rates should be greater. UNSE witness Jones testified that the
5 Company increased the off-peak rate because the current off-peak rate was too low when compared to
6 the Company's marginal cost of energy, and the difference between on- and off-peak power is not that
7 great.³²⁵ UNSE's proposed LPS-TOU rates better reflect its costs. Nor are we persuaded that Nucor
8 has presented a sufficient case for expanding the Interruptible Power Class. UNSE has not needed to
9 implement interruptions under its current IPS tariff, and we do not have the data to evaluate the revenue
10 implications of Nucor's proposal. Under current conditions, UNSE does not appear to have a need to
11 expand its ability to interrupt load.

12 UNSE's latest proposal for FPAA members is to design a seasonal rate that would allow FPAA
13 customers to save money based on the characterization of their consumption. UNSE states that it
14 proposed an alternative MGS rate tariff that would shift \$300,000 to other customers via the PPFAC.
15 UNSE did not include this tariff with the other tariffs attached to its brief. Suggesting that UNSE and
16 FPAA attempt to reach an agreement concerning a tariff for the produce industry in Santa Cruz County
17 was an attempt to encourage a rate design that would collect the appropriate costs caused by these
18 customers in a fair and equitable manner, and not only to find a solution that would result in saving
19 money for FPAA members. We do not believe it is reasonable to shift \$300,000 of costs attributable to
20 FPAA members to other ratepayers. FPAA does not appear to accept the proposal in any case,³²⁶ but
21 has not put forward an alternative for our consideration, except to support the AECC\Noble revenue
22 allocation. Many of FPAA's concerns regarding competing with Texas are associated with matters over
23 which the Commission does not control, such as tax incentives. We are sympathetic to all ratepayers
24 who face rising costs, but we have a responsibility to all customers, as well as the utility, to approve
25 fair and equitable rates.

26
27 ³²⁵ Tr. at 2620-21. UNSE proposes a differential in the summer on- and off- peak rates of \$0.091790 (\$0.125200-\$0.033410)
28 and \$0.061700 (\$0.098864 - \$0.071775) in winter. Current rates provide a summer differential of \$0.098864 and a winter
differential of \$0.071775.

³²⁶ FPAA Reply Brief at 3.

1 UNSE has indicated that it analyzed a number of options for the MGS class, including (1) no
2 demand ratchet with a high summer kW charge and a lower winter kW charge; (2) a kW ratchet that is
3 calculated strictly on summer kW demand; and (3) a higher kW charge that focused strictly on the peak
4 months of June, July and August, but that when applied to the accounts of FPAA members did not
5 produce savings.³²⁷ Neither UNSE nor FPAA presented any other reason why these options were not
6 fair except that they did not save the customers money. We cannot evaluate these options, or see their
7 bill impacts, but can presume FPAA did not prefer them. We note there are other members in the MGS
8 Class who did not intervene, and absent a convincingly better alternative to UNSE's original proposal,
9 we will approve it in this proceeding.

10 Demand ratchets may be characterized as a substitute for rates that actually reflect cost
11 causation. A rate structure that includes seasonal, multi-tiered demand, and seasonal TOU energy rates,
12 would more accurately match cost causation with revenue recovery compared to the use of ratchets.
13 Except for Nucor, which didn't object to demand ratchets as much as objecting to how the ratchet was
14 calculated, and FPAA who does object to ratchets, no other party suggested eliminating ratchets. But
15 as demonstrated by FPAA's experience and Nucor's testimony, demand ratchets are problematic and
16 can create inequitable results. In addition, there seem to be disparities between cost causation and cost
17 recovery in rate classes other than LPS and MGS, but no party intervened to identify any problems.
18 However, without an adequate alternative in this record, we decline to eliminate the existing demand
19 ratchet structure, at this time.

20 In UNSE's next rate case, we direct the Company to seriously consider designing rates that
21 match cost causation, as measured by its CCOSS, with revenue recovery, and to evaluate methods of
22 revenue recovery that do not involve ratchets. Seasonal, and on- and off-peak demand charges are
23 examples of alternatives to ratchets. It may be appropriate for the LGS and MGS classes, for example,
24 to have a demand portion of their rate comprised of a standard demand charge plus an incremental
25 charge, if the maximum demand occurs in a period other than off-peak, or the partial peak period in
26 summer. In the winter, there may not be an incremental peak demand charge. Such rates would
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28 ³²⁷ UNSE Initial Brief at 43.

1 recognize the differences in costs among generation sources, and between seasons throughout the year.
 2 Such rates could send proper cost signals all year, unlike ratchets.

3 In addition, the Company should evaluate consistency in other rate components, such as TOU
 4 rates, as the differential in on- and off-peak rates for the LPS-TOU Class is being narrowed, but the
 5 on- and off-peak differential for the LGS and MGS TOU rates are being increased in summer and
 6 decreased in winter. There may be supportable reasons for the different treatment, but the various
 7 designs should be based on cost causation, and should be consistent, fair, and equitable, and not merely
 8 self-serving.

9 Economic Development Rider ("EDR")

10 UNSE

11 UNSE proposes a discount-based economic development program that reduces the electric
 12 billing for existing or new customers that add or expand load within the Company's service territory.
 13 Under the Company's proposal, any lost non-fuel revenues resulting from discounts provided to
 14 customers through the EDR would be borne by UNSE, and the Company will not seek recovery of any
 15 lost non-fuel revenues in future rate cases.³²⁸ The proposed EDR provides that it is available "for
 16 commercial or industrial standard offer customers with a projected peak demand of 1,000 kW or more
 17 and a load factor of 75 % or higher for the highest 4 coincident-peak months in a rolling 12-month
 18 period."³²⁹ The EDR would provide a discount that phases out over five years, to customers that qualify
 19 under existing Arizona economic development tax credits.³³⁰ To qualify, a customer must be a new
 20 customer or be expanding existing operations. UNSE proposed the load and load factor requirements
 21 in order to help ensure that the new customer does not increase costs for the system. In addition, the
 22 proposed discount is higher for customers that "infill" in areas with existing facilities, as UNSE has
 23 lost 45 MW of industrial load in recent years and it would be highly beneficial to attract new industrial
 24 customers to utilize the existing facilities.³³¹

25 UNSE believes the tariff language is sufficient as proposed and does not support suggestions
 26

27 ³²⁸ Ex UNSE-29 Dukes Reb at 25.

³²⁹ Ex UNSE-31 Jones Dir at CAJ-3.

28 ³³⁰ The discount starts at 20 percent in year 1, and declines to 2.5 percent in year 5.

³³¹ UNSE Initial Brief at 44.

1 from Nucor that the tariff needs clarifications. Nor does the Company agree with FPAA that it should
2 be modified to allow more flexibility in the qualifying load factor.³³²

3 AIC

4 AIC strongly supports the EDR because encouraging economic development in UNSE's service
5 area will benefit the Company and its customers.³³³ AIC believes that attracting new businesses to
6 locate in rural Arizona is difficult, and this Rider might allow smaller communities to compete for
7 customers. AIC notes that UNSE has sufficient capacity to accommodate the discounts for new
8 businesses and the program targets those customers that UNSE can most efficiently serve. In addition,
9 AIC asserts that because UNSE is piggybacking onto the State's economic development tax credits for
10 eligibility, the Company mitigates administrative costs related to implementing the tariff.

11 Walmart

12 Walmart recommends approving the EDR because attracting large, high-load factor customers
13 to UNSE's electric system drives down the cost per unit for all customers, and promotes external
14 economic benefits in the communities where those customers locate.³³⁴

15 Nucor

16 Nucor believes that as proposed by the Company, the new EDR qualification criteria are not
17 clear, and must be clarified so that current or prospective customers can make business decisions with
18 confidence.³³⁵ Nucor states that the rider needs to clarify how the minimum load factor requirement
19 should be calculated, and how the requirement that load factors be calculated for "the highest 4
20 coincident-peak months in a rolling 12-month period" would be implemented. Nucor advocates that
21 the EDR should be revised to clarify that the calculation of the customer's monthly load factor in the
22 summer months is based on the customer's billing demand.

23 Nucor claims that it is not clear which measure of the Customer's Peak Demand should be used
24 in the formula to determine load factor. Nucor states that for an LPS or LPS-TOU customer, the current
25 options for measuring demand under current tariffs could include the customer's highest demand

26 _____
27 ³³² UNSE Reply Brief at 26.

³³³ AIC Initial Brief at 29; AIC Reply Brief at 20-21.

³³⁴ Walmart Initial Brief at 4.

³³⁵ Nucor Initial Brief at 22.

1 during a peak period, the customer's highest demand during an off-peak period, the customer's
 2 contribution to the monthly or annual system peak, the contract capacity or the 500MW minimum in
 3 part 4 of the Billing Demand section of the tariff. Nucor asserts that without clarifying the demand
 4 measurement under the EDR, the Company's new incentive may not achieve its intended result.

5 Nucor also believes that it is unclear how the Company intends to implement the requirement
 6 that load factors be calculated for "the highest 4 coincident-peak months in a rolling 12-month period."
 7 Nucor asserts that different interpretations could lead to widely varying results – for example, is it the
 8 average load factor for the four months, or that in each month the load factor exceeds 75 percent; which
 9 months are the coincident peak months; and how will the rolling calculation operate? Nucor suggests
 10 that Rider-13 EDR be clarified to provide that the calculation of the monthly load factor in the summer
 11 months is based on the customer's billing demand, and that the load factor be calculated according to
 12 the customer's total load and not just the new incremental load.³³⁶

13 **FPAA**

14 FPAA submits that UNSE's EDR rider should be flexible enough to include FPAA members.
 15 Because FPAA members typically only reach a load factor of 45 percent, even during their peak
 16 operating periods, they would not qualify for the EDR as proposed, which requires a load-factor of 75
 17 percent. FPAA encourages the Company to explore modifying the EDR to try to accommodate FPAA
 18 members.³³⁷

19 **Staff**

20 Staff states that assuming that "the energy cost are not significant," Staff supports this limited
 21 program. Staff's support does not extend to any request to recoup the lost incremental revenues in a
 22 future rate case, without "supporting record."³³⁸

23 **Analysis and Resolution - EDR**

24 There is no opposition to the adoption of an Economic Development Rider. UNSE's
 25 shareholders will absorb any lost incremental revenues. If this program is successful, the Company
 26 and its ratepayers should benefit from adding high load factor, low-cost customers. Thus, we approve

27 ³³⁶ Id. at 25.

28 ³³⁷ FPAA Initial Brief at 10.

³³⁸ Staff Initial Brief at 16.

1 Rider-13 as presented. If there are any ambiguities, we do not believe they are sufficiently great to
 2 undermine the tariff, and may allow for some flexibility in its application, as some parties have sought
 3 in this proceeding. The proposed load factor requirements are appropriate to ensure that any new or
 4 expanded business is a low-cost addition to the system. As UNSE has offered this program voluntarily
 5 and its shareholders are in essence paying for the program, absent unreasonable discrimination or
 6 provisions contrary to the public interest, UNSE should be allowed to design its parameters. All
 7 stakeholder interests will benefit if the Rider is successful which is an incentive to design and
 8 administer an effective program.

9 **Buy-Through Tariff (Alternative Generation Service)**

10 **UNSE**

11 As part of the settlement agreement in the UNS Energy merger with Fortis, UNSE agreed to
 12 propose a “buy-through” tariff available to LPS customers. Consequently, UNSE proposed
 13 Experimental Rider 14, Alternative Generation Service (“AGS”). UNSE proposed that the AGS would
 14 be available for a maximum of 10 MW of peak load, that it be available for no more than four years,
 15 and that it be available only to LPS and LPS-TOU customers with peak demands of 2,500 kW or
 16 more.³³⁹ UNSE modeled the tariff after the APS experimental AG-1 tariff, but the Company recognizes
 17 that the Commission has not yet evaluated the APS tariff and UNSE believes that tariff may be flawed.
 18 UNSE does not believe that the “buy through” tariff that it has proposed is in the public interest because
 19 it would benefit only a narrow group of industrial and commercial customers at the expense of other
 20 customers, and it is premature before the APS model is evaluated.

21 If the buy-through tariff is approved, UNSE argues that it should be capped at 10 MW. UNSE
 22 asserts that Walmart’s proposal to extend the cap to 150 MW is too large for a Company of UNSE’s
 23 size as it would include up to 85 percent of UNSE’s purchased power and would encompass UNSE’s
 24 lowest cost resources.³⁴⁰ If the tariff is adopted, UNSE argues that the proposed management fee of
 25 \$0.004 per MWh should be approved. UNSE states the management fee is intended to compensate the
 26 Company for the cost of administering the program and because it is a new tariff, the costs cannot be

27 ³³⁹ Ex UNSE-31 Jones Dir at 56-57.

28 ³⁴⁰ UNSE Initial Brief at 48.

1 known with certainty. UNSE states its estimate is the best available.

2 UNSE argues that Freeport/AECC/Noble and Walmart push for a special deal in order to
3 “hoard” much of UNSE’s low-cost purchased power resources, while forcing other customers to rely
4 on higher-cost resources, but if the market turns, and prices increase, the Company believes that they
5 will expect UNSE to stand ready to provide all the power they need. UNSE asserts this scheme is not
6 in the public interest and should be rejected.³⁴¹ UNSE argues that the AECC/Noble funding mechanism
7 would increase rates for all other customers in the MGS, LGS and LPS class and that Walmart’s
8 proposed expansion would increase the average cost of power for all other customers as well as expand
9 a flawed tariff.³⁴²

10 UNSE claims that a buy-through tariff is a poor economic development tool to retain large
11 customers, as it shifts costs to other customers and does not generate new revenue or increase efficiency
12 for the system. In contrast, UNSE argues its proposed Economic Development Rider is specifically
13 designed to shield customers from the costs of the program, while augmenting revenue and increasing
14 efficiency by attracting high load factor customers. In addition, UNSE asserts that if competitiveness
15 and affordable rates are the concern, adopting a more balanced class revenue allocation, which will
16 benefit all commercial and industrial customers, is the best solution.

17 **Walmart**

18 Walmart asserts that an AGS program would not harm other non-AGS customers, but rather
19 would replace the Company’s own wholesale market purchases with the energy purchases of the
20 customers participating in AGS, and shift the risk of the wholesale purchases from the Company’s
21 ratepayers to the AGS customers.³⁴³ Walmart believes there is ample evidence in Arizona from the
22 experience of APS’s AG-1 program, and in various other jurisdictions, that permitting customers to
23 choose their generation service is an effective way for customers to manage their electricity
24 requirements to better suit their business needs.³⁴⁴

25 Walmart recommends that the AGS not be limited to only LPS and LPS-TOU classes, but
26

27 ³⁴¹ UNSE Reply Brief at 24.

³⁴² Id. at 25.

³⁴³ Ex Walmart-2 Hendrix Dir at 9. Walmart Initial Brief at 5.

28 ³⁴⁴ Walmart Initial Brief at 5.

1 should be available to all commercial and industrial customers classes. Walmart asserts that allowing
2 a significant number of customers the opportunity to participate in AGS would attract more generation
3 service providers and create a more robust and vibrant marketplace from which AGS customers would
4 obtain their electric generation service.³⁴⁵

5 In addition, Walmart recommends that the program cap be set at 150MW, rather than 10 MW.
6 Walmart believes that the 10MW limit is arbitrary and not supported by the Company.³⁴⁶ Walmart
7 states that a 150 MW cap is appropriate because the Company already purchases 175 MW from the
8 wholesale power market, and allowing 150 MW to participate in the AGS program shelters other
9 ratepayers from market risk and volatility related to the Company's wholesale purchases.

10 Walmart also recommends that the threshold for a customer's participation be set at 1,000 kW.
11 Walmart asserts this minimum size would ensure that the participant is sufficiently large to be a
12 sophisticated user of electricity and would not need any consumer protection requirements. Further,
13 Walmart recommends that customers be allowed to aggregate utility accounts within its corporate
14 family to meet the peak demand threshold, which would allow customers to leverage economies of
15 scale to reduce their generation supply costs.³⁴⁷ Walmart asserts that limiting the term of the program
16 to only four years eliminates the ability of customers to purchase long-term contracts, especially for
17 off-site renewable contracts like solar and wind, due to the length of contract term needed by renewable
18 developers to build new projects.³⁴⁸

19 Walmart states that UNSE has not provided any documentation that supports its proposed
20 management fee of \$0.0040 per kWh, and argues that the Commission should approve a cost-based
21 management fee for the AGS.³⁴⁹

22 AECC/Noble

23 AECC/Noble strongly support a buy-through option which they claim will provide economic
24 incentives to retain large customers, as evidenced by the success that AECC member Freeport Minerals
25 Corporation has experienced in APS' AG-1 program. Thus, AECC/Noble propose to modify certain

26 ³⁴⁵ Id.

