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Docket #(s): E-01461A-15-0363

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Exhibit #: Trico 2-10; 31-322

Part 2 of 3, to see Part 1 see Barcode 0000173057 to see Part 3 see Barcode 0000173059

BEFORE THE ARIZONA CORPORATION COMMISSION

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EXHIBIT
Trico-2
ADMITTED

COMMISSIONERS
DOUG LITTLE, CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	Docket No. E- 01461A-15-0363 **AMENDMENT TO APPLICATION**

Trico Electric Cooperative, Inc. ("Trico" or "the Cooperative"), hereby submits an amendment to its Application in this docket, as reflected in the attached Supplemental Direct Testimony of Vincent Nitido and David Hedrick. The Amendment proposes a modification to rate design that would apply to **all** residential and small commercial members. Trico is filing this Amendment in light of recent developments in other dockets pending before the Commission that have occurred since the filing of Application.

The modified rate design still proposes an increase in the monthly charge from $15.00 to $20.00 for standard residential service. The modified rate design now includes a fixed monthly demand charge of $4.00 based on a minimum billed demand of 2 kW at $2.00 per kW-month. The modified volumetric energy rates are now slightly lower than originally proposed. Under the modified rate design, an average residential member using 837 kWh would see a monthly bill increase of $1.94, from $116.84 to $118.80, or 1.66 percent, which is slightly lower than the bill impact under the original proposed rate design.

RESPECTFULLY SUBMITTED this 4th day of May, 2016.

SNELL & WILMER, L.L.P

By _____

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By Jaclyn Howard

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
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ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

Supplemental Direct Testimony of

Vincent Nitido

on Behalf of

Trico Electric Cooperative, Inc.

May 4, 2016

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico or "Cooperative")?

A. I am Chief Executive Officer and General Manager of Trico.

Q. Did you previously submit testimony in this docket?

A. Yes. I submitted Direct Testimony on October 25, 2015.

Q. What is the purpose of your supplemental testimony?

A. Trico is updating its proposed rate design to include a minimum demand charge for residential and small commercial customers. We believe that three-part rates that include a demand charge will be necessary in the future for fair and equitable allocation of the fixed costs of our grid as new technologies emerge and electric service evolves. Although Trico did not initially propose three-part rates in this docket, it is something we strongly considered. We also anticipated proposing three-part rates in our next rate case. However, given events in various Commission dockets since the filing of our rate case, we believe it is important to introduce three-part rates in a very limited manner now to begin the process of educating our members about their specific demand and about demand charges in general.

Q. What is Trico proposing?

A. Trico is proposing for all its residential and small commercial customers a three-part rate that includes a demand rate of $2 per kW-month for the first 2 kW of usage with a

minimum demand of 2 kW and $0.0 per kW-month for demand above 2 kW. Demand would be based on the member's highest 15-minute non-coincident peak demand during the month, which is consistent with the design of Trico's existing demand rates for commercial customers. The volumetric energy rates would be slightly lower than previously proposed. There would still be a $20 monthly customer charge. In connection with this proposal, Trico is proposing a minimum monthly 2 kW demand such that the minimum monthly bill would be $24 for all residential members that would include the $20 customer charge and 2 kW of demand at the $2.00 per kW-month demand rate. David Hedrick's Supplemental Direct Testimony provides more detail on the rate structure, the minimum bill aspect and the bill impacts.

Under our proposal, our members will be able to see what their demand is on a monthly basis between now and the next rate case. The rate design structure and the minimum bill approach will ensure that there are no unintended or unexpected consequences on a member's bill should they have an unusual high demand in a given month. Indeed, the monthly bill for the average Trico member will be the same under this updated rate design as under our initial two-part rate design.

In conjunction with this proposal, Trico will conduct parallel member education about the demand element of energy usage. We believe this approach will prepare our members for any modifications to three-part rates which would occur as part of our next rate case.

Q. What events at the Commission have caused Trico to seek this change?

A. Since the filing of our application in this docket on October 25, 2015, there has been significant activity in various Commission proceedings regarding rate design issues and net metering issues. In particular, Commission Staff and other parties have submitted

voluminous testimony in the UNS Electric rate case about mandatory three-part rates for residential and small commercial customers. They also have submitted testimony about potential modifications to net metering in both the UNS Electric rate case and the Sulphur Springs Valley Electric Cooperative ("SSVEC") rate case. Also, subsequent to our filing, the Commission has undertaken a hearing in the Value of Distributed Generation docket that is intended to develop a methodology to assess what compensation should be paid to rooftop solar owners for excess generation produced by rooftop systems.

Q. What is the significance of the UNS Electric rate case activity?

A. There are two significant aspects of that rate case – three-part rates and net metering. First, Commission Staff proposed mandatory three part rates for all residential and small commercial customers. Staff noted that three-part rates have many advantages for all customers including sending more accurate price signals, more accurately matching costs and revenues, and more effectively incentivizing customers to reduce peak demand on the system. Staff further stated that three-part rate designs better inform customers who are considering adopting new technologies, including the impact of those technology choices on their bill. According to Staff, three-part rate design makes significant progress towards addressing the issues presented by the difficult transition to DG technologies. However, as part of the move to three-part rates, Staff proposed a transition period that would allow for customer education and keeping the rate case open to be able to address any unintended consequences for "outlier" customers.

The opposition to three-part rates focused on potential customer confusion, the lack of customer education, the potential for "outlier" results for some customers and unintended consequences from atypical demand in a month. Moreover, there has been a significant

amount of misinformation about demand charges that has appeared in public comments in the UNS Electric docket – not to mention the Trico rate case docket.

As a result, at least two Commissioners have raised concerns about jumping to three-part rates that include a demand charge without sufficient education and without customers having sufficient information about their own demand.

Second, Staff declined to take a position on net metering changes, noting that the Value of Distributed Generation was scheduled and that the Staff's mandatory three-part rate proposal addressed much of the concern about DG and the recovery of fixed grid costs.

Q. What is the significance of the SSVEC rate case activity?

A. Because three-part rates were not an option in that case, Staff addressed SSVEC's proposed net metering modifications (which are similar to Trico's proposals). Although Staff supported the elimination of kWh banking in favor of providing bill credits for excess DG generation, Staff did not agree with SSVEC's proposal to compensate excess generation at avoided cost. Staff indicated compensation should be somewhere between avoided cost and retail rates.

Q. Why is Trico proposing this modified rate design?

A. There are two key reasons. First, Trico's member-elected Board of Directors believes customer education and a sufficient amount of customer-specific demand information must be provided to customers before the implementation of three-part rates, in order to ensure members are adequately informed of the operation of the rates and how they can manage their electric usage to provide the maximum benefit of such rates to themselves and the Cooperative. Second, to the extent Trico is able to sufficiently mitigate the DG cost shift

and to provide for more equitable recovery of fixed costs from all of our members, it better positions the Cooperative to encourage the development and application of demand-reduction measures and new technologies, including DG.

Trico believes that three part rates that include a demand component are the most accurate and equitable rate structure because they best reflect the components of electric service and send the most accurate price signals to consumers. As the electric service landscape evolves, three part rates will be absolutely necessary to equitably allocate the recovery of fixed costs, to encourage customer behavior that can reduce future costs (and rates) and to provide a level playing field to various current and emerging technologies.

Because Trico intended to propose meaningful three part rates in its next rate case, it has become apparent that Trico should to take steps in this rate case to facilitate member education about their demand and the structure of three part rates in a gradual manner - without creating a situation where there may be unintended consequences.

Moreover, Trico's proposal will begin to provide more equitable recovery of fixed cost and help to mitigate the cost shift because DG customers will be paying the 2 kW of demand minimum. Trico's decision to forego demand rates initially was based in part on the hope that the Commission would materially address the cost shift resulting from net metering.

Q. How does Trico's proposal avoid unintended consequences in this initial transition to three-part rates?

A. Under our proposal, members will not be billed for their actual demand. As a result, regardless of what their demand is for a given month, each member will pay only $4.00 for a 2 kW minimum of demand for that month. However, we intend to format the bill so that

customers can see what their actual peak demand was for the month. This information will also help Trico develop the three-part rate proposals for the next rate case and better understand potential bill impacts of future proposals.

Q. Why is Trico proposing a demand rate of $2.00 per kW-month?

A. The $2.00 per kW-month does not come close to covering the fixed costs of distribution facilities. Associating demand with an actual rate helps begin to educate members on how a demand rate is applied. The $2.00 per kW-month rate, while not intended to recover a substantial amount of Trico's fixed costs, is significant enough that members will likely pay attention to the rate and begin to ask questions.

Q. Why is 2 kW an appropriate amount to include as a minimum bill?

A. The vast majority of our members have a non-coincident peak demand of more than 2 kW in any given month. We did not want the minimum bill to recover a significant amount of demand that was not actually being imposed on the Trico system but, at the same time, be set at a meaningful level that members will pay attention to. It also provides some mitigation of the cost shift imposed by DG members and other low use members who are not paying their equitable share of the fixed costs. Moreover, this level results in a $24.00 minimum bill for residential customers, which is actually $3.00 less than the monthly customer charge that Staff is proposing for SSVEC.

Q. How is Trico's proposal educational for its members?

A. Trico intends to provide significant member education to its members between now and the next rate case. The information provided to members through education process will be facilitated by having a monthly bill that includes the member's specific demand and applies a demand rate to that demand. Members will be able to see their actual demand,

understand what actions may increase or decrease that demand and put education information in context.

Q. Will members still be able to save through energy efficiency?

A. Yes. The proposed demand rate (and the limit on billed demand) will reduce the volumetric energy charge only slightly. Reducing energy consumption will still save the member money. At the same time, the member will be able to see its demand and begin to understand how other energy efficiency approaches or changes in behavior could help save even more once more robust three part rates go into effect in the next rate case.

Q. Why not just undertake member education on demand rates before the next rate case without changing rate design now?

A. We believe this approach is more interactive with members and provides more incentive for members to understand three-part rates and demand charges. Our approach will provide information as part of an actual bill in the actual bill format in which demand charges are imposed. Simply providing demand information can be easily ignored.

Moreover, this approach also allows the recovery of fixed costs from DG and other low use customers who still use the grid. It helps to mitigate the cost shifts resulting from recovering fixed costs through volumetric rates.

Q. If the three-part rate design is adopted, is Trico still requesting modification to its net metering tariff?

A. Yes. As we have set forth in our Direct Testimony, the net metering tariff in combination with our current rate design results in inequitable recovery of fixed costs from our members. Our three-part rate proposal includes only a very nominal demand charge.

Trico will still be recovering the majority of its fixed costs through volumetric rates. As a result, unless the net metering tariff is modified, DG members will continue to avoid paying their fair share of fixed costs and those fixed costs will be shifted to non-DG customers.

Moreover, the Commission needs to address the net metering cost shift problem now in order to grandfather existing DG members under the current net metering tariff. Right now, the amount of cost shift that would be "locked in" is manageable and would not result in an undue burden on the non-DG members. However, if the Commission delays, the adverse or inequitable impact of grandfathering on other members may become too great.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
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IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

SUPPLEMENTAL DIRECT TESTIMONY

OF DAVID HEDRICK

ON BEHALF OF

TRICO ELECTRIC COOPERATIVE, INC.

MAY 4, 2016

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DWH-S3 Residential TOU Billing Comparison Alternate Schedule H-4.1
DWH-S4 General Service 1 Billing Comparison Alternate Schedule H-4.1
DWH-S5 Revised Proposed Tariffs

SUPPLEMENTAL TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David W. Hedrick and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. ARE YOU THE SAME DAVID HEDRICK THAT PROVIDED PRE-FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A. My supplemental testimony provides support for Trico's request to amend its original filing to request approval of a three-part demand rate design for the Residential, Residential Time-of-Use ("TOU") and General Service 1 rate classes.

Q. WHY IS TRICO PROPOSING A RATE DESIGN WHICH INCLUDES A DEMAND CHARGE FOR THESE RATE CLASSES?

A. As discussed in the Supplemental Direct Testimony of Vincent Nitido, the three-part demand rate design provides a more fair and equitable method of recovering the fixed costs of providing service, provides a step toward reducing subsidies between customers and reduces the impact of lost fixed costs from customers with installed DG. The events in other rate cases currently at the Arizona Corporation Commission ("Commission") and discussions with Commission staff have also factored into the decision to request the three-part rate design.

Q. PLEASE DESCRIBE THE PROPOSED THREE PART RATE DESIGN FOR THE RESIDENTIAL, RESIDENTIAL TOU AND GENERAL SERVICE RATES?

A. Trico is proposing to revise the rate designs for these rate classes by including a demand charge that consists of a $2 per kW-month charge for the first 2 kW of billing demand and $0 per kW-month for all demand in excess of 2 kW. The billing demand is defined as the member's highest 15-minute non-coincident peak demand during the month. The minimum billing demand is 2 kW. The originally proposed customer charges for each class remain the same. The energy charges have been reduced to produce the same revenue requirement as originally proposed.

Q. WHY IS THE DEMAND RATE STRUCTURED IN THIS WAY?

A. The rate is structured in this manner to allow for member education about the demand rate in preparation for transition to a more complete implementation of the demand rate in a future rate case. This approach reduces the fluctuation in member impact and unintended consequences as a result of the change in rate design. The $2 per kW-month charge on a minimum of 2 kW of billing demand effectively results in a $4 fixed demand charge for every customer under the proposed rate. This will allow members to see a minimum demand charge on their monthly bill and also to see the actual monthly billing demand amount prior to being billed based on those billing units. In Trico's next rate case, a charge for the excess billing demand could then be implemented.

Q. WHAT IS THE BASIS FOR THE 2 KW MINIMUM BILLING DEMAND?

A. The sample data of approximately 18,000 residential customers indicates that the average monthly billing demand is greater than 5 kW and approximately 2.3% of residential customer bills have monthly billing demand less than 2 kW. The 2 kW minimum was selected because it is considerably less than the average demand but it is sufficient in combination with the $2 per kW-month charge to recover a portion of demand costs and convey the concept of the demand rate. The intent was to introduce a minimal demand charge component that introduces the demand rate to members, reflects a fair recovery of demand costs from all customers and minimizes customer impact from the demand rate.

Q. WHAT IS THE BASIS FOR USING THE MEMBERS 15-MINUTE NON COINCIDENT PEAK (NCP) AS THE BILLING DEMAND?

A. This measure of demand is utilized by Trico for all of its other demand rates. The NCP demand is the maximum demand reading for any 15 minute interval in the monthly billing period. As discussed in my Direct Testimony, Trico's purchased power demand-related costs are fixed and do not vary based on consumption or the time period of consumption. Trico's distribution demand-related costs are also fixed and are established based on the total capacity requirements to serve load. Based on the fixed nature of these costs, it is most appropriate to recover those costs based on the NCP billing demand which ensures recovery of those costs from the customers that cause those costs.

Q. DOES THE USE OF THE NCP BILLING DEMAND HELP TO REDUCE THE LOST FIXED COSTS THAT RESULT FROM MEMBER OWNED DG?

A. Yes. As reflected on Exhibit DWH-8 of my Direct Testimony, Trico's existing Residential energy rate includes $0.049412 per kWh of fixed purchased power demand costs and $0.040954 per kWh of fixed distribution wires costs. The total lost fixed costs for a member with DG that produces an average of 922 kWh per month is $83.34 per customer. The application of the proposed demand rate based on an NCP billing demand will provide a recovery of those fixed demand related costs based on the member's actual peak demand which is reflective of the member's use of Trico's distribution resources and purchased power demand costs. Initially, the proposed demand rate will reduce the lost fixed costs by $4 per customer per month. As the cooperative more fully implements the demand rate in future rate cases, the lost fixed costs will be further reduced.

Additionally, since the NCP billing demand will be applied to all residential and small commercial customers, the demand rate will provide a recovery of lost fixed costs associated with customers other than those with DG such as vacant homes or customers that have otherwise reduced their energy usage.

Q. WOULD A TIME BASED DEMAND RATE BE A VIABLE OPTION FOR TRICO?

A. No. Utilizing a time based demand or coincident peak billing demand as the billing unit would allow consumers the ability to avoid fixed demand charges for which there is no corresponding reduction in cost for Trico. This would not be

equitable and would result in a similar lost fixed cost situation that exists with the current two-part rate.

Q. PLEASE DESCRIBE ALTERNATE SCHEDULE H-2.1?

A. Alternate Schedule H-2.1 provides the calculation of the proposed demand rate for each of the rate classes affected. The first 2 kW of billing demand is calculated as 2 times the number of customer billing units reflecting the minimum of 2 kW per customer. The customer charges remain as originally proposed and the energy charges have been reduced slightly to produce an overall revenue requirement that is slightly lower than originally requested.

Q. HAVE YOU PROVIDED BILLING COMPARISONS UNDER THE PROPOSED DEMAND RATE FOR EACH AFFECTED RATE?

A. Yes. Attached as Alternate Schedules 4.0, 4.1 and 4.2 are comparisons of the existing rate and the proposed demand rate for Residential, Residential TOU and General Service 1.

Q. HAVE YOU INCLUDED A REDLINE VERSION OF THE PROPOSED TARIFF SHEETS?

A. Yes. The redline versions of the proposed tariff sheets for each rate are attached.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit DWH – S1

TRICO ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF DEMAND RATES FOR RESIDENTIAL, RESIDENTIAL TOU AND GENERAL SERVICE 1 RATE CLASSES

		Alternate Proposed Demand Rate				Originally Proposed Rate	
	Billing Units	Power Supply	Distr. Wires	Total	Proposed Revenue	Proposed Rates	Proposed Revenue
Residential							
Consumers	454,052		20.00	20.00	9,081,040	20.00	9,081,040
First 2 kW (Min of 2 kW)	908,104		2.00	2.00	1,816,208	0.00	-
Over 2 kW	-			0.00	-	0.00	-
First 800 kWH/Mo.	254,553,885	0.07700	0.03580	0.11280	28,713,678	0.11760	29,935,537
Excess kWh	125,377,286	0.08700	0.03580	0.12280	15,396,331	0.12760	15,998,142
WPCA					(27,938)		(27,938)
Total	379,931,171				54,979,319		54,986,781
Residential TOU							
Consumers	33,520		24.00	24.00	804,480	24.00	804,480
First 2 kW (Min of 2 kW)	67,040		2.00	2.00	134,080	0.00	-
Over 2 kW	-			0.00	-	0.00	-
kWh - On Peak	10,257,451	0.12240	0.07172	0.19412	1,991,176	0.19790	2,029,950
kWh - Off Peak	25,192,421	0.06240	0.01172	0.07412	1,867,262	0.07790	1,962,490
WPCA					-		-
Total	35,449,872				4,796,999		4,796,919
General Service 1 - Single Phase							
Consumers	16,397		23.00	23.00	377,131	23.00	377,131
First 2 kW (Min of 2 kW)	32,794		2.00	2.00	65,588	0.00	-
Over 2 kW	-			0.00	-	0.00	-
kWh	9,355,588	0.07580	0.05089	0.12669	1,185,259	0.13370	1,250,842
WPCA					-		-
Total	9,355,588				1,627,978		1,627,973
General Service 1 - Three Phase							
Consumers	1,465		31.00	31.00	45,415	31.00	45,415
First 2 kW (Min of 2 kW)	2,930		2.00	2.00	5,860	0.00	-
Over 2 kW	-			0.00	-	0.00	-
kWh	1,276,535	0.07580	0.05089	0.12669	161,724	0.13370	170,673
WPCA					-		-
Total	1,276,535				212,999		216,088

Alternate
Schedule H-2.1

Exhibit DWH – S2

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING RATE AND ALTERNATE DEMAND RATE
RESIDENTIAL

kWh Usage	Billing kW	Existing Rate	Alternate Rate	Change	% Change
Customer Charge		$15.00	$20.00	$5.00	33.33%
First 2 kW (Minimum of 2 kW)		$0.00	$2.00	$2.00	
Excess kW		$0.00	$0.00	$0.00	
First 800 kWh/Month		$0.121600	$0.112800	($0.008800)	-7.24%
Next 800 kWh/Month		$0.121600	$0.122800	$0.001200	0.99%
PPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)	-100.00%
50	2.00	$21.08	$29.64	$8.56	40.61%
100	2.00	$27.17	$35.28	$8.11	29.85%
300	2.00	$51.50	$57.84	$6.34	12.31%
500	2.00	$75.84	$80.40	$4.56	6.01%
800	2.00	$112.34	$114.24	$1.90	1.69%
1,000	2.00	$136.67	$138.80	$2.13	1.56%
3,000	2.00	$380.02	$384.40	$4.38	1.15%
5,000	2.00	$623.37	$630.00	$6.63	1.06%
837 Average	2.00	$116.84	$118.78	$1.94	1.66%
750 Median	2.00	$106.25	$108.60	$2.35	2.21%

Exhibit DWH – S3

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND ALTERNATE DEMAND RATE
RESIDENTIAL-TOU

kWh Usage	Billing kW	On-Peak kWh	Off-Peak kWh	Existing Rate	Proposed Rate	Change	Percent Change
		29%	71%				
Customer Charge				$19.00	$24.00	$5.00	26.32%
First 2 kW					$2.00	$2.00	
Excess kW					$0.00	$0.00	
Energy Charge, per On-Peak kWh				$0.193200	$0.194120	$0.000920	0.48%
Energy Charge, per Off-Peak kWh				$0.073200	$0.074120	$0.000920	1.26%
PPCA Factor, per kWh				$0.000073	$0.000000	($0.000073)	-100.00%
50	2	14	36	$24.34	$33.39	$9.05	37.18%
100	2	29	71	$29.81	$38.89	$9.08	30.46%
300	2	87	213	$51.42	$60.68	$9.26	18.01%
500	2	145	355	$73.04	$82.46	$9.42	12.90%
800	2	231	569	$105.34	$115.02	$9.68	9.19%
1,000	2	289	711	$126.95	$136.80	$9.85	7.76%
3,000	2	867	2,133	$342.86	$354.40	$11.54	3.37%
5,000	2	1,445	3,555	$558.77	$572.00	$13.23	2.37%
1,058 Avg	2	306	752	**$133.24**	$143.14	**$9.90**	**7.43%**
698 Median	2	202	496	**$94.38**	$103.98	**$9.60**	**10.17%**

Exhibit DWH – S4

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND ALTERNATE DEMAND RATE
GENERAL SERVICE 1

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$23.00	$5.00	27.78%
Customer Charge, Three Phase			$26.00	$31.00	$5.00	19.23%
First 2 Billing kW per month			$0.00	$2.00	$2.00	
Over 2 Billing kW per month			$0.00	$0.00	$0.00	
Energy Charge, per kWh			$0.133500	$0.126690	($0.006810)	-5.10%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
			Single Phase			
10.00%	2.0	146	$37.50	$45.50	$8.00	21.33%
20.00%	2.0	292	$57.00	$63.99	$6.99	12.26%
30.00%	2.0	438	$76.50	$82.49	$5.99	7.83%
40.00%	2.0	584	$96.01	$100.99	$4.98	5.19%
50.00%	2.0	730	$115.51	$119.48	$3.97	3.44%
Average	**2.00**	**570**	**$94.14**	$99.21	**$5.07**	**5.39%**
Median	**2.00**	**349**	**$64.62**	$71.21	**$6.59**	**10.20%**
			Three Phase			
10.00%	2.0	146	$45.50	$53.50	$8.00	17.58%
20.00%	2.0	292	$65.00	$71.99	$6.99	10.75%
30.00%	2.0	438	$84.50	$90.49	$5.99	7.09%
40.00%	2.0	584	$104.01	$108.99	$4.98	4.79%
50.00%	2.0	730	$123.51	$127.48	$3.97	3.21%
Average	**2.00**	**871**	**$142.34**	$145.35	**$3.01**	**2.11%**
Median	**2.00**	**546**	**$98.93**	$104.17	**$5.24**	**5.30%**

Exhibit DWH – S5

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

RESIDENTIAL SERVICE
SCHEDULE RS1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Residential Service Rate (RS1) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

STANDARD RATE RS1	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.23	$0.98	$6.33	$7.46	$20.00	$20.00
Three-Phase		$5.23	$0.98	$6.33	$7.46	$20.00	$20.00
Demand Charge ($/kW)							
First 2 kW/month	$0.00				$2.00	$2.00	$2.00
Over 2 kW/month	$0.00				$0.00	$0.00	$0.00
Energy Charge ($/kWh)							
First 800 kWh/month	$0.0770				$0.035~~840~~6	$0.03584~~06~~	$0.11287~~6~~
Over 800 kWh/month	$0.0870				$0.035~~840~~6	$0.03584~~06~~	$0.12287~~6~~

The Billing Demand shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customer's highest 15-minute interval demand for the billing month. In no event shall the Billing Demand be less than 2 kW.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge plus the Demand Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE RS2TOU

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Residential Time of Use Service Rate (RS2TOU) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

TIME-OF-USE RATE RS2TOU	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)								
Single Phase			$11.18	$0.98	$6.33	$5.51	$24.00	$24.00
Three Phase			$11.18	$0.98	$6.33	$5.51	$24.00	$24.00
Demand Charge ($/kW)								
First 2 kW per month	$0.00					$2.00	$2.00	$2.00
Over 2 kW per month	$0.00					$0.00	$0.00	$0.00
Energy Charge ($/kWh)								
On-Peak kWh	$0.1224					$0.~~075500~~ 7172	$0.~~07550~~ 07172	$0.19~~412~~ ~~79~~ 07412
Off-Peak kWh	$0.0624					$0.01~~1721~~	$0.01172	

			~~550~~	550	~~79~~

The Billing Demand shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customer's highest 15-minute interval demand for the billing month. In no event shall the Billing Demand be less than 2 kW.

RESIDENTIAL TIME OF USE SERVICE SCHEDULE (RS2TOU)

Definition of On-Peak

April 1 through October 31: For this rate schedule, on-peak hours are 1:00 p.m. to 9:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

November 1 through March 31: For this rate schedule, on-peak hours are 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge plus the Demand Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE (RS2TOU)

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

***Definition of Holidays**

Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. If a Holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a Holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 10 kW Rate (GS1) is applicable for single and three phase service for more than one residence from a single metering point, where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters and has a monthly demand of less than 10 kW. All service shall be delivered at a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Demand Charge ($/kW)							
First 2 kW per Month	$0.00				$2.00	$2.00	$2.00
Over 2 kW per Month	$0.00				$0.00	$0.00	$0.00
Energy Charge ($/kWh)	$0.0758				$0.057905 089	$0.05089 ~~79~~	$0.126693 ~~37~~

The Billing Demand shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customer's highest 15-minute interval demand for the billing month. In no event shall the Billing Demand be less than 2 kW.

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge plus the Demand Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

EXHIBIT
Trico-3
ADMITTED

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363 **STAFF'S NOTICE OF FILING SETTLEMENT AGREEMENT**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), on behalf of the Signatory Parties of the Settlement Agreement ("Agreement"), files the Agreement in the above referenced matter.

RESPECTFULLY SUBMITTED this 8th day of July, 2016.

Maureen A. Scott, Senior Staff Counsel
Matthew Laudone, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 8th day of July, 2016, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

...

...

Copy of the foregoing emailed/mailed
this 8th day of July, 2016 to:

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TRICO ELECTRIC COOPERATIVE, INC.

SETTLEMENT AGREEMENT

DOCKET NO. E-01461A-15-0363

JULY 8, 2016

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Attachments:

Attachment A — Revenue Proof, the Revenue Allocation, and the Average Residential Bill Impact Summary

Attachment B — Plan of Administration for Wholesale Power Cost Adjustor

Attachment C — Tariffs

Attachment D — Rules and Regulations and Line Extension Policy

SETTLEMENT AGREEMENT
DOCKET NO. E-01461A-15-0363
TRICO ELECTRIC COOPERATIVE, INC. RATE CASE

The purpose of this Settlement Agreement ("Agreement") is to settle all issues related to Docket No. E-01461A-15-0363, Trico Electric Cooperative, Inc.'s General Rate Case Application. This Agreement is entered into by the following entities:

Trico Electric Cooperative, Inc. ("Trico" or "Company")
Arizona Corporation Commission Utilities Division Staff ("Staff")

These entities shall be referred to collectively as "Signatories;" a single entity shall be referred to individually as a "Signatory." Other Parties may sign on at any time by filing a letter in this Docket indicating their desire to join in the Agreement and attaching a Signature page executed by the Party.

I. RECITALS

1.1 Trico filed an application for a determination of the current fair value of its utility plant and property and for an increase in its rates and charges on October 23, 2015. The application was subsequently assigned Docket No. E-0146A-15-0363. Staff notified Trico on November 30, 2015, that its Application met the sufficiency requirements of A.A.C. R14-2-103. Staff classified Trico as a Class A utility.

1.2 Subsequently, the Arizona Corporation Commission ("Commission") granted intervention to Freeport Minerals Corporation & Arizonans for Electric Choice and Competition (collectively "AECC"), the Energy Freedom Coalition of America ("EFCA"), Pima County through the Pima County Attorney's Office ("Pima County"), and Robert Hall *in pro persona.* (together with Trico and Staff, the "Parties").

1.3 On May 4, 2016, Trico filed an Amendment to its Application that proposed a revised rate design for residential and small commercial members.

1.4 Staff and other parties filed Direct Testimony on non-rate design issues on May 4, 2016. On June 1, 2016, Staff and other parties filed Direct Testimony on rate design and cost of service issues.

1.5 Staff filed a notice of settlement discussions on June 14, 2016. A meeting to discuss a possible settlement took place on June 17, 2016. The settlement

discussions were open, transparent, and inclusive of all Parties to this Docket who desired to participate. All Parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an opportunity to participate. Parties present at the meeting included Trico, Staff, EFCA and Robert Hall. The remaining Parties participated or had the ability to participate telephonically.

1.6 Staff and Trico reached an agreement in principle on June 17, 2016, which was subsequently memorialized in a Term Sheet.

1.7 Since the June 17, 2016 meeting, settlement proposals have been submitted by other Parties on issues that have been considered and evaluated by Staff and Trico.

1.8 The Signatories believe that the terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for Trico members; promote the convenience, comfort and safety, and the preservation of health, of the employees and members of Trico; and fairly and equitably resolve the issues arising from this Docket.

1.9 The Signatories believe that this Agreement balances the interests of both Trico and its customers. The significant provisions of this Agreement include:

- A modest revenue increase as proposed by Trico.
- A class revenue allocation that moves rates to levels that more closely reflect class cost.
- Updating Trico's base cost of power and the Wholesale Power Cost Adjustor.
- A rate design that is designed to recover costs in a manner that better reflects how Trico incurs its costs of service.
- Introduction of a demand rate component (at a $0.00 per-kW rate) that allows for an extended period of time for customer education regarding demand rates without any bill impacts.
- An aggressive customer education program designed to better inform customers of their electricity usage and technology options available to

customers so that the members can better control their costs and usage. This includes access by members to Trico's Smart Hub.

- Freezing of the current net metering tariff and adoption of a DG Energy Export Rate applicable to new DG customers.

- Grandfathering of the current net metering tariff for members who had DG interconnection applications submitted by May 31, 2016 so they remain on the current net metering tariff.

- Requiring Trico to propose additional demand-reduction programs for the benefit of its members and simplifying energy efficiency reporting requirements.

- An agreement that Trico's next rate case will reflect a test year no earlier than the 12 month period ending June 30 2018.

1.10 The Signatories ask the Commission to (1) find that the rates, terms and conditions of this Agreement are just and reasonable and in the public interest, along with any and all other necessary findings, and (2) approve the Agreement such that the resulting rates may become effective on January 1, 2017.

TERMS AND CONDITIONS

II. RATE INCREASE

2.1 Trico shall receive a base rate increase of $2,282,076 (or approximately 2.61%) over adjusted test-year retail revenues, reflecting a total revenue requirement of $89,762,812.

2.2 Trico's revenue requirement reflects the increase requested in its Application plus an increase in rate case expense over the amount initially requested. The increase in rate case expense remains subject to Staff's review of Trico invoices supporting the rate case expenses. Total rate case expense shall be capped at $450,000.

2.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $175,076,536. Trico utilized its original cost rate base as its fair value rate base. The jurisdictional fair value rate base includes Direct Assignment Facilities ("DAFS") which Trico has agreed to purchase from the Arizona Electric Power Cooperative, Inc. ("AEPCO").

2.4 The revenue requirement and fair value rate base result in a rate of return of 6.33% on fair value rate base. It also results in a net operating Times Interest Earned Ratio ("TIER") of 2.00 and a Debt Service Coverage ("DSC") of 1.87.

III. BILL IMPACT

3.1 Upon the effective date of the new rates, the monthly bill for a residential customer, using the annual average of 837 kWh per month, will increase by approximately $2.05 from $116.84 to $118.89, which is a 1.75% increase.

3.2 The Revenue Proof, the Revenue Allocation, and the Average Residential Bill Impact summary are appended hereto as **Attachment A.**

IV. WHOLESALE POWER COST ADJUSTOR ("WPCA")

4.1 Trico's existing base cost of power will be reset to: (i) include the current cost for wholesale power and transmission in Trico's base rates; (ii) incorporate the small reduction in rates for Trico customers due to the net impact of Trico's acquisition of DAFs; and (iii) reflect recovery of the total adjusted purchased power cost.

4.2 Trico's new base cost of power is $0.081711 per kWh.

4.3 Trico will adopt a Plan of Administration for its WPCA as set forth in **Attachment B**.

V. CLASS REVENUE ALLOCATION

5.1 The revenue allocation for each customer class will be established as Trico proposed in its Application submitted October 23, 2015.

VI. RATE DESIGN

6.1 Parties agree to the rate design as set forth in the proposed tariffs attached in **Attachment C** and as further discussed in this section below.

6.2 Standard non-TOU Residential rates (Rate Schedule RS1) will be a three-part rate design and include: (a) a $24.00 per month basic service charge; (b) a 24/7 member peak demand rate of $0.00 per kilowatt (kW), with no minimum demand – with peak demand defined, for purposes of this Agreement, as the highest 15-minute interval demand during the month; and (c) energy charges as set forth in **Attachment C.**

6.3 Trico will freeze Rate Schedule RS2TOU to prevent any customers from being added on that rate schedule. Rates will be adjusted to reflect the new revenue requirement and class revenue allocation as set forth in this Agreement. Trico will provide notice to its members that it will propose to eliminate this rate schedule in its next rate case.

6.4 Rate Schedule GS1 (Single Phase) will be a three-part rate design and include: (a) a $27.00 per month Basic Service Charge; (b) a 24/7 member peak demand rate of $0.00 per kilowatt (kW), with no minimum demand – with peak demand meaning, for purposes of this Agreement, the highest 15-minute interval demand during the month; and (c) energy (per-kWh) rates as reflected in **Attachment C**.

6.5 Rate Schedule GS1 (Three Phase) will be a three-part rate design and include: (a) a $35.00 per month Basic Service Charge; (b) a 24/7 member peak demand rate of $0.00 per kilowatt (kW), with no minimum demand – with peak demand meaning, for purposes of this Agreement, the highest 15-minute interval demand during the month; and (c) energy (per-kWh) rates as reflected in **Attachment C**.

6.6 Due to Trico's need to modify its billing system and metering, Trico will begin including demand information on residential (RS1) and small commercial (GS1) customer bills no later than six months from the effective date of the Commission's decision approving this Agreement.

6.7 Rate Schedules GS2, GS3, and GS4 and other Tariffs will be as proposed in the Application submitted October 23, 2015 and updated to reflect the revenue requirement set forth in this Agreement and to adjust the Basic Service Charge for GS2 and GS3 consistent with the GS1 as reflected in **Attachment C**.

6.8 Rate Schedules IS1 and IS2 will be combined into one rate schedule, known as IS1, and will be frozen as of the date of the Decision in this Docket. Trico agrees to notify customers of this change.

VII. NET METERING

7.1 Trico will freeze the current net metering tariff, so that it will be unavailable to members whose DG interconnection applications are received after May 31, 2016.

7.2 The Signatories to this Agreement agree that, with respect to interconnection applications received after May 31, 2016, a new DG Energy Export Tariff

will apply in lieu of the current net metering tariff. The new DG Energy Export Tariff is described below in Section VIII and included in **Attachment C.**

7.3 The Signatories agree to support Trico's request for a waiver of the net metering rules, to the extent necessary so that the new DG Energy Export Tariff can take effect as set forth in this Agreement.

VIII. NEW DG ENERGY EXPORT TARIFF

8.1 The new DG Energy Export Tariff will apply as a rider to all DG interconnection applications received after May 31, 2016 ("new DG member").

8.2 The export rate, for energy generated from a new DG member's system and delivered back to Trico ("excess energy"), will be set at $0.0770 per kWh. All excess energy from a new DG member will be credited to the member for the billing period at the export rate. Further, the Signatories agree that the export rate is the equivalent of Trico's power supply portion of the energy charge for the first tier of the proposed RS1. The cost of the export rate will be recovered through Trico's WPCA in accordance with the WPCA POA.

8.3 The energy supplied to all DG members (including new DG members) during the billing period will be billed by Trico in accordance with the rates and charges under the members' standard rate schedule. For new DG members, no netting or banking of kWh will occur during the month.

8.4 For new DG members, if credits resulting from the export rate are greater than the member's monthly bill, then that credit balance will carry forward to the following month. If there is any credit remaining at year-end, it shall be paid out at that time.

8.5 The DG export rate will work as a rider in conjunction with all of Trico's rate schedules.

8.6 The Signatories agree to support this general rate case docket being held open for 18 months from the effective date of the Commission's decision approving this Agreement to allow for the possible modification of the export rate, at Trico's or the Commission Staff's discretion, after a methodology or methodologies has been determined in Docket No. E-00000J-14-0023 (*In the matter of the Commission's Investigation of Value and Cost of Distributed Generation)*. If either Staff or Trico request a modification of the export rate,

the Signatories agree that any new rate proposed will be subject to an expedited hearing, if requested, and review and approval by the Commission.

IX. GRANDFATHERING

9.1 In concert with Sections VII and VIII of this Agreement, all Trico members who applied for DG interconnection on or before May 31, 2016 will be grandfathered on the current net metering tariff at least until the Commission issues a decision in Trico's next rate case and with the expectation that grandfathering will continue for the remaining term of the member's interconnection agreement or for 20 years, whichever is shorter. Grandfathering applies to the same service location with the same DG system.

9.2 Grandfathering only applies to the current net metering tariff as set forth in Section 9.1 above.

9.3 The Signatories agree to not support further grandfathering of the existing net metering tariffs for DG interconnection applications received after May 31, 2016.

X. MEMBER EDUCATION PROGRAM

10.1 Following the effective date of the Commission decision approving this Agreement, Trico will conduct member outreach and education regarding demand rates.

10.2 The member outreach and education will include, at a minimum: (a) the nature and operation of demand rates; (b) how members can utilize demand rates to reduce monthly bills; and (c) information on tools available from Trico and third parties to help members to manage demand (including Trico's Smart Hub® application).

10.3 Each Trico member's bill will indicate the date and time of the member's peak demand for the billing period.

10.4 Trico's education materials will highlight technology solutions including programmable thermostats and load controllers as means that could be used to minimize demand charges and monthly bills.

XI. ENERGY EFFICIENCY

11.1 Trico will propose at least two demand-reduction programs in its next Energy Efficiency Implementation Plan, which will be filed on or before June 1, 2017. These programs, to the extent possible, should act in concert with the demand-rate education program established in Section X of this Agreement.

XII. TRICO'S FILING OF ITS NEXT GENERAL RATE CASE

12.1 Trico agrees that its next rate case will reflect a test year no earlier than the 12-month period ending June 30, 2018. Trico will utilize data obtained by tracking member demand following the implementation of the initial $0.00 per-kW demand rate, in order to determine an appropriate demand rate to propose in its next rate case.

12.2 Trico agrees to propose a demand rate for RS1 and GS1 in the next rate case that is no higher than $2.00 per kW, and it will reflect a portion of distribution-demand fixed-cost component of Trico's cost of service.

12.3 As part of the application in its next general rate case, Trico will: (a) present a study of the impact of billing demand on a 15-minute interval versus a 60-minute interval; and (b) discuss customer usage and demand profile to the extent available.

12.4 The Signatories recognize that the ultimate success of a three-part rate will be dependent upon the success of Trico's educational programs and its ability to help customers navigate through the technological options that are available to assist them in controlling their demand and energy usage. The Signatories recognize that alternative options may need to be considered in the next rate case.

XIII. ADDITIONAL SETTLEMENT PROVISIONS

13.1 Trico will provide as a compliance filing a notice of the completion of the acquisition of the Direct Assignment Facilities.

13.2 The Signatories agree to the Depreciation Rates proposed by Trico in its Application submitted October 23, 2015.

13.3 Trico will revise its DG interconnection agreements for leased and owned systems to incorporate language that customers may be charged a return trip fee for a return trip to inspect installations of DG interconnections where the return trip is due to a customer or installer issue.

13.4 Trico's Rules and Regulations shall be revised as set forth in **Attachment D**.

13.5 The reporting requirements as set forth in A.A.C. R14-2-2409 shall supplant and replace any energy efficiency reporting requirements for Trico in Decision No. 71230, and any energy conservation plan requirements for Trico in A.A.C. R14-2-213. Trico will no longer be required to submit separate reports in accordance with Decision No. 71230 and A.A.C. R14-2-213 upon approval of this Agreement.