27 ³⁴⁶ Id. at 6.

³⁴⁷ Id. at 6-7.

³⁴⁸ Ex Walmart-2 Hendrix Dir at 7-8

28 ³⁴⁹ Walmart Initial Brief at 7.

1 components of UNSE's Experimental Rider 14. AECC/Noble argue that program eligibility
 2 requirements should be expanded to ensure that customers in all subsidy-paying classes have the
 3 opportunity to participate in the generation power market. They propose that customers with a total
 4 minimum peak load size of 1MW should be allowed to aggregate several smaller loads into the 1MW
 5 minimum threshold, provided that each aggregated site is owned by the same entity.

6 In addition, AECC/Noble assert that several of UNSE's pricing components, including its
 7 unbundled rate design, should be modified. Specifically, they assert that the proposed management fee
 8 and continuation of certain generation demand charges are confiscatory. They note that the proposed
 9 \$0.004/kWh management fee is six times greater than the \$0.0006/kWh management fee charged by
 10 APS for AG-1 service and should be reduced to a more reasonable amount in the range of \$0.0006/kWh
 11 and \$0.0012/kWh.³⁵⁰

12 AECC/Noble also claim that the proposed reserve capacity charge is higher than reasonable.
 13 They assert that by imposing fixed generation charges for services that a buy-through customer would
 14 not utilize, UNSE is proposing a pricing feature that does not exist in the APS AG-1 program, and they
 15 claim would in effect be a stranded cost charge. AECC/Noble assert that while a stranded cost charge
 16 may be appropriate when customers are allowed to permanently leave the utility's system for market
 17 participation, such is not the case under the buy-through proposals in this case.³⁵¹ Finally, AECC/Noble
 18 argue that the \$20 per MWh mark-up charge to the Dow Jones Electricity Palo Verde Daily Index price
 19 for replacement power is excessive and should be reduced to no greater than \$4 per MWh.

20 AECC/Noble assert that UNSE's unbundled rate design is seriously flawed because they
 21 believe it attempts to recover fixed generation related costs in the Local Delivery component of the
 22 demand charge. To do so, they assert, is contrary to the fundamentals of proper unbundled rate
 23 design.³⁵² AECC/Noble's witness Higgins provided testimony that the Local Delivery demand charge
 24 and Generation Capacity demand charge are "entirely inconsistent" with the Company's CCOSS.³⁵³

25
 26 ³⁵⁰ AECC/Noble Initial Brief at 8.

27 ³⁵¹ Id. at 8-9.

28 ³⁵² Id. at 9-11.

³⁵³ AECC/noble Initial Brief at 10, Ex AECC-1 Higgins Dir at 25. Mr. Higgins' analysis shows that the CCOSS indicates that for the LPS class, the transmission demand cost is \$3.58 per KWMonth compared to a transmission demand charge of \$3.58 per KWMonth, while the Distribution/Delivery Demand Cost is \$0.57 per kWMonth compared to a Demand Charge

1 AECC/Noble argue that by shifting generation costs onto the Local Delivery charge, which the buy-
 2 through participants would still have to pay, any potential savings to these customers would be lost.
 3 They assert that a well-designed unbundled tariff is essential to implementing a buy-through program
 4 since as participants purchase their generation from third parties, it is important that the other services
 5 they receive from the utility reflect the costs of those services.

6 AECC/Noble propose to fund the buy-through program in the amount of \$908,000 annually,
 7 such funding to be taken directly from the eligible customers classes (MGS, LGS and LPS) portion of
 8 the 50 percent share in the \$7.5 million reduction of requested revenue increase.³⁵⁴ Thus, according to
 9 AECC/Noble Solutions, if the buy-through program were not fully subscribed, the revenues set aside
 10 that turn out to be superfluous would be deferred and returned to the eligible classes through a rate
 11 adjustor like the PPFAC, or in a future regulatory proceeding.³⁵⁵

12 AECC/Noble assert that concerns about the buy-through program having potential negative
 13 impacts on the Company or its customers are not supported by the record in this proceeding. They note
 14 that UNSE and AIC contend that the \$908,000 may not be sufficient to cover the Company's potential
 15 non-fuel lost generation revenue, but AECC/Noble claim that the critics fail to specify how this amount
 16 would result in under-recovery given the Company's estimates of lost non-fuel generation revenue.
 17 AECC/Noble also claim that their funding solution places all cost responsibility for a buy-through on
 18 program-eligible customers. They state that UNSE witnesses confirmed that 10MW represents a small
 19 percentage of the Company's overall market purchases for generation in relation to its peak period and
 20 average demand, and that any "returning customer could be integrated into the UNSE system within a
 21 year."³⁵⁶ In addition, in response to criticism that the AECC/Noble funding mechanism will actually
 22 harm those customers in the eligible class who do not win the lottery to participate in the program,
 23 AECC/Noble point out that under their revenue allocation scheme, these customers are still better off

24 _____
 25 of \$0.29 per KWMonth, and the Generation Demand Cost is \$9.33per KWMonth compared to an unbundled generation
 demand charge of \$8.61 per KWMonth.

26 ³⁵⁴ AECC/Noble Initial Brief at 11, Ex AECC-1 Higgins Dir at 6. AECC states that the \$908,000 funding is greater than
 the \$331,200 identified by UNSE because AECC/Noble Solutions propose different reserve capacity charges and unbundled
 rates.

27 ³⁵⁵ AECC/Noble state that their proposed funding mechanism can work with any revenue spread allocation ultimately
 adopted by the Commission.

28 ³⁵⁶ Tr. at 2021-2023.

1 than under either the UNSE or Staff revenue allocation proposals.³⁵⁷

2 AECC/Noble argue that concerns about potential flaws in the APS AG-1 program, over the
3 appropriate management fee or under-recovery of generation revenue, are not grounds for rejecting the
4 proposed modified buy-through tariff in this proceeding.

5 Furthermore, AECC/Noble dismiss claims that the buy-through tariff raises “serious questions
6 about discrimination,” as they believe the same can be said about the Company’s proposed EDR.³⁵⁸
7 AECC/Noble believe that neither the buy-through nor the EDR constitute “unreasonable
8 discrimination” which is the only form of rate discrimination which is unlawful. AECC/Noble note
9 that the Company and AIC appear to be using a double standard when evaluating the proposals made
10 by AECC/Noble as compared with other constituencies, seeking to eliminate inter-class subsidies
11 between DG residential and non-DG residential, for example, but not making any meaningful move
12 with the subsidies provided by the large commercial and industrial classes; being willing to absorb the
13 lost non-fuel revenues associated with the EDR, but unwilling to absorb costs associated with a buy-
14 through program; and implementing rate choice options for residential customers, but not for the
15 commercial and industrial classes.³⁵⁹

16 **Nucor**

17 Nucor states that it does not oppose the adoption of a buy-through tariff, provided that it is part
18 of a broader set of changes that will reduce inter-class subsidies, and that safeguards are implemented
19 for non-participating customers.³⁶⁰ Nucor states that, from its point of view, the buy-through tariff as
20 proposed by the Company (or modified by Mr. Higgins on behalf of AECC and Noble Solutions) is a
21 workable option.

22 **AIC**

23 AIC states that the proposed buy-through rate is not ready for “primetime.” AIC shares concerns
24 about the customer-to-customer cost shift, and that the tariff may require those customers who would
25 be eligible to participate, but who do not or cannot, to incur more costs so that others may participate.

26 _____
27 ³⁵⁷ ACC/Noble Initial Brief at 13.

28 ³⁵⁸ AECC/Noble Reply Brief at 5-6.

³⁵⁹ Id. at 6-7.

³⁶⁰ Nucor Reply Brief at 7.

1 AIC points to evidence that UNSE's lowest cost power is purchased power, and if UNSE's largest
 2 customers are able to purchase in the wholesale market themselves, the average power cost for the
 3 Company's remaining customers increases, with the result that the mere existence of the buy-through
 4 tariff will increase electric bills for every other customer.³⁶¹ AIC argues that AECC and Noble have
 5 not provided a "single justification" or urgency for implementing the proposed buy-through tariff now,
 6 as opposed to waiting until the Commission has substantively reviewed the APS version.

7 AIC recommends that the Commission wait to assess the data presented in the APS pilot buy-
 8 through program before implementing a buy-through rate for other Arizona utilities.³⁶² AIC notes that
 9 APS has claimed that its experimental tariff has serious flaws resulting in alleged net losses of \$16.8
 10 million. AIC also questions the equity of AECC/Noble funding mechanism for the buy-through
 11 program as it would reserve \$908,000 of the revenue reduction agreed to in this case (increasing rates
 12 to the eligible customer class) to allow a few to participate.³⁶³ AIC claims that large customers have
 13 other options, such as entering into special contracts with the utility, or self-generation, to achieve cost
 14 savings without imposing higher costs on other ratepayers.

15 Staff

16 Staff does not address the buy-through proposal in post-hearing briefs, except to mention that
 17 it did not generally oppose AECC/Noble's funding mechanism.³⁶⁴ At the hearing, however, Staff's
 18 witness Broderick expressed the opinion that the buy through tariff is not "ready for prime time
 19 now."³⁶⁵

20 Analysis and Resolution – Buy-Through Tariff

21 UNSE is a vastly different, and much smaller utility, with many fewer large customers, than
 22 APS. At this time, we do not find that a buy-through tariff in UNSE's service area is in the public
 23 interest. Because UNSE's lowest cost power is purchased power, we have concerns that a buy-through
 24 tariff may adversely impact UNSE's other customers by increasing the cost of power. At a minimum,
 25 we believe that the APS pilot buy-through program should be evaluated before the concept is expanded

26 ³⁶¹ AIC Reply Brief at 19.

27 ³⁶² AIC Initial Brief at 25-26.

28 ³⁶³ Id. at 27.

³⁶⁴ Staff Reply Brief at 8. Staff is opposed to the AECC/Noble allocation of revenue methodology.

³⁶⁵ Tr. at 3619.

1 to include UNSE. But even then, because of UNSE's small number of large commercial and industrial
 2 end users, an APS-type program may not be appropriate for this utility. We understand that the
 3 industrial users are frustrated with paying rates that provide subsidies to the Residential Class, but we
 4 are attempting to take an incremental step to reducing inter-class subsidies in this case, and in doing
 5 so, we must balance the interests of all of UNSE's customers. We therefore decline to adopt the
 6 proposed buy-through tariff in this proceeding.

7 Net Metering

8 UNSE

9 UNSE states that its Net Metering Tariff should be modified to reflect the reality of the services
 10 being provided. It proposes a new Rider-10, Net Metering for Certain Partial Requirements Service
 11 (NM-PR) that would apply to those customers who submitted interconnection applications June 1,
 12 2015, or after.³⁶⁶

13 UNSE claims that the current net metering tariff is unfair to 98 percent of customers because
 14 the export price for DG solar power sent to the grid is higher than (approximately double) the wholesale
 15 or market cost of solar power, and because the current "banking" feature seriously distorts the price
 16 signals sent to the customer, while shifting costs to other customers, and leaving other fixed costs
 17 unrecovered. UNSE states that its modified net metering tariff would not eliminate the subsidy and cost
 18 shift, but would mitigate it significantly. According to the Company, the subsidies to solar DG are not
 19 fully eliminated because volumetric rates will still be recovering fixed costs, and DG customers, with
 20 their lower volumetric sales, will still be avoiding a portion of the fixed costs allocated to them.

21 Under the proposed Rider-10, new net metered customers would pay the proposed and
 22 applicable retail rates for all energy delivered by UNSE. The applicable retail rates would be limited
 23 to the demand based rate options. In addition, new net metered customers would be compensated for
 24 any excess energy their DG system produces and delivers to UNSE with bill credits calculated using
 25 the Renewable Credit Rate ("RCR"). New net metered customers could carry over unused bill credits
 26 to future months if they exceed the amount of their current bill.³⁶⁷

27 ³⁶⁶ Rider-10 would not apply to customers who submitted interconnection applications before June 1, 2015. UNSE Initial
 28 Brief at 30.

³⁶⁷ UNSE Initial Brief at 31.

UNSE proposed a RCR of 5.84 cents per kWh, which is equivalent to the most recent utility scale renewable energy purchased power agreement ("PPA") connected to the distribution system of UNSE's affiliate Tucson Electric Power ("TEP"). UNSE argues that this rate is a reasonable proxy for a market rate. UNSE proposes that the RCR should be adjusted annually, with the Company filing an annual RCR filing as part of its annual REST filing based on the most recent comparable utility scale PPA. The Company notes that TASC objects to the RCR because of alleged uncertainty whether it will be reset periodically, and Vote Solar suggests that customers should be able to lock in their rate for 20 years.³⁶⁸ UNSE states that it is open to the suggestion that customers could lock in a rate, or that the rate would be reset in each rate case. UNSE explains that its concern is not how often the RCR is set, but that the rate should reflect the fact that DG solar is a wholesale power resource that should be priced at a wholesale rate.³⁶⁹

Currently, DG solar customers can push excess energy onto the grid in the winter and shoulder months when the utility's cost of power is lower, and bank credits until the summer months when the utility's energy costs are much higher. UNSE asserts that eliminating the banking option for excess energy, and simply purchasing the excess energy from the customer during their billing cycle, will send more accurate price signals to the net metering customers about their true energy costs, and will help to partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements.

The current net metering tariff requires the utility to buy all the solar DG excess power, regardless of whether the utility needs it, and compensates the excess solar at a retail rate no matter when the excess power is received. It treats kWhs delivered during a less valuable off-peak period the same as kWh's delivered during a system peak, even though they have different values. UNSE asserts that a credit at the full retail rate makes no sense as a utility would never voluntarily buy energy at such an inflated price. In essence, UNSE claims, the difference between the retail and wholesale rates is a subsidy received by the solar DG customer at the expense of non-DG customers.³⁷⁰ UNSE states that

³⁶⁸ TASC Initial Brief at 10; Vote Solar Initial Brief at 19.

³⁶⁹ UNSE Reply Brief at 19. UNSE notes that at least when Staff was proposing three-part residential rates, Staff witness Broderick supported eliminating banking and replacing the retail rate with an RCR of at least \$0.07 per kWh which is near the mid-point between the retail rate and the short-term avoided cost rate for UNSE. See Staff Initial Brief at 15-16.

³⁷⁰ USNE Initial Brief at 32, Tr. at 2737 and 2758-59

1 the retail rate makes even less sense when the issues that reduce the value of solar are considered, such
2 as line losses, intermittency, phase in-balances, and reverse flow, which increase the wear and tear on
3 the distribution equipment.³⁷¹

4 UNSE argues that the banking option sends the wrong message to customers and should be
5 eliminated, because it gives the incorrect impression that energy produced today can be saved for use
6 months later, essentially conveying the message that their excess energy can be stored on the UNSE's
7 system.³⁷² UNSE also asserts that banking amplifies the lost fixed cost recovery caused by DG systems
8 because a "net zero" customer will not pay volumetric charges, which are intended to recover fixed
9 costs, and thus do not contribute to their fair share of fixed costs. UNSE states that DG customers are
10 still using the grid (at night, when their demand peaks, as well as for ancillary services), but they avoid
11 paying their fair share to such an extent that current rates are not just and reasonable.³⁷³

12 UNSE states that the solar advocates' support for banking is ironic given their support for TOU
13 pricing. TOU rates recognize that costs vary dramatically throughout the day. UNSE states they also
14 vary by season, and that a kWh of power produced at noon on a bright spring day (when system use
15 would be moderate and DG at its maximum production) has a different value than a kWh produced at
16 5 p.m. on a hot August day (when solar DG output is low and the system is near its peak).
17 Correspondingly, a kWh produced in the middle of winter, banked, and then used to offset a kWh
18 consumed from the utility during the summer peaks, has a different value than a kWh produced in the
19 summer. UNSE argues that banking ignores these realities.³⁷⁴

20 UNSE states that the volumetric retail rate includes many fixed costs that do not change
21 regardless of whether DG is purchased or not, and that the only costs the utility avoids from purchasing
22 DG energy are the variable costs of power (fuel and purchased power). UNSE states it cannot avoid
23 incurring the fixed costs of power generation because it must keep those generation assets standing
24 ready to provide power when DG solar is not available. Likewise, UNSE asserts, the costs of poles,
25 wires, and transformers are not avoided when the utility buys DG solar power. UNSE characterizes
26

27 ³⁷¹ UNSE Initial Brief at 33, Tr. at 1074-84.

³⁷² Ex UNSE-28 Dukes Dir at 20.

28 ³⁷³ UNSE Initial Brief at 34, UNSE Reply Brief at 17.

³⁷⁴ UNSE Reply Brief at 17.

1 purchased DG solar as simply a type of wholesale power that does not avoid these fixed costs. UNSE
 2 states that it could have proposed the wholesale power costs included in the PPFAC as a reasonable
 3 proxy for the value of the excess DG energy, but has instead proposed the higher cost of wholesale
 4 solar power in order to recognize the environmental benefits of solar.

5 Although some parties claim that DG solar provides additional value to the grid beyond the
 6 value provided by utility scale solar, UNSE argues that the supposed additional value of DG solar is
 7 illusory.³⁷⁵ UNSE states that claims that “environmental externalities” must be considered in valuing
 8 DG solar is misplaced because the comparison is not with fossil fuels, but between two different solar
 9 resources, each of which provide the same environmental benefits.³⁷⁶ UNSE also disputes claims that
 10 rooftop solar creates savings in generation, transmission and distribution capacity, because solar
 11 customers have similar demand (i.e. use similar amounts of capacity) as non-DG customers.³⁷⁷ UNSE
 12 states that although solar DG customers use less energy generated by the utility, their peak use remains
 13 similar, so they still need all the power plants, wires, poles and transformers that a regular customer
 14 needs. Because rooftop solar’s output is low when the system peaks in the late afternoon and early
 15 evening, UNSE disputes many of the claims by TASC and Vote Solar about the value of DG solar,
 16 including lower generation and transmission costs, avoided line losses, reduced need for ancillary grid
 17 services, benefits of geographic diversity, and employment gains.³⁷⁸ UNSE claims that electricity from
 18 rooftop panels is just electricity, and there is no justification for paying DG twice as much as utility
 19 scale solar when the environmental benefits are the same.³⁷⁹

20 In response to TASC’s claim that lowering the price of exported rooftop power would raise
 21 some sort of tax issue,³⁸⁰ UNSE asserts that the Commission should not base net metering policies on
 22 an unsupported claim regarding what the I.R.S. may or may not do.³⁸¹ Further, instead of waiting for
 23 the conclusion of the Value of DG docket, UNSE argues that the time to fix net metering is now because
 24 the timing of the Value of DG docket is unknown and the current UNSE proceeding is a rate case.

25 ³⁷⁵ Id. at 14.

26 ³⁷⁶ Id.

27 ³⁷⁷ Ex UNSE-34 Overcast Reb at 9-12.

28 ³⁷⁸ UNSE Reply Brief at 15-16.

³⁷⁹ Id. at 16.

³⁸⁰ TASC Brief at 12.

³⁸¹ UNSE Reply Brief at 17.

1 UNSE notes that TASC and Vote Solar have previously argued that net metering issues must be
 2 addressed in a rate case, where there can be a comprehensive examination of revenue allocation and
 3 consideration of all rate designs, but now press for additional delay.³⁸²

4 UNSE argues that the Net Metering Rules (A.A.C. R14-2-2306(C)) do not require a “one-to-
 5 one retail rate offset” as claimed by TASC and Vote Solar. UNSE argues that Rule 2306(C) requires
 6 that the “net kWh supplied by the Electric Utility” shall be billed in accordance with the “standard rate
 7 schedule,” and says nothing about whether the offset should be done on a one-to-one basis, or any other
 8 ratio.³⁸³ Similarly, UNSE argues that A.A.C. R14-2-2302(11) does not require a one-to-one offset, but
 9 merely states that “net metering” means “service to an Electric Utility Customer under which energy
 10 generated by [the customer] . . . may be used to offset electric energy provided by the Electric Utility.”
 11 UNSE asserts that the offset ratio or rate is not specified in the definition of “net metering.” UNSE
 12 points out that the rules allow that tariffs “may include seasonally and time of day differentiated
 13 avoided cost rates for purchases from Net Metering Customers, to the extent that Avoided Costs vary
 14 by season and time of day.”³⁸⁴ In response to claims that separate rates for DG customers would violate
 15 A.A.C. R14-2-2305,³⁸⁵ UNSE states this rule simply requires that rate changes applying only to net
 16 metering customers “[s]hall be fully supported with cost of service studies and benefit/cost analyses.”
 17 UNSE states that it fully complied with this requirement when it submitted the proposed changes in
 18 the context of a rate case with a full cost of service study and extensive testimony.³⁸⁶

19 Because it is proposing to eliminate the “banking” provision of the current net metering scheme,
 20 the Company requests a waiver of A.A.C. R14-2-2306.³⁸⁷ UNSE does not believe that the rest of its
 21 net metering proposals are inconsistent with the Commission’s Net Metering Rules, and thus do not
 22 require a waiver in order to be adopted. However, UNSE recognizes that there is disagreement on how
 23

24 ³⁸² TASC Initial Brief in the TEP Net Metering Docket (Docket No. E-01933A-15-0100) dated May 15, 2015 at 1; Vote
 25 Solar Brief in the Docket No. E-01933A-15-0100 dated May 15, 2015 at 1-2.

26 ³⁸³ UNE Reply Brief at 19.

27 ³⁸⁴ A.A.C. R14-2-2307(C).

28 ³⁸⁵ *Citing* Ex Vote Solar-6 Kobor Dir at 50.

³⁸⁶ USNE Reply Brief at 20.

³⁸⁷ Rule 2306(D) provides: “If the electricity generated by the Net Metering Customer exceeds the electricity supplied by the Electric Utility in the billing period, the Customer shall be credited during the next billing period for the excess kWh generated. That is the excess kWh during the billing period will be used to reduce the kWh supplied (not kW or kVA demand or customer charges) and billed by the Electric Utility during the following billing period.”

1 to interpret the rules, and the Company therefore seeks a waiver of any other provision of the Net
 2 Metering Rules that the Commission finds necessary in order to allow Riders R-10 and R-11 to go into
 3 effect.³⁸⁸

4 Finally, UNSE argues that the Commission does not require a specific rule to grant a waiver of
 5 the Net Metering Rules. UNSE states that beginning in 2004, with the slamming and cramming rules,
 6 the state's Attorney General began to refuse to certify rules that contained waiver provisions, and thus
 7 for a number of years, the Commission did not include waiver language provisions in new rules.
 8 Despite this, however, the Commission continued to allow waivers of these rules based on case law
 9 findings that the Commission can always waive application of its own rules, even without an express
 10 rule allowing a waiver.³⁸⁹ UNSE notes that during the process of approving the Net Metering Rules,
 11 Staff confirmed the Commission's ability to waive the rules if the circumstances warrant.³⁹⁰ Moreover,
 12 UNSE states that tariffs are given the force of law, and UNSE's Rules and Regulations provide that
 13 when there is a conflict between the Rules and Regulations and Commission Rules, the Rules and
 14 Regulations (i.e. tariff) will apply. Historically, and in this case specifically, UNSE has sought and is
 15 seeking changes in its Rules and Regulations, which are in effect waivers of the provisions of the
 16 Arizona Administrative Code.³⁹¹

17 **Staff**

18 Staff opposes UNSE's proposal to use a single PPA to establish the RCR, and also opposes any
 19 change in net metering absent the adoption of three-part rates.³⁹² Thus, Staff recommends making no
 20 changes to net metering until the Commission's Value of DG docket concludes.³⁹³

21 At the hearing, when both Staff and the Company were proposing mandatory three-part
 22 residential rates, Staff was recommending no change to net metering tariffs provided the three-part
 23 rates were adopted.³⁹⁴ However, at that time, if two-part rates were to be maintained, Staff was

24
 25 ³⁸⁸ UNSE Initial Brief at 35; UNSE Reply Brief at 20.

³⁸⁹ UNSE Reply Brief at 21-22.

26 ³⁹⁰ Citing statements by Commission Chief Counsel Kempley at May 11, 2008 Open Meeting, Docket RE-00000A-07-0608
 Open Metering Transcript at 24-25 and 32; and June 5, 2008 Hearing Transcript, Docket RE-00000A-07-0608 at 95

³⁹¹ UNSE Reply Brief at 22-23.

27 ³⁹² Staff Reply Brief at 8-9.

³⁹³ Staff Reply Brief at 9.

28 ³⁹⁴ Ex S-17 Broderick Surr at 11; Staff Initial Brief at 14.

1 recommending modifications to net metering, with an RCR to compensate exported energy of at least
2 \$0.07 per kWh.³⁹⁵

3 RUCO

4 RUCO takes an integrated approach to rate design, as its net metering proposals are intricate
5 parts of its overall rate design proposals.

6 RUCO proposes several rate options for the partial requirements DG customers:³⁹⁶ (1) a Non-
7 Export Option, under which DG customers can choose any of the Company's traditional rates offered
8 for full requirement customers, but are not allowed to export any excess power generated to the grid,
9 or can export excess power at the MCCCCG rate; (2) an Advanced DG TOU Option which includes a
10 three-part rate, with a minimum bill and a TOU demand rate during the summer and an export rate for
11 excess power to the grid for customers who exchange renewable energy credits ("RECs") of 8.5 cents
12 per kWh (\$.085/kWh), equal to the self-consumption rate (for those DG customers who do not
13 exchange RECs, the export rate would be the MCCCCG rate); (3) a RPS Bill Credit Option under which
14 customers can select any of the Company's traditional rates, and the credit rate for new DG customers
15 decreases over time as the Company's portfolio of renewable capacity increases (the credit rate would
16 start at 11 cents per kWh and go no lower than the MCCCCG rate).

17 If mandatory three-part rates are not adopted, RUCO proposed four additional rate options:³⁹⁷
18 (1) Traditional Two Part Rates with a Market Based Export Option under which DG customers
19 with a PV system that produces less than 25 percent of their annual load, full net metering
20 would be preserved for generation exports; and for partial requirement DG customers who
21 produce more than 25 percent of their annual load, generation exports would be compensated
22 at a market-based rate, calculated at the average wholesale price for that month. Compensation
23 for excess power would be paid monthly, with no banking.

24 (2) Three-part Rate Option available to all residential ratepayers with a \$12.50 customer fixed
25 charge, and full net metering would be preserved, with a tiered TOU demand charge, with the on-peak
26 summer demand charge over 30 percent higher than the on-peak winter demand charge; and

27 ³⁹⁵ Staff Initial Brief at 15; Tr. at 3713.

28 ³⁹⁶ RUCO Initial Brief at 11.

³⁹⁷ Id. at 13-15.

1 (3) Volumetric TOU Option available to all residential ratepayers, with the preservation of
2 full net metering, but an increased fixed charge of \$19.00.

3 APS

4 APS asserts that demand rates alone are not enough to address the cost shift caused by rooftop
5 solar. APS claims that the subsidy to rooftop solar was never cost-based, but was a policy decision
6 made at the time the Net Metering Rules were approved in order to encourage the fledgling rooftop
7 solar industry. Now that the solar industry is a multi-billion dollar industry, APS believes that the policy
8 decision has outlived its usefulness and should be revisited. APS supports UNSE's proposal to
9 eliminate "banking" and netting against future usage of the excess energy produced by the rooftop
10 customers. APS argues that by banking and offsetting future energy usage, the rooftop solar customer
11 is using the grid as a free battery and receiving the full retail rate for exported energy.³⁹⁸

12 APS supports the UNSE proposal to replace banking with a mechanism that gives the rooftop
13 solar customer an immediate bill credit for any exported energy at the RCR. APS asserts that the
14 current net metering scheme grossly over compensates rooftop solar customers for the value of their
15 exported energy, at the expense of non-rooftop solar customers who must pay retail for the excess
16 power. APS believes that the RCR option is a reasonable step forward when coupled with demand
17 rates to minimize both parts of the cost shift.

18 APS asserts that the solar industry's claims that demand rates will kill the solar industry are
19 overstated and is belied by APS witness Welch's study that shows that: third party leasing providers
20 have experienced declining installation costs and improved federal subsidies at the same time they have
21 increased the prices they charge customers; third party leasing providers experienced project returns of
22 40 percent in 2015; and third party solar leasing providers have headroom to adjust to changes in rate
23 structures while maintaining project returns.³⁹⁹ In any case, APS argues the claims of the solar industry
24 must be weighed against the increasing costs being imposed on non-solar customers from the unfair
25 allocation of fixed cost recovery.

26 ...

27 _____
28 ³⁹⁸ APS Reply Brief at 5.

³⁹⁹ Tr. at 3144, Ex APS- 5 Welsh Surr at 4-5; APS Reply Brief at 6.

AIC

AIC asserts that UNSE's proposed changes to the Net Metering Rules are in the public interest. AIC states that the Net Metering Rules were originally intended to incentivize early adopters of DG solar, not to create huge subsidies that shift costs from one group of customers to another. AIC argues that as the cost of solar systems declines, and with the extension of the federal tax credit, there is no need for UNSE customers to pay more for DG solar than they would pay for any other solar energy the Company could procure on the market.⁴⁰⁰ AIC asserts that the proposal to use the most recent utility scale solar contract price as a benchmark for the compensation of excess DG energy is a better reflection of the cost of energy than the current retail rate. AIC claims that the retail rate overcompensates DG customers for the excess energy they produce because it embeds fixed costs associated with maintenance of the grid, but DG customers don't incur these fixed costs. Thus, AIC claims, DG customers are credited for both the costs they avoid (e.g. fuel) and costs that they don't (poles, meters, wires, etc.).⁴⁰¹

AIC believes that the proposed RCR is a fair, market-based proxy rate that appropriately compensates customers who export excess distributed solar energy to the grid.⁴⁰² AIC argues that while not an exact proxy, utility-scale solar prices provide a more accurate reflection of the actual cost to produce solar than the retail rate. It is AIC's opinion that because the retail rate has no relation to the value of DG, and overcompensates DG customers for excess energy, non-DG customers must absorb those costs and pay more for solar energy than the Company could procure on the open market. Further, AIC asserts, by using the most recently negotiated rate, the proposed RCR recognizes that energy prices fluctuate. AIC argues that the utility-scale rate is a generous compensation because utility-scale is a more efficient resource than rooftop solar. AIC claims that using the utility-scale rate as a proxy for DG solar will incentivize solar DG to improve productivity.

AIC claims that intervenors who argue that DG solar provides greater benefits than utility-scale solar (such as higher generation capacity due to geographic diversity, greater avoided distribution costs,

⁴⁰⁰ AIC Initial Brief at 15-16.

⁴⁰¹ Id. at 16.

⁴⁰² AIC Initial Brief at 17-20. UNSE proposes to compensate excess DG energy based on the Company's most recently negotiated PPA for utility-scale solar energy, which at the time of the hearing was \$0.584/kWh based on a recent agreement with TEP. Ex UNSE-25 Tilghman Dir at 7.

1 greater grid services and greater local employment benefits) and is thus more valuable, provide no
2 substantive support for the claimed values. AIC claims that UNSE and APS witnesses refuted the
3 claims of the solar industry witnesses.⁴⁰³

4 In addition, AIC argues that modifying the Net Metering Rules will not prevent UNSE from
5 meeting its Renewable Energy Standard (“RES”) requirements, nor will it “kill” the solar industry. AIC
6 agrees with the Company that if it needs additional DG solar to meet its RES requirements it can seek
7 incentives or other transparent subsidies during its RES Implementation Plan proceedings. AIC argues
8 that providing any necessary subsidies in a transparent fashion would allow the Commission and non-
9 solar customers to better appreciate the magnitude of the solar subsidy that the DG carve-out requires,
10 and far better than when the subsidy is embedded in utility rate design.⁴⁰⁴

11 Moreover, AIC argues that the current rate structure and net metering tariffs enable solar DG
12 lessors and vendors to retain most of the margin in a DG solar transaction, and pass very little onto the
13 solar DG customers. AIC charges that solar rooftop providers seek to prevent any changes to rate design
14 or the Net Metering Rules in order to preserve their lucrative returns and shield themselves from
15 competition. AIC argues against claims that changing the Net Metering Rules will reduce solar jobs
16 because the Solar Foundation National Solar Job Census (upon which such claims are based) cannot
17 be relied upon to provide data on solar jobs in Arizona or the UNSE service territory, and does not
18 address the impacts of proposed changes in this docket.⁴⁰⁵ Further, AIC criticizes intervenors for not
19 considering the effect on job creation in the broader economy, or comparing jobs created by net
20 metering with jobs created under competitively priced solar.