XIV. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

14.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

14.2 The Signatories recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

14.3 This Agreement shall serve as a procedural device by which the Signatories will submit to the Commission their proposed settlement of Trico's pending rate case, Docket No. E-01461A-15-0363.

14.4 The Signatories recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signatories shall abide by the terms as approved by the Commission.

14.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies at law. For purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement. If a Signatory withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signatories, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signatory's application for rehearing.

XV. MISCELLANEOUS PROVISIONS

15.1 This case has attracted participants with diverse interests. To achieve consensus for settlement, Signatories may be accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with their long-term interests and with the broad public interest. The acceptance by any Signatory of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

15.2 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signatory shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court.

15.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signatories may be referred to, cited, and/or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.

15.4 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.

15.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

15.6 The Signatories shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement for the rates to become effective on January 1, 2017. The Signatories shall support and defend this Agreement before the Commission. Subject to Paragraph 14.5 above, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

15.7 This Agreement may be executed in any number of counterparts and by each Signatory in separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION STAFF

By _____
Thomas M. Broderick

Title Director, Utilities Division

Date July 8, 2016

TRICO ELECTRIC COOPERATIVE, INC.

By _____
Vincent Nitido

Title CEO/General Manager

Date July 8, 2016

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ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION STAFF

By_____
Thomas M. Broderick

Title____Director, Utilities Division____

Date____July 8, 2016____

TRICO ELECTRIC COOPERATIVE, INC.

By_____
Vincent Nitido

Title____CEO/General Manager____

Date____July 8, 2016____

ATTACHMENT A

TRICO ELECTRIC COOPERATIVE, INC.

INCOME STATEMENT -SETTLEMENT
DECEMBER 31, 2014

	Test Year 12/31/2014 (c)	Adjustments (d)	Adjusted Test Year (e)	Rate Change (f)	Adjusted Test Year w/ Rate Change (g)
Operating Revenues					
Base Revenue	$ 87,113,729	$ (1,296,163)	$ 85,817,566	$ 2,282,076	$ 88,099,642
WPCA Revenue		42,073	42,073		42,073
Fuel Bank	(1,556,638)	1,556,638	0		0
Other	1,598,596	22,501	1,621,097		1,621,097
Total	$ 87,155,687	$ 325,049	$ 87,480,736	$ 2,282,076	$ 89,762,812
Operating Expenses					
Power Production	$ 29,067	$ (3,741)	$ 25,326	$	$ 25,326
Purchased Power	51,586,301	750,858	52,337,159		52,337,159
Transmission O&M	59,857	(54,811)	5,046		5,046
Distribution-Operations	8,200,654	(3,290,766)	4,909,888		4,909,888
Distribution-Maintenance	1,760,940	43,727	1,804,667		1,804,667
Consumer Accounting	2,431,189	46,634	2,477,823		2,477,823
Customer Service	347,586	6,870	354,456		354,456
Sales	306,765	(1,036)	305,729		305,729
Administrative & General	5,324,461	144,636	5,469,097		5,469,097
Depreciation	6,559,506	685,108	7,244,614		7,244,614
Tax	3	3,742,813	3,742,816		3,742,816
Total	$ 76,606,329	$ 2,070,292	$ 78,676,621	$ 0	$ 78,676,621
Return	$ 10,549,358	$ (1,745,243)	$ 8,804,115	$ 2,282,076	$ 11,086,191
Interest & Other Deductions					
Interest L-T Debt	$ 4,866,587	$ 121,844	$ 5,088,431	$	$ 5,088,431
Interest-Other	2,364	0	2,364		2,364
Other Deductions	966,265	(59,300)	906,965		906,965
Total	$ 5,935,216	$ 62,544	$ 5,997,760	$ 0	$ 5,997,760
Operating Margin	$ 4,614,142	$ (1,807,787)	$ 2,806,355	$ 2,282,076	$ 5,088,431
Non-Operating Margins					
Interest Income	$ 198,590	$	$ 198,590	$	$ 198,590
Other Margins	114,633		114,633		114,633
G&T Capital Credits	4,552,806		4,552,806		4,552,806
Other Capital Credits	464,817		464,817		464,817
Total	$ 5,330,846	$ 0	$ 5,330,846	$ 0	$ 5,330,846
Net Margins	$ 9,944,988	$ (1,807,787)	$ 8,137,201	$ 2,282,076	$ 10,419,277
Operating TIER	1.93		1.55		2.00
Net TIER	3.00		2.60		3.05
Net TIER Excl Capital Credits	2.91		2.51		2.96
CFC DSC	1.82		1.69		1.94
Rate of Return	6.12%		5.028723%		6.33%
Rate Base	$ 172,476,155	$ 2,600,381	$ 175,076,536	$ 0	$ 175,076,536
Principal Payments	4,222,676		4,222,676		4,222,676
Percent Change to Adjusted TY Total Revenue					2.61%

Supporting Schedules:
B-2.0, C-1.0, C-2.0

Recap Schedules:
A-1.0

TRICO ELECTRIC COOPERATIVE, INC.

RATE CASE EXPENSE ADJUSTMENT- SETTLEMENT

Rate Case Expense	$	450,000.00
Number of Years to Amortize		3
Annual Expense	$	150,000.00
Test Year Amount		0.00
Adjustment	$	150,000.00

Recap Schedules:
C-2.0, C-2.1

TRICO ELECTRIC COOPERATIVE, INC.

ANALYSIS OF REVENUE BY DETAILED CLASS - SETTLEMENT

	Average Consumers	Average Monthly kWh Sold	Total kWh Sold	Adjusted Revenue	Proposed Revenue	Change	Percent Change
Residential	37,838	836	379,931,171	52,815,725	55,028,710	2,212,985	4.19%
Residential-TOU	2,793	1,058	35,449,872	4,446,579	4,801,607	355,028	7.98%
GS1 - 1Ph	1,366	570	9,355,588	1,559,607	1,629,195	69,588	4.46%
GS1 - 3Ph	122	871	1,276,535	210,252	213,165	2,913	1.39%
Substotal GS1	1,488	595	10,632,123	1,769,859	1,842,360	72,501	4.10%
GS2 - 1Ph	98	2,274	2,630,469	424,454	453,085	28,631	6.75%
GS2 - 3Ph	153	4,456	8,157,808	1,396,091	1,472,343	76,252	5.46%
Subtotal GS2	251	3,582	10,788,277	1,820,545	1,925,428	104,883	5.76%
GS3 - 1Ph	117	6,319	8,879,750	1,188,258	1,153,831	(34,427)	-2.90%
GS3 - 3Ph	302	28,865	104,685,742	13,838,193	13,308,466	(529,727)	-3.83%
Subtotal GS3	419	22,587	113,565,492	15,026,451	14,462,297	(564,154)	-3.75%
GS TOU	11	9,820	1,296,284	171,225	172,649	1,424	0.83%
GS4	5	1,694,897	101,693,786	7,243,143	7,243,143	0	0.00%
Water Pumping-1Ph	11	1,414	186,573	27,680	30,356	2,676	9.67%
Water Pumping-3Ph	48	5,503	3,143,032	437,041	471,324	34,283	7.84%
Subtotal Water Pumping	59	4,703	3,329,605	464,721	501,680	36,959	7.95%
Irrigation	11	1,982	261,544	38,364	41,762	3,398	8.86%
ToD Pumping-1Ph	2	14,741	353,776	22,852	24,607	1,755	7.68%
ToD Pumping-3Ph	27	16,470	5,371,245	599,043	622,517	23,474	3.92%
Subtotal ToD Pumping	29	16,451	5,725,021	621,896	647,124	25,229	4.06%
Interruptible - Comm	2	141,248	3,573,369	332,577	347,585	15,008	4.51%
Interruptible - Pumping	18	34,303	7,331,315	815,855	829,763	13,908	1.70%
Subtotal Interruptible	20	45,436	10,904,684	1,148,432	1,177,348	28,916	2.52%
Lighting	0	0	539,888	142,334	147,243	4,909	3.45%
Subtotal Energy Sales	42,924		674,117,747	85,709,274	87,991,351	2,282,077	2.66%
Supplemental Wheeling				150,365	150,365	0	0.00%
Total Energy Sales				85,859,639	88,141,716	2,282,077	2.66%
Other Revenue				1,621,097	1,621,097	0	0.00%
Total Revenue				87,480,736	89,762,813	2,282,077	2.61%

Supporting Schedules:
E-7.1, E-7.2, E-7.5, E-7.5.1

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
1. RESIDENTIAL							
Consumers (12-month sum)	454,052	0.00	24.00	24.00	0	10,897,248	10,897,248
Demand Charge		0.00	0.00	0.00	0	0	0
First 800 kWh/Mo.	254,553,885	0.077000	0.035930	0.112930	19,600,649	9,146,121	28,746,770
Excess kWh	125,377,286	0.087000	0.035930	0.122930	10,907,824	4,504,806	15,412,630
Net Metering Credits					(27,938)		(27,938)
Subtotal	379,931,171				30,480,535	24,548,175	55,028,710
PCA					0		0
Total					30,480,535	24,548,175	55,028,710
2. RESIDENTIAL - TOU							
Consumers (12-month sum)	33,520	0.00	28.00	28.00	0	938,560	938,560
Demand Charge		0.00	0.00	0.00	0	0	0
kWh - On Peak	10,257,451	0.122400	0.071850	0.194250	1,255,512	736,998	1,992,510
kWh - Off Peak	25,192,421	0.062400	0.011850	0.074250	1,572,007	298,530	1,870,537
Subtotal	35,449,872				2,827,519	1,974,088	4,801,607
PCA					0		0
Total					2,827,519	1,974,088	4,801,607

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
3. GENERAL SERVICE (1)							
Single Phase							
Consumers (12-month sum)	16,397	0.00	27.00	27.00	0	442,719	442,719
Demand Charge		0.00	0.00	0.00	0	0	0
kWh	9,355,588	0.075800	0.051020	0.126820	709,154	477,322	1,186,476
Subtotal					709,154	920,041	1,629,195
PCA					0		0
Total					709,154	920,041	1,629,195
Three Phase							
Consumers (12-month sum)	1,465	0.00	35.00	35.00	0	51,275	51,275
Demand Charge		0.00	0.00	0.00	0	0	0
kWh	1,276,535	0.075800	0.051020	0.126820	96,761	65,129	161,890
Minimum Bill					0	0	0
Subtotal					96,761	116,404	213,165
PCA					0		0
Total					96,761	116,404	213,165
Total Base Revenue	10,632,123				805,915	1,036,445	1,842,360
Total PCA Revenue					0	0	0
Total Revenue					805,915	1,036,445	1,842,360

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
4. GENERAL SERVICE (2)							
Single Phase							
Consumers (12-month sum)	1,174	0.00	27.00	27.00	0	31,698	31,698
First 10 kW per month	10,522.45	0.00	0.00	0.00	0	0	0
Excess kW per month	7,987.53	4.50	0.00	4.50	35,944	0	35,944
kWh	2,630,469	0.094400	0.052130	0.146530	248,316	137,126	385,443
Subtotal					284,260	168,824	453,085
PCA					0		0
Total					284,260	168,824	453,085
Three Phase							
Consumers (12-month sum)	1,836	0.00	35.00	35.00	0	64,260	64,260
First 10 kW per month	16,932.62	0.00	0.00	0.00	0	0	0
Excess kW per month	47,270.97	4.50	0.00	4.50	212,719	0	212,719
kWh	8,157,808	0.094400	0.052130	0.146530	770,097	425,267	1,195,364
Minimum Bill					0	0	0
Subtotal					982,816	489,527	1,472,343
PCA					0		0
Total					982,816	489,527	1,472,343
Total Base Revenue	10,788,277				1,267,076	658,351	1,925,428
Total PCA Revenue					0	0	0
Total Revenue					1,267,076	658,351	1,925,428

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
5. GENERAL SERVICE (3)							
Single Phase							
Consumers (12-month sum)	1,405	0.00	27.00	27.00	0	37,935	37,935
Billing kW	24,980	15.00	3.00	18.00	374,707	74,941	449,648
kWh	8,879,750	0.040100	0.034930	0.075030	356,078	310,170	666,248
Minimum Bill							
Subtotal					730,785	423,046	1,153,831
PCA					0		0
Total					730,785	423,046	1,153,831
Three Phase							
Consumers (12-month sum)	3,625	0.00	35.00	35.00	0	126,875	126,875
Billing kW	295,946	15.00	3.00	18.00	4,439,183	887,837	5,327,020
kWh	104,685,742	0.040100	0.034930	0.075030	4,197,898	3,656,673	7,854,571
Minimum Bill							
Subtotal					8,637,081	4,671,385	13,308,466
PCA					0		0
Total					8,637,081	4,671,385	13,308,466
Total Base Revenue	113,565,492				9,367,866	5,094,431	14,462,297
Total PCA Revenue					0	0	0
Total Revenue					9,367,866	5,094,431	14,462,297

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
6. GENERAL SERVICE TOU							
Consumers 1 PH (12-month sum)	60	0.00	33.00	33.00	0	1,980	1,980
Consumers 3 PH (12-month sum)	72	0.00	41.00	41.00	0	2,952	2,952
NCP Billing kW	4,649.46	0.00	5.95	5.95	0	27,664	27,664
CP Billing kW	1,843.00	29.50	0.00	29.50	54,369	0	54,369
kWh	1,296,284	0.046000	0.020100	0.066100	59,629	26,055	85,684
Subtotal					113,998	58,651	172,649
PCA					0		0
Total					113,998	58,651	172,649
7. GENERAL SERVICE (4)							
Consumers (12 month sum)	60	0.00	500.00	500.00	0	30,000	30,000
Secondary Meters (12 month sum)	456	0.00	40.00	40.00	0	18,240	18,240
Facilities Charge		0.00	0.00	0.00	0	422,282	422,282
NCP Billing kW-Transmission	20,400	0.00	0.21	0.21	0	4,284	4,284
NCP Billing kW-Distribution Sub	25,125	0.00	1.75	1.75	0	43,968	43,968
NCP Billing kW-Distribution Pri	176,974	0.00	7.19	7.19	0	1,272,444	1,272,444
NCP Billing kW-Distribution Sec	0	0.00	7.70	7.70	0	0	0
P.F. Adjust.-Transmission	4,152	0.00	0.21	0.21	0	872	872
P.F. Adjust.-Distribution Sub	4,555	0.00	1.75	1.75	0	7,971	7,971
P.F. Adjust.-Distribution Pri	2,827	0.00	7.19	7.19	0	20,326	20,326
P.F. Adjust.-Distribution Sec	0	0.00	7.70	7.70	0	0	0
kWh	101,593,785	0.000000	0.000000	0.000000	0	0	0
Wholesale Power Cost					5,422,757	0	5,422,757
Subtotal					5,422,757	1,820,387	7,243,143
PCA Revenue					0		0
Total					5,422,757	1,820,387	7,243,143

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

	Billing Units	Unbundled Rate: Power Supply	Unbundled Rate: Distrib. Wires	Unbundled Rate: Total	Unbundled Revenue: Power Supply	Unbundled Revenue: Distrib. Wires	Unbundled Revenue: Total
8. WATER PUMPING							
Single Phase							
Consumers (12-month sum)	132	0.00	27.00	27.00	0	3,564	3,564
kWh	185,573	0.104000	0.039600	0.143600	19,404	7,388	26,792
Subtotal					19,404	10,952	30,356
PCA					0		0
Total					19,404	10,952	30,356
Three Phase							
Consumers (12-month sum)	571	0.00	35.00	35.00	0	19,985	19,985
kWh	3,143,032	0.104000	0.039600	0.143600	326,875	124,464	451,339
Minimum Bill					0	0	0
Subtotal					326,875	144,449	471,324
PCA					0		0
Total					326,875	144,449	471,324
Total Base Revenue	3,329,605				346,279	155,401	501,680
Total PCA Revenue					0	0	0
Total Revenue					346,279	155,401	501,680
9. IRRIGATION							
Single Phase							
Consumers (12-month sum)		0.00	27.00	27.00	0	0	0
kWh		0.110000	0.032010	0.142010	0	0	0
Minimum Bill							
Subtotal					0	0	0
PCA					0		0
Total					0	0	0
Three Phase							
Consumers (12-month sum)	132	0.00	35.00	35.00	0	4,620	4,620
kWh	261,544	0.110000	0.032010	0.142010	28,770	8,372	37,142
Minimum Bill					0	0	0
Subtotal					28,770	12,992	41,762
PCA					0		0
Total					28,770	12,992	41,762
Total Base Revenue	261,544				28,770	12,992	41,762
Total PCA Revenue					0	0	0
Total Revenue					28,770	12,992	41,762

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Unbundled Rate:			Unbundled Revenue		
	Billing Units	Power Supply	Distrib. Wires	Total	Power Supply	Distrib. Wires	Total
10. TIME OF DAY PUMPING							
Single Phase							
Consumers (12-month sum)	24	0.00	27.00	27.00	0	648	648
NCP Billing kW	716	1.75	0.00	1.75	1,253	0	1,253
Billing kW - On Peak	4	16.00	0.00	16.00	65	0	65
kWh - On Peak	34	0.043900	0.020100	0.064000	1	1	2
kWh - Off Peak	353,742	0.043900	0.020100	0.064000	15,529	7,110	22,639
Subtotal	353,776				16,848	7,759	24,607
PCA					0		0
Total					16,848	7,759	24,607
Three Phase							
Consumers (12-month sum)	327	0.00	35.00	35.00	0	11,445	11,445
NCP Billing kW	36,165	1.75	0.00	1.75	63,289	0	63,289
Billing kW - On Peak	12,751	16.00	0.00	16.00	204,024	0	204,024
kWh - On Peak	234,052	0.043900	0.020100	0.064000	10,275	4,704	14,979
kWh - Off Peak	5,137,193	0.043900	0.020100	0.064000	225,523	103,258	328,780
Subtotal	5,371,245				503,111	119,407	622,517
PCA					0		0
Total					503,111	119,407	622,517
Total Base Revenue	5,725,021				519,959	127,166	647,124
Total PCA Revenue					0	0	0
Total Revenue					519,959	127,166	647,124
11. INTERRUPTIBLE COMMERCIAL							
Consumers 1 PH (12-month sum)	26	0.00	36.00	36.00	0	936	936
Consumers 3 PH (12-month sum)		0.00	45.00	45.00	0	0	0
NCP Billing kW	9,592	1.75	0.00	1.75	16,785	0	16,785
CP Billing kW	863	19.50	0.00	19.50	16,837	0	16,837
kWh	3,573,369	0.065300	0.022300	0.087600	233,341	79,686	313,027
Subtotal					266,963	80,622	347,585
PCA					0	0	0
Total					266,963	80,622	347,585
12. INTERRUPTIBLE PUMPING							
Consumers 1 PH (12-month sum)		0.00	36.00	36.00	0	0	0
Consumers 3 PH (12-month sum)	212	0.00	45.00	45.00	0	9,540	9,540
NCP Billing kW	23,642	1.75	0.00	1.75	41,374	0	41,374
CP Billing kW	3,795	19.50	0.00	19.50	74,003	0	74,003
kWh	7,331,315	0.065300	0.022300	0.087600	478,735	163,488	642,223
Minimum Bill						62,623	62,623
Subtotal					594,112	235,651	829,763
PCA					0		0
Total					594,112	235,651	829,763

Supporting Schedules:
E-7.1, E-7.2, E-7.2.2, E-7.2.3, E-7.4, E-7.5.3

Recap Schedules:
H-1.0

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF PROPOSED REVENUE - TOTAL - SETTLEMENT

		Billing Units	Unbundled Rate: Power Supply	Unbundled Rate: Distrib. Wires	Unbundled Rate: Total	Unbundled Revenue: Power Supply	Unbundled Revenue: Distrib. Wires	Unbundled Revenue: Total
13. LIGHTING								
Outdoor Lighting								
Security Lights	53 kWh/Month	8,129	4.33	7.67	12.00	35,199	62,322	97,520
150 Watt HPS	45 kWh/Month	12	3.68	8.14	11.82	44	98	142
250 Watt HPS	75 kWh/Month	60	6.13	6.37	12.50	368	382	750
400 Watt HPS	120 kWh/Month	132	9.81	2.89	12.70	1,295	381	1,676
55 Watt LPS	27 kWh/Month	55	2.21	9.19	11.40	122	506	627
90 Watt LPS	27 kWh/Month	444	2.21	9.19	11.40	981	4,081	5,062
135 Watt LPS	45 kWh/Month	96	3.68	8.14	11.82	353	781	1,135
100 Watt HPS	30 kWh/Month	36	2.45	9.02	11.47	88	325	413
Additional Poles		1,157	0.00	10.90	10.90	0	12,611	12,611
Subtotal						38,450	81,487	119,936
Street Lighting								
150 Watt HPS	45 kWh/Month	0	3.68	7.08	10.76	0	0	0
250 Watt HPS	75 kWh/Month	0	6.13	4.63	10.76	0	0	0
400 Watt HPS	120 kWh/Month	0	9.81	7.96	17.77	0	0	0
55 Watt LPS	27 kWh/Month	0	2.21	5.42	7.63	0	0	0
90 Watt LPS	27 kWh/Month	600	2.21	10.07	12.28	1,326	6,041	7,367
135 Watt LPS	45 kWh/Month	1,176	3.68	7.08	10.76	4,328	8,330	12,658
180 Watt LPS	54 kWh/Month	0	4.41	8.78	13.19	0	0	0
100 Watt LPS	30 kWh/Month	0	2.45	8.31	10.76	0	0	0
Wood Pole		0		1.38	1.38	0	0	0
28' Metal Pole		600		3.64	3.64	0	2,182	2,182
20' - 30' Metal Pole		1,176		4.34	4.34	0	5,100	5,100
30' - 4 Watt HPS		0		4.34	4.34	0	0	0
Subtotal						5,654	21,653	27,307
Total Base Revenue		539,888				44,104	103,140	147,243
Total PCA Revenue						0		0
Total Revenue						44,104	103,140	147,243
14. SALE FOR RESALE (SUPPLEMENTAL WHEELING)								
Base Revenue						104,565	45,800	150,365
PCA Revenue						0	0	0
Total	*	1,725,231				104,565	45,800	150,365
16. TOTAL								
Base Revenue		674,117,747				52,190,418	35,951,300	88,141,716
PCA Revenue						0	0	0
Total Revenue						52,190,418	35,951,300	88,141,716

Supporting Schedules:
E-7.1, E-7.2, E-7.2.2, E-7.2.3, E-7.4, E-7.5.3

Recap Schedules:
H-1.0

TRICO ELECTRIC COOPERATIVE, INC.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - SETTLEMENT

	Existing	Proposed	Change
Power Cost, per kWh Sold	$0.081711	$0.081711	$0.000000
WPCA Base Cost, per kWh Sold	$0.081638	$0.081711	$0.000073
WPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)
Residential			
Customer Charge	$15.00	$24.00	$9.00
First 800 kWh/Month	$0.121600	$0.112930	($0.008670)
Next 800 kWh/Month	$0.121600	$0.122930	$0.001330
Residential-TOU			
Customer Charge	$19.00	$28.00	$9.00
Energy Charge, per On-Peak kWh	$0.193200	$0.194250	$0.001050
Energy Charge, per Off-Peak kWh	$0.073200	$0.074250	$0.001050
General Service 1			
Customer Charge, Single Phase	$18.00	$27.00	$9.00
Customer Charge, Three Phase	$26.00	$35.00	$9.00
Energy Charge, per kWh	$0.133500	$0.126820	($0.006680)
General Service 2			
Customer Charge, Single Phase	$18.00	$27.00	$9.00
Customer Charge, Three Phase	$26.00	$35.00	$9.00
Demand Charge, per Billing kW			
First 10 Billing kW per month	$0.00	$0.00	$0.00
Over 10 Billing kW per month	$4.50	$4.50	$0.00
Energy Charge, per kWh	$0.138000	$0.146530	$0.008530
General Service 3			
Customer Charge, Single Phase	$18.00	$27.00	$9.00
Customer Charge, Three Phase	$26.00	$35.00	$9.00
Demand Charge, per Billing kW	$16.65	$18.00	$1.35
Energy Charge, per kWh	$0.083000	$0.075030	($0.007970)

Supporting Schedules:
E-7.6, E-7.6.1, H-2.1

TRICO ELECTRIC COOPERATIVE, INC.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - SETTLEMENT

	Existing	Proposed	Change
Power Cost, per kWh Sold	$0.081711	$0.081711	$0.000000
WPCA Base Cost, per kWh Sold	$0.081638	$0.081711	$0.000073
WPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)
General Service TOU			
Customer Charge, Single Phase	$24.00	$33.00	$9.00
Customer Charge, Three Phase	$32.00	$41.00	$9.00
Demand Charge, per NCP Billing kW	$5.95	$5.95	$0.00
Demand Charge, per CP Billing kW	$29.50	$29.50	$0.00
Energy Charge, per kWh	$0.063750	$0.066100	$0.002350
General Service 4			
Customer Charge	$500.00	$500.00	$0.00
Secondary Meter Charge	$40.00	$40.00	$0.00
Demand Charge, per Billing kW:			
Transmission Level	$0.21	$0.21	$0.00
Distribution Substation Level	$1.75	$1.75	$0.00
Distribution Primary Level	$7.19	$7.19	$0.00
Distribution Secondary Level	$7.70	$7.70	$0.00
Energy Charge, per kWh	$0.000000	$0.000000	$0.000000
Water Pumping			
Customer Charge, Single Phase	$18.00	$27.00	$9.00
Customer Charge, Three Phase	$26.00	$35.00	$9.00
Energy Charge, per kWh	$0.132600	$0.143600	$0.011000
Irrigation			
Customer Charge, Single Phase	$18.00	$27.00	$9.00
Customer Charge, Three Phase	$26.00	$35.00	$9.00
Energy Charge, per kWh	$0.124573	$0.142010	$0.017437

Supporting Schedules:
E-7.6, E-7.6.1, H-2.1

TRICO ELECTRIC COOPERATIVE, INC.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - SETTLEMENT

		Existing	Proposed	Change
Power Cost, per kWh Sold		$0.081711	$0.081711	$0.000000
WPCA Base Cost, per kWh Sold		$0.081638	$0.081711	$0.000073
WPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)
Time of Day Pumping				
Customer Charge, Single Phase		$18.00	$27.00	$9.00
Customer Charge, Three Phase		$26.00	$35.00	$9.00
Demand Charge, per NCP Billing kW		$0.00	$1.75	$1.75
Demand Charge, per On Peak Billing kW		$18.16	$16.00	($2.16)
Energy Charge, per On Peak kWh		$0.126900	$0.064000	($0.062900)
Energy Charge, per Off Peak kWh		$0.061900	$0.064000	$0.002100
Interruptible Commercial				
Customer Charge, Single Phase		$36.00	$36.00	$0.00
Customer Charge, Three Phase		$45.00	$45.00	$0.00
Demand Charge, per NCP Billing kW		$0.00	$1.75	$1.75
Demand Charge, per CP Billing kW		$29.50	$19.50	($10.00)
Energy Charge, per kWh		$0.084200	$0.087600	$0.003400
Interruptible Pumping				
Customer Charge, Single Phase		$36.00	$36.00	$0.00
Customer Charge, Three Phase		$45.00	$45.00	$0.00
Demand Charge, per NCP Billing kW		$0.00	$1.75	$1.75
Demand Charge, per CP Billing kW		$29.50	$19.50	($10.00)
Energy Charge, per kWh		$0.084200	$0.087600	$0.003400
Outdoor Lighting				
Security Lights	53 kWh/Mo	$11.48	$12.00	$0.52
150 Watts HPS	45 kWh/Mo	$11.31	$11.82	$0.51
250 Watts HPS	75 kWh/Mo	$11.96	$12.50	$0.54
400 Watts HPS	120 kWh/Mo	$12.15	$12.70	$0.55
55 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49
90 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49
135 Watts LPS	45 kWh/Mo	$11.31	$11.82	$0.51
100 Watts HPS	30 kWh/Mo	$10.98	$11.47	$0.49
Additional Pole Charge		$10.43	$10.90	$0.47

Supporting Schedules:
E-7.6, E-7.6.1, H-2.1

TRICO ELECTRIC COOPERATIVE, INC.

CHANGES IN REPRESENTATIVE RATE SCHEDULES - SETTLEMENT

		Existing	Proposed	Change
Power Cost, per kWh Sold		$0.081711	$0.081711	$0.000000
WPCA Base Cost, per kWh Sold		$0.081638	$0.081711	$0.000073
WPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)
Street Lighting				
150 Watts HPS	45 kWh/Mo	$10.30	$10.76	$0.46
250 Watts HPS	75 kWh/Mo	$10.30	$10.76	$0.46
400 Watts HPS	120 kWh/Mo	$17.00	$17.77	$0.77
55 Watts LPS	27 kWh/Mo	$7.30	$7.63	$0.33
90 Watts LPS	27 kWh/Mo	$11.75	$12.28	$0.53
135 Watts LPS	45 kWh/Mo	$10.30	$10.76	$0.46
180 Watts LPS	54 kWh/Mo	$12.62	$13.19	$0.57
100 Watts HPS	30 kWh/Mo	$10.30	$10.76	$0.46
Wood Pole Charge		$1.32	$1.38	$0.06
28' Metal Pole		$3.48	$3.64	$0.16
20' - 30' Metal Pole		$4.15	$4.34	$0.19
30' - 40' Metal Pole		$4.15	$4.34	$0.19
Miscellaneous Charges				
Service Establisment Fee		$50.00	$50.00	$0.00
Reconnect Fee		$50.00	$50.00	$0.00
Reconnect Fee After Hours		$70.00	$70.00	$0.00
Trip Fee		$50.00	$50.00	$0.00
After Hours Trip Fee		$175.00	$175.00	$0.00
Meter Test Fee		$35.00	$35.00	$0.00

Supporting Schedules:
E-7.6, E-7.6.1, H-2.1

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
RESIDENTIAL

kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge	$15.00	$24.00	$9.00	60.00%
Demand Charge	$0.00	$0.00	$0.00	0.00%
First 800 kWh/Month	$0.121600	$0.112930	($0.008670)	-7.13%
Next 800 kWh/Month	$0.121600	$0.122930	$0.001330	1.09%
PPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)	-100.00%
50	$21.08	$29.65	$8.57	40.65%
100	$27.17	$35.29	$8.12	29.89%
300	$51.50	$57.88	$6.38	12.39%
500	$75.84	$80.47	$4.63	6.10%
800	$112.34	$114.34	$2.00	1.78%
1,000	$136.67	$138.93	$2.26	1.65%
3,000	$380.02	$384.79	$4.77	1.26%
5,000	$623.37	$630.65	$7.28	1.17%
837 Average	**$116.84**	**$118.89**	**$2.05**	**1.75%**
750 Median	**$106.25**	**$108.70**	**$2.45**	**2.31%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
RESIDENTIAL-TOU

kWh Usage	On-Peak kWh 29%	Off-Peak kWh 71%	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge			$19.00	$28.00	$9.00	47.37%
Energy Charge, per On-Peak kWh			$0.193200	$0.194250	$0.001050	0.54%
Energy Charge, per Off-Peak kWh			$0.073200	$0.074250	$0.001050	1.43%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
50	14	36	$24.40	$33.45	$9.05	37.09%
100	29	71	$29.80	$38.89	$9.09	30.50%
300	87	213	$51.39	$60.68	$9.29	18.08%
500	145	356	$72.98	$82.47	$9.49	13.00%
800	231	569	$105.36	$115.14	$9.78	9.28%
1,000	289	711	$126.95	$136.93	$9.98	7.86%
3,000	867	2,133	$342.86	$354.79	$11.93	3.48%
5,000	1,445	3,555	$558.77	$572.65	$13.88	2.48%
1,058 Average	306	752	**$133.21**	**$143.25**	**$10.04**	**7.54%**
698 Median	202	496	**$94.35**	**$104.03**	**$9.68**	**10.26%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE 1

kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase	$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase	$26.00	$35.00	$9.00	34.62%
Energy Charge, per kWh	$0.133500	$0.126820	($0.006680)	-5.00%
PPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)	-100.00%
Single Phase				
50	$24.68	$33.34	$8.66	35.09%
100	$31.36	$39.68	$8.32	26.53%
300	$58.07	$65.05	$6.98	12.02%
500	$84.79	$90.41	$5.62	6.63%
800	$124.86	$128.46	$3.60	2.88%
1,000	$151.57	$153.82	$2.25	1.48%
3,000	$418.72	$407.46	($11.26)	-2.69%
5,000	$685.87	$661.10	($24.77)	-3.61%
570 Average	**$94.14**	**$99.29**	**$5.15**	**5.47%**
349 Median	**$64.62**	**$71.26**	**$6.64**	**10.28%**
Three Phase				
50	$32.68	$41.34	$8.66	26.50%
100	$39.36	$47.68	$8.32	21.14%
300	$66.07	$73.05	$6.98	10.56%
500	$92.79	$98.41	$5.62	6.06%
800	$132.86	$136.46	$3.60	2.71%
1,000	$159.57	$161.82	$2.25	1.41%
3,000	$426.72	$415.46	($11.26)	-2.64%
5,000	$693.87	$669.10	($24.77)	-3.57%
871 Average	**$142.34**	**$145.46**	**$3.12**	**2.19%**
546 Median	**$98.93**	**$104.24**	**$5.31**	**5.37%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE 2

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase			$26.00	$35.00	$9.00	34.62%
First 10 Billing kW per month			$0.00	$0.00	$0.00	0.00%
Over 10 Billing kW per month			$4.50	$4.50	$0.00	0.00%
Energy Charge, per kWh			$0.138000	$0.146530	$0.008530	6.18%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
			Single Phase			
10.00%	10.0	730	$163.79	$178.97	$15.18	9.27%
20.00%	10.0	1,460	$264.59	$285.93	$21.34	8.07%
30.00%	10.0	2,190	$365.38	$392.90	$27.52	7.53%
40.00%	10.0	2,920	$466.17	$499.87	$33.70	7.23%
50.00%	10.0	3,650	$566.97	$606.83	$39.86	7.03%
10.00%	25.0	1,825	$382.48	$406.92	$24.44	6.39%
20.00%	25.0	3,650	$634.47	$674.33	$39.86	6.28%
30.00%	25.0	5,475	$886.45	$941.75	$55.30	6.24%
40.00%	25.0	7,300	$1,138.43	$1,209.17	$70.74	6.21%
50.00%	25.0	9,125	$1,390.42	$1,476.59	$86.17	6.20%
10.00%	50.0	3,650	$746.97	$786.83	$39.86	5.34%
20.00%	50.0	7,300	$1,250.93	$1,321.67	$70.74	5.65%
30.00%	50.0	10,950	$1,754.90	$1,856.50	$101.60	5.79%
40.00%	50.0	14,600	$2,258.87	$2,391.34	$132.47	5.86%
50.00%	50.0	18,250	$2,762.83	$2,926.17	$163.34	5.91%
19.77% Avg	**15.76**	**2,274**	**$402.90**	**$431.13**	**$28.23**	**7.01%**
25.03% Avg	**8.00**	**1,462**	**$255.86**	**$277.23**	**$21.37**	**8.35%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE 2

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase			$26.00	$35.00	$9.00	34.62%
First 10 Billing kW per month			$0.00	$0.00	$0.00	0.00%
Over 10 Billing kW per month			$4.50	$4.50	$0.00	0.00%
Energy Charge, per kWh			$0.138000	$0.146530	$0.008530	6.18%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
			Three Phase			
10.00%	25.0	1,825	$390.48	$414.92	$24.44	6.26%
20.00%	25.0	3,650	$642.47	$682.33	$39.86	6.20%
30.00%	25.0	5,475	$894.45	$949.75	$55.30	6.18%
40.00%	25.0	7,300	$1,146.43	$1,217.17	$70.74	6.17%
50.00%	25.0	9,125	$1,398.42	$1,484.59	$86.17	6.16%
10.00%	50.0	3,650	$754.97	$794.83	$39.86	5.28%
20.00%	50.0	7,300	$1,258.93	$1,329.67	$70.74	5.62%
30.00%	50.0	10,950	$1,762.90	$1,864.50	$101.60	5.76%
40.00%	50.0	14,600	$2,266.87	$2,399.34	$132.47	5.84%
50.00%	50.0	18,250	$2,770.83	$2,934.17	$163.34	5.89%
10.00%	75.0	5,475	$1,119.45	$1,174.75	$55.30	4.94%
20.00%	75.0	10,950	$1,875.40	$1,977.00	$101.60	5.42%
30.00%	75.0	16,425	$2,631.35	$2,779.26	$147.91	5.62%
40.00%	75.0	21,900	$3,387.30	$3,581.51	$194.21	5.73%
50.00%	75.0	27,375	$4,143.25	$4,383.76	$240.51	5.80%
17.46% Avg	**34.97**	**4,456**	**$798.62**	**$845.30**	**$46.68**	**5.85%**
17.57% Avg	**19.20**	**2,462**	**$452.34**	**$482.16**	**$29.82**	**6.59%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE 3

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase			$26.00	$35.00	$9.00	34.62%
Demand Charge, per Billing kW			$16.65	$18.00	$1.35	8.11%
Energy Charge, per kWh			$0.083000	$0.075030	($0.007970)	-9.60%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
			Single Phase			
30.00%	10.00	2,190	$366.43	$371.32	$4.89	1.33%
45.00%	10.00	3,285	$457.39	$453.47	($3.92)	-0.86%
60.00%	10.00	4,380	$548.36	$535.63	($12.73)	-2.32%
75.00%	10.00	5,475	$639.32	$617.79	($21.53)	-3.37%
90.00%	10.00	6,570	$730.29	$699.95	($30.34)	-4.15%
30.00%	20.00	4,380	$714.86	$715.63	$0.77	0.11%
45.00%	20.00	6,570	$896.79	$879.95	($16.84)	-1.88%
60.00%	20.00	8,760	$1,078.72	$1,044.26	($34.46)	-3.19%
75.00%	20.00	10,950	$1,260.65	$1,208.58	($52.07)	-4.13%
90.00%	20.00	13,140	$1,442.58	$1,372.89	($69.69)	-4.83%
30.00%	50.00	10,950	$1,760.15	$1,748.58	($11.57)	-0.66%
45.00%	50.00	16,425	$2,214.97	$2,159.37	($55.60)	-2.51%
60.00%	50.00	21,900	$2,669.80	$2,570.16	($99.64)	-3.73%
75.00%	50.00	27,375	$3,124.62	$2,980.95	($143.67)	-4.60%
90.00%	50.00	32,850	$3,579.45	$3,391.74	($187.71)	-5.24%
48.70% Average	**17.78**	**6,319**	**$838.98**	**$821.15**	**($17.83)**	**-2.13%**
63.90% Average	**11.87**	**5,537**	**$675.61**	**$656.10**	**($19.51)**	**-2.89%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE 3

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase			$26.00	$35.00	$9.00	34.62%
Demand Charge, per Billing kW			$16.65	$18.00	$1.35	8.11%
Energy Charge, per kWh			$0.083000	$0.075030	($0.007970)	-9.60%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
			Three Phase			
30.00%	50.00	10,950	$1,768.15	$1,756.58	($11.57)	-0.65%
45.00%	50.00	16,425	$2,222.97	$2,167.37	($55.60)	-2.50%
60.00%	50.00	21,900	$2,677.80	$2,578.16	($99.64)	-3.72%
75.00%	50.00	27,375	$3,132.62	$2,988.95	($143.67)	-4.59%
90.00%	50.00	32,850	$3,587.45	$3,399.74	($187.71)	-5.23%
30.00%	100.00	21,900	$3,510.30	$3,478.16	($32.14)	-0.92%
45.00%	100.00	32,850	$4,419.95	$4,299.74	($120.21)	-2.72%
60.00%	100.00	43,800	$5,329.60	$5,121.31	($208.29)	-3.91%
75.00%	100.00	54,750	$6,239.25	$5,942.89	($296.36)	-4.75%
90.00%	100.00	65,700	$7,148.90	$6,764.47	($384.43)	-5.38%
30.00%	150.00	32,850	$5,252.45	$5,199.74	($52.71)	-1.00%
45.00%	150.00	49,275	$6,616.92	$6,432.10	($184.82)	-2.79%
60.00%	150.00	65,700	$7,981.40	$7,664.47	($316.93)	-3.97%
75.00%	150.00	82,125	$9,345.87	$8,896.84	($449.03)	-4.80%
90.00%	150.00	98,550	$10,710.34	$10,129.21	($581.13)	-5.43%
48.46% Average	**71.70**	**28,865**	**$3,617.71**	**$3,491.34**	**($126.37)**	**-3.49%**
50.94% Average	**150.00**	**55,777**	**$7,157.06**	**$6,919.95**	**($237.11)**	**-3.31%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
GENERAL SERVICE TOU