21 AIC argues that statements that UNSE is proposing to eliminate net metering are misleading,
22 as under the Company’s proposal DG customers will still receive bill credits at the full retail rate for
23 energy that they produce that offsets their usage.⁴⁰⁶ AIC argues that there is no legal or logical
24 prohibition in the Commission’s rules that preclude changes to the Net Metering Rules.

25 AIC notes that the REST Rules (A.A.C. R14-2-1802 (M)) defines net metering as:

26 ⁴⁰³ AIC Initial Brief at 18-20, citing testimony of APS Witness Brown (Ex APS-1 at 36-37) and UNSE Tilghman (Ex
27 UNSE-26 at 14).

⁴⁰⁴ Tr. at 1352.

⁴⁰⁵ AIC Initial Brief at 23, citing Ex Vote Solar-6 Kobor Dir at 55; Ex TASC-21 Fulmer Surr at 10.

⁴⁰⁶ AIC Reply Brief at 13-15.

a system of metering electricity by which the Affected Utility credits the customer at the full retail rate for each kilowatt-hour of electricity produced by an Eligible Renewable Energy Resource system installed on the customer-generator's side of the electric meter, up to the total amount of electricity used by that customer during an annualized period, and which compensates the customer-generator at the end of the annualized period for any excess credits at a rate equal to the Affected Utility's avoided cost of wholesale power.

AIC claims that a plain reading of this definition shows that net metering customers must receive credit at the full retail rate for energy that they use to offset their consumption, but are entitled to compensation for any excess credits at year end only at a rate equal to the avoided costs of the utility.

AIC notes that some intervenors rely on the lack of an explicit waiver provision in the Commission's Net Metering Rules (Article 23) to claim that the Commission cannot change the existing Net Metering Rules. However, AIC asserts that the REST Rules (Article 18) (on which TASC and Vote Solar rely for the proposition that the full retail rate credit must apply to excess energy) expressly contains such a provision.⁴⁰⁷

While A.A.C. R14-2-2306(D) authorizes DG customers to "bank" credits, AIC argues the Commission has the authority to grant a partial waiver. AIC states that Article 18 and Article 23 are related, as the Commission enacted the rules in Article 23 pursuant to the express directive and authorization contained in Article 18 that they adopt net metering rules and tariffs.⁴⁰⁸ AIC argues that it makes little sense to conclude that the Commission has authority to design and implement Net Metering Rules and tariffs pursuant to Article 18, but no authority to waive them pursuant to that same article.⁴⁰⁹

AIC further asserts that the intervenors' claims that UNSE is seeking to eliminate net metering (rather than seeking a waiver) is based on the self-serving view that "net metering" can only mean the exact program currently in place and any change to a credit rate ceases to be "net metering." AIC argues the principle concept behind net metering is that DG customers should be allowed to receive appropriate credit for electricity generated by DG systems that is available to the grid.⁴¹⁰ AIC further argues that

⁴⁰⁷ A.A.C. R14-2-1816 allows a utility to petition the Commission for a waiver from the REST Rules.

⁴⁰⁸ A.A.C. 14-2-1811 instructs the Commission to adopt rules and standards for net metering and establish net metering tariff.

⁴⁰⁹ AIC Reply Brief at 15.

⁴¹⁰ See A.A.C. R14-2-2302(11).

1 the proposed changes in this case preserve this key objective as DG customers will continue to receive
2 value for the excess energy they generate, but at a “more appropriate market-based price.”⁴¹¹

3 AIC points out that when various utilities filed to modify their net metering tariffs in separate
4 dockets, the solar industry intervenors argued that such changes should be made in a rate case. AIC
5 notes that this proceeding is a rate case. AIC asserts that suggestions to wait for the conclusions of the
6 Value of DG docket is a self-serving delay tactic to preserve the status quo. AIC believes that the
7 outcome of the generic Value of DG docket is amorphous and not designed to calculate a value for
8 solar DG once and for all. AIC claims that delaying consideration of the proposed net metering changes
9 will make the task of “righting” prices more difficult.⁴¹²

10 TASC

11 TASC opposes UNSE’s proposed modifications to its net metering tariffs, and argues that net
12 metering must remain at the retail rate.⁴¹³ TASC claims that its witness Fulmer prepared the only full
13 analysis of the costs and benefits of DG solar in this docket, finding the benefits of DG solar to be
14 between 10-14 cents per kWh.⁴¹⁴ TASC argues that UNSE’s analysis is flawed by not including all
15 benefits, not using actual usage data, extrapolating from utility-scale data, limited to short-term
16 benefits, and not looking at load reductions due to sources other than DG solar.⁴¹⁵

17 Because the proposed RCR rate is less than half of TASC’s claimed value of solar, TASC
18 argues that it would undercompensate DG customers for their exported power. Furthermore, TASC
19 asserts that when UNSE sells the exported power back to other non-DG customers at the retail rate, it
20 would receive a 100 percent markup over the RCR.

21 TASC believes the RCR could create substantial uncertainty as the Company proposes to
22 update the rate periodically. TASC notes that utility power purchase agreements from utility-scale
23 suppliers are entered into for long term fixed prices, but UNSE seeks to subject its customers to
24 constantly adjusting prices. TASC claims utilities have an incentive to game the system to create
25 uncertainty, discourage the DG customer and DG installations, while increasing their own utility-scale

26 ⁴¹¹ AIC Reply Brief at 15.

27 ⁴¹² AIC Reply Brief at 15-17.

28 ⁴¹³ TASC Initial Brief at 9.

⁴¹⁴ TASC Initial Brief at 6-7; Ex TASC-21 Fulmer Surr at 30-47.

⁴¹⁵ TASC Initial Brief at 7.

1 projects and having the ratepayers pay for them. TASC claims that once a DG customer is locked into
 2 a purchase or lease agreement of a DG system, a new adjusted RCR would make the investment
 3 untenable. TASC states no rational investor would implement DG in such an environment.⁴¹⁶

4 TASC asserts that utility scale solar is not the same as DG solar and should not set the proxy
 5 price for DG solar.⁴¹⁷ TASC claims that the Commission has already recognized that the two resources
 6 are not the same, when it adopted a “carve out” in the REST Rules, which require 30 percent of the
 7 overall renewables to come from DG solar or other distributed resources.⁴¹⁸ TASC notes that there is
 8 no market for DG exports except for the utility, and DG customers would have no choice but accept
 9 the variable pricing regime under UNSE’s proposal, while utility scale producers operate in a
 10 competitive market. TASC argues that as such, the only fair rate to use for net metering is the full value
 11 the utilities receive from the DG customers.

12 TASC claims that DG solar has added value not found in utility scale solar including: avoided
 13 energy, avoided generation capacity, avoided transmission costs, and avoided distribution costs. In
 14 addition, TASC states that solar DG offers the same emissions savings as central solar PV, but without
 15 the potential habitat, visual and cultural impacts associated with utility-scale solar.⁴¹⁹ TASC asserts
 16 that the geographic diversity of dispersed DG provides added reliability and offsets issues of
 17 intermittency that utility-scale solar cannot otherwise mitigate. Further, TASC asserts that DG solar,
 18 as a whole, enables an electric utility to defer or avoid the need to invest in capital plant that would be
 19 rate-based and lead to increased rates. TASC argues all these factors support the conclusion that DG
 20 solar is worth more to a utility and its ratepayers than utility scale solar.⁴²⁰

21 TASC urges the Commission not to value DG solar in a piecemeal fashion, and argues that the
 22 Value of DG docket is the only appropriate venue to determine the methodology for accounting for
 23 costs and benefits of DG and any changes to net metering.⁴²¹ TASC claims that there is no urgency that
 24 cannot wait for the Commission to complete the process in the Value of DG docket that is currently
 25

26 ⁴¹⁶ TASC Reply Brief at 9.

⁴¹⁷ Id. at 10.

27 ⁴¹⁸ A.A.C. R14-2-1805(B).

⁴¹⁹ TASC Reply Brief at 10-11, Ex TASC 21, Fulmer Surr at 31-32.

28 ⁴²⁰ TASC Reply Brief at 11.

⁴²¹ TASC Initial Brief at 8.

1 underway and is expected to create a methodology to value DG exports in utility rate cases.

2 TASC argues that the only way to implement the RCR, or other proxy rate, for exported power
3 is through a rulemaking because unlike other Commission Rules, the Net Metering Rules do not include
4 a waiver provision.⁴²²

5 **Vote Solar**

6 Vote Solar argues that the Commission should not approve UNSE's net metering proposal
7 because to-date solar DG has had a negligible impact on UNSE's issues of cost recovery, to do so
8 would violate the Commission's Net Metering Rules, and moreover, the proposal is flawed.⁴²³

9 Vote Solar argues that solar DG is a negligible cause of UNSE's declining sales, responsible
10 for only 3 percent of the decline in usage-per-customer, only 5 percent of the low-usage bills (300 kWh
11 or less) and just 2 percent of the alleged cost shift.⁴²⁴ Vote Solar asserts that UNSE has not quantified
12 any grid impacts or related expenses attributable to solar DG.⁴²⁵ Thus, Vote Solar believes that given
13 the low DG penetration and its negligible impacts on the grid, on reduced sales, and on the cost shift,
14 that UNSE's speculation about future impacts is not warranted and there is no need to change the
15 current DG rate or the net metering program.

16 Vote Solar states that compensation at the retail rate and banking of excess energy are
17 fundamental principles of net metering that are codified in Commission rules, but UNSE and others
18 suggest that the parties fighting to retain net metering need to justify these existing net metering
19 policies.⁴²⁶ Vote Solar argues that it is inappropriate to grant UNSE's net metering proposal because it
20 would amend or revisit the statewide Net Metering Rules in the context of a UNSE-specific rate case;
21 and UNSE's request for a "partial waiver" of the rules is actually an attempt to eliminate net metering
22 for all future DG customers. In addition, Vote Solar argues that the net metering request should also be
23 rejected because it would be duplicative to eliminate net metering and require a demand charge.⁴²⁷

24 _____

25 ⁴²² TASC Initial Brief at 7.

26 ⁴²³ Vote Solar Reply Brief at 9.

27 ⁴²⁴ Vote Solar Initial Brief at 5-8.

28 ⁴²⁵ Id. at 8-10.

⁴²⁶ Vote Solar Reply Brief at 10.

⁴²⁷ Vote Solar notes that when UNSE was proposing demand charges for all residential customers, it conceded that it would not need to address the current net metering policy. Ex UNSE-26 Tilghman Reb at 3. Staff also supported no change to net metering when it was supporting demand charges. Staff Initial Brief at 7.

1 Vote Solar argues that both the REST and Net Metering Rules give customers the right to
 2 receive the full retail rate for DG exports and to bank the excess energy because “net metering” is
 3 defined as the energy produced by a net metering customer and delivered to the grid that “may be used
 4 to offset electric energy provided by the [utility] . . . during the applicable billing period.”⁴²⁸ In addition,
 5 according to Vote Solar, A.A.C. R14-2-1802(M) (part of the REST Rules) requires compensation at
 6 retails rates by defining net metering as a system of metering electricity by which the [utility] credits
 7 the customer at the full retail rate for each kilowatt-hour of electricity produced”⁴²⁹

8 Vote Solar also notes that the Commission’s Rules prohibit singling out net metering customers
 9 for punitive or discriminatory rate treatment, and that utilities can’t charge the net metering customer
 10 any additional fees or charges, or impose any equipment or other requirements, unless the same is
 11 imposed on customers in the same rate class that the net metering customer would qualify for if they
 12 didn’t have generation equipment.⁴³⁰ Furthermore, Vote Solar argues, the Net Metering Rules state any
 13 increased charge must be justified with cost of service studies and benefit/cost analyses.⁴³¹

14 Vote Solar argues that the proposed RCR rate is flawed and should be rejected because: (1) it
 15 would unreasonably conflate distributed solar and utility-scale solar; (2) it would subject net metering
 16 customers to undue pricing uncertainty and volatility; (3) UNSE did not analyze the value of DG and
 17 whether the RCR would appropriately compensate DG exports; and (4) it would be premature to
 18 approve UNSE’s proposal before the Commission completes the pending Value of DG docket.

19 Vote Solar argues that comparing distributed solar to utility-scale solar is not an “apples to
 20 apples” comparison as there are significant differences between the two resources, including that
 21 numerous geographically-dispersed solar systems provide benefits that a single centralized utility-scale
 22 facility does not, such as greater capacity benefits, greater avoided distribution costs, and greater local
 23 employment benefits.⁴³² Other differences, according to Vote Solar, include the restraints placed on
 24 distributed generation in the rules that are not faced by utility-scale facilities, and the fact that utility-
 25 scale facilities can market their energy to multiple entities while rooftop solar only has one potential

26 ⁴²⁸ A.A.C. Rule R14-2-302(11).

27 ⁴²⁹ A.A.C. R14-2-1802(M).

⁴³⁰ A.A.C. R14-2-2305 and R14-2-1801(M).

⁴³¹ A.A.C. R14-2-3205.

28 ⁴³² Ex Vote Solar-6 Kobor Dir at 30.

1 purchaser. Vote Solar asserts that because of these differences, it would be unreasonable to compensate
2 solar customers for excess energy based on utility-scale wholesale prices.

3 Vote Solar also opposes RUCO's alternative proposals.⁴³³ Although Vote Solar believes the
4 new alternatives set forth in RUCO's Initial Brief are an improvement over the options proposed at the
5 hearing, they remain flawed. Vote Solar states that although RUCO's TOU option for solar customers
6 does not include a demand charge, it unfortunately includes a \$19 customer charge that Vote Solar
7 believes is "punitive" and unrelated to cost causation. Vote Solar also believes the RUCO proposals
8 remain overly complicated and have not been subject to discovery and a full analysis by the other
9 parties. Vote Solar states there is no evidence that the penetration of DG solar is increasing, and thus
10 there is no need to dramatically alter the rate design in the near-term. If the Commission determines
11 that the rate design for residential and small commercial needs to be revised, Vote Solar believes that
12 minimum bill and/or TOU proposals would be better options.

13 Vote Solar asserts that although UNSE focuses on solar customers, the ultimate concern appears
14 to be declining sales and cost recovery caused by the closure of several of UNSE's large industrial
15 customers, the slow pace of economic recovery, and large number of seasonal customers and vacant
16 homes. Vote Solar argues that UNSE's claims that minimum bills do not send appropriate price signals
17 seems to assume that the demand charges send more accurate signals. But, as UNSE's witness Overcast
18 testified, the proposed demand charge does not reflect cost-causation either.⁴³⁴ Vote Solar states that
19 UNSE's Initial Brief did not explain the Company's "significant reservations" with the concept of a
20 minimum bill, but, through testimony, Mr. Jones stated that it could be a move in the right direction.⁴³⁵

21 **Grandfathering Net Metered Customers**

22 **UNSE**

23 UNSE supports grandfathering DG customers who submitted completed interconnection
24 applications by June 1, 2015, on the existing net metering tariff. These customers would not be limited
25 to the three-part residential rate, but would have the option to select any residential tariff. The Company
26 acknowledges that this proposal locks in the existing cost shift, but states that it is sensitive to the

27 ⁴³³ Vote Solar Reply Brief at 12-13.

28 ⁴³⁴ Vote Solar Reply Brief at 14; Vote Solar Initial Brief at 33; Ex UNSE-34 Overcast Reb at 29 & 31.

⁴³⁵ Ex UNSE-32 Jones Reb at 43.

1 significant economic decisions that certain customers made, particularly those who also received
 2 upfront incentives to install their systems.⁴³⁶ UNSE asserts that the June 1, 2015, date is reasonable
 3 because three months earlier, new DG customers were provided a written notice that they were required
 4 to sign, acknowledging that the rate could be changed in the future.⁴³⁷

5 UNSE argues the June 1st date is not retroactive ratemaking, as it is not the effective date of the
 6 new rates, but is the cut-off for customers who are exempt from the new rate. UNSE asserts that no
 7 customer will be charged the new net metering rate until it receives Commission approval.⁴³⁸

8 UNSE believes that grandfathering provides more appropriate relief to DG customers than
 9 Staff's proposed 15 percent bill credit for pre-June 1, 2015 DG customers. UNSE also opposed Staff's
 10 post-June 1, 2015 mitigation of a \$400 per kW subsidy which UNSE states would be paid by non-DG
 11 customers through the REST or some other similar mechanism.⁴³⁹

12 Staff

13 In pre-filed testimony Staff proposed a partial bill credit for existing DG customers rather than
 14 a traditional grandfathering. Staff states that it is not necessarily opposed to some form of
 15 grandfathering as a mitigating factor, but is concerned that any form of grandfathering must clearly
 16 define the elements of the current rate design that are included in the grandfathering (such as whether
 17 it includes the basic service and energy charges which change after each rate case); establish a fair and
 18 reasonable date for identifying the affected DG customers; define how long the facility is grandfathered
 19 based on lifespan or other factors; and not impede the Commission's ability to address rates for these
 20 customers in the future.⁴⁴⁰

21 AIC

22 AIC agrees with UNSE and Staff that June 1, 2015, is a reasonable cut-off for grandfathering
 23 existing DG customers because UNSE notified its customers that it would seek changes to the net
 24 metering scheme effective after this date, and any customer submitting an application after that date
 25

26 ⁴³⁶ UNSE Initial Brief at 35.

27 ⁴³⁷ UNSE Reply Brief at 23.

28 ⁴³⁸ *Id.*

⁴³⁹ UNSE Reply Brief at 23-24 *citing* Ex UNSE-33 Jones RJ at 13, Tr. at 3709-11.

⁴⁴⁰ Staff Reply Brief at 8.

1 cannot argue that they reasonably relied on the continuation of the current net metering scheme.⁴⁴¹ In
 2 addition, AIC argues that existing DG customers should not be able to claim that they are being
 3 retroactively deprived of a full retail rate for excess energy because they are well aware that rates and
 4 incentives change over time, and part of the risk of installing solar is that it might not turn out to be as
 5 economically advantageous as customers thought. AIC asserts that UNSE cannot be forced to insulate
 6 DG customers from any changes in rates, or to guarantee them a rate of return on their investment.

7 RUCO

8 RUCO recommends that the Commission fully grandfather early adopting DG customers
 9 through June 1, 2015, at their current rates.⁴⁴² RUCO argues that, currently, the cost shift for partial
 10 requirement DG customers is manageable, and that it is important for the integrity of the Commission
 11 that it protect the benefit of the bargain for these early-adopters of DG. RUCO argues that the
 12 Commission should reject Staff's proposal to provide a partial bill credit, and rather fully grandfather
 13 these existing DG customers. RUCO argues that Staff's proposal is not fair as it does not provide those
 14 who adopted DG prior to the cutoff date with the deal they bargained for and may require them to pay
 15 back upfront incentives in order to remove their systems.⁴⁴³

16 TASC

17 TASC asserts that it is essential that the Commission fully grandfather existing net metering
 18 customers and not adopt the proposed effective date of June 15, 2015. TASC claims that mandatory
 19 demand charges imposed on DG customers who installed solar since June 15, 2015, would undermine
 20 their investment. TASC argues that the Company's proposed cut-off date is retroactive ratemaking,
 21 and contrary to numerous examples of Commission precedent for protecting customers from rate
 22 changes that would retroactively disadvantage them.⁴⁴⁴ In addition, TASC argues that the proposed
 23 effective date is arbitrary and only serves to further the Company's antipathy towards DG customers.
 24 According to TASC, the Company has failed to justify why implementing retroactive rates on a small
 25 number of DG customers is sound or just or reasonable.⁴⁴⁵

26 ⁴⁴¹ AIC Reply Brief at 17

27 ⁴⁴² RUCO Initial Brief at 17.

28 ⁴⁴³ Id. at 16-17.

⁴⁴⁴ TASC Initial Brief at 25-29.

⁴⁴⁵ TASC Reply Brief at 13.

1 **Vote Solar**

2 Vote Solar recommends that if the Commission makes any changes to the rate design affecting
3 solar customers or the net metering rules that make solar less economical, it is imperative to fully
4 grandfather existing solar customers. Vote Solar is adamant that UNSE's proposals would make solar
5 DG less economical, to the detriment of existing solar customers and to the growth of DG.⁴⁴⁶ Vote
6 Solar acknowledges that under UNSE's new proposals, some customers would experience substantial
7 bill savings, but Vote Solar claims the analysis is not complete as it does not show how those bill
8 savings would compare to solar customers' current bill savings.⁴⁴⁷

9 Vote Solar argues that it would be unfair to use a grandfather date of June 1, 2015, as it would
10 have been impossible for solar customers who applied to install systems between June 1, 2015 and the
11 date of a Decision in this matter to determine how the proposed rate and tariff modifications would
12 affect them. Vote Solar states that until there is a final Decision in this case, solar customers cannot
13 know how the new rates will affect them.

14 **AriSEIA**

15 AriSEIA believes that if there is any change in net metering policy, the changes should only
16 affect customers who sign a contract after the final Decision in this docket is approved, and that all
17 grandfathering provisions should remain in effect for 20 years after the system receives permission to
18 operate.⁴⁴⁸

19 **Analysis and Resolution – Net Metering**

20 UNSE claims that under current rate designs, solar DG customers are, as a group, not paying
21 their fair share of the costs incurred to serve them due to the unique characteristics of the way they
22 depend on the grid.⁴⁴⁹ In addition, the Company claims that solar DG is being subsidized by non-DG
23

24 ⁴⁴⁶ Vote Solar Initial Brief at 48.

25 ⁴⁴⁷ Vote Solar Reply Brief at 15, fn 70.

26 ⁴⁴⁸ AriSEIA Initial Brief at 8.

27 ⁴⁴⁹ When a UNSE customer opts to install rooftop solar, that customer essentially changes from a full-requirements customer
28 to a partial requirements customer. These customers remain dependent on the grid for their electric needs when their demand
is greater than their self-generation and when their systems are not producing electricity. They are different from full-
requirements low-usage customers because their demand on the grid can fluctuate widely and the utility must be ready to
service them instantaneously. The total load of the house does not change, nor do the utility facilities that were installed to
serve that customer. The partial requirements customer may use less energy, but require the same capacity for delivery or
production and transmission.

1 customers under current net metering tariffs, which operate to credit excess solar DG production at
2 retail rates, and allow DG customers to bank excess solar for future credits.

3 The Commission opened the Value of DG docket specifically to address methodologies for
4 determining the value and costs of solar DG to be used in rate proceedings. The hearing in the Value
5 of DG docket commenced after the conclusion of the hearing in this case with many of the parties to
6 this docket participating in both dockets. The Value of DG docket will not result in a specific rate that
7 will be applicable to UNSE. It is anticipated, however, that the Value of DG docket will yield
8 significant new information about how DG solar should be compensated.

9 We believe that the public interest favors consistent application of the results of the Value of
10 DG docket. As a result, we will keep the net metering and rate design portions of this docket open
11 pending the conclusion of the Value of DG docket. Thus, shortly after the conclusion of that docket, a
12 second phase of this docket will be convened in order to apply the findings of the Value of DG docket
13 to UNSE. In the second phase of this proceeding, in addition to determining the appropriate net
14 metering tariff for UNSE for any new DG customers who file applications for interconnection after the
15 effective date of the Decision that comes out of phase two of this proceeding, the Commission will also
16 consider the Company's request to require DG customers to take service under three-part demand rates
17 due to their status as partial requirements customers. In the interim, DG customers will be treated the
18 same as non-DG customers under the various rate options.

19 We believe that deferring consideration of the mandatory three-part rates applicable to solar
20 DG is warranted in order to consider the treatment of DG solar in a holistic manner and to avoid having
21 multiple classes of DG customers, each subject to different rate treatment, due to the timing of when
22 they elected the solar option.

23 Because solar DG represents such a small percentage of UNSE's current customers, and
24 consequently a small portion of the lost fixed cost revenues, deferring a final decision on DG rates will
25 not be a significant burden on UNSE, especially considering the revenue increase we have authorized
26 herein. We take this action with the intent that the second phase of this proceeding will convene
27 promptly following a Decision in the Value of DG docket.

28 We also note that currently the record in this case is not sufficient to determine the value or cost

1 of DG solar for UNSE or to approve a specific rate for excess DG energy produced by UNSE's DG
 2 customers. For example, UNSE alleges that there are costs associated with DG solar in the form of
 3 increased wear and tear on the system and voltage regulation; however, UNSE has not yet quantified
 4 these costs in the record of this docket. Vote Solar provided estimates of the value of DG solar but
 5 other parties have challenged the premises of the analysis and accuracy of those calculations.
 6 Furthermore, we have concerns about whether the proposed RCR, which depends on a single utility-
 7 scale PPA rate, is a reasonable proxy for the market price of excess solar DG. Other proposals were
 8 presented as late as the briefing stage of the proceeding when RUCO submitted several additional
 9 alternatives. However, none of the options were considered during the hearing; nor were they subject
 10 to cross-examination. Thus, even without the Value of DG Docket, additional proceedings, including
 11 a hearing, would be necessary in order to authorize any change to the current net metering tariff.

12 Finally, we do not believe that the Company's proposed June 1, 2015 date for determining
 13 which DG customers should be subject to newly proposed rate options or net metering treatment is
 14 reasonable. Therefore, going forward, any DG customer who files an interconnection agreement prior
 15 to the effective date of a Decision in phase two of this proceeding shall be treated the same as a DG
 16 customer who filed for interconnection prior to that date.

17 Adjustor Mechanisms

18 PPFAC

19 UNSE

20 UNSE proposes revisions to the PPFAC that would change the rate from a "per kWh rate" to a
 21 "percentage based rate." UNSE believes that a percentage based rate is more equitable, provides a more
 22 accurate price signal, and does not result in disparate percentage bill impacts when the PPFAC rate
 23 changes.⁴⁵⁰ UNSE asserts that the current PPFAC methodology is applied on a dollar per kWh basis
 24 equally across all customer classes and rate schedules and has no relationship to the customer's original
 25 base power supply rate. UNSE claims that its new proposal would be more consistent with cost-of-
 26 service ratemaking principles. The Company disagrees with Staff that the proposed change adds
 27

28 ⁴⁵⁰ UNSE Initial Brief at 54-55.

1 complexity, and notes that other surcharges, such as the LFCR, are currently assessed on a percentage
2 basis.⁴⁵¹

3 Because the Company would need to file a revised PPFAC Plan of Administration (“POA”) to
4 reflect the changes if its position is adopted, UNSE requests that the revised POA be required as a
5 compliance filing in this docket.⁴⁵²

6 **Staff**

7 Staff supports continuing the current PPFAC methodology because it is simpler. Staff states
8 that, as proposed, each customer class rate schedule has an unbundled rate component entitled Base
9 Power, and TOU rate schedules have separate Base Power rates for on-peak and off-peak times, and
10 seasonal rates have additional Base Power rates. Because UNSE proposes that the PPFAC rate be set
11 as a percentage to be applied to the Base Power Component(s) of each rate schedule, Staff believes that
12 it adds unnecessary complexity, and may shift costs among customer classes.⁴⁵³

13 **RUCO**

14 RUCO is concerned that the proposed change may shift costs between rate classes and may
15 expose the ratepayers to more risk, and consequently, recommends that the Commission deny the
16 Company’s request to modify the current PPFAC.⁴⁵⁴

17 **Analysis and Resolution – PPFAC**

18 The Company has not presented a compelling reason for changing the current method of
19 allocating fuel costs among the various rate classes in the PPFAC. Therefore, for the reasons set forth
20 by Staff and RUCO, we decline to adopt UNSE’s proposed PPFAC modifications.

21 In Direct Testimony, Staff recommended a base cost of power of \$0.053288 per kWh, which
22 results in a total expense of \$85,303,919 based on test year sales of 1,600,809,167 kWh.⁴⁵⁵ Staff used
23 the available actual costs from January through August 2015 and UNSE’s forecasted costs of
24 September through December 2015. UNSE recalculated the base cost of power to be \$0.053689 per
25 kWh using actual costs from January through December 2015, and proposed to update the base cost

26 ⁴⁵¹ UNSE Reply Brief at 34.

27 ⁴⁵² UNSE Initial Brief at 55 and UNSE Reply Brief at 35.

⁴⁵³ Staff Initial Brief at 17.

⁴⁵⁴ RUCO Initial Brief at 19.

28 ⁴⁵⁵ Ex S- 7 Keene Dir at 9.

1 based on actual costs prior to establishing new rates.⁴⁵⁶ The PPFAC will be re-set to zero when the
 2 new rates are established, and will vary monthly according to the provisions of the PPFAC POA. It is
 3 reasonable to adopt the position of UNSE and Staff, which would require UNSE to update the base
 4 cost of fuel and purchased power (resetting the PPFAC to zero) immediately prior to establishing new
 5 rates in this matter, based on Staff's methodology as proposed in the Direct Testimony of Staff witness
 6 Keene. It is also reasonable to require UNSE to file a revised PPFAC POA for Commission review and
 7 approval.

8 LFCR

9 UNSE

10 We recognize that when fixed costs are partially recovered from the volumetric energy charge,
 11 and sales of energy decline, a utility may be unable to recover all of its fixed costs. In a 2010 Policy
 12 Statement, the Commission was supportive of the use of a decoupled rate structure to address the
 13 problem.⁴⁵⁷ At that time, the Commission encouraged utilities to develop customer rate designs that
 14 support energy efficiency and work well in tandem with decoupling (or alternative mechanisms).
 15 UNSE has a partial decoupling mechanism in the form of the LFCR. The LFCR was first approved as
 16 part of the settlement approved in Decision No. 74235.

17 Although the LFCR is a critical component of providing an opportunity for the Company to
 18 recover its fixed costs, UNSE claims that its LFCR does not address the entire fixed cost problem.⁴⁵⁸
 19 By excluding the recovery of fixed generation costs and 50 percent of the remaining non-generation
 20 demand costs, UNSE argues it cannot recover all lost fixed costs resulting from compliance with
 21 Commission policies.⁴⁵⁹ The Company proposes to modify the LFCR by increasing the amount of fixed
 22 generation costs which it says are "necessary to meet current and anticipated load," as well as non-
 23 generation demand costs, and increasing the cap to 2 percent. UNSE states that fixed generation costs
 24 are significant and have been rising, and that when volumetric sales decline, the fixed costs associated
 25 with generation are not being recovered. Because UNSE is obligated to meet the load of its customers,

26 ⁴⁵⁶ Ex S-9 Keen Surr at 3.

27 ⁴⁵⁷ "Final ACC Policy Statement regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures."
 December 29, 2010, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.

28 ⁴⁵⁸ UNSE Initial Brief at 52.

⁴⁵⁹ Id.