Load Factor	NCP Billing kW	CP Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
		40%					
Customer Charge, Single Phase				$24.00	$33.00	$9.00	37.50%
Customer Charge, Three Phase				$32.00	$41.00	$9.00	28.13%
Demand Charge, per NCP Billing kW				$5.95	$5.95	$0.00	0.00%
Demand Charge, per CP Billing kW				$29.50	$29.50	$0.00	0.00%
Energy Charge, per kWh				$0.063750	$0.066100	$0.002350	3.69%
PPCA Factor, per kWh				$0.000073	$0.000000	($0.000073)	-100.00%
			Single Phase				
10.00%	10.0	4.0	730	$248.09	$258.75	$10.66	4.30%
20.00%	10.0	4.0	1,460	$294.68	$307.01	$12.33	4.18%
30.00%	10.0	4.0	2,190	$341.27	$355.26	$13.99	4.10%
50.00%	10.0	4.0	3,650	$434.45	$451.77	$17.32	3.99%
70.00%	10.0	4.0	5,110	$527.64	$548.27	$20.63	3.91%
10.00%	20.0	8.0	1,460	$472.18	$484.51	$12.33	2.61%
20.00%	20.0	8.0	2,920	$565.36	$581.01	$15.65	2.77%
30.00%	20.0	8.0	4,380	$658.54	$677.52	$18.98	2.88%
50.00%	20.0	8.0	7,300	$844.91	$870.53	$25.62	3.03%
70.00%	20.0	8.0	10,220	$1,031.27	$1,063.54	$32.27	3.13%
10.00%	30.0	12.0	2,190	$696.27	$710.26	$13.99	2.01%
20.00%	30.0	12.0	4,380	$836.04	$855.02	$18.98	2.27%
30.00%	30.0	12.0	6,570	$975.82	$999.78	$23.96	2.46%
50.00%	30.0	12.0	10,950	$1,255.36	$1,289.30	$33.94	2.70%
70.00%	30.0	12.0	15,330	$1,534.91	$1,578.81	$43.90	2.86%
51.67% Average	**15.85**	**6.3**	**6,002**	**$688.40**	**$711.07**	**$22.67**	**3.29%**
			Three Phase				
10.00%	25.0	10.0	1,825	$592.23	$605.38	$13.15	2.22%
20.00%	25.0	10.0	3,650	$708.70	$726.02	$17.32	2.44%
30.00%	25.0	10.0	5,475	$825.18	$846.65	$21.47	2.60%
50.00%	25.0	10.0	9,125	$1,058.13	$1,087.91	$29.78	2.81%
70.00%	25.0	10.0	12,775	$1,291.09	$1,329.18	$38.09	2.95%
10.00%	50.0	20.0	3,650	$1,152.45	$1,169.77	$17.32	1.50%
20.00%	50.0	20.0	7,300	$1,385.41	$1,411.03	$25.62	1.85%
30.00%	50.0	20.0	10,950	$1,618.36	$1,652.30	$33.94	2.10%
50.00%	50.0	20.0	18,250	$2,084.27	$2,134.83	$50.56	2.43%
70.00%	50.0	20.0	25,550	$2,550.18	$2,617.36	$67.18	2.63%
10.00%	100.0	40.0	7,300	$2,272.91	$2,298.53	$25.62	1.13%
20.00%	100.0	40.0	14,600	$2,738.82	$2,781.06	$42.24	1.54%
30.00%	100.0	40.0	21,900	$3,204.72	$3,263.59	$58.87	1.84%
50.00%	100.0	40.0	36,500	$4,136.54	$4,228.65	$92.11	2.23%
70.00%	100.0	40.0	51,100	$5,068.36	$5,193.71	$125.35	2.47%
34.53% Average	**51.69**	**20.6**	**13,003**	**$1,777.61**	**$1,816.22**	**$38.61**	**2.17%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
WATER PUMPING

kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase	$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase	$26.00	$35.00	$9.00	34.62%
Energy Charge, per kWh	$0.132600	$0.143600	$0.011000	8.30%
PPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)	-100.00%
Single Phase				
50	$24.63	$34.18	$9.55	38.77%
100	$31.27	$41.36	$10.09	32.27%
300	$57.80	$70.08	$12.28	21.25%
500	$84.34	$98.80	$14.46	17.14%
800	$124.14	$141.88	$17.74	14.29%
1,000	$150.67	$170.60	$19.93	13.23%
3,000	$416.02	$457.80	$41.78	10.04%
5,000	$681.37	$745.00	$63.63	9.34%
1,414 Average	**$205.60**	**$230.05**	**$24.45**	**11.89%**
1,458 Median	**$211.44**	**$236.37**	**$24.93**	**11.79%**
Three Phase				
50	$32.63	$42.18	$9.55	29.27%
100	$39.27	$49.36	$10.09	25.69%
300	$65.80	$78.08	$12.28	18.66%
500	$92.34	$106.80	$14.46	15.66%
800	$132.14	$149.88	$17.74	13.43%
1,000	$158.67	$178.60	$19.93	12.56%
3,000	$424.02	$465.80	$41.78	9.85%
5,000	$689.37	$753.00	$63.63	9.23%
5,503 Average	**$756.10**	**$825.23**	**$69.13**	**9.14%**
1,394 Average	**$210.95**	**$235.18**	**$24.23**	**11.49%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
IRRIGATION - TRHEE PHASE

kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase	$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase	$26.00	$35.00	$9.00	34.62%
Energy Charge, per kWh	$0.124573	$0.142010	$0.017437	14.00%
PPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)	-100.00%
50	$32.23	$42.10	$9.87	30.62%
100	$38.46	$49.20	$10.74	27.93%
300	$63.39	$77.60	$14.21	22.42%
500	$88.32	$106.01	$17.69	20.03%
800	$125.72	$148.61	$22.89	18.21%
1,000	$150.65	$177.01	$26.36	17.50%
3,000	$399.94	$461.03	$61.09	15.27%
5,000	$649.23	$745.05	$95.82	14.76%
1,982 Average	**$273.05**	**$316.46**	**$43.41**	**15.90%**
1,656 Average	**$232.41**	**$270.17**	**$37.76**	**16.25%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
TIME OF DAY PUMPING

Load Factor	NCP Billing kW	On-Peak Billing kW	kWh Usage	Off-Peak kWh Usage	On-Peak kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
		29%			4.36%				
Customer Charge, Single Phase						$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase						$26.00	$35.00	$9.00	34.62%
Demand Charge, per NCP Billing kW						$0.00	$1.75	$1.75	0.00%
Demand Charge, per On Peak Billing kW						$18.16	$16.00	($2.16)	-11.89%
Energy Charge, per On Peak kWh						$0.126900	$0.064000	($0.062900)	-49.57%
Energy Charge, per Off Peak kWh						$0.061900	$0.064000	$0.002100	3.39%
PPCA Factor, per kWh						$0.000073	$0.000000	($0.000073)	-100.00%
				Single Phase					
10.00%	25.0	0.0	1,825	1,825	0	$131.10	$187.55	$56.45	43.06%
20.00%	25.0	0.0	3,650	3,650	0	$244.20	$304.35	$60.15	24.63%
30.00%	25.0	0.0	5,475	5,475	0	$357.30	$421.15	$63.85	17.87%
50.00%	25.0	0.0	9,125	9,125	0	$583.50	$654.75	$71.25	12.21%
70.00%	25.0	0.0	12,775	12,775	0	$809.71	$888.35	$78.64	9.71%
10.00%	50.0	0.0	3,650	3,650	0	$244.20	$348.10	$103.90	42.55%
20.00%	50.0	0.0	7,300	7,300	0	$470.40	$581.70	$111.30	23.66%
30.00%	50.0	0.0	10,950	10,950	0	$696.60	$815.30	$118.70	17.04%
50.00%	50.0	0.0	18,250	18,250	0	$1,149.01	$1,282.50	$133.49	11.62%
70.00%	50.0	0.0	25,550	25,550	0	$1,601.41	$1,749.70	$148.29	9.26%
10.00%	75.0	0.0	5,475	5,475	0	$357.30	$508.65	$151.35	42.36%
20.00%	75.0	0.0	10,950	10,950	0	$696.60	$859.05	$162.45	23.32%
30.00%	75.0	0.0	16,425	16,425	0	$1,035.91	$1,209.45	$173.54	16.75%
50.00%	75.0	0.0	27,375	27,375	0	$1,714.51	$1,910.25	$195.74	11.42%
70.00%	75.0	0.0	38,325	38,325	0	$2,393.12	$2,611.05	$217.93	9.11%
39.59% Average	51.00	0.0	14,741	14,741	0	$931.54	$1,059.67	$128.13	13.75%
				Three Phase					
10.00%	25.0	7.3	1,825	1,745	80	$275.93	$311.55	$35.62	12.91%
20.00%	25.0	7.3	3,650	3,491	159	$394.21	$428.35	$34.14	8.66%
30.00%	25.0	7.3	5,475	5,236	239	$512.48	$545.15	$32.67	6.37%
50.00%	25.0	7.3	9,125	8,727	398	$749.02	$778.75	$29.73	3.97%
70.00%	25.0	7.3	12,775	12,218	557	$985.57	$1,012.35	$26.78	2.72%
10.00%	50.0	14.5	3,650	3,491	159	$525.87	$588.10	$62.23	11.83%
20.00%	50.0	14.5	7,300	6,982	318	$762.41	$821.70	$59.29	7.78%
30.00%	50.0	14.5	10,950	10,473	477	$998.96	$1,055.30	$56.34	5.64%
50.00%	50.0	14.5	18,250	17,454	796	$1,472.05	$1,522.50	$50.45	3.43%
70.00%	50.0	14.5	25,550	24,436	1,114	$1,945.14	$1,989.70	$44.56	2.29%
10.00%	100.0	29.0	7,300	6,982	318	$1,025.73	$1,141.20	$115.47	11.26%
20.00%	100.0	29.0	14,600	13,963	637	$1,498.82	$1,608.40	$109.58	7.31%
30.00%	100.0	29.0	21,900	20,945	955	$1,971.91	$2,075.60	$103.69	5.26%
50.00%	100.0	29.0	36,500	34,909	1,591	$2,918.10	$3,010.00	$91.90	3.15%
70.00%	100.0	29.0	51,100	48,872	2,228	$3,864.28	$3,944.40	$80.12	2.07%
16.79% Average	134.00	38.9	16,426	15,710	716	$1,796.22	$1,942.52	$146.30	8.14%

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
TIME OF DAY PUMPING - INDIVIDUAL

Load Factor	NCP Billing kW	On-Peak Billing kW	kWh Usage	Off-Peak kWh Usage	On-Peak kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase						$18.00	$27.00	$9.00	50.00%
Customer Charge, Three Phase						$26.00	$35.00	$9.00	34.62%
Demand Charge, per NCP Billing kW						$0.00	$1.75	$1.75	0.00%
Demand Charge, per On Peak Billing kW						$18.16	$16.00	($2.16)	-11.89%
Energy Charge, per On Peak kWh						$0.126900	$0.064000	($0.062900)	-49.57%
Energy Charge, per Off Peak kWh						$0.061900	$0.064000	$0.002100	3.39%
PPCA Factor, per kWh						$0.000073	$0.000000	($0.000073)	-100.00%
				Single Phase					
40.89%	1,054.6	0.12	314,815	314,783	32	$19,730.29	$22,319.67	$2,589.38	13.12%
32.62%	163.6	4.09	38,961	38,959	2	$2,704.93	$3,169.26	$464.33	17.17%
39.78% Average	1,218.23	4.21	353,776	353,742	34	$22,003.22	$24,840.93	$2,837.71	12.90%
				Three Phase					
0.04%	176.16	0.00	48	48	0	$314.97	$731.35	$416.38	132.20%
23.64%	926.16	0.00	159,800	159,760	40	$10,191.89	$12,232.98	$2,041.09	20.03%
1.82%	346.24	213.12	4,600	4,120	480	$4,498.54	$4,730.24	$231.70	5.15%
8.81%	325.20	0.00	20,920	20,920	0	$1,608.48	$2,327.98	$719.50	44.73%
2.68%	427.36	106.40	8,360	8,280	80	$2,767.52	$3,405.32	$637.80	23.05%
38.59%	708.80	0.00	199,680	199,680	0	$12,686.77	$14,439.92	$1,753.15	13.82%
28.12%	1,619.52	0.00	332,448	332,448	0	$20,914.80	$24,530.83	$3,616.03	17.29%
1.44%	565.47	165.12	7,008	6,816	192	$3,757.37	$4,675.00	$917.63	24.42%
10.66%	288.84	0.13	22,262	22,233	29	$1,695.89	$2,352.32	$656.43	38.71%
14.01%	1,943.20	522.40	198,800	191,520	7,280	$22,592.22	$24,902.20	$2,309.98	10.22%
15.43%	2,392.80	193.60	269,440	269,120	320	$20,546.58	$24,949.16	$4,402.58	21.43%
10.86%	1,185.00	629.69	93,940	85,463	7,477	$18,054.92	$18,580.95	$526.03	2.91%
19.42%	854.80	14.40	121,200	121,120	80	$8,089.83	$9,903.10	$1,813.27	22.41%
30.24%	1,936.40	0.00	427,520	427,440	80	$26,811.90	$31,169.98	$4,358.08	16.25%
28.95%	1,475.76	4.24	311,840	311,040	800	$19,766.66	$23,028.18	$3,261.52	16.50%
20.82%	3,345.60	2,906.40	508,400	426,160	82,240	$89,944.90	$85,314.80	($4,630.10)	-5.15%
13.68%	390.96	259.31	39,037	38,459	578	$7,477.88	$7,751.51	$273.63	3.66%
8.02%	320.75	320.30	18,782	10,151	8,631	$7,671.64	$7,063.16	($608.48)	-7.93%
16.33%	3,742.40	1,948.80	446,160	391,600	54,560	$66,898.48	$66,704.24	($194.24)	-0.29%
16.45%	1,144.60	707.24	137,480	99,520	37,960	$24,142.93	$22,537.61	($1,605.32)	-6.65%
12.12%	3,013.60	1,201.60	266,720	250,640	16,080	$39,707.69	$41,989.48	$2,281.79	5.75%
31.99%	169.74	125.92	39,641	29,105	10,536	$5,740.22	$5,268.79	($471.43)	-8.21%
18.94%	824.94	136.73	114,041	113,913	128	$9,870.80	$11,349.95	$1,479.15	14.99%
19.37%	1,164.52	168.08	164,640	162,160	2,480	$13,728.77	$15,684.15	$1,955.38	14.24%
29.17%	1,436.16	0.32	305,840	305,440	400	$19,297.63	$22,512.16	$3,214.53	16.66%
27.06%	2,891.12	88.00	571,120	568,640	2,480	$37,465.30	$43,439.14	$5,973.84	15.94%
7.38%	1,412.94	0.30	76,093	76,092	1	$5,033.22	$7,767.40	$2,734.18	54.32%
30.02%	2,310.96	386.08	506,400	505,280	1,120	$38,779.14	$43,051.06	$4,271.92	11.02%
18.07%	230.40	220.00	30,400	22,400	8,000	$6,425.18	$5,903.80	($521.38)	-8.11%
19.65% Total	37,570.40	10,318.16	5,402,620	5,160,568	242,052	$546,482.12	$588,296.76	$41,814.64	7.65%

Schedule H-4.8 (2)
Settlement

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
INTERRUPTIBLE COMMERCIAL

Load Factor	NCP Billing kW	CP Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
		9%					
Customer Charge, Single Phase				$36.00	$36.00	$0.00	0.00%
Customer Charge, Three Phase				$45.00	$45.00	$0.00	0.00%
Demand Charge, per NCP Billing kW				$0.00	$1.75	$1.75	0.00%
Demand Charge, per CP Billing kW				$29.50	$19.50	($10.00)	-33.90%
Energy Charge, per kWh				$0.084200	$0.087600	$0.003400	4.04%
PPCA Factor, per kWh				$0.000073	$0.000000	($0.000073)	-100.00%
			Single Phase				
30.00%	25.0	2.3	5,475	$563.77	$603.24	$39.47	7.00%
45.00%	25.0	2.3	8,213	$794.51	$843.08	$48.57	6.11%
60.00%	25.0	2.3	10,950	$1,025.16	$1,082.85	$57.69	5.63%
75.00%	25.0	2.3	13,688	$1,255.90	$1,322.69	$66.79	5.32%
30.00%	150.0	13.5	32,850	$3,202.62	$3,439.41	$236.79	7.39%
45.00%	150.0	13.5	49,275	$4,586.80	$4,878.24	$291.44	6.35%
60.00%	150.0	13.5	65,700	$5,970.99	$6,317.07	$346.08	5.80%
75.00%	150.0	13.5	82,125	$7,355.17	$7,755.90	$400.73	5.45%
30.00%	500.0	45.0	109,500	$10,591.39	$11,380.70	$789.31	7.45%
45.00%	500.0	45.0	164,250	$15,205.34	$16,176.80	$971.46	6.39%
60.00%	500.0	45.0	219,000	$19,819.29	$20,972.90	$1,153.61	5.82%
75.00%	500.0	45.0	273,750	$24,433.23	$25,769.00	$1,335.77	5.47%
51.02% Average	**369.00**	**33.2**	**137,437**	**$12,597.92**	**$13,368.83**	**$770.91**	**6.12%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
INTERRUPTIBLE PUMPING

Load Factor	NCP Billing kW	CP Billing kW 16%	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase				$36.00	$36.00	$0.00	0.00%
Customer Charge, Three Phase				$45.00	$45.00	$0.00	0.00%
Demand Charge, per NCP Billing kW				$0.00	$1.75	$1.75	0.00%
Demand Charge, per CP Billing kW				$29.50	$19.50	($10.00)	-33.90%
Energy Charge, per kWh				$0.084200	$0.087600	$0.003400	4.04%
PPCA Factor, per kWh				$0.000073	$0.000000	($0.000073)	-100.00%
			Three Phase				
10.00%	25.0	4.0	1,825	$316.80	$326.62	$9.82	3.10%
20.00%	25.0	4.0	3,650	$470.60	$486.49	$15.89	3.38%
30.00%	25.0	4.0	5,475	$624.39	$646.36	$21.97	3.52%
50.00%	25.0	4.0	9,125	$931.99	$966.10	$34.11	3.66%
70.00%	25.0	4.0	12,775	$1,239.59	$1,285.84	$46.25	3.73%
10.00%	75.0	12.0	5,475	$860.39	$889.86	$29.47	3.43%
20.00%	75.0	12.0	10,950	$1,321.79	$1,369.47	$47.68	3.61%
30.00%	75.0	12.0	16,425	$1,783.18	$1,849.08	$65.90	3.70%
50.00%	75.0	12.0	27,375	$2,705.97	$2,808.30	$102.33	3.78%
70.00%	75.0	12.0	38,325	$3,628.76	$3,767.52	$138.76	3.82%
10.00%	200.0	32.0	14,600	$2,219.39	$2,297.96	$78.57	3.54%
20.00%	200.0	32.0	29,200	$3,449.77	$3,576.92	$127.15	3.69%
30.00%	200.0	32.0	43,800	$4,680.16	$4,855.88	$175.72	3.75%
50.00%	200.0	32.0	73,000	$7,140.93	$7,413.80	$272.87	3.82%
70.00%	200.0	32.0	102,200	$9,601.70	$9,971.72	$370.02	3.85%
42.68% Average	**111.00**	**17.8**	**34,582**	**$3,483.25**	**$3,614.95**	**$131.70**	**3.78%**

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
LIGHTING

		Existing Rate	Proposed Rate	Change	Percent Change
		Rate			
Outdoor Lighting					
Security Lights	53 kWh/Mo	$11.48	$12.00	$0.52	4.53%
150 Watts HPS	45 kWh/Mo	$11.31	$11.82	$0.51	4.51%
250 Watts HPS	75 kWh/Mo	$11.96	$12.50	$0.54	4.52%
400 Watts HPS	120 kWh/Mo	$12.15	$12.70	$0.55	4.53%
55 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49	4.49%
90 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49	4.49%
135 Watts LPS	45 kWh/Mo	$11.31	$11.82	$0.51	4.51%
100 Watts HPS	30 kWh/Mo	$10.98	$11.47	$0.49	4.46%
Additional Pole Charge		$10.43	$10.90	$0.47	4.51%
PPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)	-100.00%
Street Lighting					
150 Watts HPS	45 kWh/Mo	$10.30	$10.76	$0.46	4.47%
250 Watts HPS	75 kWh/Mo	$10.30	$10.76	$0.46	4.47%
400 Watts HPS	120 kWh/Mo	$17.00	$17.77	$0.77	4.53%
55 Watts LPS	27 kWh/Mo	$7.30	$7.63	$0.33	4.52%
90 Watts LPS	27 kWh/Mo	$11.75	$12.28	$0.53	4.51%
135 Watts LPS	45 kWh/Mo	$10.30	$10.76	$0.46	4.47%
180 Watts LPS	54 kWh/Mo	$12.62	$13.19	$0.57	4.52%
100 Watts HPS	30 kWh/Mo	$10.30	$10.76	$0.46	4.47%
Wood Pole Charge		$1.32	$1.38	$0.06	4.55%
28' Metal Pole		$3.48	$3.64	$0.16	4.60%
20' - 30' Metal Pole		$4.15	$4.34	$0.19	4.58%
30' - 40' Metal Pole		$4.15	$4.34	$0.19	4.58%
PPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)	-100.00%

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF EXISTING AND PROPOSED RATES - SETTLEMENT
LIGHTING

		Existing Rate	Proposed Rate	Change	Percent Change
		Billing			
Outdoor Lighitng					
Security Lights	53 kWh/Mo	$11.48	$12.00	$0.52	4.53%
150 Watts HPS	45 kWh/Mo	$11.31	$11.82	$0.51	4.51%
250 Watts HPS	75 kWh/Mo	$11.97	$12.50	$0.53	4.43%
400 Watts HPS	120 kWh/Mo	$12.16	$12.70	$0.54	4.44%
55 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49	4.49%
90 Watts LPS	27 kWh/Mo	$10.91	$11.40	$0.49	4.49%
135 Watts LPS	45 kWh/Mo	$11.31	$11.82	$0.51	4.51%
100 Watts HPS	30 kWh/Mo	$10.98	$11.47	$0.49	4.46%
Additional Pole Charge	0 kWh/Mo	$10.43	$10.90	$0.47	4.51%
Street Lighitng					
150 Watts HPS	45 kWh/Mo	$10.30	$10.76	$0.46	4.47%
250 Watts HPS	75 kWh/Mo	$10.31	$10.76	$0.45	4.36%
400 Watts HPS	120 kWh/Mo	$17.01	$17.77	$0.76	4.47%
55 Watts LPS	27 kWh/Mo	$7.30	$7.63	$0.33	4.52%
90 Watts LPS	27 kWh/Mo	$11.75	$12.28	$0.53	4.51%
135 Watts LPS	45 kWh/Mo	$10.30	$10.76	$0.46	4.47%
180 Watts LPS	54 kWh/Mo	$12.62	$13.19	$0.57	4.52%
100 Watts HPS	30 kWh/Mo	$10.30	$10.76	$0.46	4.47%
Wood Pole Charge		$1.32	$1.38	$0.06	4.55%
28' Metal Pole		$3.48	$3.48	$0.00	0.00%
20' - 30' Metal Pole		$4.15	$4.34	$0.19	4.58%
30' - 40' Metal Pole		$4.15	$4.34	$0.19	4.58%

ATTACHMENT B

TRICO ELECTRIC COOPERATIVE, INC.
WHOLESALE POWER COST ADJUSTOR
PLAN OF ADMINISTRATION

This Plan of Administration ("POA") relates to the administration of Trico Electric Cooperative, Inc. ("Trico") Wholesale Power Cost Adjustor ("WPCA") pursuant to Decision No. _____, dated _____. The purpose of the POA is to describe how Trico currently administers its WPCA and to provide Trico flexibility to adapt to changing conditions that may impact the administration of its WPCA.

Overview:

Trico is an electric distribution cooperative that is member owned and managed as a not-for profit entity. Its member-customers elect, from its membership, a seven-member board of directors to set policy and oversee the management of the cooperative. Margins earned by Trico flow to patronage capital accounts of its members that are retired over a number of years, as permitted by Trico's financial condition.

Purchased power costs are a significant component of the Trico's cost of providing electric service to its members. The purpose of the WPCA is to allow an electric utility to recover or refund fluctuating power supply costs between rates cases.

The Commission has recognized that the distinctions between electric distribution cooperatives and investor owned utilities ("IOUs") warrant different and less onerous regulation of a cooperative's purchase power and fuel cost adjustor. See, e.g., Decision No. 50266, dated September 18, 1979. Trico has for decades been allowed to make adjustments to its WPCA rate as needed without securing Commission approval.

The WPCA Bank balance is tracked and adjustments made to the WPCA rate as necessary to move the WPCA Bank balance toward zero over a reasonable period of time. Trico and its members desire a predictable power cost from month to month, while avoiding an unreasonable over or under collected balance in the WPCA "Bank". Because of extreme temperatures in the summer and swings in wholesale power and transmission costs, the WPCA Bank balance can move rather significantly from month to month. This POA continues the Commission's longstanding practice of allowing Trico to make adjustments to its WPCA rate, up or down, as it deems appropriate to address under or over collections of the WPCA Bank Balance, subject, of course, to more specific Commission orders.

Eligible Expenses:

Commencing _____ expenses booked in the following Rural Utilities Service (RUS) Accounts in accordance with RUS procedures and protocols shall be eligible for inclusion in Trico's WPCA:

Account 555 (purchased power fuel costs, both demand and energy; solar costs (cost of excess energy procured from Net Metering and DG Energy Export Tariffs), power cost hedging charges, balancing authority)

Account 565 (transmission costs, including Direct Assignment Facilities and O&M charges)

In accordance with Commission Decision No. 66183, costs and revenues associated with the Trico General Service Schedule GS4 shall be excluded from Trico's WPCA, but the costs and revenues are to be reported as an information item on the WPCA reports.

Nothing herein shall preclude Trico from requesting the Commission to authorize recovery of additional or different costs through the WPCA, but no such costs shall be included within the WPCA by Trico without specific Commission authorization.

The Base Cost of Fuel:

The Base Cost of Fuel (Authorized Base Cost) shall be established by order of the Commission. The current Authorized Base Cost of Fuel is $_____ per kWh as established in Decision No. ____ and is effective for all electricity sold on and after _____ until adjusted by order of the Commission.

WPCA Rate:

The WPCA Rate shall be adjusted to zero effective for all electricity sold on and after _____ until adjusted in accordance with this POA or order of the Commission.

WPCA Bank Balance:

As of _____ the WPCA Bank Balance is $_____ ([under/over] collected).

Monthly Reporting:

A monthly report together with confidential invoices for all eligible expenditures and confidential supporting schedules shall be submitted to the Utilities Division. The report shall be submitted on forms approved by the Commission's Director of Utilities, or as amended from time to time by Trico with the written consent of the Director of Utilities, which amended forms shall be docketed in Trico's most recent rate case docket that has resulted in a final rate decision from the Commission. The monthly report shall be filed no later than the 30th day of the second month following the month being reported (approximately 60 days).

Annual Report and Adjustment:

Each year following Trico's Board acceptance of its annual certified outside audit performed in accordance with RUS requirements, including specific review of the purchased power costs reported through the WPCA during the audit period, Trico shall file revised year end and monthly reports, including the current year if applicable, to reflect all adjustments identified by the audit. The revised reports shall be clearly marked as "Revised" on the reporting forms and all adjustments shall be explained in a cover letter and footnotes to the schedules. Such adjusted reports shall be filed no later than six months after the end of the applicable audit period (June 30 for a calendar year audit).

Monitoring and Adjustment of WPCA Rate:

To avoid large monthly swings in the cost of electricity sold to members, Trico management shall monitor and adjust the WPCA Rate using the following general guidance:

(i) Changes to the WPCA Rate should be minimized;

(ii) The WPCA Bank balance should not become under or over collected in excess of $2,000,000;

(iii) In the event the WPCA Bank balance does equal or exceed $2,000,000, Trico shall make an adjustment in its WPCA Rate within sixty (60) days following the submittal of a monthly report indicating the bank balance threshold was exceeded in an effort to move the balance close to zero during the next twelve months;

(iv) The level of adjustment shall be based upon a twelve month forward looking period commencing with the last period for which a monthly report was filed with the Commission; and

(v) The current Board-approved operating budget will be used for the current year projections. Future projections will be based on the prior twelve months' prices and sales, adjusted for likely changes, unless based upon known and definite data (such as an approved rate change for a power/transmission supplier or a new customer load).

Trico management shall regularly review the status of the WPCA Bank balance with the Trico Board of Directors. All adjustments to the WPCA Rate shall be approved by the Trico Board of Directors.

ATTACHMENT C

TRICO ELECTRIC COOPERATIVE, INC.

Marana, Arizona

STANDARD OFFER TARIFFS

Effective

_____

ELECTRIC RATES

STANDARD OFFER TARIFF

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ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

RESIDENTIAL SERVICE
SCHEDULE RS1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Residential Service Rate (RS1) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

STANDARD RATE RS1	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)								
Single-Phase			$5.23	$0.98	$6.33	$11.46	$24.00	$24.00
Three-Phase			$5.23	$0.98	$6.33	$11.46	$24.00	$24.00
Demand Charge ($/kW)	$0.00					$0.00	$0.00	$0.00
Energy Charge ($/kWh)								
First 800 kWh/month	$0.0770					$0.035930	$0.035930	$0.112930
Over 800 kWh/month	$0.0870					$0.035930	$0.035930	$0.122930

The Billing Demand shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customer's highest 15-minute interval demand for the billing month.

RESIDENTIAL SERVICE
SCHEDULE RS1

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE RS2TOU (FROZEN)

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. The Residential Time of Use Service (RS2TOU) is applicable to Customers only prior to the effective date of this tariff. No new Customers will be accepted on this tariff after the effective date of the tariff.

Application

The Residential Time of Use Service Rate (RS2TOU) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

TIME-OF-USE RATE RS2TOU	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$11.18	$0.98	$6.33	$9.51	$28.00	$28.00
Three Phase		$11.18	$0.98	$6.33	$9.51	$28.00	$28.00
Energy Charge ($/kWh)							
On-Peak kWh	$0.1224				$0.071850	$0.071850	$0.194250
Off-Peak kWh	$0.0624				$0.011850	$0.011850	$0.074250

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE (RS2TOU) (FROZEN)

Definition of On-Peak

April 1 through October 31: For this rate schedule, on-peak hours are 1:00 p.m. to 9:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

November 1 through March 31: For this rate schedule, on-peak hours are 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

RESIDENTIAL TIME OF USE SERVICE SCHEDULE (RS2TOU) (FROZEN)

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

***Definition of Holidays**

Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. If a Holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a Holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 10 kW Rate (GS1) is applicable for single and three phase service for more than one residence from a single metering point, where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters and has a monthly demand of less than 10 kW. All service shall be delivered at a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Demand Charge ($/kW)	$0.00				$0.00	$0.00	$0.00
Energy Charge ($/kWh)	$0.0758				$0.051020	$0.051020	$0.126820

The Billing Demand shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customer's highest 15-minute interval demand for the billing month.

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative

generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS2
GENERAL SERVICE 10 KW TO 200 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service 10 kW to 200 kW Rate (GS2) is applicable for single and three phase service where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters; the monthly billing demand is greater than 10 kW but less than 200 kW and has an average monthly load factor of 30% or less based on twelve months of actual consumption history, or in the absence of such history, on service load characteristics. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Billing Demand Charge* ($/kW/Month)							
First 10 kW/month	no charge						no charge
Each kW over 10 kW/month	$4.50						$4.50
Energy Charge ($/kWh)	$0.094400				$0.052130	$0.052130	$0.146530

GENERAL SERVICE
SCHEDULE GS2
GENERAL SERVICE 10 KW TO 200 KW

*The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

GENERAL SERVICE
SCHEDULE GS2
GENERAL SERVICE 10 KW TO 200 KW

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 12,000 kW Rate (GS3) is applicable for single and three phase service where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters; the monthly billing demand is between 10 kW and 11,999 kW. All service shall be delivered to a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three-Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Billing Demand Charge* ($/kW/Month)	$15.00				$3.00	$18.00	$18.00
Energy Charge ($/kWh)	$0.040100				$0.034930	$0.034930	$0.075030

*The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month.

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Power Factor

The Customer shall maintain power factor of not less than 95% leading or lagging. The Cooperative shall have the right to measure such power factor at any time. Should such measurement establish that the power factor of the Customer is less than 95% leading or lagging, the Customer shall upon 60 days written notice correct such power factor to 95%. If not timely corrected, the Cooperative shall have the right to increase the kWh for billing purposes by one percent for each one percent of power factor below 95% leading or lagging.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE TIME OF USE - EXPERIMENTAL SCHEDULE GSTOU

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. This rate is limited to the first 100 qualified Customers.

Application

The General Service Time of Use Rate – Experimental (GSTOU) is applicable for single and three phase service for any Customer who would otherwise be eligible for either the General Service 1 (GS1), General Service 2 (GS2) or General Service 3 (GS3) rate. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$11.18	$0.98	$6.33	$14.51	$33.00	$33.00
Three-Phase		$11.18	$0.98	$6.33	$22.51	$41.00	$41.00
Billing Demand Charge* ($/kW/Month)	$0.00				$5.95	$5.95	$5.95
Coincident Demand Charge** ($/kW/Month)	$29.50				$0.00	$0 .00	$29.50
Energy Charge ($/kWh)	$0.046000				$0.020100	$0.020100	$0.066100

GENERAL SERVICE TIME OF USE - EXPERIMENTAL
SCHEDULE GS-TOU

Minimum Monthly Charge

The greater of the following:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Power Factor

The Customer shall maintain power factor of not less than 95% but not greater than unity. The Cooperative shall have the right to measure such power factor at any time. Should such measurement establish that the power factor of the Customer is less than 95% or greater than unity, the Customer shall upon 60 days written notice correct such power factor to 95% to unity. If not timely corrected, the Cooperative shall have the right to increase the kWh for billing purposes by one percent for each one percent of power factor below 95% or above unity.

Billing Demand

The billing demand shall be the maximum kilowatt demand established by the Customer for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a suitable metering device, but not less than the highest billing demand in the previous eleven months.

Coincident Demand

The Coincident Demand is the Customer's monthly metered demand as recorded by suitable metering device at the time of the SWTC peak.

Other Provisions

The Customer will be provided by the Cooperative with information concerning historical SWTC monthly peak dates and times.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not

guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Greater Than 2000 kW and Less Than 10,000 kW Rate (GS4) is applicable for three-phase service for all electric service used for Commercial, Business, Professional and Industrial peak loads in excess of 2,000 kW but not to exceed 9,999 kW which are supplied at one point of delivery and measured through one meter. Existing Customers served by this tariff may continue to take service under this tariff if they met tariff eligibility requirements prior to the effective date. Service under this rate tariff cannot be interrupted intentionally to avoid demand charges.

Alternately, at the Customer's option it may take delivery at multiple delivery points with one primary metering point provided that the Customer pays the Cooperative a non-refundable contribution in aid of construction or, at the Cooperative's discretion, the Cooperative will install the facilities required to serve multiple delivery points and the Customer will pay for such facilities pursuant to a monthly facilities charge assessed based upon a cost analysis to serve the load. The Cooperative has the right to meter in the most practicable manner, either primary or secondary voltage. Service is available only if the Cooperative has adequate facilities to serve the Customer or if adequate facilities can be built at the Customer's expense to provide such service.

Type of Service

At available transmission or distribution voltages determined by the Cooperative. Where service of the type desired by the Customer is not already available at the point of delivery, additional charges under the Cooperative's RRLEP and special contract arrangements may be required prior to service being furnished.

Monthly Rate

a. Customer Charge:

Meter Cost	$450.97 per month
Meter Reading	$ 0.98 per month
Billing	$ 6.33 per month
Access	$ 41.72 per month
Total Customer Charge	$500.00 per month

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

b. Distribution Demand Charge at the Applicable Metering Point:

Transmission Delivery	$0.21 per kW of Billing Demand, or
Distribution Substation Delivery	$1.75 per kW of Billing Demand, or
Distribution Primary Delivery	$7.19 per kW of Billing Demand, or
Distribution Secondary Delivery	$7.70 per kW of Billing Demand

Definition of Service Levels

Transmission Delivery is defined as service taken at 69 kV or higher.

Substation Delivery is defined as service taken directly from the low side bus of the distribution substation or where Customer has requested that multiple points of delivery be metered at the low side bus of the distribution substation. Where multiple delivery points are metered at the low side bus of the distribution substation, the Customer will be charged an additional facilities charge for the Cooperative-owned, operated or maintained facilities on the Customer side of the meter

Distribution Primary is defined as service taken at standard distribution voltages where the Customer owns the final distribution transformation equipment or where the Customer has requested that multiple points of delivery be metered at a single primary metering location. Where multiple delivery points are metered at a single primary metering location, the Customer will be charged an additional facilities charge for the Cooperative-owned, operated or maintained facilities on the Customer side of the meter.

Distribution Secondary is defined as service taken at standard secondary voltages where the Cooperative owns the final distribution transformation equipment.

c. Wholesale Power Cost:

The Wholesale Power Cost shall be the cost of electricity to serve the Customer, including but not limited to, capacity, energy, transmission, ancillary services and fuel charges for the current billing period plus adjustments applied to the current monthly billing to account for differences in actual purchased electricity costs billed in previous periods from all providers who provide services in connection with the Wholesale Power Cost. The Wholesale Power Cost will be calculated using the billing units defined in the same manner as defined in the wholesale rate to the Cooperative, including any ratchet provisions in the wholesale rate. The Customer's billing units may be adjusted for line losses, as determined by the Cooperative, to calculate the Customer's power cost at the wholesale supplier's metering point to the Cooperative.

d. Facilities Charge:

An additional monthly charge for the provision of distribution facilities as determined by the written Agreement between the Cooperative and the Customer.

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

Determination of Facilities Billing Demand

The Billing Demand for purposes of determining the Distribution Demand Charge will be the greater of: (1) the contract demand as defined in the Agreement for Electric Service, (2) the highest maximum thirty-minute demand established during the current and previous eleven billing periods, or (3) 2,000 kW.

Minimum Monthly Charge

The greater of the amount specified in the written Agreement between the Cooperative and the Customer or the sum of the monthly Customer Charge, Distribution Demand Charge, and Facilities Charge, not including any wholesale power cost adjuster or any other adder approved by the Arizona Corporation Commission.

Power Factor

The Customer shall maintain power factor at the time of the Customer's maximum demand as close to unity as possible. The Cooperative shall have the right to measure such power factor at any time during the billing period. In the event the power factor measured at the time of the Customer's maximum demand is less than 95% lagging or leading, such maximum shall be adjusted for billing purposes by dividing such maximum measured demand by the measured power factor multiplied by 0.95.

Tax Adjustment

To each of the charges computed in this Tariff, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues and/or the price or revenue from the electric distribution, capacity and energy and transmission and ancillary services, sold and/or the volume of energy purchased for sale and/or sold hereunder.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions, or use of service, the Cooperative will assist in determining if a change in rate schedule is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

All electric service provided pursuant to this Tariff shall be set forth in a written agreement between the Cooperative and the Customer. Any service provisions that are different from the provisions of the Tariff shall be set forth in a written agreement that will require the approval of the Arizona Corporation Commission. The written agreement shall contain, among other provisions, provisions for a Contract Demand, Minimum Monthly Charge and a Facilities Charge to cover capital costs and operation and maintenance costs, if applicable. Should the Customer request service at the Transmission Delivery rate, and should the line connections be made directly with the lines of the Cooperative's transmission provider, then the contract may become a three-party contract to cover the provisions required by the Cooperative's transmission provider.

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

WATER PUMPING SERVICE
SCHEDULE WP (FROZEN)

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Water Pumping Service Rate (WP) is applicable to all electric pump installations that are furnishing water to Customers on a commercial basis prior to July 1, 1992 in accordance with Decision Number 57915. All water pumping Customers connected after the effective date will be placed on applicable General Service Rate. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three-Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Energy Charge ($/kWh)	$0.104000				$0.039600	$0.039600	$0.143600

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

WATER PUMPING SERVICE
SCHEDULE WP (FROZEN)

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

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Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

IRRIGATION SERVICE
SCHEDULE IR1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Irrigation Service Rate (IR1) is applicable to all single and three phase irrigation pumping installations of ten (10) horsepower pumps or larger. This rate is only applicable to farm use. Not applicable where water is sold to other Customers, not for resale, breakdown or standby or auxiliary service. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three-Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Energy Charge ($/kWh)	$0.110000				$0.032010	$0.032010	$0.142010

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity
3. The amount specified in the written contract between the Cooperative and the Customer

IRRIGATION SERVICE
SCHEDULE IR1

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

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Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

TIME OF DAY PUMPING SERVICE
SCHEDULE TODP

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Time of Day Pumping Service Rate (TODP) is applicable to all water pumping installations of ten (10) horsepower pumps or larger. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

TIME OF DAY RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$14.15	$27.00	$27.00
Three-Phase		$5.54	$0.98	$6.33	$22.15	$35.00	$35.00
Billing Demand Charge ($/kW)* On-Peak	$16.00						$16.00
Billing Demand Charge ($/kW)** Off-Peak	$0.00				$1.75	$1.75	$1.75
Energy Charge($/kWh)							
On-Peak	$0.043900				$0.020100	$0.020100	$0.064000
Off-Peak	$0.043900				$0.020100	$0.020100	$0.064000

*The Billing Demand Charge On-Peak shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month during the on-peak period of that billing month.

TIME OF DAY PUMPING SERVICE
SCHEDULE TODP

**The Billing Demand Charge Off-Peak shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month during the off-peak period of that billing month.