1 it argues that generation fixed costs should be part of the LFCR recovery. UNSE claims that the
 2 proposed changes would better address the impacts of the continuing expansion of the Commission-
 3 mandated renewable and energy efficiency programs. UNSE notes that any wholesale sales from its
 4 generation assets are already credited against the PPFAC and, if there is any concern about double
 5 recovery as a result of the LFCR, the Company would credit any excess back to customers.⁴⁶⁰

6 The Company also proposes to simplify the LFCR charge into a single line on the bill, rather
 7 than to split the charge into EE and REST components. Finally, the Company proposes to eliminate
 8 the fixed charge option in the LFCR because no customers have opted to use this option.⁴⁶¹

9 The Company argues that opposition to the proposed changes is based on unrealistic, or
 10 inaccurate, assumptions and speculation that the Company has flexibility to adjust its power purchases
 11 to match its short-term needs.⁴⁶² Rather than denying recovery, of its generation costs based on
 12 speculation, UNSE asserts the Commission can simply require the Company to credit the PPFAC to
 13 the extent it sells wholesale power at a cost in excess of its fixed costs recovery to ensure there is no
 14 double recovery.⁴⁶³

15 UNSE states that it is experiencing increased DG and EE deployment that will soon result in
 16 lost fixed cost revenues that exceed the 1 percent cap (particularly if the LFCR is revised to include
 17 recovery of fixed generation costs and a portion of lost demand rates). UNSE states that the increased
 18 cap will avoid undue deferral of excess amounts and provide better temporal matching for recovery of
 19 lost fixed cost revenues. In response to Staff's opposition, which assumes lower fixed cost losses
 20 resulting from DG, UNSE states that keeping the cap would not eliminate LFCR recovery, but simply
 21 defer it, and customers will eventually pay the amount due under the LFCR.⁴⁶⁴

22 In response to RUCO's claim that including fixed generation costs would turn the LFCR into a
 23 "full decoupler" that would shift risk to the residential customers,⁴⁶⁵ UNSE argues that the issue is not
 24 about risk, but the fundamental principle of ratemaking that rates must recover the prudently incurred

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 26 ⁴⁶⁰ UNSE Reply Brief at 33.

27 ⁴⁶¹ UNSE Initial Brief at 52.

28 ⁴⁶² Id. at 53.

⁴⁶³ Id.

⁴⁶⁴ Id. at 54.

⁴⁶⁵ RUCO Initial Brief at 18.

1 costs of providing utility service.

2 TASC has suggested that the LFCR is “likely unconstitutional.”⁴⁶⁶ However, the Company
3 asserts that the LFCR was established in a rate case with a full fair value finding, and thus complies
4 with all requirements of the Arizona Constitution.⁴⁶⁷ UNSE states that the LFCR helps it recover its
5 fixed costs and thereby helps ensure that the Commission meets its constitutional obligation to approve
6 just and reasonable rates.

7 Furthermore, UNSE asserts, to the extent the LFCR is considered an adjustor mechanism, it
8 also meets all the requirements that courts have set for such mechanisms-- i.e. it is set in a rate case,
9 based on specific costs, and does not change the rate of return. UNSE claims that the recent court of
10 appeals decision in *Residential Util. Consumer Office v. Arizona Corp. Comm’n*,⁴⁶⁸ does not invalidate
11 the LFCR. UNSE claims that the LFCR is different than the System Improvement Benefit (“SIB”)
12 mechanism that was found to violate the fair value requirement in the recent RUCO case. The SIB
13 involved utility plant added between rate cases, with annual surcharges that increase rates based on the
14 added rate base. UNSE states that the LFCR does not have either feature because the rate base,
15 operating expenses and rate of return remain unchanged, and the LFCR simply adjusts the volumetric
16 rates to account for some of the reduced kWh volume.⁴⁶⁹

17 RUCO

18 RUCO asserts that including generation losses is contrary to the design and purpose of the
19 LFCR and argues that the Commission should reject the Company’s proposal to include generation
20 losses in the LFCR.⁴⁷⁰ RUCO argues the LFCR was not designed to recover lost generation fixed costs
21 as it is not a full revenue decoupling mechanism. RUCO contends that to treat it as such shifts risk to
22 the residential customers. RUCO agrees with Staff that the Company’s purchased power program has
23 a significant amount of flexibility, which allows it to adjust its purchases to match its short-term needs,
24 and purchased power is not affected if energy is delivered to a new or existing customer or sold off
25

26 ⁴⁶⁶ TASC Initial Brief at 36-37.

27 ⁴⁶⁷ *Simms v Round Valley Light & Power Co.*, 80 Ariz. 145, 151, (1956) (The Arizona Constitution requires the commission
to find the fair value of a utility’s property and use such finding as a rate base for calculating just and reasonable rates).

⁴⁶⁸ 238 Ariz. 8 ¶ 50, 355 P.3d 610, 620 (App. 2015) cert. granted Feb 9, 2016.

⁴⁶⁹ UNSE Reply Brief at 31-2.

28 ⁴⁷⁰ RUCO Initial Brief at 17.

1 system.

2 **Staff**

3 Staff did not address the LFCR in its post-hearing briefs. In its pre-filed testimony, however,
4 Staff recommended that the Commission reject the Company's proposed changes to the LFCR, except
5 it agreed that the Company should be permitted to eliminate the Fixed Charge Option.⁴⁷¹ Staff believes
6 that the Company's purchased power program has a significant amount of flexibility that would allow
7 the Company to adjust its purchases to match its short-term needs. Staff states that the LFCR is not
8 designed to compensate for non-specific sales losses or business climate changes, nor was it intended
9 to shift risk to customers.

10 Staff believes the current LFCR, which provides for the recapture of a portion of distribution
11 costs collected in the volumetric rates, is sufficient when the Company also collects distribution costs
12 from demand charges that do not fluctuate with declining sales as much as volumetric charges. Staff
13 opposed the increase in the cap because the mechanism has not yet reached the 1 percent cap, and if
14 the other changes to the LFCR are not adopted, then there is no need to increase the cap.

15 **Vote Solar**

16 Vote Solar opposes UNSE's proposed modifications to the LFCR.⁴⁷² Vote Solar provided
17 testimony that because UNSE can avoid the fixed generation costs associated with DG and EE, those
18 costs should not be included in the LFCR.⁴⁷³

19 **TASC**

20 TASC argues that the proposed LFCR mechanism should be denied as unconstitutional
21 pursuant to the recent decision of the Arizona Court of Appeals that found a SIB mechanism was
22 unconstitutional.⁴⁷⁴ TASC believes that the SIB and the LFCR are substantially similar for purposes
23 of constitutional analysis, as they allow a utility to increase rates and revenue between rate cases, and
24 if the SIB is ultimately found to be unconstitutional, the LFCR would likely be as well. TASC argues
25 that given the uncertainty that surrounds the use of adjustor mechanisms, the Commission should

26 ⁴⁷¹ Ex S-5 Solganick Rate Dir at 52-57; Ex S-6 Solganick Surr at 14.

27 ⁴⁷² Vote Solar Reply Brief at 14.

28 ⁴⁷³ Ex Vote Solar-6 Kobor Dir at 46.

⁴⁷⁴ TASC Initial Brief at 36; *Residential Utility Consumer Office ("RUCO") v Arizona Corp. Comm'n*, 238 Ariz. 8 (App. 2014), cert granted Feb. 9, 2016.

1 refrain from expanding its reach.

2 **Analysis and Resolution – LFCR**

3 UNSE has not met its burden to show that its proposed changes to the LFCR mechanism are in
4 the public interest. The LFCR mechanism is not intended to operate as a full de-coupler mechanism,
5 but rather to collect the lost fixed cost revenues associated with Commission-mandated programs such
6 as Energy Efficiency and DG. However, we will allow UNSE to eliminate the fixed charge option in
7 its LFCR given that no customers have chosen this option.

8 **Transmission Cost Adjustor - TCA**

9 **UNSE**

10 UNSE is not seeking modification of its Transmission Cost Adjustor, but states that it has not
11 agreed with Staff on a final version of a POA. UNSE requests that the Commission require the filing
12 of a final TCA POA as a compliance item in this Order.⁴⁷⁵ The actual TCA rate will be set near to zero
13 as the revenues currently being recovered through the TCA are now being recovered through base rates.

14 **Staff**

15 Staff does not discuss the TCA in post-hearing briefs. Staff's pre-filed testimony indicates that
16 at that time, Staff and the Company still had disagreements concerning the TCA POA. Staff
17 recommended that the Company provide an updated POA for the TCA before the conclusion of the
18 proceeding.⁴⁷⁶

19 **Analysis and Resolution**

20 We direct UNSE to file a revised TCA POA for Staff's review. Staff should prepare a
21 Recommended Order addressing the Company's filing, and any interested party to this proceeding may
22 file comments on UNSE's filing or the proposed Staff Order.

23 **Property Tax Deferral**

24 **UNSE**

25 UNSE requests that the Commission grant it authority to defer two types of property tax
26 expenses for two issues. First, the Company requests a deferral of the legal costs, as well as the property
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28 ⁴⁷⁵ UNSE Initial Brief at 56.

⁴⁷⁶ Ex S-12 Van Epps Surr at 2.

1 tax reductions that may be obtained from the property tax appeal, for the Gila River plant. UNSE states
2 that the appeal would result in substantial savings that will benefit ratepayers for decades. Second,
3 UNSE requests authority to defer property tax expenses that result from tax rates that are higher or
4 lower than the test year. UNSE states that its effective tax rate is constantly increasing, leaving it with
5 unrecovered tax expenses year after year. Neither type of deferral would change rates in this case, but
6 would allow UNSE to request recovery in a future rate case.

7 UNSE is currently disputing the Arizona Department of Revenue ("ADOR") \$50 million
8 property tax valuation of Gila River. UNSE claims a value of \$29 million, with the difference due to
9 different interpretations of property tax law. The plant has an estimated remaining life of 35 years, so
10 UNSE claims that a successful appeal would benefit ratepayers for many years, and under UNSE's
11 proposal ratepayers would begin to benefit immediately from a successful appeal, without waiting for
12 a new rate case.⁴⁷⁷

13 UNSE argues that it is not certain that if it prevails in the appeal that it will be awarded legal
14 fees, and even if it is, the award will be less than the actual legal costs. UNSE argues that deferral of
15 the legal fees is needed to compensate the Company for its legal expenses, and any legal fees recovered
16 from ADOR will be credited against the deferral. The Company argues that RUCO's proposed cap on
17 costs is not reasonable because UNSE cannot know how long the case will take. UNSE could avoid
18 100 percent of the legal costs by not appealing, and ratepayers would be responsible for 100 percent of
19 the property tax expense.

20 UNSE also argues that a deferral for the changes in property tax rates is reasonable and in the
21 public interest. Property tax expense is a function of property valuation and tax rates. When property
22 values fall, taxing authorities have compensated by raising property tax rates. These effects can cancel
23 each other out, but because UNSE is constantly making capital improvements, the value of its property
24 typically rises, thus, the Company is hit with both increasing valuations and increasing tax rates. The
25 result was that in the last rate case, the level of property tax expense approved for recovery in rates fell

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28 ⁴⁷⁷ Ex UNSE-15 Rademacher Reb at 8.

1 short of UNSE's actual tax payments.⁴⁷⁸ USNE asserts that unless some type of deferral or other relief
 2 is granted, it will never "catch up," and rates will never recover the full amount of property taxes paid
 3 on property serving customers. Thus, the Company requests deferral of 100 percent of the property
 4 taxes above or below the test year caused by increases or decreases in the composite tax rate. UNSE
 5 claims that this will not allow UNSE to timely recover all property tax expenses, but the Company
 6 believes it is a step in the right direction.⁴⁷⁹

7 UNSE provided a sample calculation to be performed each year until UNSE's next rate case:⁴⁸⁰

1) Test Year Assessed Value	\$59,950,520
2) Gila Assessed Value Reduction – Successful Appeal*	\$3,780,000
3) Adjusted Assessed Value (1-2)	\$56,170,520
4) Actual Composite Rate **	12.5000%
5) Test Year Composite Rate	11.2370%
6) Deferral Change in Composite Rate (3x(4-5))	\$709,411
7) Deferral: Gila Value Reduction (2x5)	(\$424,760)
8) Deferral Appeal Expenses**	\$25,000
9) Total Deferral (6+7+8)	\$308,651

18 *\$21 million possible reduction in full cash value multiplied by 18 % assessment ratio

19 **For illustrative purposes only

20 UNSE states that RUCO's claim that Mohave County property tax rates have not increased is
 21 based on a review of the primary tax rate between 2014 and 2015, and ignores the trend of increasing
 22 rates from 2010 to 2014, as well as other components of the Company's overall Mohave County
 23 property tax rates. UNSE states that its composite tax rate has increased 15.5 percent from 2012 to
 24 2015.⁴⁸¹

26 ⁴⁷⁸ UNSE states that the composite property tax rate approved in the last rate case, based on 2012 tax bills, was 10.0087
 27 percent, but the tax rates in effect in 2013 – 2015 were higher at 10.7666 percent to 11.5599 percent. UNSE Initial Brief at
 58.

27 ⁴⁷⁹ UNSE Initial Brief at 59.

28 ⁴⁸⁰ Ex UNSE-14 Rademacher Dir at 19.

⁴⁸¹ UNSE Reply Brief at 37-38.

RUCO

RUCO recommends a 50/50 cost sharing between the Company and ratepayers for any benefits resulting from a successful appeal of the Gila River valuation, and also recommends that a cap be placed on the costs to protect ratepayers.⁴⁸² RUCO does not dispute that ratepayers would benefit from an appeal of the Gila River property taxes. RUCO believes that a successful appeal would provide equal benefits to the Company and ratepayers.⁴⁸³

RUCO opposes granting the Company an accounting order for property taxes above or below the test year level. RUCO asserts that it is not the case in Mohave County that, as property values have declined, tax rates have increased. In addition, RUCO argues that although APS was granted such a deferral order, it was bargained for as part of a settlement which reduced the cost of equity by 100 basis points. RUCO doesn't believe there is any reason to depart from the traditional method of accounting for property taxes in UNSE's case.

Staff

Staff did not address this issue in post-hearing briefs, but in pre-filed testimony recommended accepting the Company's property tax deferral because it allows for recovery of items that are beyond the control of the Company and balances the interest of consumers and shareholders.⁴⁸⁴ Staff believes it was a reasonable compromise because the legal costs would be offset by the benefits.⁴⁸⁵

According to Staff, because UNSE's book value of assets rises with its annual capital expenditures, when a taxing authority raises tax rates, UNSE's tax payments increase, and the test year level of property taxes will fall short of actual tax payments. Staff notes that the Commission approved a property tax deferral for APS in 2012, but Staff claims UNSE's request differs somewhat from that approved for APS.⁴⁸⁶ For example, UNSE proposed recovery of 100 percent of any property tax increase or decrease, whereas the APS deferral has limits on the percentage increase in the property tax rate; and the UNSE proposal would recover both positive and negative balances over the same three-year period, while the APS deferral required the Company to recover positive balances over ten years,

⁴⁸² RUCO Initial Brief at 19.

⁴⁸³ RUCO Reply Brief at 13

⁴⁸⁴ Ex S-1 Mullinax Dir at 30-34.

⁴⁸⁵ Tr. at 595.

⁴⁸⁶ Decision No. 73183 (May 24, 2012).

1 and negative balances to be refunded over three years. Further, Staff points out that UNSE is requesting
 2 a property tax deferral related to the Gila River valuation methodology and cost of appealing, and
 3 although UNSE plans to appeal the Mohave County valuation of Gila River, in the interim it must make
 4 tax payments based on the higher valuation.

5 **Analysis and Resolution – Property Tax Deferral**

6 The proposed deferral appropriately balances the interests of the ratepayers and shareholders.
 7 The Company is not required to appeal the Gila River valuation, and in the event of a successful appeal,
 8 ratepayers will benefit over the life of the plant. The benefits of the lower valuation would be substantial
 9 and it is fair that the costs of obtaining those benefits should be considered. In addition, with the
 10 periodic nature of rate cases, but the annual assessment of property taxes, there is always a lag in
 11 recovering these expenses. They are not an expense over which the utility has any control, and UNSE
 12 provided evidence that composite property tax rates have increased over recent years.⁴⁸⁷ A deferral of
 13 the increased expense attributable to a change in the composite tax rate is reasonable. Thus, we concur
 14 with Staff that the Company's deferral proposal should be adopted.

15 **Other Requested Approvals**

16 **Approval of Depreciation Rates**

17 UNSE proposed new depreciation rates based on an updated depreciation study.⁴⁸⁸ The
 18 proposed rates are lower for many asset accounts and result in an overall decrease in depreciation
 19 expenses. No party to the docket opposed the proposed depreciation rates. UNSE requests that the
 20 Commission approve the proposed depreciation rates. We adopt UNSE's proposed depreciation rates.

21 **Approval of Revisions to USNE's Rules and Regulations**

22 UNSE proposed revisions to its Rules and Regulations in an effort to modernize the tariff, bring
 23 them closer to the Rules and Regulations of its sister company, TEP, and clarify areas that have caused
 24 undue confusion.⁴⁸⁹ UNSE believes that it has resolved all of Staff's concerns, but not all of ACAA's
 25 concerns. UNSE does not agree with the following requests by ACAA with respect to its Rules and
 26 Regulations:

27 ⁴⁸⁷ Ex UNSE-14 Rademacher Dir at 16.