Definition of On-Peak

April 1 through October 31: For this rate schedule, on-peak hours are 1:00 p.m. to 9:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

November 1 through March 31: For this rate schedule, on-peak hours are 6:00 a.m. to 10:00 a.m., and 6:00 p.m. to 10:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

Metering Cost

The Customer shall pay the Cooperative, prior to installation, any cost for the Time-of-Day Energy and Demand Meter, which cost exceeds the metering cost that would be incurred by the Cooperative for such a pumping installation without a Time-of-Day Meter.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative

will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

***Definition of Holidays**

Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. If a Holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a Holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
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Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

LIGHTING SERVICE
SCHEDULE OL1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Lighting Service Rate (OL1) is applicable to Cooperative owned and operated lighting facilities generally on private property and otherwise subject to local jurisdictional lighting ordinances.

Type of Service

Single-phase, unmetered, 60 hertz, at one standard voltage 120/240.

Monthly Rate

For the Cooperative owned, operated and maintained lighting, the monthly rate shall be as follows, based on estimated average monthly usage for unmetered lights:

Cooperative-Owned and Maintained Lighting Service	Power Supply		Distribution			Total Rate
			Billing	Access	Total	
Security Lights	$4.33			$7.67	$7.67	$12.00
Additional Poles for Lights				$10.90	$10.90	$10.90
150 Watt HPS	$3.68			$8.14	$8.14	$11.82
250 Watt HPS	$6.13			$6.37	$6.37	$12.50
400 Watt HPS	$9.81			$2.89	$2.89	$12.70
55 Watt LPS	$2.21			$9.19	$9.19	$11.40
90 Watt LPS	$2.21			$9.19	$9.19	$11.40
135 Watt LPS	$3.68			$8.14	$8.14	$11.82
100 Watt HPS	$2.45			$9.02	$9.02	$11.47

LIGHTING SERVICE
SCHEDULE OL1

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

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Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff does not exist, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services. A Service Availability Charge shall be paid by the Customer who elects to have the lighting service disabled but remain connected in place. Lights disabled or disconnected for a period of 6 consecutive months are considered idle or inactive, and shall be subject to inspection requirements prior to reactivation depending on the jurisdictional authority.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

LIGHTING SERVICE
SCHEDULE OL1

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

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Effective Date: _____

STANDARD OFFER TARIFF

STREET LIGHTING SERVICE
SCHEDULE SL1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Street Lighting Service Rate (SL1) is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds within the Cooperative's Certificated Area as contracted with city, town or other governmental entities. This tariff applies to Customer provided lighting facilities which are operated by the Cooperative.

General Maintenance

The Cooperative shall have no duty to inspect the facilities to determine if any lights of any of the facilities operated by the Cooperative are not functioning or satisfactorily functional. The duty of inspecting the functioning state of the lights is the obligation of the Customer. When the Cooperative is properly notified by the Customer that such lights or other facilities are not functioning or satisfactorily functioning, the Cooperative within a reasonable time will maintain such lights or facilities.

Light or Pole Numhering

Customer will provide and affix physical numbering of all lights on the light standard or lighting poles for all installations in order to facilitate accurate inventory, reporting, and locating. Affixed numbering is required prior to energizing facilities. Numbering must be durable, weather proof, and be legible from the ground and shall follow the numbering scheme the Cooperative will provide to the Customer.

Maintenance By The Cooperative

Rates include all labor and material necessary for the operation, inspection, cleaning, and/or replacement by the Cooperative of lamps, photocells and standard fixture glassware. Replacement is limited to certain glassware such as is commonly used and manufactured in reasonably large quantities which the Cooperative is able to obtain in a reasonable timeframe and reasonable cost for the Customer furnished lighting, based on the manufacturer's data provided by the Customer or already on record with the Cooperative. The Cooperative will invoice the Customer, at the Cooperative's rate, the cost for all other replacement material (not labor) used such as poles, fixtures, ballasts, non-standard glass, wiring or fusing type devices.

Installation and Maintenance by Customer

The Customer is responsible for all the supply, installation and materials, including, but not limited to, foundations, metal light standards, approved light poles if wood, fixtures, secondary wiring,

STREET LIGHTING SERVICE
SCHEDULE SL1

boxes, trenching, backfill, shading, conduit system, fusing, circuit breakers and electrical panels, from the Cooperative's designated distribution facilities to the point of delivery at each of the Customer's street light facilities. The point of delivery is defined for the tariff as the point of connection at the base of the pole when the Cooperative's source is underground or at the drip loop at the top of the pole when the Cooperative's source is overhead. This includes providing all applicable design, engineering, drawings, plans, permits and inspections related to the Customer's installation and which have been approved by the Cooperative. The Customer is responsible for all maintenance and repair of lighting circuitry beyond the point of delivery, damage repairs or replacements to lighting foundations, and damage repairs or replacements to any underground boxes and for all trench stability and backfills.

Type of Service

Single-phase, unmetered, 60 hertz, at one standard voltage 120/240.

Monthly Rate

For the Customer owned and Cooperative maintained street lighting system including lamps and glass replacements, subject to the Customer's responsibility set forth above, the monthly rate shall be as follows, based on estimated average monthly usage for unmetered lights:

Customer-Provided and Cooperative-Maintained Lighting Service	Power Supply		Distribution			Total Rate
			Billing	Access	Total	
150 Watt HPS	$3.68			$7.08	$7.08	$10.76
250 Watt HPS	$6.13			$4.63	$4.63	$10.76
400 Watt HPS	$9.81			$7.96	$7.96	$17.77
55 Watt LPS	$2.21			$5.42	$5.42	$7.63
90 Watt LPS	$2.21			$10.07	$10.07	$12.28
135 Watt LPS	$3.68			$7.08	$7.08	$10.76
180 Watt LPS	$4.41			$8.78	$8.78	$13.19
100 Watt HPS	$2.45			$8.31	$8.31	$10.76
Standard Wood Pole (25' – 30')*				$1.38	$1.38	$1.38
10' - 20' Metal Pole				$3.64	$3.64	$3.64
21' – 30' Metal Pole				$4.34	$4.34	$4.34
31' – 40' Metal Pole				$4.34	$4.34	$4.34

*Measured from the top of foundation base to top of metal pole or from existing grade to top of wood pole

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

STREET LIGHTING SERVICE
SCHEDULE SL1

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff does not exist, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services. A Service Availability Charge shall be paid by the Customer who elects to have the lighting service disabled but remain connected in place. Lights disabled or disconnected for a period of 6 consecutive months are considered idle or inactive, and shall be subject to inspection requirements prior to reactivation depending on the jurisdictional authority.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

INTERRUPTIBLE SERVICE
SCHEDULE IS1 (FROZEN)

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. The Interruptible Service Rate (IS1) is applicable to Customers only prior to the effective date of this tariff. No new Customers will be accepted on this tariff after the effective date of the tariff.

Application

The Interruptible Service for Commercial and Industrial rate (IS1) is applicable for General Service Customers for Commercial, Business, Professional, and Industrial, Irrigation Pumping and Water Pumping loads from in excess of 10 kW and a monthly load factor greater than 30% in any month within a 12 month period. The Cooperative shall have the right to meter the installation in the most practical manner, either primary or secondary voltage, and to determine the number of meter (service) points at any installation.

In the event the Customer has metered demand at the time of the Arizona Electric Power Cooperative, Inc. (AEPCO) or its successor organization, peak more than twice in a calendar year, the Cooperative may disconnect the controlling device and discontinue Interruptible Service. A Customer removed for non-compliance may not be considered for Interruptible Service for a minimum of eighteen (18) months.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase.

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$11.18	$0.98	$6.33	$17.51	$36.00	$36.00
Three-Phase		$11.18	$0.98	$6.33	$26.51	$45.00	$45.00
Coincident Demand Charge* ($/kW/Month)	$19.50						$19.50

INTERRUPTIBLE SERVICE FOR COMMERCIAL AND INDUSTRIAL SCHEDULE IS1 (FROZEN)

Billing Demand Charge** ($/kW/Month)	$0.00	$1.75	$1.75	$1.75
Energy Charge ($/kWh)	$0.065300	$0.02230	$0.02230	$0.08760

*The Coincident Demand Charge is applied to the Customer's monthly measured demand as recorded by suitable metering device at the time of the SWTC peak or if Trico does not initiate control at the proper time to avoid the SWTC billing peak or if the control system does not properly function to disconnect the load, the Customer will not be billed the Coincident Demand Charge. However, the Customer will be billed the Coincident Demand Charge using the Customers demand from the time of the last successful Trico initiated control.

** The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15-minute interval demand for the billing month.

Metering Cost

The Customer shall pay the Cooperative, prior to installation, any cost for the time-of-use and demand meter, special metering or control equipment which cost exceeds the cost that would be incurred by the Cooperative for non-interruptible service.

Control and Metering

The service will be interrupted anytime Trico anticipates the possibility of a maximum monthly peak kilowatt demand. Control will be initiated by Trico and the control signal will be via radio-controlled equipment or notification will be provided to the Customer by telephone or some other normal method of load control. The Cooperative will not interrupt more than twelve times in any given month.

The account will be metered with a time-of-use/demand meter to enable Trico to accurately measure the Customer's kW Demand during control periods and at the time of monthly SWTC billing peak. If Trico does not initiate control at the proper time to avoid the SWTC billing peak or if the control system does not properly function to disconnect the load, the Customer will not be billed the Coincident Demand Charge. However, the Customer will be billed the Coincident Demand Charge using the Customers demand from the time of the last successful Trico initiated control.

An Interruptible Service Agreement, discussing all conditions of interruptible service, will be signed by Trico and the Customer.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be

assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule. Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES 100 KW AND GREATER SCHEDULE COGEN1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities 100 kW and Greater Rate (COGEN1) is applicable to Customers of the Cooperative that own and operate qualified cogeneration and small power production facilities of 100 kW or more that meet qualifying status as defined under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission's regulations and pursuant to the Arizona Corporation Commission's Decision No. 52345. The facility's generator(s) and Customer's load must be located at the same premise.

The owner of the Qualifying Facility (QF) shall enter into a contract pertaining to the operation of the QF by the QF owner with the Cooperative to implement this schedule COGEN1 consistent with the terms and conditions set forth herein.

Type of Service

Single- or three-phase, alternating current, 60 cycles, at available secondary or primary voltages at one standard voltage as may be selected by the Customer.

Supplementary Power

A. Definition of Supplementary Power
Supplementary power is the kW capacity and related kWh energy purchased by the QF in excess of the production capability of the QF's generating equipment.

B. Rates
The rates charged for supplementary power shall be the appropriate standard offer retail Tariff of the Cooperative which is applicable to the QF's class of service or any new retail rate agreed to by the parties and approved by the Arizona Corporation Commission.

C. Determination of Supplementary Energy
Supplementary energy shall be equal to the metered kWh being supplied to the QF, less any kWh billed as standby or maintenance energy.

D. Determination of Supplemental Demand
Supplemental demand shall be the greater of:

1. The metered demand, measured in accordance with the Cooperative's appropriate standard offer retail rate schedule, less any standby and maintenance demand; or
2. The minimum supplemental billing demand specified in the QF's contract.

Standby and Maintenance Power

A. Definition of Standby - Maintenance Power
Standby and maintenance power is the kW capacity and related kWh supplied by the Cooperative attributable to forced or scheduled outages by the QF, respectively.

B. Rates
Reservation/Capacity Charge
The reservation/capacity charge for standby and maintenance power shall be the sum of the distribution billing demand charge in the applicable direct access retail rate schedule plus the applicable demand charges in AEPCO's Tariff and SWTC's Tariff each month multiplied by the contract Standby Capacity, as determined in Section E. of this section.

Energy Charge
The rate applicable to standby and maintenance energy shall be the sum of the distribution energy charge in the applicable direct access retail rate schedule plus the current energy rate from AEPCO multiplied by the sum of the Standby Energy and Maintenance Energy as determined in Sections C and D of this section.

C. Determination of Standby Energy
Standby energy is defined as electric energy supplied by the Cooperative to replace power ordinarily generated by the Customer's generation facility during unscheduled full and partial outages of said facility. Standby energy is equal to the difference between the maximum energy output of the Customer's generator(s) and the energy measured on the Customer's generator meter(s) for the billing period, except those periods where energy supplied by the Cooperative is zero.

D. Determination of Maintenance Energy
Maintenance energy is defined as energy supplied to the Customer to a maximum of the Contract Standby Capacity times the hours in the Scheduled Maintenance period. Maintenance periods shall not exceed 30 days and must be scheduled during off peak months. Customer shall supply the Cooperative with a maintenance Schedule for a 12-month period at least 60 days prior to the beginning of that period, which is subject to the Cooperative's approval. Energy used in excess of a 30-day period of unauthorized maintenance energy shall be billed on the Supplemental Power Rate as specified in this Schedule.

E. Contract Standby Capacity kW
Contract Standby Capacity kilowatt (kW) amount is the amount of cogeneration or self-generation capacity for which the Customer contracts with the Cooperative for Standby Service. If the contract Standby Capacity is exceeded and not covered by the Supplementary Power provisions of this tariff, then the contract standby capacity is

automatically increased to the new level. The Contract Standby Capacity kW cannot exceed the maximum net output rating(s) of the connected generator(s).

Basic Service Charge

The monthly basic service charge shall be the service charge contained in the Cooperative's current applicable retail rate schedule.

Conditions of Service

Scheduled outages for maintenance by the QF shall be submitted each December to AEPCO for the next coming year for its approval. Scheduled outages will not be permitted during the months of April through October.

Interconnection Charge

The QF shall pay all costs associated with any and all additions, modifications or alterations to SWTC's or Trico Electric Cooperative's electric system necessitated or incurred in the establishment and operation of the interconnection with the QF, including but not limited to any and all modifications required for the metering of power and energy or for the efficient, safe and reliable operation of the QF's facilities with SWTC's electric system or the Cooperative's electric system.

Facility Charge on Dedicated Facilities

The QF shall be required to pay to the Cooperative a monthly facilities charge to recover all related costs of any dedicated facilities constructed to serve the QF on a firm power and energy basis.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Contract Period

As provided in the Cooperative's agreement for service with the Customer.

OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES 100 KW AND GREATER SCHEDULE COGEN1

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

COGENERATION QUALIFYING FACILITIES SERVICE
SCHEDULE QF1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Cogeneration Qualifying Facilities Rate (QF1) is applicable to owners of co-generation qualifying facilities and small power production facilities under 100 kW who are retail Customers and who enter into a written contract with the Cooperative with respect to such service. Service shall be supplied at one point of delivery where part or all of the electrical requirements of the Customer can be supplied from a source or sources, owned by the Customer, and where such sources are connected for parallel operation of the Customer's system with the system of the Cooperative. Customer sources may include but are not limited to windmills, water wheels, solar conversion and geothermal devices, each of which is capable of generating less than 100 kW.

Type of Service

The type of service furnished the Customer pursuant to this rate tariff shall be determined in the reasonable discretion of the Cooperative.

Monthly Rate

All purchases from the Cooperative and sales to the Cooperative shall be treated separately. For capacity and energy supplied by the Cooperative to the Customer, the applicable rate shall apply. For energy supplied by the Customer to the Cooperative, the rates shall be as follows:

> For non-firm power the purchase rate will be the sum of the wholesale energy and fuel charges from the Cooperative's wholesale power supplier. For firm service the purchase rate will be the non-firm purchase rate plus ten percent (10%).

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes of governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

COGENERATION QUALIFYING FACILITIES SERVICE
SCHEDULE QF1

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

STANDARD OFFER TARIFF

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

SERVICE ESTABLISHMENT FEE:

For the establishment of service to a single existing connection:	**$ 50.00**
For the establishment of service to a single new construction service connection:	**$ 100.00**

A Service Establishment Fee shall entitle the Customer to one service connection including transfer of service. The Service Establishment Fee shall be non-refundable, non-transferable and shall not apply against a final or other bill rendered by the Cooperative to the Customer. An additional Service Establishment Fee shall be collected for each additional service connection, or transfer of service.

RE-ESTABLISHMENT FEE DURING REGULAR HOURS:	**$ 50.00**
RE-ESTABLISHMENT FEE AFTER REGULAR HOURS:	**$ 70.00**

A fee will be charged to re-establish electric service when it is reconnected to the same Customer who requested the service to be disconnected. If the disconnection period is 12 months or less, the applicable monthly Customer Charge for each month of the disconnection period shall also be paid by the Customer. Should the Customer request the re-establishment after regular hours, the after-hours fee will be charged.

SERVICE CALLS AND SERVICE CONNECTION FEES:	**$ 50.00**
RETURN TRIP:	**$ 50.00**

The fees for Service Calls, Return Trip and Service Connections during regular hours shall be charged in accordance with Section 144 of the Rules, as defined below. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Fees shall be applicable for each trip made.

A. For interruptions caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to work beyond the point of delivery.

B. For reconnection of electric service to any Customer previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative System, failure to establish credit and/or sign an agreement for service, or any other reason authorizing the Cooperative to make such disconnections; per trip.

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

C. For response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the point of delivery.

D. To a Customer who fails to comply with any of the Cooperative's Conditions for Supplying Service requirements listed under Section 106 or any other applicable section, or fails to meet any of the Customer's Responsibility. Including return trips for Cooperative inspection of distributed generation.

SERVICE CALLS AFTER REGULAR HOURS:

For calls requiring a meter crew:	**$ 70.00**
For calls requiring a service crew:	**$ 175.00**

The fees for Service Calls after Regular Hours shall be charged in accordance with Section 144 of the Rules, as defined below. The amount of the Service Fees shall be determined by the type of personnel needed. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Fees shall be applicable for each trip made.

A. For interruptions caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to perform any work beyond the point of delivery.

B. For reconnection of electric service to any Customer previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative system, failure to establish credit and/or sign an agreement for service or any other reason authorizing the Cooperative or any other such disconnection. Such work will be performed only when requested and agreed to by the Customer.

C. For response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the point of delivery.

D. To a Customer who fails to comply with any of the Cooperative's Conditions for Supplying Service requirements listed under Section 106 or any other applicable section of the Rules, or fails to meet any of the Customer's Responsibility in Steps.

METER RE-READS: **$ 25.00**

The fees for Meter Re-reads shall be charged in accordance with Section 315 of the Rules which has been amended to read as follows. The Cooperative will reread a meter at the request of the Customer for a fee, provided that the original reading was not in error. When a reading is found to be in error, the re-read shall be at no charge to the Customer.

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

CUSTOMER-REQUESTED METER TESTS: **$ 35.00**

The fees for Customer-Requested Meter Tests shall be charged in accordance with Section 331 of the Rules. However, if the meter is found to be in error by more than three percent (3%), no meter testing fee will be charge to the Customer.

SERVICE CHARGE FOR INSUFFICIENT FUNDS CHECK, PAYMENT TRANSACTION RETURN OR CHARGE BACK: **$ 30.00**

The fees for insufficient funds check, payment transaction returns, or charge backs shall be charged in accordance with Section 337 of the Rules.

LATE PAYMENT CHARGE: **1% of Unpaid Balance**

A one percent (1%) late payment charge on the unpaid balance will be applied after 30 days, from the date the bill is rendered, as defined in Section 321 of the Rules.

COLLECTION FEE: **$ 50.00**

This fee will be applied each time a Cooperative authorized representative must make a field contact regarding a delinquent bill, picks up a payment at the request of the Customer, or must return to the same premises when the Customer fails to have funds available for a service reconnect, previously disconnected for non-payment, as defined in Section 144 of the Rules.

SERVICE AVAILABILITY CHARGE:

A Service Availability Charge may be charged to reimburse the Cooperative for its operating expenses with regard to idle or standby services. The Service Availability charge may be based on the monthly Customer charge or minimum, per Section 372 of the Rules, or be based upon the Cooperative's estimate of its actual operating costs for such idle or standby services, whichever the Cooperative determines appropriate.

INTEREST ON DEPOSITS:

The Cooperative will pay an interest rate on deposits, as referred to in Section 126 of the Rules, equal to the Annual Three Month Commercial Financial Paper (TMCFP) rate as published by the Federal Reserve. This floating interest rate is applicable to Customer security deposits held by the Cooperative for new Customers or Customers who have not paid their bills in a timely fashion. The Cooperative will update the TMCFP rate annually, in January of each year.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: September 1, 2013

STANDARD OFFER TARIFF

DEMAND SIDE MANAGEMENT ADJUSTMENT SCHEDULE DSMA

Background

On August 10, 2010, the Arizona Corporation Commission ("Commission") issued Decision No. 71819 that contained an Electric Energy Efficiency Standard ("EEES") which set forth annual energy efficiency requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval of a Demand Side Management ("DSM") Tariff to fund such energy efficiency requirements.

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. The standard Rules, Regulations and Line Extension Policies of the Cooperative, as on file from time to time with the Arizona Corporation Commission, shall apply where not inconsistent with this tariff.

Application

The Cooperative shall recover its costs for Commission pre-approved DSM programs through a DSM mechanism which shall provide for a separate and specific Commission accounting for pre-approved DSM costs. The Demand Side Management Adjustment Tariff (DSMA) shall be applicable to all Customers receiving standard service and will be assessed monthly, per billing meter, on a per kilowatt-hour of the retail electricity purchased by the consumer.

Monthly Rate

The DSMA shall be applied to all monthly bills at $0.000058 per kilowatt-hour, per billing meter.

The DSMA is in addition to all other rates and charges applicable for service to the Customer.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2016

STANDARD OFFER TARIFF

RENEWABLE ENERGY STANDARD TARIFF
SCHEDULE RES

Background
On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") which set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval a RES Tariff to fund such renewable energy requirements.

Availability
In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application
On all bills for all governmental and agricultural members/customers, a Renewable Energy Standard Surcharge mandated by the Arizona Corporation Commission ("Commission") will be assessed monthly, per billing meter, at the lesser of the per kilowatt-hour of retail electricity purchased by the consumer, or the maximum, both as stated below. In the case of unmetered services, Trico Electric Cooperative, Inc. ("Cooperative") shall, for purposes of billing the RES Surcharge and subject to the maximum assessment set forth herein, use the lesser of (i) the load profile or otherwise estimated kWh required to provide the service in question; or (ii) the service's contract kWh.

Monthly Rate

Customer	kWh	Maximum
Governmental and Agricultural	$0.000438	$18.50

RENEWABLE ENERGY STANDARD TARIFF
SCHEDULE RES

Application

On all bills in all other tariff service categories than those listed above, an RES Surcharge mandated by the Commission will be assessed monthly, per billing meter, at the lesser of the per kilowatt-hour of retail electricity purchased by the consumer, or the maximum stated below.

In the case of unmetered services, the Cooperative shall, for purposes of billing the RES Surcharge and subject to the maximum assessment set forth herein, use the lesser of (i) the load profile or otherwise estimated kWh required to provide the service in question; or (ii) the service's contract kWh.

Monthly Rate

Customer	kWh	Maximum
Residential	$0.002380	$1.20
Non-Residential	$0.002380	$59.50
Non-Residential (equal to or greater than 3,000 kW)	$0.002380	$1,135.00

RES Surcharge Cap for Residential Prepaid Service (RPS) customers: $0.04 per day

The RES Surcharge is in addition to all other rates and charges applicable to service to the members/customers.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

STANDARD OFFER TARIFF

RENEWABLE ENERGY CUSTOMER SELF-DIRECTED TARIFF SCHEDULE RESD

Background

On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") that set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval a RES Customer Self-Directed Option Tariff as defined below.

Availability

The RES Customer Self-Directed Option is available to single and three phase service for Non-Residential Customers with multiple meters that pay more than $25,000 annually in RES Surcharge funds pursuant to the Renewable Energy Standard Tariff for any number of related accounts or services within the Trico Electric Cooperative, Inc. ("Cooperative") service territory ("Eligible Customer").

Application

An Eligible Customer may apply to the Cooperative to receive funds to install Distributed Renewable Energy Resources. An Eligible Customer seeking to participate in this program shall submit to the Cooperative a completed application that describes the Renewable Energy Resources that it proposes to install and the projected cost of the project. An Eligible Customer shall provide at least half of the funding necessary to complete the project described in its application.

An Eligible Customer shall enter into a contract with the Cooperative that specifies, at a minimum the following information: the type of Distributed Generation ("DG") resource, its total estimated cost, kWh output, its completion date, the expected life of the DG system, a schedule of the Eligible Customer's expenditures and invoices for the DG system, Cooperative payments to an Eligible Customer for the DG system and the amount of a Security Bond or Letter of Credit necessary to ensure the future operation of the Eligible Customer's DG System, metering equipment, maintenance, insurance and related costs.

Before connection to the Cooperative's electrical system, an Eligible Customer's DG Resource shall meet all of the Cooperative's DG interconnection requirements and guidelines.

All Renewable Energy Credits derived from the project, including generation and extra credit multipliers, shall be applied to satisfy the Cooperative's Annual Renewable Energy Requirement.

The funds annually received by an Eligible Customer pursuant to this tariff may not exceed the amount annually paid by the Eligible Customer pursuant to the RES Surcharge Tariff.

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

VOLUNTARY RENEWABLE ENERGY STANDARD PROGRAM TARIFF SCHEDULE VRES

Availability

The Renewable Energy Standard ("RES") Voluntary Contribution Program is available to all Customers of Trico Electric Cooperative, Inc. ("Cooperative") who wish to contribute funds in support of the construction and acquisition of renewable resources.

Background

On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") that set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona. The RES Plan may be modified from time to time on further application to the Commission. Funds to support the RES Plan are collected by the Cooperative pursuant to Commission Rules and applicable RES Surcharge tariffs and are remitted to Cooperative for expenditure in accordance with the terms of the approved RES Plan. The purpose of this RES Voluntary Contribution Program is to allow Customers an option to contribute additional amounts if they desire in support of the RES Plan.

Contribution Program

Participation in the Contribution Program is voluntary. Any Customer desiring to participate in the Contribution Program may do so by completing and returning to the Cooperative a form supplied by the Cooperative specifying the amount of the monthly contribution. Customers may purchase 50 kWh blocks of green energy for an additional cost of $2.00 per block. The amount of the cost of the blocks selected will then be added to the Customer's bill on a monthly basis. All monthly contributions associated with this tariff shall be utilized to permit the participation in the Contribution Program. Customers may cancel their participation in the Contribution Program at any time by notifying the Cooperative at least 30 days in advance of the Customer's billing date of their decision to cancel effective as to such billing date on a form supplied by the Cooperative.

Elections to participate or to cancel participation in the Contribution Program may only be by completion of applications on forms supplied by the Cooperative, which are available at the Cooperative's main office or on the Cooperative's website.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

SUNWATTS SUN FARM TARIFF
SCHEDULE RESF

Background and Availability

The Arizona Corporation Commission ("Commission") approved the Renewable Energy Standard and Tariff Rules ("REST Rules") in Decision No. 69127 dated November 14, 2006, which set out the renewable energy requirements for all affected electric utilities in the State of Arizona. Trico Electric Cooperative, Inc. ("Cooperative") has prepared a REST Plan which provides for rebate support of Customer owned renewable resources and larger scale renewable resources. The REST Plan may be modified from time to time on further application to the Commission.

The Residential Community Solar Demonstration Project Voluntary Purchase Program ("SunWatts Sun Farm") is part of the Cooperative REST Plan and is available to all RS1, RS1TOU, GS1, GS2 and GS3 Customers of the Cooperative who wish to participate in support of renewable resources through purchase of energy output from the installation of a Cooperative-owned Photovoltaic (PV) generation facility. A Customer may purchase panel output up to but not to exceed their average monthly kWh energy usage in the last twelve month period up to a maximum of 10,000 watts per Customer.

The Sun Watts Sun Farm is designed to produce 227,000 watts and is located at the Cooperative office facility at 8600 W. Tangerine Road, Marana, Arizona 85658. The Cooperative plans to utilize all proceeds associated with this tariff for future expansion of the SunWatts Sun Farm through construction of additional SunWatts Sun Farm renewable resources.

Program

The SunWatts Sun Farm provides for voluntary participation by residential and small commercial Customers which may benefit renters and other Customers who cannot install renewable resources on their property, to Customers that want to expend only a small amount of initial capital on renewable energy.

Any Customer desiring to participate in the SunWatts Sun Farm must complete and return an application. Participation shall be on a first-come, first-serve basis until the full output of the facility is assigned. Each applicant awarded panel output will enter into a purchase contract with the Cooperative, which will specify the rights and obligations of the arrangements for a twenty year term.

SUNWATTS SUN FARM TARIFF
SCHEDULE RESF

Customers may purchase the output of PV panels from the SunWatts Sun Farm in ¼, ½ and full panel increments. The Customer will be billed the full cost of the panels contracted as a one-time up-front charge.

The Customer will receive a credit for the energy output of the panel(s), estimated to be 432 kWh per year, per panel, in accordance with the rates and charges under the Customer's Standard Rate Schedule in a similar fashion as the Cooperative's Net Metering Tariff Schedule NM. The Cooperative will apply the credit to the Customer's monthly bill for the 20 year term of the purchase contract or until such time as the Customer's purchase contract is terminated or the Customer assigns some or all of the solar panels subject to a purchase contract subject to the Cooperative's written approval. The Cooperative shall retain the rights to all the Renewable Energy Credits (RECs) produced by the Sun Watts Sun Farm.

Pricing of the Sun Watts Sun Farm panels is described in the table below:

Panel Size	Cost
Quarter Panel	$230
One Half Panel	$460
Full Panel	$920

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

SUNWATTS SUN FARM MONTHLY PARTICIPATION TARIFF
SCHEDULE RESFM

Background and Availability

The Arizona Corporation Commission ("Commission") approved the Renewable Energy Standard and Tariff Rules ("REST Rules") in Decision No. 69127 dated November 14, 2006, which set out the renewable energy requirements for all affected electric utilities in the State of Arizona. Trico Electric Cooperative, Inc. ("Cooperative") has prepared a REST Plan which provides for rebate support of customer owned renewable resources and larger scale renewable resources. The REST Plan may be modified from time to time on further application to the Commission.

The Residential Community Solar Demonstration Project Voluntary Purchase Program ("SunWatts Sun Farm") is part of the Cooperative REST Plan and is available to all RS1, GS1, GS2 and GS3 customers of the Cooperative who wish to participate in support of renewable resources through the purchase of energy output from the installation of a Cooperative-owned Photovoltaic (PV) generation facility. Customers being served under the Cooperative's time of use or self-generation tariffs may not purchase power under this Schedule RESFM (including, but not limited to the Cooperative's Net Metering Tariff Schedule NM).

Program

The Sun Watts Sun Farm is located at the Cooperative office facility at 8600 W. Tangerine Road, Marana, Arizona 85658. The SunWatts Sun Farm provides for voluntary participation by residential and small commercial customers which may benefit renters and other customers who cannot install renewable resources on their property, as well as, customers that want to expend minimal initial capital on renewable energy. The Cooperative plans to utilize all proceeds associated with this tariff for future expansion of the SunWatts Sun Farm through construction of additional SunWatts Sun Farm renewable resources.

A customer may purchase panel output up to but not to exceed their minimum monthly kWh energy usage in the last twelve-month period. A Customer can purchase solar energy output in solar blocks of 432 kWh per year or 36 kWh per month. The Cooperative will apply the energy charge to the customer's monthly bill for a 20-year term or until such time as the customer cancels his/her participation in the program.

SUNWATTS SUN FARM MONTHLY PARTICIPATION TARIFF
SCHEDULE RESFM

Rate

Wholesale power, transmission and distribution fixed costs will be applied to all energy delivered, including energy delivered under this Schedule RESFM. The customer is responsible for paying (each month) all charges incurred under their applicable rate schedule, and the total solar energy contracted for multiplied by the applicable Solar Block Energy Rate. Any demand based or fixed charges under the Customer's current Rate will not be affected by elections under Schedule RESFM. No discounts specified in any of the above-listed standard offer tariffs will apply to this Rate. Table 1 below provides a summary of the proposed Cooperative Standard Offer Tariffs effective _____ and Table 2 provides the resultant customer energy rate for each rate class with the RESSFM Tariff applied.

Table 1: Standard Offer Tariffs

Rate Class	Fixed Cost Portion Energy Rate ($/kWh)	Variable Cost Portion Energy Rate ($/kWh)	Total Energy Rate ($/kWh)
RS1 First 800 kWh/mo Over 800 kWh/mo	 $0.08213 $0.09213	 $0.0308 $0.0308	 $0.11293 $0.12293
GS1	$0.09602	$0.0308	$0.12682
GS2	$0.11573	$0.0308	$0.14653
GS3	$0.04423	$0.0308	$0.07503

Table 2: Schedule RESFM Applied to Standard Offer Tariffs

Rate Class	Fixed Cost Portion Energy Rate ($/kWh)	Solar Block Energy Rate ($/kWh)	Total Energy Rate ($/kWh)
RS1 First 800 kWh/mo Over 800 kWh/mo	 $0.08213 $0.09213	 $0.06132 $0.06132	 $0.14345 $0.15345
GS1	$0.09602	$0.06132	$0.15734
GS2	$0.11573	$0.06132	$0.17705
GS3	$0.04423	$0.06132	$0.10555

SUNWATTS SUN FARM MONTHLY PARTICIPATION TARIFF
SCHEDULE RESFM

Terms and Conditions

1. Participation in this program is limited in the Cooperative's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis.

2. Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty-year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Schedule RESFM is prohibited. Should the Customer cancel service for any reason, his or her subscription under RESFM will expire.

3. Customers may add or delete solar blocks once within a twelve-month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4. Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. Any electric usage below the amount covered by the solar block(s) will not be rolled forward and credited again to the Customer's usage in the following month.

5. All contracted solar block energy and associated charges in a billing month will be excluded from the calculation of the Cooperative's Wholesale Power Cost Adjustor (WPCA) and REST charges and/or credits.

6. The Cooperative shall retain the rights to all the Renewable Energy Credits (RECs) produced by the Sun Watts Sun Farm.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: _____

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Availability

Net Metering service is available to all Customers of Trico Electric Cooperative, Inc. (Cooperative) with a qualifying Net Metering Facility. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades. The electric energy generated by or on behalf of the Customer from a qualifying Net Metering Facility and delivered to the Cooperative's distribution facilities may be used to offset electric energy provided by the Cooperative during the applicable billing period. The Net Metering Tariff (NM) is applicable to Customers who have submitted Interconnection Applications prior to June 1, 2016. No new Customers will be accepted on this tariff after May 31, 2016.

Net Metering Facility means a facility for the production of electricity that:

a. Is operated by or on behalf of the Customer and is located on the Customer's premises;
b. Is intended primarily to provide part or all of the Customer's requirements for electricity;
c. Uses Renewable Resources, a Fuel Cell or CHP (as defined below);
d. Has a generating capacity less than or equal to 125% of the Customer's total connected load, or in the absence of Customer load data, capacity less than or equal to the Customer's electric service drop capacity; and
e. Is interconnected with and can operate in parallel and in phase with the Cooperative's existing distribution system.

Service under this tariff is available provided the rated capacity of the Customer's Net Metering Facility does not exceed the Cooperative's service capacity. The Customer shall comply with all of the Cooperative's interconnection standards. The Customer is also required to sign and complete a net metering application prior to being provided Net Metering Service.

Metering

Metering installed for the service provided under this tariff shall be capable of registering and accumulating the kilowatt-hours (kWh) of electricity flowing in both directions in a billing period.

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Monthly Billing

If the kWh energy supplied by the Cooperative exceeds the kWh energy that is generated by the Customer's Net Metering Facility and delivered back to the Cooperative during the billing period, the Customer shall be billed for the net kWh energy supplied by the Cooperative in accordance with the rates and charges under the Customer's Standard Rate Schedule.

If the kWh energy generated by the Customer's Net Metering Facility and delivered back to the Cooperative exceeds the kWh energy supplied by the Cooperative in the billing period, the Customer shall be credited during subsequent billing periods for the excess kWh energy generated. The Cooperative shall apply the credit by using the excess kWh energy generated during the billing period to reduce the kWh energy supplied (not kW or kVA demand or Customer charges) and billed by the Cooperative during the subsequent billing periods.

Customers taking service under time-of-use rates who are to receive credit in a subsequent billing period for excess kWh energy generated shall receive such credit during the following billing periods during the on- or off- peak periods corresponding to the on- or off- peak periods in which the kWh energy were generated by the Customer.

Each Calendar Year, for the Customer bills produced in October (September usage) or in the last billing period that the Customer discontinues service under this tariff, the Cooperative shall issue a check or billing credit to Customers with Net Metering Facilities for the balance of any credit due in excess of amounts owed by the Customer to the Cooperative for Non-Firm Power. The payment for any remaining credits shall be at the Cooperative's Annual Average Avoided Cost. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh. Any payment for Firm Power will be pursuant to a separate contract.

Administrative Charge

In order to determine accurate billing and usage, net metering Customers will need to have interval meter data available (minimum data collection of every half hour). This information is needed to ensure accurate billing and to calculate the net kWh energy billed or credited to the Customer's account. The following table shows the incremental costs for the increased data collection applicable to all rate classes.

Administrative Charge	Monthly Rate
Monthly Data Cost	$3.38

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Definitions

1. Annual Average Avoided Cost: Defined as the average annual wholesale fuel and energy costs per kWh energy purchased from the Cooperative's wholesale power supplier during the calendar year. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh.

2. Calendar Year: The Calendar Year is defined as October 1 through September 30, for the purpose of determining the billing credit for the balance of any credit due in excess of amounts owed by the Customer to the Cooperative.

3. Renewable Resource: Means natural resources that can be replenished by natural processes, including biomass, biogas, geothermal, hydroelectric, solar or wind.

4. Combined Heat and Power or CHP: Means a system that generates electricity and useful thermal energy in a single, integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility (also known as cogeneration).

5. Fuel Cell: Means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be from Renewable Resources.

6. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.

7. Firm Power: Electric power available from the Customer's facilities, upon demand, at all times with an expected or demonstrated reliability that is covered by a separate multiparty purchase agreement among the Customer, and the Cooperative.

8. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. On-peak and off-peak time periods will be determined by the applicable Standard Rate Schedule.

9. Standard Rate Schedule: Any of the Cooperative's retail rate schedules with metered kWh charges.

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85653
Filed By: Vincent Nitido
Title: General Manager/CEO

Effective Date: _____

DG ENERGY EXPORT TARIFF
SCHEDULE NM1

Availability

Service Under this tariff is available to all customers of Trico Electric Cooperative, Inc. (Cooperative) with a qualifying Renewable Distributed Generation (DG) Facility that applied for interconnection after May 31, 2016. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades. The electric energy generated by or on behalf of the customer from a qualifying Renewable DG Facility and delivered to the Cooperative's distribution facilities (Export Energy) will be credited to the Member by the Cooperative during the applicable billing period in accordance with the provisions of the Monthly Billing described herein.

Renewable DG Facility means a facility for the production of electricity that:

a. Is operated by or on behalf of the customer and is located on the customer's premises;
b. Is intended primarily to provide part or all of the customer's requirements for electricity;
c. Uses Renewable Resources, a Fuel Cell or CHP (as defined below);
d. Has a generating capacity less than or equal to 125% of the customer's total connected load, or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity; and
e. Is interconnected with and can operate in parallel and in phase with the Cooperative's existing distribution system.

Service under this tariff is available provided the rated capacity of the customer's Renewable DG Facility does not exceed the Cooperative's service capacity. The customer shall comply with all of the Cooperative's interconnection standards. The customer is also required to sign and complete a DG Energy Export Tariff application prior to being provided Service under this tariff.

Metering

Metering installed for the service provided under this tariff shall be capable of registering and accumulating the kilowatt-hours (kWh) of electricity flowing in both directions in a billing period.

EXPORT ENERGY TARIFF
SCHEDULE NM1

Monthly Billing

The energy (kWh) supplied by the Cooperative to the customer during the billing period, shall be billed by the Cooperative in accordance with the rates and charges under the customer's Standard Rate Schedule.

The energy (kWh) generated by the customer's Renewable DG Facility and delivered back to the Cooperative (Export Energy) shall be credited to the customer during the billing period at the Cooperative's Export Energy Rate. The Cooperative's Export Energy Rate shall be set at $0.0770 per kWh. Any payment for Firm Power will be pursuant to a separate contract. . If credits resulting from the Export Energy are greater than the customer's monthly bill, then that credit balance will carry forward to the following month. There will be no netting, rollover or banking of excess energy (kWh) within the month or to the following month.

All rates and charges are subject to change including the Export Energy Rate as may be approved by the Commission from time to time.

Administrative Charge

In order to determine accurate billing and usage, customers taking service under this tariff will need to have interval meter data available (minimum data collection of every half hour). This information is needed to ensure accurate billing and to calculate the net energy (kWh) billed or credited to the customer's account. The following table shows the incremental costs for the increased data collection applicable to all rate classes.

Administrative Charge	**Monthly Rate**
Monthly Data Cost	$3.38

EXPORT ENERGY TARIFF
SCHEDULE NM1

Definitions

1. Export Energy Rate: The Cooperative's Export Energy Rate shall be set at $0.0770 per kWh.

2. Renewable Resource: Means natural resources that can be replenished by natural processes, including biomass, biogas, geothermal, hydroelectric, solar or wind.

3. Combined Heat and Power or CHP: Means a system that generates electricity and useful thermal energy in a single, integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility (also known as cogeneration).