28 ⁴⁸⁸ Ex UNSE-7 White Dir Exhibit REW-1.

⁴⁸⁹ UNSE Initial Brief at 63-64.

1 1. ACAA requested that CARES customers be held harmless from the modifications
2 regarding deposits in Subsection 3.B.3. UNSE believes equitable treatment among customers
3 regarding deposits is appropriate, and states that it takes significant efforts to provide workable
4 solutions for its customers who face challenges in paying bills or deposits. (We addressed this dispute
5 under our discussion of the CARES option).

6 2. UNSE does not agree with ACAA's request to excuse customers who file for
7 bankruptcy form providing a deposit. UNSE states that Subsection 3.B.2 is consistent with the
8 approved Rules and Regulations of other Arizona utilities, and that a deposit on a post-petition account
9 is an appropriate assurance of payment under 11 U.S.C. § 366.

10 3. In Subsection 12.H, ACAA requested the use of a current limiting device as an
11 alternative to disconnection for low-income customers. UNSE states that this provision has been
12 withdrawn in response to Staff's concerns.⁴⁹⁰

13 **Staff**

14 Staff has reviewed UNSE's proposed modifications to its Rules and Regulations and made
15 suggested revisions throughout the hearing process. UNSE submitted a red-lined version to Staff
16 reflecting the agreed revisions. Staff states that with one minor exception, Staff has determined that the
17 revised Rules and Regulations are acceptable.⁴⁹¹

18 **Analysis and Resolution – Rules and Regulations**

19 ACAA did not address the bankruptcy deposit issue or the current limiting device in post-
20 hearing briefs. Thus, it is not clear if these issues remain in dispute. In any event, we find UNSE's
21 proposals concerning these issues to be reasonable. We are not aware of any remaining dispute between
22 the Company and Staff concerning the Rules and Regulations. Consequently, we approve the final
23 version submitted with UNSE's Initial Brief, and direct the Company to file a clean version as a
24 compliance filing.

25 **Plans of Administration for REST and DSM surcharges**

26 Staff requested that UNSE submit a new POA for its REST surcharge and its DSM surcharge.

27 _____
28 ⁴⁹⁰ Tr. at 683-84.

⁴⁹¹ Staff Initial Brief at 16. Staff's Brief did not identify the minor exception.

1 The Company states that it submitted both POAs, but that the Company and Staff have not yet agreed
 2 upon final versions of either. UNSE requests that the Commission order the Company to submit final
 3 versions of the REST and DSM POAs as compliance items within 60 days of the Decision in this
 4 docket, for Commission review and approval. The Company states that it will continue to work with
 5 Staff to refine the draft POAs that were submitted.⁴⁹²

6 * * * * *

7 Having considered the entire record herein and being fully advised in the premises, the
 8 Commission finds, concludes, and orders that:

9 FINDINGS OF FACT

10 1. On May 5, 2015, UNSE filed with the Commission an Application for a rate increase.
 11 Accompanying the Application and its attendant Schedules, UNSE filed the Direct Testimony of David
 12 Hutchens, Terry May, Michael Sheehan, Carmine Tilghman, Kenneth Grant, Ann Bulkley, Ronald
 13 White, Jason Rademacher, David Lewis, Dallas Dukes, Craig Jones, and Denise Smith.

14 2. On June 3, 2015, the Company filed an amendment to the Application.

15 3. On June 4, 2015, Staff notified the Company that its Application met the sufficiency
 16 requirements of the Arizona Administrative Code ("A.A.C.") and classified the Company as a Class A
 17 utility.

18 4. On June 9, 2015, after consultation with Staff and RUCO, UNSE filed a Motion for
 19 Procedural Schedule which proposed a schedule for the hearing.

20 5. By Procedural Order dated June 22, 2015, the proposed schedule was adopted and the
 21 matter was set for hearing to commence on March 1, 2016, at the Commission's Tucson office.

22 6. Intervention was granted to RUCO, APS, WRA, Vote Solar, TASC, Nucor, Noble,
 23 Walmart, SWEEP, AECC, ACAA, AIC, AURA, ASDA, SSVEC, Trico, FPAA, and ArISEIA.

24 7. On July 16, 2015, AIC filed a Motion for Leave to Intervene and to Supplement the
 25 Procedural Order to Clarify Application of the Ex Parte Rules.

26 8. By Procedural Order dated, August 13, 2015, it was ordered that A.A.C. R14-3-113 (ex
 27

28 ⁴⁹² UNSE Initial Brief at 64.

1 parte rule) applies to individual members of intervening membership organizations.

2 9. On September 9, 2015, UNSE filed a Notice of Mailing and Publication indicating that
3 notice of the hearing was mailed to its customers as a bill insert beginning on August 1, 2015, and
4 ending on August 31, 2015; published in newspapers of local circulation in UNSE's service territory
5 on August 3, 2015, August 4, 2015 and August 5, 2015;⁴⁹³ and also placed in the Mohave County
6 Library District Lake Havasu in Lake Havasu, Arizona; the Mohave County Library District Kingman
7 in Kingman, Arizona; and the Nogales-Rochlin Library in Nogales, Arizona on August 12, 2015.

8 10. On September 18, 2015, UNSE filed Supplemental Information In Support of
9 Application, comprised of schedules to the proposed revised PPFAC POA.

10 11. On November 5, 2015, ACAA filed the Direct Testimony (except that related to rate
11 design and cost of service) of Cynthia Zwick. On November 6, 2015, Direct Testimony (except that
12 related to rate design and cost of service) was filed for: Steve Chriss by Walmart; Mark Fulmer and J.
13 Randall Woolridge by TASC; Jeffrey Michlik and Robert Mease by RUCO; Jeff Schlegel by SWEEP;
14 and Howard Solganick, Barbara Keene, Elijah Abinah, Donna Mullinax, Candrea Allen, and Eric Van
15 Epps by Staff.⁴⁹⁴

16 12. On December 9, 2015, Direct Testimony on Rate Design and Cost of Service was filed
17 by: ACAA for Zwick; Walmart for Chris Hendrix and Gregory Tillman; RUCO for Lon Huber; AECC
18 and Noble for Kevin Higgins; Nucor for Jay Zarnikau; AURA for Patrick Quinn and Thomas Alston;
19 AIC for Gary Yaquinto and Daniel Hansen;⁴⁹⁵ WRA for Kenneth Wilson; SWEEP for Mr. Schlegel;
20 FPAA for Lance Jungmeyer and Kent Simer; APS for Charles Miessner and Ahmad Faruqui; Vote
21 Solar for Briana Kobor; and Staff for Mr. Solganick and Thomas Broderick.

22 13. On January 19, 2016, UNSE filed the Rebuttal Testimony of Mr. Hutchens, Mr. Grant,
23 Ms. Bulkley, Mr. Lewis, Mr. Rademacher, Mr. Sheehan, Mr. Tilghman, Mr. Dukes, Mr. Jones, Ms.
24 Smith, and H. Edwin Overcast; and ACAA filed the Rebuttal Testimony of Ms. Zwick.

25 14. On January 21, 2016, UNSE filed a Motion for Preliminary Pre-hearing Conference,
26 seeking to schedule witnesses prior to the Pre-Hearing Conference to facilitate planning. On January

27 ⁴⁹³ The *Kingman Daily Miner*, *Nogales International*, *Santa Cruz Valley Power Pak*, and *Today's News-Herald*.

⁴⁹⁴ SWEEP filed an Errata to its November 9, 2015 testimony on November 9, 2015.

28 ⁴⁹⁵ On December 21, 2015, AIC filed a corrected copy of Mr. Hansen's testimony that included all exhibits.

1 22, 2016, Staff filed a Response to the Motion, supporting the Company's request.

2 15. By Procedural Order dated January 25, 2016, in lieu of scheduling a preliminary pre-
3 hearing conference, the parties were directed to confer and submit a proposed witness schedule prior
4 to the Pre-hearing Conference set for February 26, 2016.

5 16. On January 26, 2016, AURA filed a Motion to Extend Procedural Schedule. AURA
6 sought to extend the filing of Surrebuttal Testimony and the hearing in this matter for approximately
7 two months because UNSE's Rebuttal Testimony adopted Staff's recommended rate design, which
8 included mandatory residential demand charges. AURA argued UNSE's modified rate design was an
9 abrupt change of position which warranted additional time for discovery and preparation. RUCO filed
10 a Response to AURA's Motion on January 26, 2016, supporting the request.

11 17. On January 27, 2016, UNSE filed an Opposition to AURA's Motion, arguing that its
12 acceptance of Staff's recommended rate design that was first advanced on December 9, 2015, is not
13 sufficient grounds to delay the rate case.

14 18. On January 27, 2016, ACAA, Vote Solar, SWEEP and WRA filed Responses to
15 AURA's Motion, supporting the requested continuance.

16 19. On January 28, 2016, AIC filed its Opposition to AURA's Motion.

17 20. On January 29, 2016, ARUA filed a Reply in Support of its Motion.

18 21. By Procedural Order dated January 29, 2016, AURA's Motion to Extend the Procedural
19 Schedule was denied on the grounds that acceptance of Staff's recommendations in Rebuttal Testimony
20 is not unusual and the prospect of mandatory residential demand rates was made an issue in the case
21 since at least December 9, 2015 when Staff filed its rate design testimony. In addition, it was found
22 that as a practical matter, delaying this rate case would adversely affect a number of proceedings
23 involving many of the parties to this case scheduled before the Commission throughout 2016.

24 22. On January 29, 2016 and February 3, 2016, the Sun City Homeowners Association
25 ("SCHOA") and the Property Owners and Residents Association of Sun City West ("PORA"),
26 respectively, filed requests to intervene. On February 2, 2016, UNSE filed an Opposition to SCHOA's
27 Intervention Application.

28 23. By Procedural Order dated February 5, 2016, the requests to intervene were denied on

1 the grounds that neither SCHOA nor PORA represent ratepayers who reside within UNSE's service
 2 territory; residential ratepayers were already adequately represented by other intervenors; and the
 3 requests were not timely. These entities were informed that they could file public comments.

4 24. On February 16, 2016, after conferring with the parties to the proceeding, the Company
 5 filed a Proposed Witness Schedule.

6 25. On February 18, 2016, Staff filed a Request for an Extension to File Surrebuttal
 7 Testimony from February 19, 2016 to February 23, 2016.⁴⁹⁶

8 26. By Procedural Order dated February 19, 2016, Staff's requested extension was granted
 9 for all affected parties, and the filing deadline for Rejoinder Testimony was extended to February 29,
 10 2016.

11 27. On February 19, 2016, Surrebuttal Testimony was filed by Walmart for Mr. Tillman
 12 and Mr. Hendrix.

13 28. On February 23, 2016, Surrebuttal Testimony was filed by: ACAA for Ms. Zwick;
 14 RUCO for Mr. Huber and Mr. Michlik; AECC and Noble for Mr. Higgins and Michal McElrath; Nucor
 15 for Dr. Zarnikau; TASC for Mr. Fulmer and Mr. Woolridge; SWEEP for Mr. Schlegel; WRA for Mr.
 16 Wilson; AURA for Mr. Quinn, Mr. Alston and Scott Rubin; FPAA for Mr. Simer; APS for Mr.
 17 Miessner, Dr. Faruqui, Cory Welch and Ashley Brown; AIC for Mr. Yaquinto and Mr. Hansen; Vote
 18 Solar for Ms. Kobor; and Staff for Mr. Solganick, Ms. Keene, Ms. Mullinax, Yue Liu, Ms. Allen, Mr.
 19 Van Epps, and Mr. Broderick.

20 29. A Pre-Hearing convened on February 26, 2016, as scheduled in the June 22, 2015 Rate
 21 Case Procedural Order. Appearing through counsel at the Pre-hearing Conference were: UNSE, APS,
 22 TASC, FPAA, RUCO, Walmart, Nucor, AIC, SWEEP, WRA, ACAA, Vote Solar, AECC, Noble,
 23 AURA, SSVEC, ASDA, and Staff. The parties discussed the hearing schedule and the pre-filed
 24 proposed witness schedule was discussed, modified and adopted. TASC notified the parties that it was
 25 considering identifying an expert witness to address the issues raised by an APS witness in Surrebuttal
 26 Testimony.⁴⁹⁷ UNSE and APS requested that TASC identify any potential new witness as soon as

27 _____
 28 ⁴⁹⁶ Responses to Staff's request were filed on February 19, 2016 by APS, AIC, AECC and Noble.

⁴⁹⁷ February 26, 2016 Pre-Hearing Conference Transcript at 25.

1 possible.⁴⁹⁸

2 30. On February 29, 2016, UNSE filed the Rejoinder Testimony of Mr. Hutchens, Mr.
3 Grant, Ms. Bulkley, Mr. Lewis, Mr. Sheehan, Mr. Tilghman, Mr. Dukes, Mr. Jones, Mr. Overcast and
4 Ms. Smith.

5 31. On February 29, 2016, TASC filed a Motion to Strike APS Surrebuttal Testimony of
6 Ashley Brown and Corey Welch and Motion to Continue Surrebuttal Testimony, on the grounds the
7 testimony of the two witnesses were not disclosed until they filed Surrebuttal Testimony.

8 32. The hearing convened as scheduled on March 1, 2016, before a duly authorized
9 Administrative Law Judge at the Commission's Tucson offices. The proceeding commenced with
10 public comment.⁴⁹⁹ The pending Motion to Strike was discussed and denied.⁵⁰⁰ The hearing reconvened
11 on March 3, 2016 and concluded on March 23, 2016. At the conclusion of the hearing, the ALJ took
12 the matter under advisement, pending the filing of Final Schedules, late-filed exhibits and Closing
13 Briefs.

14 33. On March 3, 2016, TASC filed an Expedited Motion for Expedited Responses to
15 Discovery Requests Served on APS. The same date, APS filed a Response to Supplement Record
16 Regarding TASC's Expedited Responses to Discovery Request. On March 8, 2016, the Expedited
17 Motion was discussed on the record, at which time the parties reported they were attempting to reach
18 a consensual resolution.⁵⁰¹

19 34. On March 8, 2016, TASC filed an Expedited Motion to Compel in which it sought an
20 order requiring UNSE to respond to TASC's Data Request 10.1. The Motion was discussed and granted
21 on the record on March 8, 2016.⁵⁰²

22 35. By Procedural Order dated March 9, 2016, the Commission ordered UNSE to publish
23 public notice of three Public Comment Meetings scheduled for March 22, 2016, in Nogales, Arizona,
24 and on March 31, 2016 in Kingman and Lake Havasu, Arizona.

25
26 ⁴⁹⁸ *Id.* at 29-31.

27 ⁴⁹⁹ At the commencement of the hearing, the Commission was in the process of scheduling additional Public Comment
meetings in locations within UNSE's service area, but had not yet finalized the details.

28 ⁵⁰⁰ Hearing Transcript ("Tr. at 120-136.

⁵⁰¹ Tr. at 260-1.

⁵⁰² Tr. at 817-823.

1 36. On March 24, 2016, UNSE filed a Notice of Publication indicating that Notice of the
2 Public Comment Sessions was published in newspapers of local circulation on March 15, 2016, and
3 March 16, 2016.

4 37. The Commission conducted Public Comment Meetings in Nogales on March 22, 2016
5 and in Kingman and Lake Havasu on March 31, 2016. The Commission determined that additional
6 public comment should be conducted, and set a second Public Comment Meeting in Lake Havasu on
7 April 18, 2016. By Procedural Order dated April 6, 2016, the Commission scheduled the Public
8 Comment Meeting and ordered UNSE to publish public notice.

9 38. On April 4, 2016, UNSE filed Late-Filed Exhibits UNSE-45 to UNSE-47 regarding a
10 revised SGS rate; Late-Filed Exhibit UNSE-48, providing a revenue requirement spreadsheet; and
11 Updated Schedules.

12 39. On April 13, 2016, Commissioner Burns filed a Letter in the docket requesting
13 additional information from the parties concerning alternative rate designs to mandatory three-part
14 residential rates, the cost of equity if three-part rates are not adopted, and a discussion of the
15 reasonableness of the proposed transition time to three-part rates.