4. Fuel Cell: Means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be from Renewable Resources.

5. Non-Firm Power: Electric power which is supplied by the customer's generator at the customer's option, where no firm guarantee is provided, and the power can be interrupted by the customer at any time.

6. Firm Power: Electric power available from the customer's facilities, upon demand, at all times with an expected or demonstrated reliability that is covered by a separate purchase agreement among the customer and the Cooperative.

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. On-peak and off-peak time periods will be determined by the applicable Standard Rate Schedule.

8. Standard Rate Schedule: Any of the Cooperative's retail rate schedules with metered energy (kWh) charges.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: October 27, 2015

ESTIMATION METHODOLOGIES
SCHEDULE EM

Application

The Estimation Methodologies Rate (EM) is applicable for purposes of bill estimation for all tariffs in the event a valid meter reading cannot be acquired. The Cooperative will make every reasonable attempt to secure an accurate reading of the meter. The Cooperative will make special efforts to secure an accurate reading of the meters for accounts with demand reading.

This rate is not applicable to resale or standby services.

Conditions for Estimated Bills

Estimated bills will be issued only under the following conditions:

A. Labor shortages or work stoppages beyond the control of the Cooperative.

B. Severe weather conditions, emergencies or other causes beyond the Cooperative's control which prevent the Cooperative from reading the meter.

C. Circumstances that make it dangerous or impossible to read the meter, including but not limited to: locked gates, blocked access to meters, threatening or abusive conduct of Customers, vicious or dangerous animals or missing meters.

D. Failure of a Customer who reads his own meter to deliver his meter reading to the Cooperative in accordance with the requirements of the Cooperative billing cycle. E. To facilitate timely billing for Customers using load profiles.

Notice of Estimation

Each bill based on estimated usage will indicate that it is an estimated bill and note the reason for estimation.

Estimation Procedures

Trico currently utilizes a Customer information system (CIS) for billing, bill calculations and bill estimations.

A. Detailed descriptions of estimation procedures for each of the conditions are numbered 1-12 below include but are not limited to:

ESTIMATION METHODOLOGIES
SCHEDULE EM

	Conditions for Estimated Bills	Estimation Procedures
1.	A kWh estimate with at least one year of history for the same Customer at same premise or new Customer with at least one year of premise history.	The CIS system calculates the estimate using the kWh, same month one year prior, from the same premise.
2.	A kWh estimate with less than 12 months' history for the same Customer at same premise.	The CIS system calculates the estimate using the kWh of the preceding month from the same premise.
3.	A kWh estimate with less than 12 months' history for a new Customer but with history on the premise.	The CIS system calculates the estimate using the kWh of the preceding month from the same premise.
4.	A kWh estimate with no prior consumption history.	The CIS system will bill the fixed monthly Customer charge only. The kWh will be billed with the next valid read in accordance with the Arizona Administrative Code.
5.	A kW estimate with a least one year of history for the same Customer at same premise or new Customer with one year of premise history.	The CIS system calculates the estimate using the kW, same month one year prior, from the same premise.
6.	A kW estimate with less than 12 months' history for the same Customer at same premise.	The CIS system calculates the estimate using the kW of the preceding month from the same premise.
7.	A kW estimate with less than 12 months' history for a new Customer but with history on the premise.	The CIS system calculates the estimate using the kW of the preceding month from the same premise.
8.	A kW estimate with no prior consumption history.	The CIS system does not estimate, a service order is issued for a meter technician to obtain a valid read.
9.	Time-of Use estimate with at least one year of history for the same Customer at same premise or new Customer with at least one year of premise history.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on-peak" and "off-peak" kWh reads, same month one year prior from the same premise.
10.	Time-of-Use estimate with less than 12 months' history for the same Customer at same premise.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on peak" and "off-peak" kWh of the preceding month from the same premise.
11.	Time-of-Use estimate with less than 12 months' history for a new Customer but with history on the premise.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on peak" and "off-peak" kWh of the preceding month from the same premise.
12.	Time-of-Use estimate with no prior consumption history for a new Customer at new premise.	The CIS system will bill the fixed monthly Customer charge only. The kWh will be billed with the next valid read in accordance with the Arizona Administrative Code.

ESTIMATION METHODOLOGIES
SCHEDULE EM

B. Variance in estimation methods for differing conditions.

Examples of differing causes for estimation include, but are not limited to: tampering, energy diversion, damaged or destroyed meter, partial meter failure, and meter reading equipment failure.

In the event the meter has been tampered with or destroyed, or energy diversion has occurred, the methods referred to in item A. above still apply, prorating the usage if the estimation period is less than a full billing cycle. Examples;

Tampering and/or Energy Diversion:

A valid read was obtained on October 1, Year Two. A tampering or energy diversion is discovered on October 15th, the meter has the same reading from October 1, Year Two. An investigation reveals the service is active and electricity is being consumed. The same service history indicated a kWh usage of 900 kWh for the month of October Year One. A manual estimate will prorate based upon a daily average of the 900 kWh divided by the number of days in the history record the same month (31) for a total of 29 kWh per day times the number of days tampered (15) for a final estimate of 435 kWh.

If the service does not have a 12 month history the same formula is used with the past 3 month average.

In the event the investigation reveals evidence that the tampering or energy diversion occurred for a period exceeding one month, the Cooperative will use the applicable estimation procedure to the point in time that the tampering or energy diversion may be definitely fixed, or 12 months.

Meter Damaged/Destroyed:

The same estimation procedure as described in item A. above is used if it is determined that the damage or destruction is caused by the Customer to the point in time that the damage or destruction may be definitely fixed or 12 months.

In the event the damage or destruction is otherwise caused, the estimation procedure is the same as described in item A. above, but the Customer responsibility is limited to 3 months for residential Customers and 6 months for non-residential Customers.

Partial Meter Failure:

If a meter is found to be deficient in recording any portion of the actual usage, the kW and kWh are estimated based on the percentage of deficiency for a period limited to 3 months for residential Customers and 6 months for non-residential Customers.

ESTIMATION METHODOLOGIES
SCHEDULE EM

C. Conditions when estimations are calculated by the CIS system.

The CIS system calculates the estimate when the meter of a service does not record a valid read for the normal billing cycle for any of the reasons listed under "Conditions for Estimated Bills" above.

D. Conditions when estimations are made manually

The manual estimate is made when there is a partial meter failure, or there is tampering, or a damaged/destroyed meter for less than the normal billing cycle and the bill must be prorated.

E. Procedures to minimize the need for using estimated data.

If feasible, the meter reader is asked to return to the service for a valid read. If the service has access problems an Offsite Meter Reading (OMR) or Automated Meter Reading (AMR) device may be installed. However, the Cooperative shall have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with property used in furnishing service and the exercise to any and all rights secured to it by law or the Arizona Corporation Commission.

F. Procedures for estimating first and final bills.

First and final bills are not estimated unless the meter fails. If the reading is not recorded for the first bill, the first bill is issued for the fixed monthly charge only. The total kWh will be billed on the first valid read. The final bill is not issued until such time a valid read is secured.

In the event of metering equipment that is damaged, destroyed or absent for the first or final bill, the estimate is the same as B. and D. above.

In the event of metering equipment failure for the first or final bill, the estimate is the same as B. and D. above.

In the event of metering equipment failure, is damaged, destroyed or absent for an account with a demand reading, for the first or final bill, the kWh and/or kW estimate is based on the connected equipment operating characteristics.

G. Procedure for estimation using Customer specific data.

If there is no service history available on which to base an estimate, the kWh and/or kW estimate is based on the connected equipment operating characteristics.

ESTIMATION METHODOLOGIES
SCHEDULE EM

H. Prepaid Electric Service Estimation Methodology.

If there are communication issues that prevent the Cooperative from obtaining a valid daily kWh reading, the kWh consumption will continue to accumulate in the meter. When a valid daily reading results in a negative account balance, the Customer will be notified that they have 2 business days to replenish the account to avoid disconnection for a negative balance. The web portal will indicate no usage for the days with missing kWh readings. The Cooperative will provide all notices in this order: 1) home phone, 2) voicemail, 3) written letter, or 4) e-mail (if available).

If after 7 days of no valid kWh readings, the Cooperative will physically check and/or replace the meter, the Customer will be notified and one of the following actions will be applied to determine or estimate the kWh consumption:

1. If a valid reading can be obtained from the meter and the reading results in a negative account balance, the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection for a negative account balance.
2. If the Cooperative cannot obtain a valid reading from the meter, Trico will use the last valid 5-day average kWh consumption, to determine the amount of kWh to be applied to the account. If this calculated billing results in the account having a negative account balance the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection for a negative account balance.
3. If the Customer does not have any prior consumption history, Trico will bill the daily fixed charges, plus applicable taxes only. If this billing results in the account having a negative account balance, the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: May 19, 2015

EXPERIMENTAL TARIFF

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Availability

Available, on a voluntary basis, to Customers in the territory served by the Cooperative for Residential Use throughout the Cooperative's Service Area where the facilities of the Cooperative are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served, subject to the Cooperative's Service Conditions.

Participation allowed under this Tariff shall be determined by the Cooperative. Customers specified under Arizona Administrative Code R14-2-211.A.5 shall not be eligible for Schedule RPS. These ineligible Customers include, but are not limited to, those where termination of service would be especially dangerous to the health of the Customer, as determined by a licensed medical physician; those Customers where life supporting equipment used in the home is dependent on utility service; and those Customers where weather would be especially dangerous to health.

Application

Applicable, by request of the Customer only, to a Customer otherwise served under the Cooperative's Residential Service, Rate Schedule RS1 for all Single Family Dwellings when all service is supplied at one Point of Delivery through a single Service Line and Energy is metered through one Meter.

Not applicable to resale or standby or Customers that are served on any other rate schedule or Customers on the Cooperative's Levelized Billing Plan, deferred payment plan or installment plan.

Type of Service

The Type of service available under this schedule will be determined by the Cooperative and will only include 120/240 volt single phase residential accounts.

Monthly Rate

STANDARD RATE RESIDENTIAL PREPAID SERVICE	Power Supply		Metering	Meter Reading	Billing	Access	Total	Total Rate
Customer Charge ($/Customer/Day)			$0.1719	$0.0322	$0.2081	$0.3768	$0.7890	$0.7890
Demand Charge ($/kW)	$0.00					$0.00	$0.00	$0.00
Energy Charge ($/kWh)	$0.0770					$0.03593	$0.03593	$0.11293

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases in accordance with the Wholesale Power Cost Adjustor Plan of Administration.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

The RPS tariff is subject to the REST Surcharge on a per kWh basis as all other Trico rates, but with the use of a daily (rather than monthly) REST Surcharge Cap. The methodology for calculating a daily REST surcharge Cap is based on the following formula; the Monthly Residential Rest Surcharge maximum × 12 months ÷ 365 days rounded to nearest mill (1/10 of a penny).

Demand Side Management Programs - DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

The following Service Conditions of the Cooperative (based on A.A.C. R14-2 -201 to 213), on file with the Commission, shall NOT apply to the following: RRLEP 125 through 131; RRLEP 301 through 303; RRLEP 307, 318; RRLEP 320 through 322; RRLEP 324; RRLEP 342 through 351; and RRLEP 358.

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Experimental Service Conditions Applicable to Prepaid Metering Service Only

A. Availability:

The Prepaid Electric Service is available only to new or existing residential Customers with the following exceptions:

1. Residential critical load Customers are excluded from the prepaid electric service program.
2. Customers identified under ACC R14-2-211A.5 and those Customers under appropriate circumstances but beyond the scope of ACC R14-211.A.5 are not eligible for this rate.
3. Invoice groups which include loans or special billing.
4. Customer must have a valid email account and phone capable of receiving the messages and low balance alerts.

B. Enrollment:

The Customer must make a request and complete a Prepaid Electric Service Application.

1. In addition to the information provided in Rule 101, the prepaid applicant is encouraged to provide the following:
   a. Secondary email address
   b. Cell phone number with text capability and/or second phone number
   c. Other approved method of communication other than US Postal Mail.
2. The Cooperative will allow enrollment into prepaid service if the Customer meets the eligibility requirements, including:
   a. The Customer must pay all applicable fees prior to commencement of service.
   b. A $50.00 credit balance has been established to activate the account.

C. Billing, Payments and Information:

Paper statements will not be provided under the prepaid program. Billing information, as well as payment and account information can be obtained at:

1. Trico business offices during normal business hours.
2. Integrated Voice Recognition (IVR) at 520-744-2944 or 1-866-999-8441.
3. Online at www.trico.coop 24 hours a day.

D. Estimating Prepaid Balances and Customer Notices:

1. Trico can provide an estimate based upon the most current use history of the Customer, of the suggested amount to be initially deposited with Trico and the estimated days that such prepayment should provide paid electric service for the Customer.
2. As energy is consumed, the credit balance is reduced until either the balance is exhausted or additional payments are added to the balance. Balances can be checked online at www.trico.coop any time. Upon request, Customers can be notified of their estimated balance by email, and/or other electronic means if Customer provides the necessary contact information.
   a. The notice will be generated daily when the Customer's credit balance is less than their current daily average usage times four (4). The daily average usage will be calculated using up to the previous thirty (30) days of consumption history.
   b. These estimates are based on the historic information available but can be affected by changes in the Customer's usage or needs. The Customer is responsible for ensuring that a credit balance is maintained on the account.

E. Transfers and optional Debt Recovery for Outstanding Balances

1. Accounts that are on existing post-paid electric service may be converted to prepaid electric service.

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

2. When existing Customers that convert from post-paid residential service the existing deposit, if any, is applied toward any outstanding balance of the post-paid account with the remaining credit applied to prepaid service.
3. All post-paid fees and unbilled energy charges must be paid in full except for the provisions below:
   a. There is a debt recovery feature available within limits to recover amounts due from a prior post-paid account, when applying for prepaid service. A percentage (20% to 50%) of each prepaid electric service payment can be applied to an outstanding debt up to $400.00
   b. Outstanding amounts over $400.00 must be paid down to the $400.00 level prior to being eligible for the prepaid electric service program.
   c. The Customer agrees to make prepaid payments of sufficient amounts to pay down the outstanding amounts in no more than four (4) months.
   d. If the Customer fails to pay the outstanding balance within the four (4) months allowed, Trico has the right to disconnect the prepaid service until the outstanding balance is paid in full.
4. Trico will transfer the existing membership fee on the post-paid to the new account where the Customer will not be required to make an additional payment.
5. The Customer may elect to convert from prepaid electric service back to post-paid service. At which time, the Cooperative may require full payment of the deposit to continue service. Customers who cancel their prepaid accounts may not re-apply for a new Prepaid account at the same location for a six (6) month period.

F. Terminating and Restoring Prepaid Electric Service:

Prepaid meters are equipped to allow remote disconnection / reconnection of service.

1. Service terminated at the request of the Customer will receive a refund of any remaining credit on the account after all final bill amounts have been calculated.
2. Electric service may be subject to immediate disconnection any time the account does not have a credit balance.
3. Following a disconnect because the account does not have a credit balance, the Customer must pay any unpaid balance from the result of energy consumption from the time the account has reached a zero ($0.00) balance and when the Cooperative issued the disconnection command, plus purchase a minimum of $20.00 prepaid electric service, if applicable, before service is reconnected.
4. If an account is disconnected because the account does not have a credit balance and does not become current after ten (10) days, the account will be considered closed and the Cooperative will mail a final bill to the last known address of the Customer on file for all unpaid charges.
5. Service will not be disconnected where weather will be especially dangerous to health as defined in the Cooperative's Rules or as determined by the Commission.

ATTACHMENT D

Rules, Regulations & Line Extension Policies

Trico Electric Cooperative, Inc.
Rules, Regulations and Line Extension Policies
Effective Date: _____

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DEFINITIONS

1. ABBREVIATIONS: Certain references, organizations and regulatory agencies have been abbreviated to acronyms throughout as a matter of convenience.

   ACC - Arizona Corporation Commission

   NEC - National Electrical Code

   NESC - National Electrical Safety Code

   NRUCFC (CFC) or CFC - National Rural Utilities Cooperative Finance Corporation

   RRLEP – These Rules, Regulations & Line Extension Policies

   RUS - Rural Utilities Service

2. ADVANCE IN AID OF CONSTRUCTION (ADVANCE): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement the value of which may be refundable.

3. AGREEMENT: Synonymous with "Contract" as used herein.

4. APPLICANT: Any person, firm, agent, organization, corporation or governmental body applying for electric service from the Cooperative.

5. APPLICATION: A request to the Cooperative for electric service, as distinguished from an inquiry as to the availability or charges for such service.

6. ARIZONA CORPORATION COMMISSION: The regulatory authority of the State of Arizona having jurisdiction over Trico Electric Cooperative, Inc., abbreviated as "ACC" in these RRLEP.

6. AUTOMATIC METER READING (AMR): Automatic Meter Reading (AMR) is the remote collection of consumption data from Customers' utility meters using telephony, radio frequency, power-line and satellite communications technologies.

7. BILLING DEPOSITS: As used in Sections 119 through 126 of these RRLEP, it shall be deemed to mean deposits made by Customers as a guaranty of the payment of the bills for electric service rendered by the Cooperative.

8. BILLING MONTH: The period between any two regular readings of the Cooperative's meters at approximately 30 day intervals.

9. BILLING PERIOD: The time interval between two consecutive meter readings that are taken for billing purposes.

10. CODES: Applicable electric Codes may be the NEC the NESC any Rule or Regulation adopted by RUS, or by a City, Town, County and/or State authority. Any such permitting, clearance requirements or specification the Cooperative deems necessary and or prudent in accordance with sound engineering practices and safety guidelines.

11. CONNECTED LOAD: Total of the nameplate ratings or measured load of the electrical equipment connected to the electrical installation or system.

12. CONTRIBUTION IN AID OF CONSTRUCTION (CONTRIBUTION): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement or service connection Tariff, none of which is refundable.

13. COOPERATIVE: Trico Electric Cooperative, Inc.

14. COOPERATIVE EQUIPMENT: The service lines, meter installations, structures, devices, apparatus, hardware and other facilities installed by or on behalf of, and/or owned by, the Cooperative and/or other transmission and distribution facilities of the Cooperative's system.

15. COOPERATIVE'S SPECIFICATIONS: Established standards and requirements supplied to Customers to obtain, construct, or maintain their electric service equipment, in accordance with applicable Codes, sound engineering, construction and financial practices.

16. CUSTOMER: The person or entity in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service.

17. CUSTOMER CHARGE: The amount the Customer must pay the Cooperative for the availability of electric service, excluding any electricity used, as specified in the Cooperative's Tariffs.

18. CUSTOMER'S SERVICE ENTRANCE: In general, all conductors, devices, apparatus, and hardware on the Customer's side of the Point of Delivery, except the Cooperative's meter installation.

19. DAY: Calendar day.

20. DEMAND: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

21. DEVELOPER: Any individual, partnership, corporation, governmental agency, or other organization, funding and/or developing lots or parcels of land for use, sale or lease, either improved or unimproved with real property improvements on such lots or parcels.

22. DISTRIBUTION LINES: Any of the Cooperative's power system lines operated at distribution voltages below 69 kV.

23. EFFECTIVE DATE: The effective date of these RRLEP, as approved by the ACC.

24. ELECTRICAL SERVICE: The availability of electric energy, metered or otherwise, available to the Customer within established standards of voltage and frequency to the Point of Delivery.

25. ELDERLY: A person who is 62 years of age or older.

26. ENERGY: Electrical energy, expressed in kilowatt-hours (kWh).

27. HANDICAPPED: A person with a medically diagnosed physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living or protect oneself from neglect or hazardous situations without assistance from others.

28. ILLNESS: A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

29. INABILITY TO PAY: Circumstances where a residential Customer:

    A. Is not gainfully employed and unable to pay; or

    B. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the Customer receives his bill and can obtain verification of that fact from the government welfare assistance agency; and

    C. Has an annual income below the published federal poverty level and can produce evidence of this; and

D. Signs a declaration verifying that the Customer meets one of the above criteria and is either Elderly, Handicapped, or suffers from Illness.

30. INTERRUPTIBLE ELECTRIC SERVICE: Electric service that is subject to interruption as specified in the Cooperative's Tariff.

31. KILOWATT (kW): A unit of power equal to 1,000 watts.

32. KILOWATT HOUR (kWh): Electric energy equivalent to the amount of electric energy delivered in one hour when delivery is at a constant rate of 1 kilowatt.

33. LINE EXTENSION: The lines and equipment necessary to extend the electric distribution system of the Cooperative to provide service to one or more additional Customers.

34. MASTER METER: A meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

35. MEMBER: Any Member of the public, including person, firm, association, corporation and bodies politic or subdivision thereof, who has qualified for Membership as provided for in the By-Laws of the Cooperative.

36. METER: The instrument for measuring and indicating or recording the flow of electricity that has passed through it.

37. METER INSTALLATION: The meter(s) and auxiliary devices and hardware, if any, constituting the Cooperative's equipment needed to measure energy use and/or billing demand supplied to the Customer.

38. METER TAMPERING: Any situation where a meter or associated devices and wiring has been illegally altered. Common examples are but are not limited to; meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

39. MINIMUM CHARGE: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Cooperative's Tariffs.

40. NEW SERVICE ESTABLISHMENT FEE: A charge as specified in the Cooperative's Tariffs for service requiring new construction.

41. PERMANENT SERVICE: Electric service, which in the opinion of the Cooperative, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

42. PERSON: Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

43. POINT OF DELIVERY: The point where facilities (whether owned, leased, or under license by a customer) connect to the Cooperative's facilities, as denoted in the Cooperative's electric service specifications or by written agreement.

44. POWER: The rate of generating, transferring or using electric energy, usually expressed in kilowatts.

45. PREMISES: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

46. PROPER NOTICE: Unless specified otherwise, a written message delivered by first class mail, via email, or in person by one party to the other at the recipient's last known address, the period of notice commencing from the date of email delivery or mailing.

47. REGULAR HOURS: The hours 8:00 a.m. to 4:30 p.m. Monday through Friday shall be considered regular hours, except for Cooperative holidays. However, service hours may be worked at hours different from those listed as regular hours.

48. RESIDENTIAL USE: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, residential water well and other residential uses and includes use in apartment buildings, mobile home parks, and other multiunit residential buildings.

49. SERVICE AREA: The territory in which the Cooperative has been granted a Certificate of Convenience and Necessity (CC&N) and is authorized by the law to provide electric service.

50. SERVICE AVAILABILITY CHARGE: A charge for the purpose of maintaining adequate revenue to cover the operating costs of an extension of line whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs.

51. SERVICE CONNECTION/DISCONNECTION: The attachment/detachment of electric service by an authorized representative of the Cooperative including operation of Customer owned disconnect devices, if appropriate for safety reasons.

52. SERVICE ESTABLISHMENT: The establishment of electric service to the Customer when the Customer's facilities are ready and acceptable to the Cooperative and the Cooperative needs only to install or read a meter or turn the service on.

53. SERVICE LINE: The line extending from a distribution line or transformer to the Customer's premises or Point of Delivery.

54. SERVICE RECONNECT CHARGE: The charge as specified in the Cooperative's Tariffs which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is discontinued for failure otherwise to comply with the Cooperative's Tariffs, or these RRLEP.

55. SERVICE REESTABLISHMENT CHARGE: A charge as specified in the Cooperative's Tariffs for service at the same location where service disconnection was made for the same Customer.

56. SINGLE FAMILY DWELLING: A house, an apartment, a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as a permanent home.

57. SPINE FACILITIES OR BACKBONE FACILITIES: A large capacity electric distribution system generally not directly connected to individual lots and designed, sized, and constructed to provide adequate service of the proper phase and voltage to the boundary of blocks or large parcels within an approved Master Planned Development in which such blocks or parcels are intended to be subdivided in the future into platted blocks or subdivisions for residential and commercial uses; or the large capacity electric distribution system required to serve an area comprised of a large subdivision or several subdivisions or many platted subdivisions which are not part of a Master Planned Development but which by their proximity to each other and by their zoned uses are similar in nature to a Master Planned Development, and in this event such spine system may be adjacent to individual lots.

58. TARIFFS: The documents filed with the ACC which list the services and products offered by the Cooperative and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products.

59. TEMPORARY SERVICE: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Cooperative, is for operations of a speculative character

is also considered temporary service and will be required to make an advance for the cost of retiring the service .

60. TERRITORIAL EXTENT: The RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate Tariffs of the ACC, in which such event modifications shall govern where applicable.

61. THIRD PARTY NOTIFICATION: A notice sent to an individual or a public entity willing to receive notification of the pending discontinuance of service of a Customer of record in order to make arrangements on behalf of said Customer satisfactory to the Cooperative.

62. TRICO: Trico Electric Cooperative, Inc.

63. WEATHER ESPECIALLY DANGEROUS TO HEALTH: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

PART 1.
APPLICATION FOR ELECTRIC SERVICE

101. APPLYING FOR ELECTRIC SERVICE

Trico may require a new Applicant for service to appear at Trico's offices at 8600 W. Tangerine Rd., Marana, Arizona, to produce proof of identity and sign the appropriate application form or contract before service is supplied by Trico.

102. APPLICATION FOR SERVICE

A. The application for service form may require, but not necessarily be limited to, the following information:

1. Name or names of Applicant(s).
2. Service address or location and telephone number.
3. Billing address/telephone number if different from service address.
4. Address where service was previously provided and email address (when available)
5. Date Applicant will be ready for service.
6. Statement as to whether premises have been previously supplied with electric service, and if so, date service was discontinued and the reason therefore.
7. Purpose for which service is used.
8. Statement as to whether Applicant is owner, tenant or agent for the premises. For tenants, a copy of the signed rental agreement and contact information for owner.
9. Information concerning the energy and demand requirements of the Customer.
10. Type and kind of life support equipment used, or to be used, by the Customer.
11. Applicant's social security number, driver's license number or other state issued identification.
12. Applicant's verification of legal age.
13. Name, phone number, relationship and address of Applicant's closest living relative not living in the home.

B. Customer specific information shall not be released without specific prior written authorization unless the information is requested by law enforcement or other public agency, or is requested by the ACC or its Staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer.

C. Where service is requested by two or more individuals at the same location, Trico has the right to collect the full amount owed from any one of the Applicants.

D. In the absence of a signed application or contract for service, the supplying of electric service by the Cooperative and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Cooperative and Customer for furnishing and receiving electric service under the Cooperative's applicable rates, minimums and provisions for making electric service available.

103. DOUBTFUL PERMANENCY

If, in the Cooperative's opinion, the nature of the Customer's requirement for electric service is doubtful as to whether it constitutes Permanent Service, then the Customer must enter into a contract with the Cooperative and pay the entire cost of construction, including any necessary equipment to serve the Customer (e.g., transformers and associated structures), as well as the cost of retirement of facilities to be installed for the purposes of providing service to the Customer.. The contract shall include provisions that when the permanent nature of the service has been established to the satisfaction of the Cooperative, the RRLEP that pertain to Permanent Service shall be applicable.

104. EXTENSION OF LINE REQUIRED

When an extension of the Cooperative's electric lines is requested, the Cooperative shall advise the Applicant(s) of the provisions of the line extension policies in Sections 201-217, including the costs associated with the proposed line extension. Provisions of the line extension policy are limited to services applicable in the Cooperative's approved Tariffs, utility grade quality of power, and construction is limited to the Cooperative's construction standards. Provisions of the line extension policy are limited to the Cooperative's established alternating nominal distribution voltages 14.4/24.9 kV, Y-Y transformation and construction limited to the Cooperative's construction standards. Other distribution voltages and transmission voltages may be provided on case-by-case basis. The Cooperative has established alternating nominal transmission voltage of 69kV or 115kV that are available in many areas of the Cooperative's system.

105. SERVICE BEYOND SCOPE OF LINE EXTENSION POLICY

When the service requested is different from the standard conditions as noted in Section 104 and elsewhere in this policy, service may be extended to the Applicant(s) under a separate contractual agreement which shall be filed with the ACC.

106. CONDITION FOR SUPPLYING SERVICE

The Cooperative reserves the right to determine the conditions under which an extension will be granted. Conditions for service and extending service to the Customer will be based upon the following:

A. Customer has wired his premises in accordance with the applicable Codes.

B. Customer has installed the electric service entrance equipment in a suitable location and with suitable protection so that the loss of power or the partial loss of voltage, or phases does not damage the Customer's facilities, electric system, and or appliances.

C. In case of temporary construction service, the electric service entrance equipment shall conform to 106.A and 106.E.

D. All such installations shall be in accordance with the Cooperative's specifications and located at an outdoor location accessible to the Cooperative.

E. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper rights-of-way locations.

F. Developers shall have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

G. The Customer agrees to have his installation comply and continue to maintain compliance with the applicable Codes. The Customer will also provide, at their own expense all permitting, licensing, clearances and processes and periodic inspections under their control for which they are responsible, prior to the service being connected.

H. The Customer will be responsible for the electric bills of all services.

I. Customer agrees that failure to maintain compliance with the Codes is cause for disconnection of the service. Code compliance is required before service will be restored.

J. A reduced starter acceptable to the Cooperative shall be installed by the Customer for all 200 HP motors and above and may be required by the Cooperative for motors 40 HP and above.

107. IDENTIFICATION OF LOAD AND PREMISES

The premises and electric load to be served by the Cooperative shall be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Cooperative shall be required to act upon a request for electric service. Existing electric with multiple services at the premises may require that the Customer provide the Cooperative's meter number for the service they wish to connect.

108. IDENTIFICATION OF RESPONSIBLE PARTY

The identity of the party(ies) responsible for accounts in the name of any Customer shall be established in a manner acceptable to the Cooperative. Any person applying for service to be connected in the name of or in care of another Customer shall furnish to the Cooperative acceptable written approval from that Customer guaranteeing payment of all bills under the account. Application for service by a minor shall be subject to written assurance of a party responsible for such service as required by the Cooperative. The Customer is responsible in all cases for service supplied to the premises until the Cooperative has received proper notice of the effective date of termination or transfer of service. The Customer shall also promptly notify the Cooperative of any change in billing address.

109. ASSIGNMENT OF RATE TARIFF

The Cooperative shall use its best efforts to assign the appropriate rate Tariff for the customer's service based on the available data at the time of the service application. The Cooperative shall use its best efforts to notify the Customer of the applicable rate Tariff if the Customer's service classification has changed after initial application, and shall not be required to refund the difference in charge under different rate Tariffs. Upon written notification of any material changes in the Customer installation or load conditions, the Cooperative will assist in determining if a change in rate Tariff is desirable, but not more than one such change at the Customer's request may be made within any 12-month period.

110. TAMPERING WITH OR DAMAGING COOPERATIVE EQUIPMENT

The Customer agrees, when accepting service, that no one except authorized Trico representatives shall be allowed to remove or replace any Cooperative equipment installed on the Customer's property. The Customer will be held responsible for any broken seals, tampering, or interfering with the Cooperative's meter(s), equipment, or property installed on the Customer's premises. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or Customer's wrongful act or omission on the part of any of the Customer's agents, employees, licensees, or contractors. The Cooperative also has the right to refer any matter regarding tampering to the appropriate law enforcement authorities as a criminal matter, including for criminal damage to utility equipment.

111. GROUNDS FOR REFUSAL OF SERVICE

The Cooperative may refuse to establish service if any of the following conditions exist:

A. The Applicant is indebted to the Cooperative and the Applicant has not paid the outstanding balance and fees in full.

B. A condition exists which in the Cooperative's judgment is unsafe or hazardous to the Applicant, the general population, or the Cooperative's personnel or facilities.

C. Applicant refuses to provide the Cooperative with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements.

D. Customer is known to be in violation of any of the Cooperative's Tariffs filed with the ACC.

E. Failure of the Customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer, and which the Cooperative has conditioned providing service upon.

F. Applicant falsifies or misrepresents his or her identity for the purpose of obtaining service.

G. Applicant is in violation of these RRLEP or any applicable Rule or regulation of the ACC or any applicable law, or is in default as to any prior agreement between the Applicant and the Cooperative.

H. Customer has failed to comply with the Codes or permitting/inspection requirements.

112. SCHEDULING OF SERVICE ESTABLISHMENT

After an Applicant has complied with the Cooperative's application and deposit requirement, the requirements of Sections 104-106, and has been accepted for service by the Cooperative, the Cooperative shall schedule that Customer for service establishment.

113. SERVICE ESTABLISHMENT EXCEPTION

Service establishments shall be scheduled for completion within five working days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five working day limitation.

114. SERVICE ESTABLISHMENT BY THE COOPERATIVE

Service establishment shall be made only by a qualified Cooperative service representative or its agent or contractor.

115. TEMPORARY SERVICE PAYMENT REQUIREMENTS

Applicants for Temporary Service may be required to pay the Cooperative in advance of service establishment, a contribution in aid of construction, based on the estimated cost of installing and removing the facilities, less any salvage, necessary for furnishing the desired service. Temporary Service must meet the requirements of any and all applicable Codes as defined in these RRLEP.

116. TEMPORARY SERVICE - LESS THAN ONE MONTH

Where the duration of service is to be less than one month and the Applicant does not have any outstanding debts to the Cooperative, the Applicant may also be required to advance a sum of money equal to the estimated bill for service and a service establishment fee in lieu of a minimum-security deposit.

117. TEMPORARY SERVICE - MORE THAN ONE MONTH

Where the duration of service is to exceed one month, the Applicant may also be required to meet the deposit requirements of the Cooperative.

118. CHANGE OF CLASSIFICATION

If at any time during the term of the agreement for temporary services the character of a temporary Customer's operations change so that in the opinion of the Cooperative, the Customer is classified as permanent, the terms of the Cooperative's RRLEP applicable to Line Extensions will apply. Cost of retirement advance shall be refunded to the Customer once the service is no longer classified as temporary.

119. BILLING DEPOSIT REQUIREMENTS

The Cooperative will not require a deposit from an Applicant for service if the Applicant is able to meet any of the requirements below:

1. The Applicant has existing service with the Cooperative of a comparable nature, was not delinquent in payment (including returned payments) more than twice during the last 12 consecutive months, has not been disconnected for non-payment, nor had more than two insufficient funds checks, e-checks, credit card or other electronic payments declined.
2. The Applicant can produce a letter of credit from a current electric utility receiving service for a minimum of the past two years; and was neither delinquent in payment more than twice during the last 12 consecutive months of service nor was disconnected for non-payment.

120. BILLING DEPOSIT RECEIPT

The Cooperative may issue a nonnegotiable receipt to the Applicant for the billing deposit. The inability of the Customer to produce such a receipt shall in no way impair his right to receive a refund of the billing deposit, if it is reflected on the Cooperative's records.

121. INTEREST ON BILLING DEPOSITS

Billing Deposits shall be interest bearing; the interest rate and method of calculation is defined in the Schedule of Special Charges, Interest on Billing Deposits clause.

122. BILLING DEPOSIT REFUND

Billing deposits will automatically be refunded by applying the billing deposit and accrued interest to the account by the Cooperative after 12 consecutive months, during which time the Customer has not been delinquent more than two times in a 12-month period, or at the discretion of the Cooperative at any time before service is discontinued. Upon discontinuance of service, the Cooperative shall have a reasonable time, but not less than three working days (Monday through Friday excluding holidays) in which to read and remove its meters and to ascertain that the obligations of the Customer have been duly performed before being required to return a billing deposit. Upon final discontinuance of the use of the service and full settlement of all bills by the Customer, any billing deposit, not previously refunded, with accrued interest, (if any), in accordance with the provisions of this policy will be returned to the Customer or at the Cooperative election, it may be applied to the payment of any unpaid accounts of the Customer and the balance, (if any), returned to the Customer. Deposits paid due to tampering will be held for a minimum of two years or applied to the final bill, if service is terminated before the end of the two-year minimum.

Upon written request, an existing deposit may be transferred to another account holder if the deposit is eligible for refund or if a vacating customer wishes to transfer his/her deposit to the new tenant and the final bill has been paid in full.

123. BILLING DEPOSIT AMOUNT

The amount of a billing deposit required by the Cooperative shall be determined according to the following terms:

A. Residential Customer billing deposits may be equal to no more than two times that of the Customer or customer class, estimated average monthly bill.

B. Non-residential Customer billing deposits may be equal to no more than two and one-half times that of the Customer's estimated average monthly bill.

124. BILLING DEPOSIT ADJUSTMENT

A. The Cooperative may review the Customer's usage after service has been connected and adjust the billing deposit amount based upon the Customer's actual usage.

B. The Cooperative may require a residential Customer to establish or reestablish a billing deposit if the Customer has become delinquent in the payment of two monthly bills within a 12 consecutive month period or has been disconnected for service during the last 12 months.

125. BILLING DEPOSIT PER METER

A separate billing deposit may be required for each meter installed.

126. BILLING DEPOSITS AND SERVICE SUSPENSION

Customer billing deposits shall not prevent the Cooperative from terminating the agreement for service with a Customer, or suspending service for any failure in the performance of Customer obligations under the agreement for service, or any violation of the Cooperative's RRLEP in effect from time to time as approved by the ACC.

127. OBLIGATIONS OF MEMBER

In addition to the provisions of these RRLEP and the Cooperative's Tariffs, each Member shall be bound by the Articles of Incorporation and By-Laws of the Cooperative, as the same may be amended from time to time. Customers who elect not to become a Member shall be bound by these RRLEP and the Cooperative's Tariffs.

128. MEMBERSHIP LIMIT

No Customer may hold more than one membership and a membership may be held jointly by a legally married couple pursuant to the provisions of the By-Laws of the Cooperative.

129. RESPONSIBILITY OF THE COOPERATIVE

The Cooperative shall use reasonable diligence to provide or continue to provide electric service; but if in the event service fails, is interrupted, curtailed, becomes defective or becomes unlawful to provide, due to any cause that is beyond the reasonable control of the Cooperative (including from acts of God or the public enemy, accidents, strikes, labor troubles or by action of the elements, the inability to secure rights-of-way, governmental permits, or certificates, franchises or licenses) then the Cooperative will not be liable for any inability to provide such service. The Cooperative shall also not be liable to the Customer or any other person for damages resulting from failures, interruptions or defects of service or any consequential damages sustained by the Customer or person due to any such failure, interruption or defect of service.

130. RATE TARIFFS

The Cooperative shall make available, upon Customer request, the rate Tariff pursuant to which the Customer receives electric service from the Cooperative.

131. TARIFFS AND RRLEP

The Cooperative shall make available upon Customer request a summary of the Cooperative's Tariffs or the Cooperative's RRLEP concerning:

A. Billing Deposits

B. Termination of service

C. Billing and collection

D. Complaint handling

These RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate Tariffs of the ACC, in which such event modifications shall govern where applicable.

132. RECORD OF CONSUMPTION

The Cooperative upon request of a Customer shall provide a statement of actual consumption by such Customer for each billing period during the prior 12 months unless such data is not reasonably attainable.

133. CUSTOMER RIGHTS

The Cooperative shall inform all new Customers of their right to obtain the information specified in Section 130, 131 and 132.

134. RESPONSIBILITY OF THE CUSTOMER

The Customer, in addition to the other responsibilities set forth in these RRLEP, shall be responsible for:

A. Use of electric service.

B. The repair or maintenance of Customer-owned equipment beyond the Point of Delivery, including any condition that adversely affects the Cooperative's service to the Customer or to others.

C. Prompt notification to the Cooperative by the fastest available means of outages.

D. Prompt notification to the Cooperative of any material changes in the Customer's installation or load conditions.

E. Prompt notification to the Cooperative of any other conditions in the Customer's electric service resulting in substandard or irregular electric service.

F. The Customer shall provide all utility easements and access as required under Section 145 at no cost to the cooperative.

135. SERVICE CALL FEES

In general, there is no charge to the Customer for service calls related to voltage problems, malfunctions of the Cooperative's equipment and other areas where the Cooperative is responsible. The Cooperative may charge a fee for the services defined below in accordance with the applicable Tariffs of the Cooperative. The amount of the service fee will be determined by the type of personnel needed and whether the work is performed during working or nonworking hours. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Some examples of these service calls are (but are not limited to) the following:

A. Each Customer may be charged a fee for the Service Establishment, reestablishment, or reconnection of utility services, including transfers of service or return trips in the event the initial trip was unsuccessful due to the fault of the Customer. The Service Establishment fee shall entitle the Customer to one service connection. The Service Establishment fee is non-refundable, non-transferable and does not apply against a final or any other bill rendered by the Cooperative to the Customer.

B. A response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the Point of Delivery.

C. An interruption caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to perform any work beyond the Point of Delivery.

D. The Customer's service was previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative system, failure to establish credit and/or sign an agreement for service, or any other reason authorizing the Cooperative to make such disconnection.

E. A reestablishment of electric service to be reconnected when the same Customer who requested the service to be disconnected, remains a resident at the same premises.

F. A return trip to the same premises when the Customer fails to comply with the Cooperative's conditions for supplying service or fails to supply access to the premises for the initial trip.

136. SERVICE INTERRUPTION

The Cooperative may temporarily suspend service to make repairs, replacements, maintenance, tests or inspections of Cooperative equipment or to make tests, inspections, connections or disconnections of Cooperative service. The Cooperative shall make reasonable efforts to notify the Customer about the need for and the duration of a planned service interruption, but it may suspend service in an emergency situation without prior notice to the Customer.

137. DAMAGES TO THE COOPERATIVE

In the event any of the causes of interruptions set forth in Section 135 or any negligence by the Customer or Customer's electric service cause damage to the Cooperative's property or personnel or the ability of the Cooperative to provide service to others, the responsible party shall be fully liable to the Cooperative therefor and the service charges set forth in such Sections shall not affect the right to recover the amount of such damages.

138. SERVICE CHARGES DUE

The service charges and damages referred to in Sections 135 and 137 shall be added to the Customer's monthly bill and be subject to collections and termination. The Customer must pay all charges for reconnection of any service disconnected for non-payment prior to reconnection.

139. MOBILE HOME PARKS

A. The Cooperative shall have the right to refuse service to all new construction of and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is metered to each unit by the Cooperative. This includes the Cooperative having the right to refuse any Master Meter arrangement for the expansion of such existing parks. Line extensions and service connections to serve such expansion shall be governed by the Line Extension and Service Connection Policy of the Cooperative.

B. Permanent residential mobile home parks for the purpose of this Section shall mean mobile home parks where, in the opinion of the Cooperative, the average length of stay for an occupant is a minimum of six months.

C. For the purposes of this Section, expansion means the addition of permanent residential spaces in excess of that existing at the effective date of this Section.

140. RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS, AND OTHER MULTI-UNIT RESIDENTIAL BUILDINGS

A. Trico will not allow any Master Meter arrangement for construction of any new apartment complex, condominium, or multi-unit residential building unless:

1. a centralized heating, ventilation and/or air conditioning system will serve all of the buildings within the apartment or condominium complex; and
2. the contractor can provide to the Cooperative an analysis demonstrating that the central unit will result in a favorable cost benefit relationship.

B. At a minimum, the cost/benefit analysis should consider the following elements for a central unit as compared to individual units:

1. Equipment and labor costs
2. Financing costs
3. Maintenance costs
4. Estimated kWh usage
5. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units)
6. Cost of meters and installation
7. Customer account cost (one account vs. several accounts)

141. CUSTOMER PROVIDED FACILITIES

Each Customer obtaining service shall be responsible for all electric facilities on the Customer's side of the Point of Delivery, including the service entrance and the meter socket. In addition, Customers obtaining 200 amp or larger service may be responsible for the service lines as determined by the Cooperative.

142. METER LOCATION

Meters and service switches in conjunction with the meter shall be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection and where such activities will not cause intolerable interference and inconvenience to the Customer. The Customer shall provide and maintain, without cost to the Cooperative, at a suitable and easily accessible location, sufficient and proper space for installation of meters as set forth in the Codes and/or Trico's specifications.

143. METER SERVICE LINE ALTERATION

Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide and have installed at his expense all wiring materials and equipment necessary for relocating the meter and service line connection and the Cooperative may make a charge not to exceed the actual cost for moving the meter and/or service line as set forth in Section 203.

144. COOPERATIVE FACILITIES

A. The Cooperative shall provide facilities adequate to service the electric load agreed upon at the time of application for service or service upgrade in accordance with applicable Tariffs and electric utility standards, but not electric load added after the last effective service agreement. If the Customer has any question as to the adequacy of the Cooperative's electric facilities then the Customer is responsible to obtain whatever assurance necessary to alleviate those concerns and the Cooperative is obligated to advise the Customer of the process and, if necessary, costs to respond to the Customer's concerns.

B. The cost of any service line in excess of the size or length required to provide adequate service shall be paid as set forth in Sections 104 and 105.

145. RIGHTS-OF-WAY

The Cooperative shall be granted rights-of-way and easement(s) over the property of the Customer, of sufficient width for the construction, maintenance, operation, repair, replacement, relocation, removal or use of any and all wire, poles, machinery, supplies, equipment, metering and regulating and other apparatus and fixtures necessary or convenient for the supplying of electric service to the Customer. The Cooperative shall be given safe and unimpaired access at reasonable times to the premises of the Customer for the purpose of reading meters, testing, repairing, relocating, removing or exchanging any or all equipment or facilities necessary to provide or remove electric service to the Customer. Immediate and unannounced access may be necessary when the Cooperative is dealing with an outage or emergency. The required easement(s) and access shall be conveyed to the Cooperative prior to service being made available to the Customer without cost to the Cooperative. The Cooperative may discontinue service after proper notice is issued if there are violations of the required safe and unimpaired access.

146. OBLIGATION FOR RIGHTS-OF-WAY

The Cooperative shall not be obligated to bear any part of the cost of obtaining rights-of-way, easements, licenses or permits. The Customer may be required to put up a non-interest bearing cost deposit(s) before work to obtain said rights-of-way can begin or continue. Any part of the deposit not used for obtaining rights-of-way may be applied toward and become part of the deposit required as set forth in Section 119 or Part 2 of this policy.

It is the Customer or Applicant's responsibility to obtain the right-of-way from all third parties; however, the Cooperative may assist when resources exist to do so, at the expense of the Customer. It is the Customer or Applicant's responsibility to notify the third parties, neighbor(s) and/or adjacent landowners of the design, surveying and construction activities that could affect them or their surroundings.

147. CUSTOMER FACILITIES IN RIGHTS-OF-WAY

When the Cooperative discovers that a Customer or his agent is performing work or has constructed facilities adjacent to or within an easement or rights-of-way and such work, construction or facility or establishes or owns any vegetation, ornamental or not, that obstructs or poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules, regulations, Codes or Trico's specifications or significantly interferes with the Cooperative's access to equipment, the Cooperative shall notify the Customer or his agent and shall take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

148. RIGHTS-OF-WAY EASEMENTS FOR ELECTRIC DISTRIBUTION AND SERVICE LINES

The Cooperative shall construct or cause to be constructed and shall own, operate and maintain all electric distribution and service lines along public streets, roads and highways and on public lands and private property which the Cooperative has the legal right to occupy.

149. RIGHTS-OF-WAY IN SUBDIVISIONS

Rights-of-way and easements suitable to the Cooperative must be furnished by the developer at no cost to the Cooperative and in reasonable time to meet service requirements. No electric facilities shall be installed by the Cooperative until the final grades have been established and furnished to the Cooperative. In addition, the easement strips, alleys, and streets must be graded by the developer to standards determined by the Cooperative, before the Cooperative will commence construction. Such clearance and grading must be maintained by the developer during construction by the Cooperative.

150. RELOCATION OF FACILITIES

If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of facilities, or if deemed advisable by the Cooperative to require changing any underground to overhead or overhead to underground, the cost of any damage, relocation, replacement and/or resulting repairs shall be borne by the developer or the property owner of the real property which adversely affected the Cooperative facilities.

151. SERVICE UPGRADE POLICY

When the Cooperative receives written notification from the Customer of plans to upgrade an existing service panel or plans to increase the load demand or in any way alter the existing service configuration or source voltage, the Cooperative shall determine the ability and efficacy of its existing facilities to sustain safe, reliable, and adequate service to satisfy the Customer's service changes. The Cooperative will require load information and electrical data from the Customer and Cooperative will determine the alterations, upgrades, replacements, or additions of facilities, if any, required by the Cooperative to accommodate the Customer's changes. The Customer shall be charged the cost of construction and labor associated with retirement of any existing facilities for any service upgrade requiring material changes by the Cooperative. When in the Cooperative's opinion the existing facilities are eligible for replacement related to normal maintenance, a credit for the current value of the replacement materials may be given. The Cooperative shall apply a credit allowance exactly equal to the material and labor cost of any special equipment, such as transformers, required to serve the Customer. The cost of any line extension in excess of that allowed at no charge shall be paid for by the Applicant as a non-refundable Contribution in Aid of Construction. The conditions for supplying or refusing electric service in Sections 106 and 111, respectively, shall apply to service upgrades.

PART 2.
LINE EXTENSIONS

201. STATEMENT OF POLICY

The provisions of this policy shall define the conditions governing line extensions. Extensions of distribution or transmission facilities and lines of existing standard voltages necessary to furnish permanent electric service to Applicants and Customers of the Cooperative will be made by the Cooperative in accordance with the provision of this Part 2 and the Sections in Part 1 and 3 that are applicable, (e.g. 104, 105 and 364). These provisions shall apply throughout the entire Service Area of the Cooperative unless modified by the provisions of an effective rate Tariff or specific order of the ACC, in which cases the provisions of the rate Tariff or order shall govern to the extent applicable.

The Cooperative will construct, own, operate and maintain lines along public streets, roads and highways, which the Cooperative has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Cooperative may be obtained without cost to or condemnation by the Cooperative.

A. Upon request by an Applicant for a line extension, the Cooperative shall prepare without charge, a preliminary sketch and rough estimate of the costs to be paid by the Applicant.

B. Any Applicant for a line extension requesting the Cooperative to prepare detailed plans, specifications, or cost estimates, may be required to deposit with the Cooperative an amount equal to the estimated cost of preparation. The Cooperative, upon request, will make available within 90 days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed line extension. Where the Applicant authorizes the Cooperative to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be non-refundable. If the extension is to include oversizing of facilities to be done at the Cooperative's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdivisions providing the utility with approved plats shall be provided with plans, specifications, or cost estimates within 45 days after receipt of the deposit referred to in Section 208B.

C. When the Cooperative requires an Applicant to contribute funds for a line extension, the Cooperative will furnish the Applicant with a line extension agreement.

D. All line extension agreements requiring payment by the Applicant shall be in writing and signed by both parties.

E. The provisions of this policy shall apply only to those Applicants who in the Cooperative's judgment will be a Permanent Service.

F. In all applications of an equipment allowance of line extension costs, the equipment allowance shall follow the requirements of a Permanent Service Point of Delivery on the Customer's real property, at one location, unless multiple Points of Delivery are deemed by the Cooperative reasonable and economical.

G. The Cooperative will charge a New Service Establishment Fee per service to each Applicant requiring construction of a new service, in accordance with the applicable approved Tariffs.

202. MINIMUM WRITTEN AGREEMENT REQUIREMENTS

Each line extension agreement or cost letter, at a minimum, will include the following information:

A. Name and address of Applicant

B. Proposed service address and location

C. Description of requested service

D. Description and sketch of the requested service, line extension and if in a duly recorded real estate subdivision, of the subdivision with the lot numbers thereof

E. A cost estimate is to include materials, labor, reasonable overhead, and other costs as necessary

F. Payment terms

G. A concise explanation of any refunding provisions if applicable

H. Explanation of required easements, if any, or confirmation of existing easements adequate and legal for Trico's use prior to Trico's commitment to a line extension route and agreement

I. After the easements are obtained and the agreement is signed, the Cooperative will provide the estimated number of days to start construction and the number of days needed to complete construction of the line extension

J. Any service availability charge

203. LINE EXTENSION COSTS

Line extension costs shall be established through use of a power line design program, and using Trico's historical costs, information, and data, to calculate the following:

A. Material

B. Direct labor

C. Overhead: Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs such as:

1. Indirect labor
2. Engineering
3. Transportation
4. Taxes, e.g. (FICA, State & Federal Unemployment which are properly allocated to construction)
5. Insurance
6. Stores expense
7. General office expenses allocated to costs of construction
8. Power operated equipment
9. Employee Pension and Benefits
10. Margins
11. Miscellaneous expenses properly chargeable to construction

D. All extension agreements shall be signed by the Customer, and all applicable deposits and/or contributions in aid of construction shall be paid to the Cooperative, prior to construction.

204. LINE EXTENSION MEASUREMENT

Line extension measurement for design and cost purposes shall be along the most direct and practical route of construction required, and no equipment allowance shall be granted for any facility beyond the most direct and practical route to the nearest practical Point of Delivery as determined by the Cooperative.

205. EXTENSION TO RESIDENTIAL CUSTOMERS

A Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall grant an equipment allowance not to exceed $1,500 per Permanent Service, applied as a credit towards the Applicant's line extension fees. In addition, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers and metering equipment, required to serve the customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to residential Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

206. EXTENSION TO NON-PERMANENT RESIDENTIAL CUSTOMERS

A. Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformer and metering equipment required to serve the Customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment

allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to non-permanent residential Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

207. EXTENSION TO GENERAL SERVICE 3 AND 4 CUSTOMERS

A. Equipment Allowance: A Customer with an applicable rate Tariff of General Service 3 (GS3) or General Service 4 (GS4) is not eligible for an equipment allowance whatsoever, and is wholly responsible for the full-calculated cost of any line extension, which the Customer will pay as a non-refundable Contribution in Aid to Construction.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to GS3 and GS4 Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

208. OVERHEAD OR UNDERGROUND DISTRIBUTION FACILITIES WITHIN DULY-RECORDED REAL ESTATE SUBDIVISIONS OR COMPARABLE UNRECORDED DEVELOPMENT

A. General Statement: With respect to overhead or underground distribution facilities within a duly recorded subdivision, the Cooperative will be responsible for the construction of the electric facilities for Residential Customers. All Commercial Customers within subdivision will be covered by Sections 201 through 204, and either Section 207 or 209 (whichever is applicable). In the event the extension is underground the Developer of the recorded subdivision shall provide and install at Developer's expense the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes, and other preparation for electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative. At its option, the Cooperative may elect at the Developer's expense to perform the necessary activities to fulfill the Developer's responsibility hereunder; provided, the expense to the Developer is equal to or less than the expense in the event the Developer performed such activities.

B. Application Fee: The Developer shall pay a $75 per lot non-refundable application fee before the Cooperative shall be obligated to commence the electric design for the subdivision, including planning or design of off-site facilities. For extensions in subdivisions not directly connected to facilities providing service to subdivision lots, but that will be connected to the Cooperative's facilities providing service to subdivision lots ("Spine Facilities" or "Backbone Facilities"), the Cooperative shall collect a nonrefundable application fee equal to the design, inspection, and rights-of-way costs. In that case, the fee will be calculated to serve such Spine Facilities, or five percent of the total calculated cost to construct, design, inspect, and obtain right-of-way, of such Spine Facilities, whichever is greater.

C. Agreement: Distribution facilities will be constructed by the Cooperative within a subdivision or development in advance of application for Permanent Service, after the Cooperative and the Developer of the subdivision or development have entered into a written contract which provides, among other things, for:

1. Equipment Allowance for Developers: The Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers required to serve the future Customers. The Applicant will pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

2. Contribution in Aid of Construction: The total calculated installed cost of such distribution facilities and Spine Facilities, exclusive of transformers, shall be paid to the Cooperative as a non-refundable Contribution in Aid of Construction. The total calculated installed cost shall include all electric facilities that include Spine Facilities or Backbone Facilities required and sized to serve the total construction of the subdivision or development, and may include all or a portion of off-site facility extensions or off-site facility improvements which the Cooperative has deemed necessary to serve the subdivision or development. The Developer shall be required to install all

conduit systems, equipment and transformer basements, and furnish and install all concrete equipment pads per the Cooperative's requirements, including all such conduit and associated facility to the service side of any customer applying for service before the Cooperative is obligated to serve said Customer. The non-refundable lot application fee required per Section 208.B shall be deducted from the total calculated installed cost. A written agreement with a term of five years commencing from the date of completion of construction of these electric facilities, shall be executed by the Developer and the Developer shall pay Trico all deposits in the amounts stated in the agreement prior to the installation of the electric facilities. If after five years, from the completion of the construction of the distribution facilities the development is not complete, the Cooperative shall have the right to execute and record a lien on the unsold portion of the property to secure: (1) the payment by the Developer to the Cooperative of any existing and new service availability charges, which is the fixed fee set forth in the applicable Tariff for idle services; or (2) the cost to the Cooperative to retire or abandon the unused facilities, whichever in the Cooperative's opinion is in the best interest of the Cooperative; or (3) the Cooperative shall have the right to retire any or all of the idle facilities it deems necessary, with proper notice, in accordance with Section 364.

3. Actual Cost of Construction. Within 60 days after the completion of construction, inspection and closeout by the Cooperative of the facilities to serve the subdivision or development, the Cooperative may advise the Developer in writing of the actual costs of such construction. In the event the actual costs are given to the Customer and such actual costs are less than the calculated cost for which payment has been made by the Developer to the Cooperative, the Cooperative shall promptly refund to the Developer the difference. In such event if such actual costs are greater than such calculated cost, the Cooperative shall invoice to Customer and the Customer shall promptly pay such invoiced amount.

D. Service to Residential Customer: Each residential customer or his or her agent (Applicant) within duly recorded real estate subdivisions will be required to make application for service in accordance with Sections 201-205.

209. ALL OTHER EXTENSIONS.

A non-refundable Contribution in Aid of Construction for line extensions is required for all other line extensions of any class or type not otherwise provided in these RRLEP, but which are covered by the standard offer provisions of Section 104. The following formula will determine the amount of the Applicant's non-refundable Contribution in Aid of Construction for such extensions. If the amount calculated below is zero or negative, no Contribution in Aid of Construction is required for provision of electric service.

Cooperative's Allowable Investment = Annual Revenue / Return Factor

Total Project Cost = Direct Cost + System Cost

Applicant's Contribution = Total Project Cost – Cooperative's Allowable Investment

Where:

Direct Cost	=	The cost of distribution or transmission facilities necessary to provide electric service to Customer, determined by estimating all necessary expenditures, including, but not limited to, metering, services, transformers, and rearrangement of existing electrical facilities. This cost includes only the cost of the above-mentioned facilities that are necessary to provide service to the particular customer requesting service and does not include the costs of facilities necessary to meet future anticipated load growth, or to improve the service reliability in the general area for the benefit of existing and future customers.
System cost	=	Cooperative's average allocated investment costs associated with Customer's on-peak and off-peak demands as approved in Cooperative's most recent rate case for the appropriate class of Customer. Investment cost accounts considered in determining the allocated investment costs are those applicable 300 series FERC accounts and other rate base items, including plant held for future use, cash working capital, materials and supplies, prepayments, customer deposits, reserve for insurance and other cost-fee capital.
Annual Revenue	=	Estimated annual revenue from Customer computed from estimated demand and kWh, excluding fuel cost and sales tax.
Return Factor	=	Fixed charge rate, including O&M, taxes, insurance, necessary to convert an annual revenue stream to the total revenue associated with estimated life of project.

The Cooperative's Allowable Investment will be determined based on Annual Revenue for the current 12-month period.

210. CONVERSION OF EXISTING LINE

A. To the extent the provisions of Arizona Revised Statutes, Title 40, Chapter 2, Article 6.1 ("Article 6.1") are applicable, a conversion of overhead to underground lines shall be made pursuant to Article 6.1.

B. In the event that Article 6.1 is not applicable, when requested by Customer or Customers to convert all or a portion of distribution lines from single-phase to three-phase overhead, or single phase to three-phase underground or from overhead to underground, the following shall be applicable to such conversion:

1. The Customer(s) shall provide all utility easements and access as required by Section 145 at no cost to the Cooperative.

2. The Customer(s), at the Customer's (Customers') expense, shall provide the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, in accordance with the specifications and schedules of the Cooperative and local

codes and shall perform all street, curb and sidewalk repairs at the Customer's expense in accordance with local jurisdiction prior to the Cooperative's commencement of the conversion.

3. The Customer(s) shall pay to the Cooperative a Contribution in Aid of Construction the cost of the existing line at present value, less credit for salvage, if any, plus retirement cost, plus any applicable line extension costs, less any applicable equipment allowances, prior to the start of construction.

4. The Customer(s) shall sign any additional agreements, which may include a consensual lien to secure payment of all unpaid obligations of the Customer(s) pursuant to this Section 210, which shall be recorded in the office of the county recorder.

211. ADVANCES UNDER PREVIOUS RRLEP AND CONTRACTS

At the time these new RRLEP are approved by the ACC all existing agreements, contracts, or cost letters with or to customers shall remain in effect in accordance with the term or time period stated in those agreements, contracts, or cost letters; and amounts advanced under the conditions established by a Section previously in effect shall remain nonrefundable or will be refunded in accordance with the requirements of such effective contract under which the advance was made.

212. EXTENSIONS FOR TEMPORARY SERVICE

Extensions for Temporary Service (including for operations of a speculative character or questionable permanency) will be made in accordance with the provisions pertaining to Temporary Service set forth in Section 115 through 118.

213. SPECIAL OR EXCESS FACILITIES

Under these RRLEP, the Cooperative shall install only those facilities which it deems are necessary to render service in accordance with the rate Tariffs. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Cooperative normally would install, the extra cost thereof shall be paid by the Customer.

214. PRIMARY VOLTAGE SERVICE

When the Cooperative agrees to provide primary service to a new or existing Customer, the Point of Delivery shall be determined solely by the Cooperative. The Customer shall provide the entire distribution system between the Point of Delivery and the Customer's load, unless otherwise specified in the written agreement between the Customer and the Cooperative (where the agreement shall provide for facilities charge(s), for the Cooperative's distribution on the Customer's side, from the Point of Delivery). The system will be treated as primary service for the purposes of billing. The Cooperative reserves the right to approve of or require modification of the Customer's distribution plan or system prior to installation and connection with Trico's system. Instrument transformers, meters, poles and all other equipment associated with the primary service metering will be installed by the Cooperative at the Customer's expense. The Customer and the Cooperative will agree on who will pay for the facilities on the Customer's side (load side) of the Point of Delivery. Facilities charge(s) as part of the monthly power bill will include applicable charges for operations, maintenance, depreciation, customer expense, administration expense, and rate of return. Unless otherwise set forth in the written agreement between the Customer and the Cooperative, the Customer will pay, as a Contribution in Aid of Construction, 100 percent of the cost of any line extension – as well as any and all upgrades to the distribution and transmission facilities between the nearest existing Trico power facility capable of providing for the Customer's load and the point of delivery, of such size and capacity required to serve the Customer, less any oversize or excess facilities constructed for the Cooperative's system needs. The Customer will have the option to pay

for the cost of all upgrades to the nearest existing facilities that may not otherwise be capable of providing the requested load to the Customer's requested Point of Delivery if it would be the least cost to the Customer.

215. PROTECTIVE EQUIPMENT

The Customer shall provide, own, and maintain such protective equipment necessary to ensure isolation of the Customer's service from the Cooperative's system due to abnormal conditions. It is the responsibility of the Customer to provide protection and/or power -conditioning devices required to provide the quality of power necessary for optimum performance of voltage-sensitive equipment. Voltage sensitive equipment is defined as equipment that does not function with utility grade power, e.g. computers. Some motors may be sensitive to the loss of a phase. It is the Customer's responsibility to protect their equipment from loss of voltage, phase, frequency, or deviation in standard voltage.

216. CUSTOMER GENERATION EQUIPMENT

A. A Customer installing any means of stand-by generation, which is not intended to become interconnected with the Cooperative's service, shall install a double-throw transfer switch that will prevent connection of the Customer's equipment to the Cooperative's power system.

B. A Customer installing any generation equipment intended to operate in parallel with the Cooperative's electric system, must meet all the provisions of the Cooperative's policies and guidelines. The Customer shall make no connections to the electric system without specific inspection and approval by the Cooperative and shall enter into a parallel operation, power sale and interconnection agreement with the Cooperative.

C. The Cooperative shall be notified to inspect, and if satisfactory, approve said connection. Any unapproved installations shall be grounds for immediate disconnection of the Customer's service.

217. RELOCATION OF COOPERATIVE FACILITIES

When the Cooperative is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer shall reimburse the Cooperative for the total cost of the work to be performed prior to the start of construction. When the relocation involves underground facilities, the Customer's responsibilities in Section 210 shall apply.

PART 3.

METER READING, BILLING, COLLECTION AND TERMINATION OF SERVICE PROCEDURES

301. FREQUENCY OF METER READING

The Cooperative reserves the right to read meters on a schedule less frequent than monthly where the location is so remote or inaccessible that fewer actual readings are in the best interest of operating economy. However, in no event will meters be read less frequently than every three months. Every attempt shall be made to read meters monthly on as close to the same day as practical. However, meter readings may be scheduled for periods of not less than 25 days or more than 35 days.

302. ESTIMATION OF BILL, FIRST AND SECOND MONTH

If the Cooperative is unable to read the meter on the scheduled meter read date, the Cooperative will estimate the consumption for the first and, if applicable, the second billing period thereafter in accordance with the Estimation Methodology Tariff, Schedule EM as approved by the ACC.

303. ESTIMATION OF BILL AFTER SECOND MONTH

After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Cooperative will make every attempt to secure an accurate reading of the meter.

304. ESTIMATED BILLS

Subject to the provisions of Section 306, estimated bills will be issued according to Trico's Estimation Methodology Tariff, Schedule EM and under the following conditions:

A. Labor shortages or work stoppages beyond the control of the Cooperative.

B. Severe weather conditions or emergencies or which prevent the Cooperative from reading the meter.

C. Circumstances that make it dangerous or impossible to read the meter, including but not limited to: locked gates, blocked access to meters, threatening or abusive customers, vicious or dangerous animals or missing meters.

D. Failure of customer who reads his own meter to deliver his meter reading to the Cooperative in accordance with the requirements of the Cooperative billing cycle.

E. To facilitate timely billing for customers using load profiles.

305. NOTICE OF ESTIMATION

Each bill based on estimated usage will indicate that it is an estimated bill.

306. RECORD OF CONSUMPTION

The registration of the Cooperative's meter at the Customer's Point of Delivery shall constitute evidence of the amount of energy and/or billing demand used by the Customer, except where unmetered service is supplied. However, in the event of failure of the Cooperative's meter or inability of an authorized representative of the Cooperative to obtain an actual reading, a reasonable estimate shall be made per Section 302.

307. RATE TARIFFS BASED ON SINGLE POINT OF DELIVERY

Unless otherwise specifically provided in the rate Tariff or by contract, each of the Cooperative's rate Tariffs are based upon the supplying of electric service to one Customer at a single Point of Delivery and at a single voltage and phase classification, and any additional service supplied to the

same Customer at other Points of Delivery or at a different voltage of phase classification shall be separately metered and billed, except as provided in Section 317.

308. MEASURING OF ELECTRIC SERVICE

All energy sold to Customers, and except that sold according to fixed charge Tariffs, shall be measured by commercially acceptable measuring devices owned and maintained by the Cooperative, except where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the ACC.

309. MORE THAN ONE METER

When there is more than one meter at a location, the service and metering equipment shall be so tagged or plainly marked as to indicate the location metered.

310. METER MULTIPLIERS

Meters which are not direct reading shall have the multiplier plainly marked on the meter, meter panel or meter base.

311. RECORDING METER DATA

All data taken from recording meters shall be marked with the date of the record, meter number, Customer information, data multiplier, transformer multiplier(s), date removed and items measured.

312. METER SETTINGS

Metering equipment shall not be set "fast" or "slow" to compensate for supply transformer or line losses.

313. CUSTOMER REQUESTED REREADS

The Cooperative, at the Customer's request, will reread that Customer's meter once within 10 working days after such request by the Customer.

314. REREAD CHARGE

The Cooperative may charge the Customer for any reread at a rate on file and approved by the ACC in Trico's Schedule of Special Charges, if the original reading was not in error. When a reading is found to be in error, the reread shall be at no charge to the Customer.

315. ACCESS TO CUSTOMER PREMISES

The Cooperative shall at all times have the right of safe ingress to and egress from the premises at all reasonable hours for any purpose reasonably connected with the Cooperative's property used in furnishing service, reading meters, and the exercise of any and all rights secured to it by law or these RRLEP. The Cooperative will continue to check the meter, including Automated Meters, periodically or for cause. Failure on the part of the Customer to comply with these RRLEP for access to its meter may lead to the discontinuance of service. An authorized agent/representative of the Cooperative, is authorized to enter any premises using Trico's electricity to inspect the use and quality of the electricity (A.R.S. § 40-431), to read meters, and to connect or disconnect services (A.A.C. R14-2-211).

316. FREQUENCY AND METHODS OF BILLING.

The Cooperative shall bill monthly for services rendered by sending the bill via the United States Mail, e-mail, posting to a secure website or other acceptable means of delivery.

317. COMBINING OF METER READINGS

Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two or more meters will not be combined unless otherwise provided for in the Cooperative's Tariffs.

318. MINIMUM BILLING INFORMATION

Each bill for residential service will contain the following minimum information:

A. Date and meter reading at the start of the billing period or number of days in the billing period

B. Date and meter reading at the end of the billing period

C. Billed usage and demand

D. Rate Tariff number/designation

E. Cooperative's telephone number

F. Customer's name

G. Service account number

H. Amount due and due date

I. Past due amount and subject to termination date

J. Adjustment factor, where applicable

K. Taxes

L. The ACC's address.

319. BILLING TERMS

All bills for electric service are due and payable no later than 15 days from the date the bill is rendered as evidenced in Section 320. The Cooperative shall consider any bill delinquent when payment is not received within this time frame and the Customer may incur a late payment charge.

320. EVIDENCE OF RENDERING DATE

For purposes of this Section, the date a bill is rendered may be evidenced by:

A. The postmark date

B. The mailing date

C. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two days)

D. The transmission date of electronic bills

321. DELINQUENT BILLS

All delinquent bills for which payment has not been received within five days shall be subject to the provisions of the Cooperative's termination procedures.

322. PLACE OF PAYMENT

All payments shall be made at or mailed to the office of the Cooperative or to the Cooperatives authorized payment agency. Payments can also be made by credit card, e-check, bank draft or recurring credit card payments. No payment shall be deemed made until received by the Cooperative. A service fee may be required on credit card and e-check transactions.

323. APPLICABLE RATE TARIFF

Each Customer shall be billed under the applicable Tariff indicated in the Customer's application for service.

324. FAILURE TO RECEIVE BILLS/NOTICES

Failure by the Customer to receive bills or notices, which were properly placed in the United States mail, by secure website, by e-mail or other acceptable means of delivery, shall not prevent such bills from becoming delinquent nor relieve the Customer of his obligations therein.

325. COMMENCEMENT DATE

Charges for service commence when the service is installed and connection made, whether used or not.

326. METER ERROR CORRECTIONS

If any meter, after testing, is found to be more than three percent three percent in error, either fast or slow, proper correction between three percent three percent and the amount of the error shall be made of previous readings and adjusted bills shall be rendered according to the following terms:

A. For the period of three months immediately preceding the removal of such meter from service for testing, or from the time the meter was in service since last tested, but not exceeding three months since the meter shall have been shown to be in error by the test.

B. From the date the error occurred, if the date of the cause can be definitely fixed.

327. METER TEST / BILLING ADJUSTMENT

No adjustment shall be made by the Cooperative except to the Customer last served by the meter tested.

328. CUSTOMER REQUESTED METER TESTS

The Cooperative shall test a meter upon Customer request, and the Cooperative shall be authorized to charge the Customer for such meter test according to the Tariff on file and approved by the ACC. However, if the meter is found to be in error by more than three percent, no meter-testing fee will be charged to the Customer.

329. UNAUTHORIZED CONNECTIONS/ALTERATIONS

No person, except a representative acting on behalf of the Cooperative shall alter, remove or make any connections to the Cooperative's meter or service equipment.

330. METER SEALS

No meter seal may be broken or removed by anyone other than an authorized representative of Trico acting on behalf of the Cooperative. However, the Cooperative may give its consent to break or remove the seal by an approved electrician, employed by a Customer, when deemed necessary to the Cooperative.

331. METER TAMPERING AND THEFT OF POWER

In cases of tampering with meter installations, interfering with the proper working thereof; or any other theft of service by any person, or evidence of any such tampering, interfering, theft, or service diversion, including the falsification of Customer read meter readings; that service shall be liable to immediate discontinuance of service.

332. TAMPERING AND THEFT CHARGES

Pursuant to Arizona Revised Statutes, Sections 40-491 through 40-495, the Cooperative shall be entitled to collect from the Member/Customer whose name the service is in, the appropriate rate for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also any additional security deposits as well as all expenses incurred by the Cooperative for property damages, investigation of the illegal act, and all legal expenses and court costs if necessary. Arizona law allows Trico to collect triple damages from power thieves.

333. ALTERNATIVE METHODS OF PAYMENT

Customers may pay their bills for electric service furnished them by the Cooperative in the following alternative methods:

A. Payment by cash, bank cashier's check, bank certified check, valid personal check or electronic check drawn on a commercial bank insured by the Federal Deposit Insurance Corporation or a savings and loan association insured by the Federal Savings and Loan Insurance Corporation.

B. Payment by a valid credit card accepted by the Cooperative. Payment by credit card shall not be deemed accepted by the Cooperative unless and until authorized by the bank administering the use of the credit card for the Customers.

C. A service fee may be required on electronic transactions.

334. PAYMENT TRANSACTION RETURN OR CHARGE BACK

The Cooperative shall be allowed to recover a fee, as approved by the Commission, for each instance where Customer tenders payment for electric service with an insufficient funds check, payment transaction return or charge back.

335. METHODS OF PAYMENT AFTER RECEIPT OF TRANSACTION RETURN OR CHARGE BACK

When the Cooperative is notified by the Customer's bank that there is a payment transaction return tendered for electric service, the Cooperative may require the Customer to make payment in cash, by money order, cashier's check, or other means which guarantee the Customer's payment to the Cooperative.

336. CUSTOMER'S OBLIGATION TO RENDER PAYMENT

A Customer who tenders payment transaction return shall in no way be relieved of the obligation to render payment to the Cooperative under the original terms of the bill nor defer the Cooperative's provision for termination of service for nonpayment of bills. In the event a Customer makes a partial payment, the Cooperative may accept the partial payment and apply it on the Customer's account. However, the Customer shall remain liable to the Cooperative for the unpaid portion of the account and for the purpose of these RRLEP; only full payment shall be deemed to constitute payment.

337. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION

Only cash, money order or cashier's checks will be accepted if two insufficient funds checks, transaction returns or charge backs have been received by the Cooperative within a twelve-month period in payment of any billing. A returned check cannot be paid with another check.

338. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION AND TERMINATION OF SERVICE

Electric service will be subject to disconnect following the procedure as set forth in Section 355 for payment transaction return or charge backs that have not been made good.

339. LEVELIZED BILLING PLAN

The Cooperative, at its option, may offer its Customers a levelized billing plan.

340. LEVELIZED BILLING PLAN REQUIREMENTS

If the Cooperative offers a levelized billing plan, the Cooperative shall develop, upon the Customer's request, an estimate of the Customer's levelized billing for a 12-month period based upon:

A. Customer's actual consumption history, which may be adjusted for increased past usage and abnormal conditions such as weather variation.

B. For new Customers, the Cooperative will estimate consumption based on the Customer's anticipated load requirements.

C. The Cooperative's Tariffs approved by the ACC applicable to that Customer's class of service.

341. LEVELIZED BILLING PLAN INFORMATION TO CUSTOMER

The Cooperative shall provide the Customer a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly electric bill, and the Cooperative's right to adjust the Customer's billing for any variation between the Cooperative's estimated billing and actual billing.

342. MINIMUM INFORMATION ON MONTHLY LEVELIZED BILL

For those Customers being billed under a levelized billing plan, the Cooperative shall show at a minimum, the following information on the Customer's monthly bill:

A. Actual consumption

B. Amount due for actual consumption

C. Levelized billing amount due

D. Accumulated variation in actual versus levelized billing amount

343. ADJUSTMENTS TO LEVELIZED BILLS

The Cooperative may adjust the Customer's levelized billing in the event the Cooperative's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost; such review to adjust the amount of the levelized billing may be initiated by the Cooperative or upon Customer request.

344. DEFERRED PAYMENT PLAN

The Cooperative, prior to termination, may offer to qualifying residential Customers a deferred payment plan for unpaid bills.

345. DEFERRED PAYMENT PLAN AGREEMENT TERMS

Each deferred payment agreement entered into by the Cooperative and the Customer due to the Customer's Inability to Pay an outstanding bill in full shall provide that service will not be discontinued if:

A. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement.

B. Customer agrees to pay all future bills for utility service in accordance with the billing and collection Tariffs of the Cooperative, unless otherwise noted the deferred portion of the unpaid balance will be due at the same time as normal monthly bills; the deferred balance will be included as a line item on the bill.

C. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed six months.

346. DETERMINING INSTALLMENT PAYMENT SCHEDULE

For the purposes of determining a reasonable installment payment schedule under these RRLEP, the Cooperative and the Customer shall consider the following conditions:

A. Size of the account

B. Customer's ability to pay

C. Customer's payment history

D. Length of time that the debt has been outstanding

E. Circumstances which resulted in the debt being outstanding

F. Any other relevant factors related to the circumstances of the Customer

347. ESTABLISHMENT OF AGREEMENT/TERMINATION DATES

Any Customer who desires to enter into a deferred payment agreement shall execute such agreement prior to the Cooperative's scheduled termination date for nonpayment of bills; Customer failure to execute a deferred payment agreement prior to the scheduled termination date shall not prevent the utility from discontinuing service for nonpayment. A deferred payment agreement may include a late payment charge as approved by the ACC in a Tariff proceeding.

348. REQUIREMENTS OF DEFERRED PAYMENT AGREEMENT

If a Customer has not fulfilled the terms of a deferred payment agreement, the Cooperative shall have the right to disconnect service pursuant to the Cooperative's termination of procedures and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

349. CHANGE OF OCCUPANCY

Not less than three working days advance notice must be given to the Cooperative to discontinue service or to change occupancy.

350. OUTGOING PARTY RESPONSIBILITY

The outgoing party shall be responsible for all electric service provided and/or consumed up to the scheduled turn-off date. The outgoing party is also responsible for providing access to the meter so that Trico may obtain a final meter reading.

351. NON-PERMISSIBLE REASONS TO TERMINATE ELECTRIC SERVICE

The Cooperative will not disconnect service for any of the reasons stated below:

A. Delinquency in payment for services rendered to prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

B. Failure of the Customer to pay for services or equipment, which are not regulated by the ACC.

C. Failure to pay for a bill to correct a previous under billing due to an inaccurate meter or meter failure if the Customer agrees to pay over a reasonable period of time.

D. The Cooperative will not terminate residential service where the Customer has an inability to pay and is making arrangements for payment, alternative power supply, or to relocate the resident, in the event that:

1. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous or life threatening to the Customer or a permanent resident residing on the Customer's premises, health, or

2. Life supporting equipment used in the home that is dependent on electric service for operation of such apparatus, or

3. Where Weather Especially Dangerous To Health as defined herein or as determined by the ACC occurs.

E. Residential service to ill, elderly, or handicapped persons who have an Inability to Pay will not be terminated until all of the following have been attempted:

1. The Customer has been informed of the availability of funds from various government and social assistance agencies of which the Cooperative is aware.

2. A third party previously designated by the Customer has been notified and has not made arrangements to pay the outstanding electric bill, provided that the Customer, or a third person designated by the Customer, uses his or her best efforts to obtain funds to pay the Cooperative's bills from various governmental or social assistance agencies which are known to them.

3. Arrangements or attempts to receive utility assistance must be made prior to the termination date on the bill. Payment guarantees from government or social assistance agencies must be received by the Cooperative via fax or e-mail prior to termination. Any balance not paid by the assistance or guaranteed payment, is the responsibility of the Customer and subject to termination in accordance with Section 355.

F. A Customer utilizing the provisions of D. or E. above may be required to enter into a deferred payment agreement with the Cooperative within 10 days after the scheduled termination date.

G. Disputed bills where the Customer has complied with the ACC's Rules on Customer bill disputes.

352. TERMINATION OF SERVICE WITHOUT NOTICE

Electrical service may be disconnected without advance written notice under the following conditions:

A. The existence of an obvious and imminent hazard to the safety or health of the Customer or the general population or the Cooperative's personnel or facilities.

B. The Cooperative has evidence of meter tampering, theft of service, or damage or loss to the Cooperative's property pertaining to the service to the Customer.

C. Failure of a Customer to comply with the curtailment procedures.

D. An emergency requiring immediate discontinuance of service.

E. Generator installations not approved by the Cooperative.

353. RESTORATION OF SERVICE

The Cooperative shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Cooperative.

354. SERVICE TERMINATION WITHOUT NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one year and shall be available for inspection by the ACC.

355. TERMINATION OF SERVICE WITH NOTICE

The Cooperative may disconnect service to any Customer for any reason stated below, as per the notice requirements set forth in these RRLEP.

A. Customer violation of any of the Cooperative Tariffs.

B. Failure of the Customer to pay a delinquent bill for electric service.

C. Failure to meet or maintain the Cooperative's deposit requirements.

D. Failure of the Customer to provide the Cooperative reasonable access to its equipment and property.

E. Customer breach of a written contract for service between the Cooperative and Customer.

F. When necessary for the Cooperative to comply with an order of any governmental agency having such jurisdiction.

G. When a hazard exists which is not imminent, but in the opinion of the Cooperative, it may cause personal injury or property damage.

H. When the service installation fails to meet Codes per Section 106. G.

I. Failure by the Customer to pay for damages, caused by the Customer, to the Cooperative's property or personnel.

J. Failure of the current occupant to transfer service into his/her name, if there is sufficient evidence that the current account holder is deceased.

356. SERVICE TERMINATION WITH NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service with notice. This record shall be maintained for one year and be available for ACC inspection.

357. TERMINATION NOTICE

The Cooperative shall not terminate electric service to any of its Customers without providing advance written notice to the Customer of its intent to disconnect service, except under those conditions specified where advance written notice is not required.

358. ADVANCE WRITTEN NOTICE INFORMATION REQUIRED

Such advance written notice shall contain, at a minimum, the following information:

A. The name of the person whose electric service is to be terminated and the address where service is being rendered

B. An explanation of the violation thereof or the amount of the bill which the Customer has failed to pay in accordance with the payment policy of the Cooperative, if applicable.