16 40. On April 18, 2016, a second Public Comment Session convened in Lake Havasu,
17 Arizona.

18 41. On April 20, 2016, UNSE filed a Notice of Publication indicating that it had the public
19 notice of the April 18, 2016 Public Comment meeting published in the *Today's New-Herald*, a
20 newspaper of general circulation in UNSE's service territory on April 12, 2016.

21 42. On April 22, 2016, Staff filed a notice of the initiation of settlement discussions to
22 commence at a date and time to be determined, and inviting all parties to participate in the settlement
23 efforts.

24 43. On April 25, 2016, Staff filed Notice of Settlement Discussions for April 28, 2016, at
25 the Commission's offices, with a conference bridge available.

26 44. On April 25, 2016, Opening Briefs were filed by UNSE, RUCO, AIC, AURA, Vote
27
28

1 Solar, SWEEP/WRA/ACAA, Nucor, Walmart, APS, AECC/Noble, TASC, FPAA and Staff.⁵⁰³

2 45. On April 25, 2016, Chairman Little filed a Letter in the docket, expressing concern
3 about the public reaction to the proposed three-part rates for residential customers and encouraging the
4 parties to explore alternative rates not involving mandatory demand charges, and suggesting
5 consideration of a renewable credit rate for net metering customers that could be fixed for a period of
6 time.

7 46. On April 28, 2016, Commissioner Forese filed a Letter in the docket seeking additional
8 information on the severe health and economic conditions in UNSE's territory and the adequacy of the
9 low-income programs.

10 47. On May 10, 2016, Commissioner Stump filed a Letter in the docket encouraging the
11 parties to discuss a market-based aggregation credit approach to net metering along the lines of a
12 proposal in Maine or RUCO's RPS Bill Credit Option, or other market-based approach.

13 48. On May 11, 2016, Reply Briefs were filed by UNSE, APS, AECC/Noble, TASC,
14 RUCO, AURA, Nucor, Vote Solar, AIC, TASC, FPAA, AriSEA, and Staff.

15 49. UNSE is an Arizona public service corporation engaged in the generation, transmission
16 and distribution of electricity to approximately 93,000 customers in Mohave and Santa Cruz Counties,
17 Arizona.

18 50. UNSE is a wholly-owned subsidiary of Unisource Energy Corporation, which in turn is
19 a wholly-owned subsidiary of Fortis. UNSE is an affiliate of UNS Gas, Inc. and TEP.

20 51. UNSE's current rates were established in Decision No. 74235 (December 31, 2013),
21 based on a test year ending June 30, 2012, with rates effective on January 1, 2014.

22 52. For purposes of this proceeding, the Company, Staff, and RUCO reached accord that
23 UNSE's adjusted test year OCRB is \$270,293,000, and that the fair value of the Company's
24 jurisdictional rate base for the test year is \$354,001,000. No party objected to the agreed FVRB. We
25 concur with the parties that for purposes of this rate case, UNSE's FVRB is \$354,001,000.

26 53. In the test year, UNSE had adjusted Operating Revenues of \$156,717,000, and adjusted
27

28 ⁵⁰³ SSVEC filed a Notice that it would not be filing post-hearing briefs.

1 Operating Income of \$10,530,000, resulting in a rate of return on its FVRB of 2.97 percent.

2 54. In the test year, the Company had a capital structure consisting of 47.17 percent long-
3 term debt and 52.83 percent equity.

4 55. Using The Company's actual capital structure is appropriate for establishing rates in this
5 matter.

6 56. A return on common equity of 9.50 percent and an embedded cost of long-term debt of
7 4.66 percent are appropriate estimates of the cost of capital for purposes of this rate case.

8 57. A FVROR of 5.63 percent on UNSE's FVRB produces rates that are just and reasonable.

9 58. It is reasonable to authorize for UNSE an increase in its gross revenue requirement of
10 \$15.1 million, an increase over test year revenues of 9.6 percent.

11 59. It is reasonable to transition UNSE's Residential and SGS customers to TOU rates,
12 while also offering these customers options to choose a traditional two-part rate or three-part rate with
13 a demand charge component. To have as many customers as possible opting for the TOU option, the
14 TOU rates should be the default rate for existing and future Residential and SGS Classes.

15 60. In order to transition customers to the new rates in an orderly fashion, it is reasonable
16 to require UNSE to propose a transition plan which includes an education program and timeframe for
17 Commission approval.

18 61. It is reasonable to authorize, during the transition period, two-part volumetric rates for
19 the Residential and SGS Classes as discussed herein, such rates to be effective as directed herein and
20 to remain in effect until the Commission approves permanent default TOU rates and other rate options.

21 62. Because we adopt a different revenue allocation than either Staff or the Company, and
22 are modifying their proposed monthly customer charge from \$15 to \$13 per month, until UNSE files
23 new rate schedules and proof of revenue that conform to our authorizations herein, we cannot provide
24 an exact bill impact analysis. However, factoring in our approved revenue allocation to the Residential
25 Class and a lower monthly customer charge which places a higher percentage of the increase in the
26 commodity charges than proposed, we estimate that under the transition two-part rates, an average
27 residential customer using 830 kWhs a month would see a monthly bill of approximately \$87.52, an
28

1 increase of \$2.36, or 2.7 percent, over current rates.⁵⁰⁴

2 63. The Value of DG docket is currently open and actively considering and evaluating
3 methodologies for determining the value and costs of solar DG to be used in rate proceedings. A
4 consistent application of the eventual findings and conclusions of the Value of DG docket promotes
5 good public policy and is in the public interest.

6 64. It is reasonable to hold the net metering and rate design portion of this docket for the
7 Residential and SGS Classes open for a second phase of this proceeding to commence shortly following
8 the conclusion of the Value of DG docket in order that the findings in that docket can be applied to
9 UNSE's net metering tariffs, and to consider whether DG customers who submit applications for
10 interconnection after the effective date of the Decision in phase two should be transitioned to mandatory
11 three-part demand rates or be assessed charges for the required second meter.

12 65. Until the conclusion of the second phase of this proceeding, and future order of the
13 Commission, it is reasonable to treat DG customers the same as non-DG customers in terms of rate
14 options.

15 66. The Company's proposed June 1, 2015 date for determining which DG customers shall
16 be subject to newly proposed rate options or net metering treatment is not reasonable. Going forward,
17 any DG customer who files an interconnection agreement prior to the effective date of a Decision in
18 phase two of this proceeding shall be treated the same as a DG customer who filed for interconnection
19 prior to that date.

20 67. It is reasonable to update the base cost of power based on actual costs prior to
21 establishing new rates, and to re-set the PPFAC to zero when the new rates go into effect. It is also
22 reasonable to require UNSE to file a revised PPFAC POA for Commission review and approval.

23 68. It is reasonable to approve the Rules and Regulation changes attached to UNS Electric,
24 Inc.'s Initial Brief.

25 69. It is reasonable to direct UNSE to file a revised TCA POA for review and approval by
26 the Commission.

27 ⁵⁰⁴ The ultimate TOU and optional demand rate options adopted after the transition period will be designed on a revenue
28 neutral basis such that the revenue collected from the Residential Class will not be changed, but individual customers will
experience different impacts based on their usage patterns.

1 70. It is reasonable to require UNSE to file a Plan of Administration for the Demand Side
2 Management adjutor for review and approval by the Commission.

3 71. It is reasonable that UNSE's LFCR mechanism shall continue in effect without the
4 proposed modifications by UNSE, except that the fixed rate option should be eliminated. It is
5 reasonable to require UNSE to file a proposed Plan of Administration for the LFCR mechanism for
6 review and approval by the Commission.

7 72. It is reasonable that UNSE's REST mechanism shall continue and to require UNSE to
8 file a proposed Plan of Administration for the REST mechanism for review and approval by the
9 Commission.

10 73. It is reasonable that at the effective date of the new rates approved in this Decision, the
11 TCA rate shall be reset to zero, or as close to zero as practicable, and to require the Company to file a
12 final Plan of Administration for the TCA for review and approval.

13 74. It is reasonable for UNSE's proposed Rider R-10, Net Metering for Certain Partial
14 Requirements Services (NM-PRS) and Rider R-11, Renewable Credit Rates, as well as
15 recommendations by other parties regarding UNSE's proposed tariff based on the conclusions of the
16 Value of DG docket, to be considered as part of phase two of this proceeding.

17 75. It is reasonable for UNSE's Rider-12 Interruptible Service to be approved.

18 76. It is reasonable for UNSE's Rider R-13, Economic Development Rider, to be approved,
19 and effective on the effective date of the rates approved herein.

20 77. It is reasonable for UNSE's Rider-14, Alternate Generation Service, to be denied.

21 78. It is reasonable that UNSE should be authorized to defer for future recovery, the
22 following: (1) one hundred percent of the property taxes above or below the test year amount of
23 property taxes, caused by increases or decreases to UNS Electric Inc.'s composite property tax rates;
24 and (2) all property tax savings derived from appealing the property tax value of Gila River Unit 3,
25 together with all attorney's fees, taxable costs, legal expenses and all other costs associated with the
26 appeal process.

27 ...

28 ...

CONCLUSIONS OF LAW

1. UNSE is a public service corporation within the meaning of the Arizona Constitution, and A.R.S. §§ 40-203, -204, -221, -250 and -361.

2. The Commission has jurisdiction over UNSE and the subject matter of the Rate Application.

3. Notice of the Rate Application and hearing was provided in accordance with the law.

4. UNSE's FVRB is \$354,001,000.

5. A FVROR of 5.63 percent is fair and reasonable in this case.

6. The rates and charges authorized herein are just and reasonable and should be approved.

ORDER

IT IS THEREFORE ORDERED that UNS Electric, Inc. shall file by August 31, 2016, a revised schedule of rates and charges consistent with the discussion herein, and a proof of revenue showing that based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedule of rates and charges shall be effective for all services provided on and after September 1, 2016, and shall remain in effect until further order of the Commission.

IT IS FURTHER ORDERED that UNS Electric, Inc. shall, by September 30, 2016, file optional rate schedules for the Residential and SGS Classes that provide for Time-of-Use rates, Super Peak Time-of-Use rates, three-part rates, with a demand charge, and three-part Time-of-Use rates, and a plan for transitioning the Residential and SGS Classes to default Time-of-Use rates consistent with the discussion herein.⁵⁰⁵

IT IS FURTHER ORDERED that following the filing of the proposed permanent rates and transition plan, the Hearing Division shall elicit recommendations from the parties in order to develop a process for Commission approval of the permanent rates and transition plan.

IT IS FURTHER ORDERED that the net metering and rate design portion of this docket shall

⁵⁰⁵ As a point of clarification, only the Residential and SGS Class rates are subject to the transition process and require further action by the Commission to be made permanent.

1 remain open pending approval of the optional rate schedules for the Residential and SGS Classes.

2 IT IS FURTHER ORDERED that phase two of this proceeding to consider any proposed
3 changes to UNS Electric, Inc.'s net metering tariffs and proposed rate options for Residential and SGS
4 DG customers shall commence shortly after the issuance of an Order in the Value of DG docket.

5 IT IS FURTHER ORDERED that UNS Electric, Inc. shall notify its affected customers of the
6 revised schedules of rates and charges authorized herein, including the plan to transition to Time-of-
7 Use rates and other rate options, by means of an insert in its next regularly scheduled bill and posting
8 on its website, in a form acceptable to the Commission's Utilities Division.

9 IT IS FURTHER ORDERED that the Rules and Regulation changes attached to UNS Electric,
10 Inc.'s Initial Brief as Exhibit 3 are approved, and UNS Electric, Inc. shall file in this docket, revised
11 Rules and Regulations consistent with this Decision, as a compliance item by August 31, 2016.

12 IT IS FURTHER ORDERED that the revised depreciation rates set forth in Dr. White's Direct
13 Testimony (Ex UNSE-7 White Dir) are approved, to be in effect on and after September 1, 2016.

14 IT IS FURTHER ORDERED that the revised Miscellaneous Service Charges proposed by Mr.
15 Jones (Ex UNSE-31 Jones Dir at 69-71) are approved, and UNS Electric Inc. shall file the revised
16 Miscellaneous Service Charges in its revised schedules of rates and charges.

17 IT IS FURTHER ORDERED that UNS Electric, Inc. shall by September 30, 2016, file a Plan
18 of Administration for the Demand Side Management adjustor and a revised Plan of Administration for
19 its Transmission Cost Adjustor for review and approval by the Commission.

20 IT IS FURTHER ORDERED that Lost Fixed Cost Adjustor Mechanism shall continue in effect,
21 and UNS Electric, Inc. shall file no later than September 30, 2016, a proposed Plan of Administration
22 for the Lost Fixed Cost Adjustor Mechanism for review and approval by the Commission.

23 IT IS FURTHER ORDERED that UNS Electric Inc.'s Renewable Energy Standard and Tariff
24 mechanism shall continue and UNS Electric, Inc. shall file no later than September 30, 2016, a
25 proposed Plan of Administration for the Renewable Energy Standard and Tariff mechanism for review
26 and approval by the Commission.

27 IT IS FURTHER ORDERED that the Purchased Power and Fuel Adjustor Mechanism
28 ("PPFAC") shall continue to operate on a per kWh basis, and the formula used to calculate the monthly

1 PPFAC rates shall be modified to include consideration of the bank balance, and UNS Electric Inc.
2 shall by September 30, 2016, file a revised Plan of Administration for the PPFAC with the Commission
3 for review and approval.

4 IT IS FURTHER ORDERED that at the effective date of the new rates approved in this
5 Decision, the Transmission Cost Adjustor rate shall be reset to zero, or as close to zero as practicable,
6 and UNS Electric, Inc. shall file by September 30, 2016, a final Plan of Administration for the
7 Transmission Cost Adjustor with the Commission for review and approval.

8 IT IS FURTHER ORDERED that UNS Electric Inc.'s proposed Rider R-10, Net Metering for
9 Certain Partial Requirements Services (NM-PRS) and Rider R-11, Renewable Credit Rates, as well as
10 recommendations by other parties regarding UNSE's proposed tariff based on the conclusions of the
11 Value of DG docket, shall be considered as part of phase two of this proceeding.

12 IT IS FURTHER ORDERED that UNS Electric Inc.'s Rider-12 Interruptible Service is
13 approved, and UNS Electric Inc. shall file Rider R-12 with the Commission on or before August 31,
14 2016, to be effective for service on and after September 1, 2016.

15 IT IS FURTHER ORDERED that UNS Electric Inc.'s Rider R-13, Economic Development
16 Rider is approved, and UNS Electric Inc. shall file Rider R-13 with the Commission on or before
17 August 31, 2016, to be effective for service rendered on and after September 1, 2016.

18 IT IS FURTHER ORDERED that UNS Electric Inc.'s Rider-14, Alternate Generation Service
19 is denied.

20 ...

21 ...

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23 ...

24 ...

25 ...

26 ...

27 ...

28 ...

1 IT IS FURTHER ORDERED that UNS Electric, Inc. is authorized to defer for future recovery,
 2 the following: (1) one hundred percent of the property taxes above or below the test year amount of
 3 property taxes, caused by increases or decreases to UNS Electric Inc.'s composite property tax rates;
 4 and (2) all property tax savings derived from appealing the property tax value of Gila River Unit 3,
 5 together with all attorney's fees, taxable costs, legal expenses and all other costs associated with the
 6 appeal process.

7 IT IS FURTHER ORDERED that this Decision shall become effective immediately.

8 BY ORDER OF THE ARIZONA CORPORATION COMMISSION.
 9

10
 11 CHAIRMAN LITTLE

COMMISSIONER STUMP

12
 13 COMMISSIONER FORESE

COMMISSIONER TOBIN

COMMISSIONER BURNS

14
 15 IN WITNESS WHEREOF, I, JODI JERICH, Executive Director
 16 of the Arizona Corporation Commission, have hereunto set my
 17 hand and caused the official seal of the Commission to be affixed
 18 at the Capitol, in the City of Phoenix, this _____ day
 19 of _____ 2016.

20 JODI A. JERICH
 21 EXECUTIVE DIRECTOR

22 DISSENT _____

23
 24 DISSENT _____
 25 JR:rt

SERVICE LIST FOR:

UNS ELECTRIC, INC.

DOCKET NO.:

E-04204A-15-0142

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