C. The date on or after which service may be terminated.

D. A statement advising the Customer to contact the Cooperative's office at 8600 West Tangerine Road and/or telephone for information regarding any deferred payment or other procedures which the Cooperative may offer or work out some other mutually agreeable solution to avoid termination of the Customer's electric service.

E. A statement advising the Customer that the Cooperative's stated reason for the termination of services may be disputed by contacting the Cooperative at 8600 West Tangerine Road, Marana, Arizona, and/or telephone advising the Cooperative of the dispute and making arrangements to discuss the cause for termination with a responsible representative of the Cooperative in advance of the scheduled date of termination. The responsible representative shall be empowered to resolve the dispute and the Cooperative shall retain the option to terminate service after affording this opportunity for a meeting and concluding that the reason for termination is just and advising the Customer of his right to file a complaint with the ACC.

359. THIRD PARTY NOTIFICATION

Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

360. TIMING OF TERMINATION WITH NOTICE

The Cooperative shall give at least five days advance written notice prior to the termination date.

361. DELIVERY OF NOTICE OF TERMINATION REQUIREMENT

Such notice shall be considered given to the Customer when a copy thereof is left with the Customer or posted first class in the United States mail, addressed to the Customer's last known address.

362. SERVICE TERMINATION DATE

If after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Cooperative for the payment thereof, or in the case of a violation of the Cooperative's RRLEP the Customer has not satisfied the Cooperative that such violation has ceased, the Cooperative may then terminate service on or after the day specified in the notice without giving further notice.

363. SERVICE TERMINATION BY COOPERATIVE

The service may only be disconnected by an authorized representative of the Cooperative, by a means acceptable to the Cooperative.

364. RETIREMENT OF FACILITIES

A. Retirement of facilities upon termination of service: The Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises upon the termination of service. Customer's property (e.g. meter pedestal) attached to the Cooperatives property will be left on the Customer's premises unless other arrangements are made. If the Customer requests that electric facilities remain on Customer's premise they shall be obligated to pay monthly Customer charges or minimums in accordance with the applicable rate Tariff.

B. Retirement of idle facilities: Whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs the Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises. The Cooperative will give proper notice of retirement of facilities as set forth for termination in Sections 360 and 361. If the Customer requests that electric facilities remain on Customer's premise they shall be obligated to pay monthly Customer charges or minimums in accordance with the applicable rate Tariff.

365. LANDLORD/TENANT RULE

In situations where service is rendered at an address different from the mailing address of the bill or where the Cooperative's Landlord/Tenant Agreement exists and that the landlord is the Customer of the Cooperative, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Cooperative will not disconnect service until the following actions have been taken:

A. Where it is feasible to provide service, the Cooperative, after providing notice as required in these RRLEP, shall offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to subscribe, the Cooperative may disconnect service pursuant to the RRLEP.

B. The Cooperative will not attempt to recover from a tenant or condition service to a tenant with the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

C. If Trico terminates services to a tenant for non-payment by a tenant, and if a Landlord/Tenant Agreement exists, then the Cooperative will, upon request, reconnect at no charge to the Landlord's name – if the Landlord has no outstanding debts due to the Cooperative.

PART 4. ADMINISTRATIVE AND HEARING REQUIREMENTS

401. INVESTIGATION OF CUSTOMER SERVICE COMPLAINTS

The Cooperative shall make a full and prompt investigation of all service complaints made by its Customers.

402. RESPONSE TIME ON COMPLAINTS

The Cooperative shall respond to the complainant within five working days as to the status of the Cooperative's investigation of the complaint.

403. NOTIFICATION OF COMPLAINT INVESTIGATION FINDINGS

The Cooperative shall notify the complainant of the final disposition of each complaint. Upon request of the complainant, the Cooperative shall report the findings of its investigation in writing.

404. RIGHT OF APPEAL

The Cooperative shall inform the Customer of his right of appeal to the ACC.

405. RECORDING REQUIREMENTS OF COMPLAINTS

The Cooperative shall keep a record of all written service complaints received which shall contain, at a minimum, the following data:

A. Name and address of complainant

B. Date and nature of complaint

C. Disposition of the complaint

D. A copy of any correspondence between the Cooperative, the Customer, and/or the ACC.

This record shall be maintained for a minimum period of one year and shall be available for inspection by the ACC.

406. CUSTOMER BILL DISPUTES

Any Cooperative Customer who disputes a portion of a bill rendered for Cooperative service shall pay the undisputed portion of the bill and notify the Cooperative's designated representative that such unpaid amount is in dispute prior to the delinquent date of the bill.

407. COOPERATIVE'S RESPONSIBILITIES ON BILL DISPUTES

Upon receipt of the Customer notice of dispute, the Cooperative shall:

A. Notify the Customer within five working days of the receipt of a written dispute notice.

B. Initiate a prompt investigation as to the source of the dispute.

C. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Cooperative shall report the results of the investigation in writing.

D. Inform the Customer of his right of appeal to the ACC.

408. CUSTOMER'S RESPONSIBILITY UPON INVESTIGATION COMPLETION

Once the Customer has received the results of the Cooperative's investigation the Customer shall submit payment within five working days to the Cooperative for any disputed amounts owed to the

Cooperative. Failure to make payment shall be grounds for termination of service as outlined in Section 355.

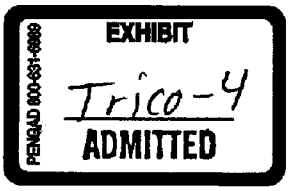
409. RESOLUTION OF SERVICE AND/OR BILL DISPUTES BY THE ARIZONA CORPORATION COMMISSION

A. In the event a Customer and the Cooperative cannot resolve a service and/or bill dispute, the Customer may file a written statement of dissatisfaction with the ACC; by submitting such notice to the ACC, the Customer shall be deemed to have filed an informal complaint against the Cooperative.

B. The Cooperative may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

C. The Cooperative shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one year and make such records available for ACC inspection.

BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

Testimony of Vincent Nitido

In Support of Settlement Agreement

on Behalf of

Trico Electric Cooperative, Inc.

July 29, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico or "Cooperative")?

A. I am Chief Executive Officer and General Manager of Trico.

Q. Did you previously submit testimony in this docket?

A. Yes. I submitted Direct Testimony on October 25, 2015. I also submitted Supplemental Direct Testimony on May 4, 2016, proposing an updated rate design in this case.

Q. What is the purpose of your Testimony here?

A. The purpose of my Testimony is to support the July 8, 2016 Settlement Agreement ("Settlement Agreement") that was filed with the Arizona Corporation Commission ("Commission") in this Docket. In my Testimony, I will: (1) describe the factors that justify the base rate increase; (2) describe the settlement process that the Company undertook and why it supports the Settlement Agreement; and (3) provide an overview and some of the detail for the key provisions of the Settlement Agreement.

II. BACKGROUND AND SUMMARY.

Q. Please summarize the reasons why Trico filed this general rate case on October 25, 2015.

A. The principal reason for Trico's rate case is to address increasing inequities regarding who pays for the use of Trico's electric grid. Trico believed that its rate proposals would lead to more equitable and sustainable rates for its Members. These proposals seek to modify Trico's rate design to: (i) recover fixed grid costs associated with existing distributed generation within Trico's service territory by increasing the fixed monthly customer charge and decreasing the volumetric energy rate for all members; (ii) better match fixed cost recovery by customer class to the cost of service for that class; and (iii) reduce the fixed cost-shift and resultant subsidies to members who install rooftop solar or other distributed generation ("DG").

With respect to DG, Trico supports renewable resources, including the sustainable growth of distributed generation ("DG") in its service area. However, under current rate design and net metering, Trico believes DG growth is placing undue burdens on its non-DG members and is not sustainable in the long run. As I explained in my Direct Testimony, as a member-owned cooperative, Trico has a fiduciary duty to its members as a whole to ensure that its rates are fair and equitable to *all* of its member-customers.

Trico serves a predominantly rural member base across a large service territory, which results in a higher cost of service (including fixed costs) per member-customer than the State's investor-owned electric utilities. That equates to relatively higher rates, and when members generate power utilizing DG under the current net metering tariff, relatively higher levels of fixed costs that are either lost or shifted to non-DG members. Trico experienced steady growth in the installation of distributed generation in its service

territory from 2005, when the Cooperative implemented its first renewable energy plan, and thereafter following the Commission's adoption of the Renewable Energy Standard and Tariff rules ("REST Rules"). That sustainable level of growth continued as the cost of rooftop photovoltaic ("PV") systems declined and efficiencies improved, even as Trico and other Arizona utilities reduced and ultimately eliminated upfront incentives.

Following the introduction of the financial leasing model in Trico's service territory in 2014, however, the number of applications for DG interconnections skyrocketed. In 2013, Trico received 160 applications the year. In December 2014 alone, however, Trico received 114 applications. Trico received 74 applications in January 2015, and 174 applications in February 2015. That escalating trend has continued. To put it in perspective, Trico's 2014 test year in this docket reflected 551 interconnected DG systems at the start of 2014. The adjusted test year, which includes interconnected DG systems as of the original grandfather date of February 28, 2015 reflects an additional 711 systems added over 14 months, for a total of 1,262. That does not include an additional 359 systems which Trico has interconnected as of the revised grandfather date included in the Settlement Agreement of May 31, 2016 for a total of 1,621, all of which, under the Settlement Agreement, would be grandfathered under the current net metering tariff for the life of the interconnection agreement. Put another way, under the current net metering tariff, Trico's non DG members subsidize $89.91 per month in fixed grid costs for each interconnected DG system. That equates to an annual subsidy in the amount of $1,749,000 per year as of May 31, 2016 or $35 million over the 20 year life of the interconnection agreements. That subsidy is continuing to escalate at an alarming rate, and is not sustainable under our current rate design and net metering tariff because the subsidy is ultimately passed on to Trico members without DG. Even at this point, Trico will be locking in a cost shift to non-DG members of over $1.5 million per year for the next 20 years. Trico's member-elected Board of Directors believes that partially reducing the net

metering subsidy to DG members on a going forward basis is a fair and equitable step toward mitigating the cost shift inherent in the current rate, while continuing to support the growth of solar resources in the Cooperative's service territory.

Trico is also seeking a revenue increase of $2,282,076 (or 2.61%) over its adjusted 2014 test year revenues. It has been seven years since our last rate case and I am pleased that we have been able to keep our cost increases to this level. The requested increase relates principally to the recovery of fixed costs associated with existing net metered DG systems; the costs incurred by Trico to conduct this rate case, which are significantly higher than a typical electric distribution cooperative rate case; and the carrying costs of certain direct assigned facilities ("DAFs") to be acquired from Arizona Electric Power Cooperative ("AEPCO"), which costs will be correspondingly removed from Trico's Wholesale Power Cost Adjuster ("WPCA").

Q. Please summarize why Trico filed an Amendment to its original Application on May 4, 2016, proposing an updated rate design?

A. Following the filing of Trico's original application in this docket on October 25, 2015, developments in various Commission proceedings regarding the net metering of DG led Trico to believe that three-part rates including a demand component are the most appropriate way to allocate the fixed costs of the Trico electric grid as new technologies emerge. I discussed those developments in more detail in my May 4, 2016 Supplemental Testimony in support of the Amendment. A recurring concern raised regarding three part rates in other proceedings was the potential for customer confusion and the need for customer education prior to implementation of the rates. The potential for "outlier" results for some customers was also noted. Accordingly, Trico proposed to implement three part rates gradually, in a manner intended to introduce the concept to our members, while

simultaneously providing education and guidance to them regarding the operation of demand rates and the ways to manage electric load to reduce their bills.

Trico's Amendment initially proposed a demand rate of $2 per kW-month for the first 2 kW of usage with a minimum demand of 2 kW and $0.0 per kW month for demand above 2kW for all residential and small commercial (GS-1) members. Volumetric energy rates were lowered to produce a revenue-neutral rate proposal. The approach was intended to provide demand information to the members while avoiding unintended consequences should a member have and unusual or unanticipated spike in electric usage.

Following subsequent discussions with Commission Staff and internal consideration, Trico determined it is more appropriate to introduce a demand rate without charge for residential and small commercial members for the period prior to the Cooperative's next rate case, to collect and analyze member demand data, while simultaneously providing the aforementioned member education. That proposal is memorialized in the Settlement Agreement discussed below.

III. COMPONENTS OF THE SETTLEMENT AGREEMENT.

Q. Please describe the changes between Trico's May 4, 2016 Amendment and the Settlement Agreement?

A. The principal changes in rate design are a reduction in the demand charge to $0.00 per kW-month with no monthly minimum, and an increase in the monthly customer charge to $24.00 for residential customers on the Company's standard (non-TOU) rate schedule. Trico had proposed a monthly charge of $20.00 per month in its May 4, 2016 Supplemental Direct Testimony. The volumetric energy rate would be reduced to produce a revenue neutral result, while preserving the level of fixed grid cost recovery proposed in

Trico's May 4, 2016 Amendment. Providing demand information on the members' bills without a demand charge will introduce the concept of three-part rates to members without unintended consequences, allow for education outreach by the Cooperative and provide significant demand information to the Cooperative to analyze prior to implementing demand charges. Similar changes in rate design are proposed for small commercial customers, including a monthly customer charge of $27.00 for GS1 (single-phase) members and $35.00 for GS1 (three-phase) members, with a demand charge of $0.00 per kW-month.

Trico also will use data obtained by tracking member demand following the implementation of the initial $0.00 per-kW demand rate, in order to determine whether it is appropriate to propose a demand rate in its next rate case, which can be based on a test year reflecting a 12-month period ending no earlier than June 30, 2018.

The Settlement Agreement also provides for a new DG Energy Export Tariff to take effect in lieu of the current net metering tariff once a decision approving the Settlement Agreement is issued by the Commission. I discuss the DG Energy Export Tariff in more detail later in my testimony. The new DG Energy Export Tariff will apply to those DG members applying for interconnection after May 31, 2016.

From a revenue requirement standpoint, the only significant difference is a revised rate case expense from $150,000 to $450,000 amortized over a three-year period. This revision results in a slight increase over the revenue requirement Trico originally proposed (from 2.49 to 2.63 percent), but more accurately reflects what Trico will actually spend to process this rate case, which has been significantly more complicated and contested than a typical small electric cooperative rate case. The resulting rate of return on FVRB remains at 6.33 percent.

The revenue requirement in the Settlement Agreement is $89,762,812 from $87,480,736, or an increase of $2,282,076, which is equal to approximately 2.63 percent over adjusted 2014 test-year revenues. Fair Value Rate Base ("FVRB") equals $175,076,536 and includes the carrying costs of certain direct assignment facilities ("DAFs") to be acquired from AEPCO, which costs will be correspondingly removed from Trico's WPCA.

Q. Does the rate design proposed in the Settlement Agreement address recovery of fixed costs for more than just from DG members?

A. Yes. The challenge presented with recovery of fixed costs of the grid through volumetric energy rates is that it creates financial disincentives to utilities that wish to promote not only DG, but also energy efficiency, demand side management and other energy saving technologies. For that reason, the concept of "decoupling" fixed cost recovery from volumetric energy rates has been considered in Arizona and other states for many years. The recent surge in DG interconnection applications has brought the issue to the forefront for electric utilities and public utility commissions across the United States. While Trico believes that ultimately, demand rates in conjunction with a higher basic service charge are the best and most equitable way to recover the fixed costs of building, maintaining and financing the electric grid, increasing monthly customer charges closer to the actual cost of service will allow Trico to recover a higher percentage of those fixed costs pending the implementation of well-designed demand rates.

Q. How does Trico plan to introduce the concept of demand information to its residential and small commercial members?

A. The Settlement Agreement provides that Trico will conduct member outreach and education that includes, at a minimum, information on the nature and operation of demand rates, how members can use such rates to minimize their monthly bills and information on tools available from Trico and third parties to help members manage demand. Each

member's bill will include the member's peak demand in kW, indicate the date and time of the member's peak demand for the billing period; and education materials will highlight technology solutions including programmable thermostats and load controllers. Trico anticipates developing a comprehensive outreach and education plan under the parameters of the Settlement Agreement following approval of the Settlement Agreement by the Commission.

Q. Are there limits on Trico's ability to propose a demand rate in the next general rate case?

A. Yes. In keeping with the concept of gradually introducing demand rates to residential and small commercial customers, Trico has agreed that any demand rate for members on rate schedules RS1 or GS1 (single-phase or three-phase) will be no larger than $2.00 per-kW in the next rate case. This demand rate will reflect a portion of the distribution demand fixed-cost component of Trico's cost of service.

Q. Has Trico agreed to additional demand reduction measures under the Settlement Agreement?

A. Yes. Under the Settlement Agreement, Trico will propose at least two demand-reduction programs in its next Energy Efficiency Implementation Plan, which Trico will file on or before June 1, 2017. To the extent possible, these programs will be included in the demand-rate education and outreach Trico will undertake.

Q. Please explain the DG Energy Export Tariff proposed under the Settlement Agreement?

A The Settlement Agreement provides for a new DG Energy Export Tariff to take effect in lieu of the current net metering tariff once a decision approving the Settlement Agreement is issued by the Commission. That new DG Energy Export Tariff will apply to those DG

members applying for interconnection after May 31, 2016. Thus, the new DG Energy Export Tariff would *only* apply to DG Members who submit an application for interconnection *after* May 31, 2016, and then, *only* following the effective date of a decision in this case. All DG members will remain on the current net metering tariff until the effective date of the decision in this case. Those DG members who had submitted applications for interconnection on or before May 31, 2016 will be grandfathered on the existing current net metering tariff.

Under the new DG Energy Export Tariff, the energy supplied by Trico to a DG member during the billing period will be billed by Trico in accordance with the rates and charges under the member's standard rate schedule. Because this is essentially a rider to standard rate schedules, the DG Energy Export Tariff will work in conjunction with all of Trico's rate schedules. For example, a DG member on Trico's RS1 rate schedule will be billed in accordance with the rates and charges on that schedule. There will be no netting or banking of energy (kWh) during the month. If credits received from the export energy are greater than the member's monthly bill, then that credit balance will carry forward to the next month; but there will be no rollover of excess energy (kWh) to the following month.

Q. What would be the compensation for excess energy exported onto Trico's system from DG members' systems under the DG Energy Export Tariff?

A. The new export rate applying to excess energy produced by a DG member's system and exported onto Trico's distribution system will be set at $0.0770 per kWh. This rate is the equivalent of Trico's power supply portion of the energy charge for the first tier of the standard residential (RS1) rate schedule. Recovery of the cost of the exported energy will be permitted through Trico's WPCA, as described in the WPCA Plan of Administration ("POA") attached to the Settlement Agreement.

Q. Would the DG Export Rate be subject to modification prior to Trico's next rate case?

A. Yes. The Commission Staff and Trico have agreed to support that the general rate case remain open for 18 months following the decision, for possible modification of the export rate at either parties' discretion, following the establishment of one or more methodologies in the ongoing "Value of Solar" docket (more formally known as *In the matter of the Commission's Investigation of Value and Cost of Distributed Generation* – Docket No. E-00000J-14-0023). Any new rate would be subject to review and approval by the Commission.

Q. Will the proposed new DG Energy Export Tariff will be applied retroactively?

A. No. As I indicated previously, the DG Energy Export Tariff will apply to applications submitted after May 31, 2016, but will take effect only after the decision in this case. Thus, members who apply after May 31, 2016 will remain on the current net metering tariff until the effective date of the decision, and thereafter will be on the new DG Energy Export Tariff. There will be no retroactive application of the new DG Energy Export Tariff for the period prior to the decision. Members who applied on or before May 31, 2016 will remain on the existing net metering tariff. The Settlement Agreement provides that all Trico members who applied for DG interconnection on or before May 31, 2016, will be grandfathered on the current net metering tariff at least until the conclusion of Trico's next rate case, but with the expectation that grandfathering will continue for the remaining term of those members' interconnection agreement or 20 years, whichever happens to be shorter. The parties have acknowledged, however, that the right of future Commissions to make a determination in future rate cases cannot be impeded.

Q. Are elements of rate design, other than net metering, grandfathered under the Settlement Agreement?

A. No. Other than the net metering tariff, there is no grandfathering of rates or rate design for DG or other members. Once new rates are approved and in effect, all members will be subject to the applicable rate schedule. For residential customers (both DG members and non-DG members) the three-part rate set forth in rate schedule RS1 will apply, for example. All DG members have received notice that their rates are subject to Commission approved changes.

Q. Are there other limitations to grandfathering set forth in the Settlement Agreement?

A. Yes. Grandfathering will only apply to the same service location with the same DG system. Any DG member who moves a DG system from one location to another after May 31, 2016, will no longer be grandfathered, and the system will be subject to the then-applicable tariff. Also, if a DG member replaces a DG system with a new one after May 31, 2016 the new system will not be grandfathered and will be subject to the then-applicable tariff.

Q. Is there anything else in the Settlement Agreement specifically regarding the interconnection of DG systems?

A. Yes. The Settlement Agreement also requires Trico to revise its DG interconnection agreements, for both leased and member-owned systems, to provide that members may be charged a return trip fee for a return trip to inspect installations of DG interconnections where the return trip is due to member or installer issues.

Q. Is Trico seeking a waiver of the Net Metering Rules (A.A.C. R14-2-2301 et. seq.) to the extent necessary, for approval of the new DG Energy Export Tariff and other changes from the current net metering tariff?

A. Yes, the Settlement Agreement supports of the requisite waivers to implement these changes.

IV. IMPACT OF THE SETTLEMENT AGREEMENT.

Q. What would be the impact of the settlement on the average and median residential member?

A. Under the terms of the Settlement Agreement, residential members using the average of 837 kWh would experience an overall increase in their monthly bill in the amount of approximately $2.05 or 1.75 percent over current rates, from $116.84 to $118.89. Residential customers with median usage of approximately 750 kWh would experience an increase of $2.45 or 2.31 percent, from $106.25 to $108.70, in their monthly bill. I should note that Trico's last rate increase of approximately 8.4 percent for the average residential member was based on a 2007 test year, and implemented in September of 2009, so the requested rates represent an increase of less than 0.25 percent per year over the past seven years.

Q. Would the Settlement Agreement disproportionately impact Trico's fixed or low income members?

A. It would not. While Trico does not have or maintain data relating to the income of its members, the Cooperative does coordinate with its low-income members to obtain bill payment assistance through the Low Income Home Energy Assistance Program (LIHEAP), a Federally-funded program or other community assistance related programs (including the Pascua Yaqui Social Services) that help low-income individuals and

households with their home energy bills. During the 2014 test year, 675 Trico members received payment assistance. The average monthly kWh usage for those 675 members in 2014 was 973 kWh, which is higher than the average residential usage of 837 kWh per month. The net impact to the monthly bill of the members who received payment assistance would be approximately $2.26, or 1.65 percent, which is a *smaller* percentage increase as compared to the system average for all residential members of $2.05, or 1.75 percent. Thus, because low-income members in Trico's service area on average use more energy than the average residential member, the overall impact of the Settlement Agreement on their monthly bill is lower on a percentage basis.

Q. What impact would the Settlement Agreement have on Trico's recovery of fixed grid costs?

A. Under the Settlement Agreement Trico would grandfather 1,621 existing DG Members under the current Net Metering Tariff, which results in a under-recovery of fixed grid cost of $89.91 per month for the average residential net metering customer under current rates and a total under-recovery of $1,749,000 per year. Under the rates in the Settlement Agreement, which proposes a small decrease in the residential energy rates and a corresponding increase in the fixed customer charge, the under-recovery from grandfathered existing DG members is reduced by $8.19 per net metering customer (to $81.72 per month). This corresponds to an annual reduction of $159,300 in under-recovery of fixed grid cost under the Settlement Agreement (down to $1,589,700 per year for all the grandfathered net metering customers.) New net metering customers under the Settlement Agreement would produce an under-recovery of fixed grid cost of $60.28 per month for the average residential net metering customer. Please refer to David Hedrick's testimony and Exhibit DWH – S1 for more detail.

Q. Do you believe the Settlement Agreement would adversely impact solar DG in the Trico service territory?

A. No. First, by utilizing the $0.077/kWh export rate under the Settlement Agreement and the average DG export percentage of 60% for Trico's service territory, the Settlement Agreement produces an average credit of $0.091417/kWh from base rates (not including additional benefits such as avoided sales taxes). That is higher than Tucson Electric Power Company's (TEP's) current full net metering retail credit (summer first block) of $ 0.091311/kWh. By all accounts, rooftop DG is continuing to increase in the TEP service territory. As Mr. Hedrick has noted in his testimony, Trico's comparatively higher fixed costs and associated higher retail rates provide more value for net metered DG in its service territory. I am concerned that DG systems in our service area are being designed to export more energy than is used on-site. However, I would also note that as a greater percentage of DG energy is used on-site, the effective credit increases. Solar witnesses in other dockets have claimed that DG energy exports are often as low as 30%. If that is the case, the average base rate energy credit would be $0.10213/kWh under the Settlement Agreement.

Second, if history is an indication, a gradual reduction in solar DG subsidies by Trico will not result in a significant reduction in the deployment of DG in the service territory. Trico, like other Arizona electric utilities, first reduced, then eliminated up-front incentives for rooftop solar DG as the cost of DG systems reduced and the efficiency of solar panels increased over time. Notwithstanding the elimination of up-front incentives, which averaged $15,000 per DG member, the deployment of rooftop DG has continued to escalate. The fact that Trico is now receiving several times more DG interconnection applications each month than it did three years ago suggests a modest reduction in the subsidies paid by Trico members for rooftop DG as proposed under the Settlement Agreement is appropriate and would not result in a significant reduction in the

deployment of rooftop DG in the Trico service territory. Indeed, even though the "payback" period for rooftop systems may increase slightly under the Settlement Agreement as compared to today's payback period, the payback period will still be shorter than it was in the near past. PV prices have been decreasing significantly and steadily over the past years.

Q. Has Trico evaluated the growing amount of lost-fixed costs due to DG?

A. Yes. Mr. Hedrick's Testimony in Support of the Settlement Agreement provides a cost-of-service based analysis of Trico's unrecovered and shifted fixed grid costs in DWH-S1. Based on that analysis, unrecovered fixed costs associated with serving a DG member under Trico's existing rate and net metering tariff is $89.91 per member per month. And because the number of DG members is increasing, the overall subsidization will also increase. EFCA's assertion that Trico has not conducted any meaningful analysis about the amount of lost-fixed costs are incorrect.

V. SETTLEMENT PROCESS.

Q. Please provide an overview of the settlement process.

A. There are six parties to this docket: Trico, Freeport Minerals Corporation & Arizonans for Electric Choice & Competition (collectively "AECC"), EFCA, Pima County, Robert Hall, and Staff. Formal settlement discussions took place on June 17, 2016, after they were noticed. All parties to the docket had opportunity to participate in the settlement discussions and a settlement in principle was reached between Trico and Staff. A settlement term sheet was prepared and distributed to the parties on June 22, 2016. Thereafter, the final details of the Settlement Agreement were negotiated and incorporated into a definitive draft. All parties were given an opportunity to review on the Settlement

Agreement before it was finalized, and all parties were given the opportunity to become Signatories to the Settlement Agreement before it was filed on July 8, 2016.

Q. Robert Hall, a Trico DG customer, provided Direct Testimony on rate design issues. What is your response to his testimony?

A. I believe the Settlement Agreement addresses most of Mr. Hall's concerns. The new DG Energy Export Tariff is comparable to Mr. Hall's bill crediting proposal. Mr. Hall believes exported energy should be valued at a rate higher than avoided cost, and Trico's proposal of $0.0770 per kWh is significantly higher than avoided cost. I believe Mr. Hall also supports analyzing member demand information and providing outreach and education prior to implementing demand rates, consistent with Trico's commitment in the Settlement Agreement.

VII. TRICO'S SUPPORT OF THE SETTLEMENT AGREEMENT.

Q. Do you believe the Settlement Agreement is in the public interest?

A. Yes. It bears repeating, electric cooperatives like Trico have a fundamentally different economic and governance model from investor-owned utilities. Cooperatives are owned and run by the members that they serve, for the sole benefit of the members. Cooperative Directors, as Cooperative members, do not have an incentive to provide a return to third-party investors, or to maximize the profitability of the Cooperative to the detriment of its members. To the contrary, the fundamental responsibility of an Electric Cooperative Board is to provide safe, reliable energy to members, at the lowest cost while maintaining a financially sound organization, consistent with its legal requirements and social responsibilities.

To that end, Trico has maintained a vibrant renewable energy portfolio, utilizing its members' resources carefully to fund incentives for distributed solar generation including large-scale projects for commercial members and rooftop solar for its residential members. Trico's relatively higher costs of doing business make solar DG a more attractive investment in the Trico service area, and consequently, Trico has experienced an explosive growth in the amount of applications to interconnect rooftop solar DG, the majority of which relate to leased systems. Like electric utilities and public utility commissions across the United States, Trico's Board has been seeking to balance the resulting unrecovered (or in the case of cooperatives, shifted) fixed costs of building, maintain and financing the electric grid, against the responsibility to create and maintain a sustainable growth of renewable resources. In addition, because Trico is member-owned, lost fixed costs that are not otherwise recovered through Trico's Wholesale Power Cost Adjuster (i.e. fixed costs of the distribution system) act to reduce the capital accounts of non-DG members until such costs are included in the revenue requirement through a rate case, which results in an immediate shift of cost from the DG members to the remaining members.

Over time, as the cost of DG declined and efficiencies improved, Trico, like other electric utilities, reduced and finally eliminated up-front incentives of as much as 50% of the cost of a rooftop solar DG system that averaged $15,000 per DG member, while applications for DG interconnections continued to increase at escalating levels. The volume of DG interconnection applications in Trico's service area has led the Trico Board to conclude that a modest reduction, *not elimination*, of the subsidy that the Cooperative provides through the net metering of rooftop DG will partially mitigate the unrecovered and shifted fixed grid costs associated with the Cooperative's current net metering tariff, while continuing to provide adequate incentive for a sustainable growth in renewable resources within the Trico service area. For the reasons described above, I believe the

Settlement Agreement reached with Commission Staff provides that balance, and is in the public interest.

Q. Does that conclude your Settlement Testimony?

A. Yes it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

Reply Testimony of Vincent Nitido

In Support of Settlement Agreement

on Behalf of

Trico Electric Cooperative, Inc.

August 15, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. Did you file Direct Testimony in Support of the Settlement Agreement on behalf of Trico Electric Cooperative, Inc. ("Trico or "Cooperative") on July 29, 2016?

A. Yes.

Q. What will you be addressing in your Responsive Testimony?

A. First, I will again discuss Trico's status as a rural electric cooperative, and how that impacts our ability to withstand the continued escalation of lost and shifted fixed grid costs. I believe that is necessary because EFCA and its consultants continue to ignore the disparate impact of cost shifts associated with distributed solar generation (DG) on a Member owned electric distribution cooperative, and instead are proposing the imposition of rates and requirements geared to much larger vertically-integrated utilities.

Second, I will support the proposal in the Settlement Agreement dated July 8, 2016 between Trico and Commission Staff (Settlement Agreement) for the Cooperative to recover a portion of its fixed costs through an increased customer charge that all Trico Members pay, including Members with DG. The proposed charge provides a more equitable means for recovering certain fixed costs that each Member requires for service. The increased customer charge combined with the proposed lower energy charge also is a revenue neutral means of reducing the monthly subsidy for DG systems, while preserving the ability of DG Members to offset their own energy usage at the full retail rate.

Third, I will defend the DG Energy Export Tariff of $0.077 per kWh proposed under the Settlement Agreement as a reasonable and necessary means of addressing the immediate issue of escalating shifts in fixed grid costs to Trico's non-DG Members. I will explain why EFCA's proposal to delay addressing the issue further pending a second phase of the Commission's Value of Solar Proceeding, while grandfathering all new DG systems in the meantime, will result in significantly higher levels of subsidized fixed costs and higher rates for Trico's non-DG Members.

Finally, I will again discuss the Cooperative's proposal to provide demand information to its Member-owners, along with education and outreach to its Member-owners regarding the use of demand rates and how to utilize them to reduce their monthly bills. I will also discuss the utilization of demand data obtained in the period prior to the Cooperative's next rate case, as a reasonable, relevant and measured approach to determine if and how the implementation of demand charges is appropriate to Trico's specific circumstances.

II. TRICO'S CIRCUMSTANCES ARE UNIQUE AND DO NOT LEND THEMSELVES TO EFCA'S PROPOSALS.

Q. What are the circumstances unique to Trico that make EFCA's proposals difficult to accept?

A. As I discussed in my Direct Testimony, Trico is a non-profit rural electric distribution cooperative. Trico is governed by a 7-Member Board of Directors that are themselves Cooperative Members elected by their fellow Cooperative Members. The Cooperative serves what is essentially the rural ring around metropolitan Tucson, which is served by Tucson Electric Power Company (TEP). Trico provides distribution services only to its 39,000 Members, 95% of whom are residential Members. Generation and transmission are acquired from third-party providers under wholesale contracts, and the costs are passed

through to the Cooperative's Members without markup. All of that presents particular issues for Trico with respect to the current net metering of DG within its service territory.

For example, as a non-profit cooperative, Trico has no investors that receive a return on their investment, nor does it have anyone to share the financial impact of lost and shifted fixed grid costs. Those costs by definition must be paid by other Trico Members, though higher rates. That direct impact requires the Trico Board to assess and maintain a balance between the need to promote the development of solar resources within the service territory against the cost to Trico's Members, and to do so in a way that is fair and equitable to all Trico Members.

As I have discussed previously, because Trico serves an area that is not economically viable for investor owned utilities to serve, Trico's fixed grid costs are necessarily higher than those of utilities serving more densely populated areas. That translates to significantly higher rates for Trico's residential Members compared to TEP's residential customers, for example. Which means that DG provides more comparative value to installers in Trico's service territory, and as a result, a higher amount of lost and shifted fixed grid costs to Trico Members. Trico's proximity to TEP essentially makes the Cooperative a more lucrative target for giant solar installers such as SolarCity that have the ability to mobilize a huge sales force and marketing effort within the Tucson area. Consequently, Trico has experienced an unprecedented and disproportionately large flood of applications for residential rooftop DG interconnection. The ability of large solar installers to accelerate the volume of DG interconnections is the reason this rate case was filed, the reason Trico needs immediate relief from the severe cost shifts associated with that acceleration, and why a "grandfathering" date beyond that proposed in the Settlement Agreement will not work under Trico's circumstances. We need to stop the bleeding now.

I think it's also important to reiterate that because Trico acquires wholesale transmission and generation from third-party providers at fixed prices, it does not receive a price signal based on the time of day, and consequently does not benefit from its current time of use tariff. That issue is exacerbated by the fact that because the Cooperative serves a load that is 95% residential, its monthly distribution system peaks occur most often on the weekend.

For those reasons, I think it is misplaced for EFCA and its consultants to continue to rely on studies, surveys and selected data from larger investor owned utilities like San Diego Gas & Electric Company (SDG&E) to support recommendations for a Member owned and governed rural electric cooperative.

Q. EFCA has now submitted testimony from Mr. Quinn, who alleges that because there is no formal consumer advocate in this case, he is representing the consumer viewpoint. Do you agree?

A. No. Again, like other electric cooperatives formed to provide electricity to areas that for-profit investor owned utilities could not or would not serve economically, Trico is a non-profit, Member owned cooperative. That means Trico is governed by the Members we serve. Our 39,000 Members elect a Board of Directors from among themselves, and the Members that constitute the Board of Directors are charged with running the Cooperative in the best interest of all of its Members. That is the reason, for example, that Mr. Quinn's former employer, Residential Utility Consumers Organization (RUCO), does not receive funding from Cooperative Members or participate in Cooperative rate cases. So Mr. Quinn's assertion that he is the only "consumer advocate" in Trico's rate case is disingenuous at best. Trico is governed by a Board of "consumer advocates," and it is the decision of that Board of Trico Members that the Settlement Agreement strikes a fair and appropriate balance among Trico Members who wish to participate in distributed generation, against the costs to be borne by non-participating Trico Members. Mr. Quinn's

alter ego, Arizona Utility Ratepayers Alliance, has been funded by solar interests and he is appearing on behalf of EFCA in this docket. EFCA's largest Member is SolarCity, which happens to be the largest vendor of rooftop solar generation in the country (and in Trico's service territory). He is hardly in a position to claim that he is an "advocate" of anyone other than solar interests. It is neither reasonable nor appropriate for him to swoop in at the behest of SolarCity's advocacy organization in order to substitute his judgment for that of a Member elected Board of Directors.

Q. Is Trico's situation different from those of Sulphur Springs Valley Electric Cooperative (SSVEC) or UNS Electric, Inc. (UNSE)?

A. Yes, as I have discussed, Trico has and is still experiencing an unprecedented flood of applications for DG interconnection, and a corresponding escalation of lost and shifted fixed grid costs. Even after announcing its proposed changes in the compensation for net metered DG, Trico received 404 applications in 2015 (458 installs) and received 293 applications through July of 2016. Again, I believe this is largely because of Trico's proximity to TEP and its status as a comparatively lucrative opportunity for SolarCity. My understanding is that SSVEC which is a similarly sized cooperative, is now receiving significantly fewer applications (only 121 installs in 2015 and 35 installs to date in 2016), so while SSVEC has the same issue with respect to lost and shifted fixed costs associated with DG, it is not escalating as rapidly. Like Trico, SSVEC does not receive a time of day price signal from its power and transmission suppliers, consequently it does not benefit from implementing a residential time of use rate. But while Trico now has more than 2,500 Members on its residential time of use rate, SSVEC has very few. Finally, unlike Trico, SSVEC does not currently have the metering capability to implement demand rates, and appropriately, is not seeking to implement a program to educate its Members about such rates or to collect demand data for its Members to analyze.

The difference between Trico and UNSE's situations are even more pronounced. UNSE is for all intents and purposes a much larger vertically-integrated investor owned utility with entirely different demographics from Trico. Trico does not have an integrated distribution, transmission and power supply in one company like UNSE. Trico is billed through several contracts for its power based on a single monthly energy rate and a fixed dollar charge for capacity. With respect to power supply Trico currently gets no benefit from usage at different times of the day or week.

Trico currently purchases transmission from Arizona Public Service Company (APS), Tucson Electric Power Company (TEP) and Arizona Electric Power Cooperative (AEPCO). Some of these transmission service agreements are point to point with a set reserve capacity cost which does not differ if we use less, however the majority of the transmission service agreements are for network service which is billed based on Trico's load ratio share of each system's total cost at the time of each of the system peaks. These transmission systems peak at different times, and it would be virtually impossible to design an effective retail rate signal based on a transmission load ratio share charge. In an integrated utility like UNSE, a single system peak occurs at the same time for the entire system which, if reduced, could potentially save or defer the need for new generation and/or transmission facilities. In a small distribution cooperative like Trico, where we acquire power supply and transmission from other large integrated utilities, it is much more difficult to quantify or even have any impact on the systems of others (e.g. even if Trico did reduced costs for APS's transmission system, it is very unlikely that Trico would ever directly see any of those savings which could then be passed through to the Trico retail Members).

In addition, because Trico load is 95% residential, its distribution system peaks most often on the weekends rather than during the week as is the case for most urban utilities with

more substantial commercial load. This would make an effective distribution system time of use rate difficult for residential Members who would typically want to have weekends as off-peak times.

For those reasons, I do not believe it appropriate to compare the positions or proposals of UNSE, SSVEC and Trico in their respective rate cases, or to cite a *Recommended Opinion and Order* in one case as precedent or support for a position taken by the solar industry in any other case. Trico's facts and circumstances stand on their own.

Q. Can you explain further why it is important to take action now given Trico's unique circumstances?

A. Yes. Trico had 551 residential DG Members at the beginning of the 2014 test year (this includes all DG Members in Trico's area from 2005 to 2014 or 9 years). As of February 28, 2015, Trico had 1,262 DG Members. As of the end of July 2016, including applications pending installation, Trico now has approximately 1,700 DG Members. Thus, since the start of the test year, the DG in Trico's service area has expanded from just over 1% to **over 4% of Trico's total Members**.

Based on our current rate design and net metering, most of those 4% are paying only a small portion of the fixed costs allocated to them and are avoiding paying almost $2 million of fixed costs annually. Those avoided costs are shifted to the other Members. If those cost shifts are locked in through grandfathering over 20 years, you are looking at $40 million to be shifted to fewer than 40,000 members. Further delay and further grandfathering will only increase those numbers.

The settlement agreement provisions will help mitigate the increasingly inequitable recovery of Trico's fixed costs (and related cost shift). Trico has been attempting to

address this issue since the beginning of 2015. Given the exponentially increasing levels of DG in its service area, consideration of the settlement agreement cannot wait.

III. THE INCREASED CUSTOMER CHARGE SET FORTH IN THE SETTLEMENT AGREEMENT IS AN APPROPRIATE MEASURE TO MITIGATE THE FIXED COST SHIFTS RESULTING FROM A RAPID INCREASE IN ROOFTOP SOLAR DEPLOYMENT IN TRICO'S SERVICE AREA.

Q. Mr. Monsen asserts the increase in Trico's fixed customer charge represents "a significant change in rates." Do you agree?

A. No. Again, the increase in the residential customer charge is offset by a reduction in the energy rates and the introduction of block rates that further reduce the energy rate for the first 800 kWh, producing a revenue neutral shift in some of the fixed costs of service from the volumetric energy rate to the customer charge. Residential Members using the average of 837 kWh would experience an overall increase in their monthly bill in the amount of approximately $2.05 or 1.75% over current rates.

It is true that Members who use significantly lower energy will see a higher percentage increase in their monthly bill because of the increased customer charge. The customer charge represents a portion of the direct access *average* cost to serve a residential Member. For that reason, Trico believes the use of appropriately designed demand rates would likely be a better means of recovering fixed costs, and Trico has agreed to provide demand information and begin education and outreach to its Members regarding demand rates, while collecting and analyzing demand data, pending consideration of demand charges in the Cooperative's next rate case.

I think it is important to reiterate that low usage Members are not necessarily low income Members. As I have noted in my previous testimony, the average Trico Member seeking help through low-income assistance programs uses significantly more energy that the average residential usage of 837 kWh. The overall impact of the proposed rates on such low income Members would be lower than for the average Member on a percentage basis.

Q. Mr. Monsen argues that the increased customer charge proposed under the Settlement Agreement is inconsistent with the principle of "gradualism." How do you respond?

A. As Trico has set forth – and EFCA has not disputed – the basic service costs for Trico's residential Members is almost $32 per month, which is the cost of having Trico's infrastructure, the service connection, in place to serve the minimum load before any energy is provided to the Member. The $24 per month customer charge still covers only two-thirds of this cost. In an effort to recover an equitable amount of fixed costs from its Members, the increase in the monthly charge moves halfway between the current charge of $15 and the actual fixed costs it is intended to cover. Moreover, Trico has added a tier in its volumetric rates to mitigate the increase for lower usage Members. I believe this is a fair balance and results in a gradual bill impact for the vast majority of Trico Members.

Further, not to be flippant, but I wish Mr. Monsen had spoken with his client and its member, SolarCity, about gradualism a few years ago. Trico has been dealing with an unprecedented flood of applications for DG interconnections since the latter part of 2014, when SolarCity began the heavy marketing of leased residential rooftop DG systems in Trico's service area. That explosive growth occurred and is continuing, notwithstanding the reduction and eventual elimination of up-front incentives for DG systems. Under the current net metering tariff, given the specifics of Trico's circumstances, Trico's non-DG Members subsidize $89.91 per month in fixed grid costs for each interconnected DG

system. That equates to an annual subsidy of $1.75 million annually as of May 31, 2016, the proposed grandfathered date under the Settlement Agreement, and it increases with every new DG interconnection. That is an issue that *must* be addressed -- it will continue to escalate unless we do. What Trico and Commission Staff have agreed to is a compromise measure that begins to address the issue. That measure includes a revenue neutral shift in some of the fixed grid costs from the volumetric energy charge to the fixed customer charge, so that all residential Members, including those with DG, contribute to the fixed grid costs incurred by all of those residential Members. This in conjunction with the DG Energy Export Tariff reduces the DG subsidy from $89.91 per month to about $60.00. As I noted previously, the net impact of that measure to the average non-DG residential Member is a bill increase of less than 2 percent. In light of the extraordinary circumstances we are dealing with, I would submit that the rate proposal agreed to by Commission Staff and Trico is clearly consistent with the principle of gradualism.

Q. In his Direct Testimony, William A. Monsen recommends that, in lieu of an increased customer charge, Trico adopt a "minimum monthly bill that is trued up annually for residential Members that is revenue neutral relative to its current fixed charge." Would that adequately address the issues of unrecovered fixed grid costs and cost shifts to Trico's non-DG Members?

A. No. In support of his recommendation, Mr. Monsen cites the testimony of B. Thomas Beach on behalf of the Alliance for Solar Choice in the Commission's Value of Solar docket (Docket No. E-00000J-14-0023). In his testimony, Mr. Beach concedes that "[cost-shift] impacts on non-participants are most likely to be a concern in the residential market, because residential solar systems export a higher percentage of their output and because most of the residential cost of service is recovered through volumetric rates." As Mr. Monsen notes, one of the solutions to that issue proposed by Mr. Beach is to "adopt a monthly minimum bill to recover customer-related costs, thus ensuring that all Members

make a minimum contribution to the costs of the utility infrastructure that serves them (*e.g., metering, billing, and customer accounts service).*" [Monsen testimony p. 21, citing Beach testimony pp. 26-27, *parenthetical added by Mr. Monsen*]. Mr. Beach indicates that "a minimum bill can be set to assure recovery from all Members of customer related costs which do not vary with usage." [Beach testimony p. 27]. Again, Trico's Cost of Service set forth in Schedule G-6.0 demonstrates that Trico's fixed customer related costs including line extension, metering and meter reading, customer records and service equate to $31.83 per month for each residential Member. Trico's proposed customer charge under the Settlement Agreement is $24 per month. Thus, even under the Cooperative's proposal, it will not fully recover the full amount of fixed customer related costs, the balance of which must be recovered through the Cooperative's volumetric energy rate. Adopting instead a minimum bill that is "revenue neutral" relative to Trico's current customer charge of $15 would exacerbate the fixed cost recovery and cost shift issues, not address them. Mr. Hedrick addresses the minimum monthly bill concept further in his testimony.

IV. THE DG ENERGY EXPORT TARIFF AGREED TO BY TRICO AND COMMISSION STAFF PROVIDES A FAIR AND REASONABLE SUBSIDY THAT WILL CONTINUE TO PROMOTE THE DEVELOPMENT OF SOLAR RESOURCES IN TRICO'S SERVICE TERRITORY AT A REDUCED COST TO NON-DG MEMBERS.

Q. Do you agree with EFCA's position that Trico's proposed compensation for excess energy is inadequate?

A. No. Mr. Monsen incorrectly implies that the proposed DG Energy Export rate of $0.077/kWh was calculated simply as a halfway point between Trico's avoided cost and retail rate. While the rate was derived through settlement discussions and not through pricing analysis, as Section 8.1 of the Settlement Agreement explicitly states, the proposed rate represents the "equivalent of Trico's power supply portion of the energy charge for the first tier of the proposed RS1 Tariff." The "power supply portion of the energy charge" includes all the variable and fixed costs of the power supply and all the fixed cost of the transmission system, not just "brown wholesale energy." See Schedule H-2.1.

I believe the $0.077/kWh rate proposed in the Settlement Agreement represents a reasonable balance of the Cooperative's goal of promoting the sustainable growth of solar energy in its service territory against the cost to non DG Members of subsidizing that growth. As I noted in previous testimony, the Settlement Agreement produces an average energy credit from base rates of $0.091417/kWh, utilizing the $0.077/kWh export rate. That is higher than TEP's current full net metering retail credit, which appears to work for TEP's DG customers. It is also higher than the $0.09/kWh solar lease rate assumed by Mr. Monsen in his analysis. Mr. Monsen's adoption of the testimony of other witnesses in the Commission's Value of Solar Docket and the UNS

Electric rate case regarding *potential* benefits of DG in order to assess the *actual* value of exported energy to Trico is at best an esoteric exercise that ignores the difference between an electric distribution cooperative and vertically-integrated investor owned utilities.

Q. Do you agree with Mr. Monsen's assertion that Trico's proposed excess energy buyback rate forces DG customers to take unreasonable price risk?

A. No. In his Direct Testimony, Mr. Monsen states that "Trico's buyback rate could change significantly each year. This would cause great economic uncertainty for Members who are considering long-term investments in solar DG systems." [Monsen June 1, 2016 Direct Testimony, p. 25] Under the Settlement Agreement, the DG Energy Export Tariff is set at $0.077/kWh. Changes in the DG Energy Export Tariff may be made only in conjunction with a continuation of this rate case (for up to 18 months) with opportunity for all parties to participate following the completion of the Commission's Value of Solar Proceeding, or in a future rate case, which is based on a test year and as a practical matter cannot be conducted "each year." Mr. Monsen has also asserted that "it is unlikely that a developer of utility-scale solar systems would be willing to enter into a long-term Power Purchase Agreement with Trico that had such a highly uncertain purchase price. However, Trico appears to believe that solar DG Members should be forced to accept risks that other owners of solar projects would not accept." [Monsen Direct Testimony, p. 25] That is a strikingly inapt analogy which ignores that fact that unlike rooftop DG which is compensated at tariffed rates, utility scale solar contracts are market-based agreements resulting from arms-length negotiations between the parties. Those arms-length negotiations typically produce energy prices that are much less than half of the current cost of rooftop solar DG to the utilities. Trico's DG Energy Export Tariff rate of $0.077/kWh under the Settlement Agreement is still significantly higher than the current

market price of long-term power purchase agreements associated with utility scale solar projects.

V. THE GRANDFATHERING PROVISIONS IN THE SETTLEMENT AGREEMENT ARE FAIR, REASONABLE AND CONSISTENT WITH PAST REGULATORY PRACTICE.

Q. Mr. Monsen asserts that Trico's grandfathering proposal should apply to all net metering Members with existing DG systems and those who submit a completed interconnection application within 30 days after the decision in this docket becomes unappealable. Is this a recommendation Trico can support?

A. No. While Mr. Monsen utilizes national industry data and cost model assumptions to analyze the potential impact of the Settlement Agreement on the continued development of rooftop DG in Trico's service territory, the reality is that the volume of DG interconnection applications to Trico is controlled to a very large extent by the marketing efforts of SolarCity, the only EFCA Member that does business in the Trico service area. By way of illustration, on February 26, 2015, Trico filed an application to modify its net metering tariff on substantially the same terms as proposed in its original Application in this docket, proposing a grandfathering deadline of February 28, 2015. In the next two days, Trico received 99 applications for rooftop DG interconnections, 76 of which were SolarCity systems. After February 28, 2015, SolarCity announced that it would cease doing business in Trico's service territory, and interconnection applications dropped to 10-15 per month, approximately the volume experienced by the Cooperative prior to the marketing of the leased solar model in its service territory by Solar City. In November of 2015, SolarCity advised Trico it would resume activity in the Cooperative's territory, and applications for DG interconnections increased to over 50 per month. That volume of applications is resulting in the acceleration of unrecovered and shifted fixed grid costs, and is unsustainable for Trico.

The bottom line is that there is a very high probability that grandfathering applications received at a date in the future will result in a flood of applications before that date, locking in an additional large amount of unrecovered and shifted grid costs for an extended period of time. In the Settlement Agreement Trico agreed to grandfather net metering for Members who submitted applications on or before May 31, 2016, including an additional 359 Members within the grandfathered group over that proposed in Trico's original application in this docket of 1,262 grandfathered Members. I believe that is both reasonable and appropriate, given that all Members who file applications for DG interconnections are provided with and required to acknowledge receipt of notice of the current rate proceeding before their application is completed. A sample of the form of acknowledgement is attached as **Exhibit VN-1**. To put this in perspective, Trico's cost of service study filed with this application included 551 residential DG Members at the beginning of the 2014 test year (this includes all DG Members in Trico's area from 2005 to 2014 or 9 years'). Trico's original grandfather date for DG Members as of February 28, 2015 reflected 1,262 DG Members as of that date, and including applications pending installation, Trico now has almost 1,700 DG Members. The DG in Trico's service area has expanded *over the course of this proceeding* from just over 1% to over 4% of Trico's total Members.

Q. Mr. Monsen asserts that the language of the Settlement Agreement opens the door to the elimination of all grandfathering in the next Trico rate case. How do you respond?

A. Trico has committed in the Settlement Agreement to support continuing the grandfathering for the remaining term of the member's interconnection agreement or for 20 years, whichever is shorter. However, neither Trico nor the Commission Staff can bind future Commissions, through a Settlement Agreement or otherwise.

Q. EFCA has asserted that "grandfathering" Members on the net metering tariff as of a date prior to a final decision in this docket constitutes "retroactive ratemaking," and appears to be illegal. Would you agree with that?

A. Absolutely not. To the contrary, it is typical in rate cases before the Commission to apply new rates to *all* Members of the affected class. If new rates were to be applied in this docket in the way rates are typically adjusted following a rate case, all DG Members would be subject to the new rates going forward. In this case, the Trico Board of Directors determined that Members who applied for DG interconnections prior to Trico's original application to modify its net metering tariff on February 26, 2015 should be "grandfathered" under the existing net metering tariff, because they had likely acquired and sized their DG systems based on the net metering tariff at the time without knowledge of the proposed changes. Accordingly, Trico proposed an exception to the usual ratemaking practice for those Members with applications on file prior to March 1, 2015. As part of the Settlement Agreement, Trico agreed to extend that exception to Members with applications accepted on or before May 31, 2016, thereby including an additional 359 Members within that exception. While all Members applying for DG interconnections after February 28, 2015 have been explicitly advised of Trico's request to modify the net metering tariff for applications filed after that date, the Trico Board of Directors believed it appropriate to include the additional Members in large part because many of them had been incorrectly advised by their solar vendor that the Commission could not legally change the net metering tariff as of the effective date of a decision in this docket for anyone installing a DG system before the decision.

It is important to reiterate, that under the Settlement Agreement, while the existing net metering tariff is frozen after May 31, 2016, *all* DG Members will remain on the existing net metering tariff until after the effective date of a Commission decision in the docket.

Thereafter, DG Members with applications filed after May 31, 2016 will be subject to the new DG Energy Export Tariff in lieu of the current net metering tariff. There would be no application of the DG Energy Export Tariff to DG Members for any period prior to the Commission decision in this docket, because *that* would be retroactive ratemaking.

Q. Is "freezing" a tariff prior to the date of a Commission decision unprecedented?

A. No. In fact freezing a current tariff so that it will be unavailable as of a date certain subject to final Commission decision has been used by utilities and accepted by the Commission as a way to mitigate unintended issues with an existing tariff pending a determination of an appropriate resolution of the issues by the Commission. Perhaps the most pertinent example of that is the reduction and eventual elimination over time by Trico and other Arizona utilities of up-front subsidies for rooftop solar in response to rapid increases in rooftop solar deployment. Trico as well as the other Arizona regulated utilities, reduced its up-front incentives over a period of about five years. Once the incentive dollars budgeted for in the REST plan were exhausted Trico would notice its Members and solar contractors that new DG applications would receive the up-front incentives as approved in the next Trico REST plan. In each case, notice was provided to Members of Trico's intent to reduce the up-front subsidies as of a date certain, and Trico received subsequent approval of those reductions from the Commission in its REST plans.

Q. Mr. Monsen also asserts that Trico must grandfather the rate design for DG Members. Do you agree?

A. No. We are treating all Members the same with respect to rate design and the rates charged for service. No Members should expect that rates and rate design will remain unchanged in perpetuity. Indeed, the Commission has urged utilities across Arizona to include such a notice in net metering materials provided to DG Members. Trico has done so since February 2014. **See Exhibit VN-2.**

Moreover, it is unclear what Mr. Monson means by grandfathering rate design. His arguments could be construed to suggest that even the monthly customer charge should never be increased for DG Members.

In effect, Mr. Monsen is asking that DG Members be treated as a separate customer class. This is at odds with EFCA's position in other dockets that DG Members cannot and should not be treated differently than other Members.

VI. INTRODUCTION OF A DEMAND RATE WITH A $0.00/kW CHARGE, IN COMBINATION WITH MEMBER OUTREACH, EDUCATION AND ANALYSIS IS A REASONABLE MEANS OF ASSESSING WHETHER DEMAND CHARGES ARE A FAIR AND APPROPRIATE MEANS OF ALLOCATING FIXED COSTS IN FUTURE RATE CASES.

Q. Why does Trico believe it is important to introduce the concept of a demand charge to its Members now?

A. In its initial filing, Trico did not seek to introduce the concept of demand charges, but rather to partially address the issue of lost and shifted grid costs by raising the fixed customer charge and reducing the compensation for exported DG from the retail energy rate to avoided cost. Trico believed then that properly designed demand rates are the most accurate and equitable way to allocate the fixed costs of building, maintaining and financing the electric grid, but elected not to introduce a new element of rate design to its Membership without sufficient opportunity to collect and analyze Member demand data, conduct adequate Member education and outreach and ensure the rates have no unanticipated negative effects. As I indicated in prior testimony, activity in various Commission proceedings regarding rate design issues and net metering led us to believe

that if the Cooperative intended to implement demand rates in a subsequent rate case, it would be critical to begin the process of educating our Members and analyzing the potential impact of demand rates well beforehand. With that in mind, Trico has now agreed under the Settlement Agreement to implement a demand rate at a $0.00/kW charge on residential and small commercial Member bills for the purpose of providing Members with monthly peak demand information. That information, combined with a Member Education Program as provided in the Settlement Agreement, will serve as a platform from which to propose well designed demand charges in a future rate case.

Q. How soon could that future rate case occur?

A. Under the Settlement Agreement, Trico has agreed its next test year will end no earlier than June 30, 2018. It typically takes several months following the end of a test year to prepare and file a rate case, and in excess of one year to complete the case once filed. It is therefore unlikely that new rates could be in effect before January 1, 2020.

Q. Are there any limits on the imposition of demand charges in the Cooperative's next rate case?

A. Yes. Trico has agreed to proposed demand rates for residential and small commercial Members no higher than $2/kW, reflecting a portion of the distribution-demand component of Trico's cost of service. The parties to the Settlement Agreement have also agreed that alternative options may need to be considered in the next rate case.

Q. What is the purpose of having a $0.00/kW demand rate in place? Why not simply provide education to Members regarding demand rates?

A. The purpose of including a $0.00/kW demand rate on Member bills is to assist in the education of Members about demand rates, and to include the rate in the Cooperative's billing system in order to provide Trico the necessary time to ensure that all Members are

metered appropriately and the billing systems are in place to effect the billing of demand to each Member. In addition, having demand information in the billing system will facilitate Trico's ability to analyze demand data for rate design and Member education. For example, Trico anticipates that ultimately it will be able to utilize the collected demand information to provide billing comparisons to Members enabling, them to assess the impact of any future demand rate proposals.

Q. Both Messrs. Monsen and Quinn assert that demand charges should not be implemented before a comprehensive education plan regarding the nature and use of demand rates is developed and provided to Members. Is that a fair position to take?

A. Yes. That is why we are proposing to implement a $0.00/kW demand charge in this rate case. The $0.00 charge serves to include the rate in the Cooperative's billing system in order to collect and analyze demand information in conjunction with an extensive and well-planned Member education plan on demand rates. Once the Settlement Agreement is approved, the Cooperative will invest the time and expense of developing such a plan, so that it is in place and effective well before the Cooperative's next rate case. In that way, parties to any future rate case will have an opportunity to assess the analysis conducted by the Cooperative and effectiveness of the Cooperative's comprehensive education plan regarding the nature and use of demand rates, before demand charges are implemented.

Q. Why not develop a demand-billing pilot program as Mr. Monsen suggests on page 36 of his July 29 testimony?

A. As we have discussed, including the demand rate element in our billing system allows Trico to fully and accurately study every Member's demand and make better decisions about whether and how to implement actual demand rate charges in the future. Solar entities, such as EFCA, have argued that utilities have not adequately studied various aspects of demand rates or other DG related topics. And, ironically, they now argue

against Trico implementing a robust and more thorough and accurate way to study and assess demand rates. A demand-billing pilot program would essentially allow a limited subset of Members to self-select participation, based on a Member's assessment of whether the program would benefit that particular Member's usage and situation. Trico does not believe that would provide a complete analysis of Member demand for the entire Trico system, or would provide as good an opportunity to conduct outreach and education regarding demand rates for the entire Trico Membership.

Q. Mr. Monsen argues at page 31 that "Where a demand charge was implemented, there was a significant drop-off of applications for DG facilities." What is your response?

A. Mr. Monsen makes that statement after discussing Salt River Project's resent adoption of a demand charge for DG Members. What Mr. Monsen does not provide in his testimony is that the SRP demand charge is as high as $17.52 per kW for summer months. Mr. Monsen's assertion is deceptive at best and completely ignores the specifics of the Settlement Agreement's demand rate proposal. There is no basis for an assumption that the introduction of a $0.00/kW demand charge for the purpose of collecting and analyzing demand information and conducting education and outreach will result in a drop off of applications for DG interconnection.

Q. In your initial Direct Testimony, you indicated that Trico was not proposing demand rates for DG Members. Why does Trico now believe it is appropriate to implement a $0.00/kW demand charge for its DG Members?

A. Trico believed then and now, that properly designed demand rates are the most accurate and equitable way to allocate the fixed costs of building, maintaining and financing the electric grid, but elected not to introduce a new element of rate design to its Membership without sufficient opportunity to collect and analyze Member demand data, conduct

adequate Member education and outreach and ensure the rates have no unanticipated negative effects.

Trico's original filing proposed an increased customer charge, declining block energy rate, and a change in the net metering tariff to eliminate netting and pay for exported DG at Trico's avoided cost rate. Members who applied for DG interconnection before March 1, 2015 would be grandfathered under the existing net metering tariff. Trico still believes that creating a demand charge only for DG Members would not be appropriate, and is proposing to implement a $0.00/kW demand charge for all residential and small commercial Members, including those with DG, in order to obtain and study demand data; conduct Member outreach and education; and determine whether to propose demand rates for all residential and small commercial Members in the Cooperative's next rate case as an appropriate recovery mechanism for fixed grid costs.

VII. TRICO HAS THE TECHNICAL CAPABILITY TO FAIRLY AND EFFECTIVELY IMPLEMENT A DEMAND-RATE COMPONENT.

Q. Mr. Monsen asserts that Trico lacks the technical capability to provide useful information to residential Members about demand charges and the potential impact to their bills. Do you agree?

A. No. Of Trico's total 46,086 active meters, approximately 97% are currently capable of measuring and recording demand (and are in fact now recording demand). With some additional configuration of the Trico billing software, Trico can capture the demand data to provide to its Members and to utilize for analysis. Trico has approximately 1,350 meters on its system that currently cannot be configured to measure and record demand. Trico has proposed to replace these 1,350 meters and make the necessary modifications to its billing software within six months of the approval of the effective date of the Commission's decision approving the Settlement Agreement.

Q. Do you agree with Mr. Monsen that billing demand on one peak interval would be asking its Members to monitor and adjust their behavior based on 3,000 15-minute intervals each month?

A. No. Interval demand data is not necessary for Members to have the ability to minimize peak demand. After the fact interval data could actually be confusing and overwhelming, as a Member would need to remember what appliances were on at any given time rather than simply being mindful of reducing their peak demand by avoiding simultaneous use of major appliances. Most Members would not find historical interval data to be a useful tool. Instead, by simply avoiding using the washing machine, clothes dryer, dishwasher, stove/oven at the same time, a Member will create a lower peak demand than by running all the appliances at the same time. Many appliances have timers that could be set to assist in coordinating the use of the appliances to avoid simultaneous use. Many energy reduction measures can also help to lower peak demand such as washing clothes in cold water, setting the hot water heater temperature down, installing energy-efficient compact fluorescent bulbs, etc. Other new technologies also exist to assist with demand and energy management such as battery storage equipment.

Trico believes that the education and analysis of the impacts will be the most important factors on the success of a demand reduction program. Trico does have interval data available for about 30% of its existing meters and Trico plans to utilize this data in its analysis of the impacts of a demand rate on Members and also to help it to formulate its education program.

VIII. FREEZING THE CURRENT RESIDENTIAL TIME-OF-USE ("TOU") OPTION IS APPROPRIATE.

Q. Do you believe that the current time of use tariff is effective for Trico's residential Members? Please explain.

A. No. Currently Trico's long term wholesale power contracts charge Trico based on a single monthly energy rate which does not differ by time of day or day of the week. This means that when Members on the TOU rate receive an overall reduction in energy costs by reducing peak usage, Trico does not receive a corresponding reduction in its energy costs. Thus, in effect, the reduction in costs to the TOU Members is subsidized by other Members. With respect to the fixed cost of wholesale power Trico pays a fixed dollar amount that does not change based on usage or the time of that usage. Until such time as Trico can get time of use price signals from its power suppliers, it will not be possible for Trico to have an effective TOU tariff.

Q. Does Trico intend to propose a new TOU tariff for its residential Members? If yes, please explain. Will that tariff be effective with a demand charge? Please explain.

A. Not as this time. Unless and until such time as Trico's long term wholesale power contracts provide more granularity at least with respect to energy charges Trico does not believe that a TOU tariff will be effective.

Trico does not believe that the existing TOU tariff would be effective with a demand charge. The demand charge proposed in the Settlement Agreement for the residential and small commercial is to provide a signal to the Member of their use of the Trico distribution facilities which corresponds to their highest monthly demand (the size of the distribution facilities needed to serve their peak demand). Because this highest demand can happen any time, it could result in causing a peak to occur at a time when the

Member is trying to shift its energy usage to off-peak hours under the TOU tariff. This could result in the TOU Member having two signals that work against each other.

IX. OTHER ISSUES.

Q. Why does Trico plan to revise its DG interconnection agreements for leased and owned systems to incorporated language that Members may be charged a return trip fee for a return trip to inspect installations of DG interconnections?

A. Trico charges a return trip fee for all its other services such as for interruptions caused by the Member, for reconnection of service after disconnect for non-payment, for response to power interruptions where the Member's equipment is at fault, etc. However, Trico currently does not charge a fee for a return trip to inspect installations of DG interconnections, when the Member or solar contractor is at fault. I would note that the return trip fee does not cover the entire cost of the return trip but rather provides a cost signal to deter return trips from occurring. The most common reasons for requiring a return trip to inspect DG facilities include: inverter malfunctions, incorrect wiring and bent meter socket jaws. Trico does not have a significant number of return trips for DG interconnection inspections. For example Trico completed 98 inspection trips for DG in the last half of 2015. Only five of those inspection trips were return trips. As in the case of any fee, if a Member believes it has been improperly assessed, Trico Members would have recourse to challenge the fee directly to Trico and by complaint to the Commission.

Q. Mr. Quinn expresses concern that Trico "continues to modify its proposed rates and structure to be more harmful to ratepayers while sticking them with the bill." Do you have a response?

A. Certainly. Trico's original budget for expenses in this rate case was preliminarily estimated at $150,000, based on historic expenses in previous rate cases. Trico's last rate

case, based on a 2007 test year, was completed in 2009, at a cost of approximately $200,000. That case involved issues relating to the Cooperative's revenue requirement, time of use rates and line extension policy. The Commission hearing on that rate case took approximately two hours. The hearing for *this* rate case is scheduled to last at least 3 full days. The reason for that, and for the increase in rate case expense to $450,000 is not because Trico "continues to modify its proposed rates." Trico would have accepted the terms proposed in its original rate filing. Rather, it is because Trico's Member-elected Board of Member-directors sought to reduce, not eliminate, the subsidy for the benefit of solar DG paid by non-DG Members at a time when the Cooperative is being overrun with applications for DG interconnection. As has been the case in other dockets involving attempts to mitigate cost shifts associated with DG, SolarCity through its advocacy fronts, has fiercely contested nearly every element of the Cooperative's rate case, filed voluminous data requests relating to things like the "final official results of the last election in which [each Trico Board Member] participated," and has continued to advocate maintaining the status quo at best.

Trico's Members are its Member-owners, and the Cooperative's Member-elected Board of directors makes decisions based on the best interest of all of its Member-owners. In this case, the Board determined that the Settlement Agreement represents an equitable balance of the need to continue the sustainable development of solar resources within Trico's service area, against the cost of doing so to its Members. That judgment should not be second-guessed by the Nation's largest vendor of rooftop solar who stands to gain from every dollar of subsidy paid by Trico Members.

Q. Does that conclude your Settlement Testimony?

A. Yes,

Exhibit VN – 1

TRICO
ELECTRIC COOPERATIVE, INC.

A Touchstone Energy® Cooperative

February 22, 2016

RE: TRICO SUNWATTS PV PROGRAM INTERCONNECTION APPLICATION

Dear Trico Member:

Trico Electric Cooperative, Inc. (Trico) has received your Photovoltaic (PV) Interconnection Application. Before we conduct a review of your Application and provide you with the authorization to begin the installation of your proposed PV system, we want you to be aware of a couple of items that will likely impact the savings calculation promised to you by your solar installer with the installation of your PV system.

There is currently a generic proceeding, being led by the Arizona Corporation Commission (ACC), to determine the value and cost of solar. The final outcome of this proceeding may have an impact on what Trico will pay you for the energy generated by your PV system. Other proceedings are also taking place in which different proposals are being made by various parties including the ACC Staff.

Additionally, on October 23, 2015, Trico filed a rate case with the ACC. In this filing, Trico requested to modify its current net metering tariff. If approved by the ACC, Trico's new net metering tariff will mean that any power not immediately consumed by your household will be paid to you at the avoided cost rate of $0.03662 per kilowatt hour, on each monthly bill. You will no longer be allowed to roll any excess energy over within the month or to the next month's bill to use when your system is unable to produce enough energy to meet your needs, such as at night or on a cloudy day.

Trico strongly suggests that you incorporate the current ACC generic proceeding and Trico's proposed new net metering rate structure into your decision-making process and savings/costs calculations.

If Trico's proposal is approved by the ACC, the average Trico solar member with a PV system installed after February 28, 2015, will pay approximately **$42** per month more on their monthly bill than under the existing net metering tariff. We do not know what additional impact the generic ACC proceeding may have on your bill at this time.

Neither Trico's proposed net metering tariff nor the February 28, 2015, implementation date has been approved by the ACC at this time. In the Trico rate case, the ACC Utilities Division Staff and/or intervenors may propose different modifications to the net metering

tariff which may affect your bill in other ways. The ACC is not bound by any party's proposal, and may accept, reject, or modify any proposed rate, charge or term of service.

It is Trico's hope that your solar contractor has communicated the possible impacts to you, pending a decision by the ACC to the generic proceeding on the value and cost of solar and Trico's rate case. However, we have found that many of our Members have not been adequately advised of what is happening with this issue.

In addition, the Arizona legislature has passed Arizona Revised Statute (A.R.S.) § 44-1763, effective January 1, 2016, in an effort to ensure that you are advised of what you are agreeing to when you decide to install a PV system. Members buying, financing or leasing a solar distributed energy generation system (System) must receive certain disclosures form the manufacturer and solar installers regarding warranties, payment obligations, performance data and major System components as set forth in A.R.S § 44-1763.

As part of the installer's interconnection application process for the purchase or lease of a System, members must acknowledge on the form enclosed that they have had the opportunity to review their contract documentation to ensure that it contains all the required information set forth in the attached A.R.S. § 44-1763.

If after reviewing the enclosed information you still wish to move forward with the installation of your PV system, please sign below and return the signed acknowledgement to Trico. Upon receipt, Trico will proceed with its review of your PV Interconnection Application. Trico will reject interconnection applications which do not include a signed copy of this acknowledgement.

Due to a large increase in the number of Applications at the end of 2015 and beginning of 2016, Trico's application review and interconnection of new PV systems will be delayed. Trico is reviewing Applications on a first-come, first-served basis and will contact you or your solar installer once your Application has been reviewed. Please DO NOT install your PV system until you receive written confirmation that your Application has been reviewed and approved by Trico for installation.

Thank you for your interest in Trico's renewable energy programs. If you have any questions, please contact Trico's Sunwatts Desk, at (520) 744-2944, ext. 1524 or via email at sunwatts@trico.coop.

MEMBER AKNOWLEDGEMENT
FINANCING, SALE OR LEASE AGREEMENTS FOR DISTRIBUTED GENERATION
ADHERENCE TO A.R.S. § 44-1763

I, Member:

- Have read and understand that there is a generic proceeding to evaluate the value and cost of solar and that Trico has proposed modifications to its net metering tariff through its rate case proceeding that may have a significant impact on distributed generation (including rooftop solar) savings.
- Have read the attached A.R.S. § 44-1763 requirements.
- Have been given the opportunity to review the contract documentation for the purchase or lease of my System to ensure that it contains all the required information set forth on the attached A.R.S. § 44-1763.

_____ _____
Member Signature Date

_____
Member Printed Name

_____
Address, City, State, Zip

_____ _____
Trico Account # Phone Number

_____
Email Address

Note: Trico will reject interconnection applications which do not include a signed copy of this acknowledgement.

Arizona Revised Statute (A.R.S.) § 44-1763

44-1763. Distributed energy generation system agreements; disclosures; exception

A. An agreement governing the financing, sale or lease of a distributed energy generation system to any person or a political subdivision of this state must:

1. Be signed by the person buying, financing or leasing the distributed energy generation system and must be dated. Any agreement that contains blank spaces affecting the timing, value or obligations of the agreement in a material manner when signed by the buyer or lessee is voidable at the option of the buyer or lessee until the distributed energy generation system is installed.

2. Be in at least ten-point type.

3. Include a provision granting the buyer or lessee the right to rescind the financing, sale or lease agreement for a period of not less than three business days after the agreement is signed by the buyer or lessee and before the distributed energy generation system is installed.

4. Provide a description, including the make and model of the distributed energy generation system's major components or a guarantee concerning energy production output that the distributed energy generation system being sold or leased will provide over the life of the agreement.

5. Separately set forth the following items, if applicable:
   a. The total purchase price or total cost to the buyer or lessee under the agreement for the distributed energy generation system over the life of the agreement.
   b. Any interest, installation fees, document preparation fees, service fees or other costs to be paid by the buyer or lessee of the distributed energy generation system.
   c. If the distributed energy generation system is being financed or leased, the total number of payments, the payment frequency, the amount of the payment expressed in dollars and the payment due date.

6. Provide a disclosure in the sale and financing agreements, to the extent they are used by the seller or marketer in determining the purchase price of the agreement, identify all current tax incentives and rebates or other state or federal incentives for which the buyer may be eligible and any conditions or requirements pursuant to the agreement to obtain these tax incentives, rebates or other incentives.

7. Identify the tax obligations that the buyer or lessee may be required to pay as a result of buying, financing or leasing the distributed energy generation system, including:
    a. The assessed value and the property tax assessments associated with the distributed energy generation system calculated in the year the agreement is signed.
    b. Transaction privilege taxes that may be assessed against the person buying or leasing the distributed energy generation system.
    c. Any obligation of the buyer or lessee to transfer tax credits or tax incentives of the distributed energy generation system to any other person.

8. Disclose whether the warranty or maintenance obligations related to the distributed energy generation system may be sold or transferred to a third party.

9. Include a disclosure, the receipt of which shall be separately acknowledged by the buyer or lessee, if a transfer of the sale, lease or financing agreement contains any restrictions pursuant to the agreement on the lessee's or buyer's ability to modify or transfer ownership of a distributed energy generation system, including whether any modification or transfer is subject to review or approval by a third party. If the modification or transfer of the distributed energy generation system is subject to review or approval by a third party, the agreement must identify the name, address and telephone number of, and provide for updating any change in, the entity responsible for approving the modification or transfer.

10. Include a disclosure, the receipt of which shall be separately acknowledged by the buyer or lessee, if a modification or transfer of ownership of the real property to which the distributed energy generation system is or will be affixed contains any restrictions pursuant to the agreement on the lessee's or buyer's ability to modify or transfer ownership of the real property to which the distributed energy generation system is installed or affixed, including whether any modification or transfer is subject to review or approval by a third party. If the modification or transfer of the real property to which the distributed energy generation system is affixed or installed is subject to review or approval by a third party, the agreement must identify the name, address and telephone number, and provide for updating any change in, the entity responsible for approving the modification or transfer.

11. Provide a full and accurate summary of the total costs under the agreement for maintaining and operating the distributed energy generation system over the life of the distributed energy generation system, including financing, maintenance and construction costs related to the distributed energy generation system.

12. If the agreement contains an estimate of the buyer's or lessee's future utility charges based on projected utility rates after the installation of a distributed energy generation system, provide an estimate of the buyer's or lessee's estimated utility charges during the same period as impacted by potential utility rate changes ranging from at least a five

percent annual decrease to at least a five percent annual increase from current utility costs. The comparative estimates must be calculated based on the same utility rates.

13. Include a disclosure, the receipt of which shall be separately acknowledged by the buyer or lessee, that states:
    a. Utility rates and utility rate structures are subject to change. These changes cannot be accurately predicted. Projected savings from your distributed energy generation system are therefore subject to change. Tax incentives are subject to change or termination by executive, legislative or regulatory action.
    b. Before the maintenance or warranty obligation of a distributed energy generation system under an existing lease, financing or purchase agreement is transferred, the person who is currently obligated to maintain or warrant the distributed energy generation system must disclose the name, address and telephone number of the person who will be assuming the maintenance or warranty of the distributed energy generation system.
    c. If the seller's or marketer's marketing materials contain an estimate of the buyer's or lessee's future utility charges based on projected utility rates after the installation of a distributed energy generation system, the marketing materials must contain an estimate of the buyer's or lessee's estimated utility charges during the same period as impacted by potential utility rate changes ranging from at least a five percent annual decrease to at least a five percent annual increase form current utility costs.
    d. This section does not apply to an individual or company, acting through its officers, employees or agents, that markets, sells, solicits, negotiates or enters into an agreement for the sale, financing or lease of a distributed energy generation system as part of a transaction involving the sale or transfer of the real property to which the distributed energy generation system is or will be affixed.

Exhibit VN – 2

Attachment A

DISCLAIMER

POSSIBLE FUTURE RULES and/or RATE CHANGES
AFFECTING YOUR PHOTOVOLTAIC (PV) SYSTEM

The following is a supplement to the On-Grid PV Interconnection Enrollment Form with Trico Electric Cooperative, Inc. (Trico).

1. Your PV system is subject to the current rates, rules and regulations established by the Arizona Corporation Commission (Commission). The Commission may alter its rules and regulations and/or change rates in the future. If this occurs, your PV system is subject to those changes and you will be responsible for paying any future increases to electricity rates, charges or service fees from Trico.

2. Trico's electricity rates, charges and service fees are determined by the Commission and are subject to change based upon the decision of the Commission. These future adjustments may positively or negatively impact any potential savings or the value of your PV system.

3. Any future electricity rate projections which may be presented to you are not produced, analyzed or approved by Trico or the Commission. They are based on projections formulated by external third parties not affiliated with Trico or the Commission.

4. Trico proposed a new net metering tariff in the rate case it filed with the Arizona Corporation Commission (Commission) on October 23, 2015 in Docket No. E-01461A-15-0363. Trico requested that the proposed new Net Metering Tariff apply to Interconnection Applications received after February 28, 2015. Neither the proposed tariff nor the February 28, 2015 implementation date has been approved by the Commission at this time. In Trico's rate case, the Commission's Utilities Division Staff and/or intervenors may propose different modifications to the Net Metering Tariff which may affect your bill in other ways. The Commission is not bound by any party's proposal, and may accept, reject, or modify any proposed rate, charge or term of service. For further information, please visit Trico's website at **www.trico.coop**.

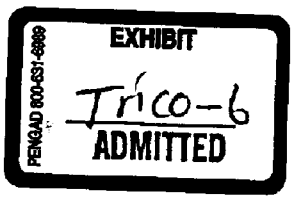
By signing below, you acknowledge that you have read and understand the above disclaimer. Please return to Trico.

_____ _____
(Member's Printed Name) (Member's Signature)

_____ City_____ State____ Zip Code _____
(Member's Service Address)

_____
(Date)

BEFORE THE ARIZONA CORPORATION COMMISSION



COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

TESTIMONY

OF DAVID HEDRICK

IN SUPPORT OF SETTLEMENT AGREEMENT

ON BEHALF OF

TRICO ELECTRIC COOPERATIVE, INC.

JULY 29, 2016

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DWH-S2 CALCULATION OF LOST FIXED COST RECOVERY AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE – GRANDFATHERED CUSTOMERS

BACKGROUND AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David W. Hedrick and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. ARE YOU THE SAME DAVID HEDRICK THAT PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will provide support for the Settlement Agreement.

TESTIMONY IN SUPPORT OF AGREEMENT

Q. HAS TRICO AND COMMISSION STAFF REACHED A SETTLEMENT AGREEMENT?

A. Yes, Trico and Commission Staff have reached an agreement on all issues in this proceeding.

Q. WHAT ARE THE PROVISIONS OF THE AGREEMENT WITH RESPECT TO THE RATE INCREASE?

A. The agreement provides for a base rate increase of $2,282,076 which produces a total revenue requirement of $89,762,812. The Company's fair value rate base is $175,076,536. The resulting rate of return is 6.33%, the Operating Times Interest Earned Ratio ("TIER") is 2.00 and the Debt Service Coverage ("DSC") of 1.87.

Schedule A-2.0 in Attachment A of the settlement agreement is the income statement reflecting the settlement increase and calculation of the financial metrics.

Q. STAFF RECOMMENDED A REVENUE INCREASE OF $1,972,842 IN ITS DIRECT TESTIMONY. WHAT CHANGED TO ALLOW FOR AN INCREASE OF $2,282,076 INCREASE REFLECTED IN THE AGREEMENT?

A. Staff initially recommended a lower revenue increase based on Staff's objection to Trico's adjustment to test year billing determinants for Residential customers with installed DG. Subsequent to the filing of Staff's testimony, Trico provided the actual load data for the customers in question which allowed staff to verify that the revenue adjustment was appropriate. The increased revenue requirement in the settlement also reflects an increase in rate case expense from $150,000 to $450,000 which is supported by the invoiced costs to date. The $450,000 rate case expense is amortized over a three year period for a total annualized rate case expense included in the test year expenses of $150,000 as shown on Schedule C-2.11 in Attachment A of the settlement agreement.

Q. IS THE RATE INCREASE AMOUNT IN THE SETTLEMENT REASONABLE?

A. Yes. The rate increase in the settlement will allow Trico to meet its financial objectives as discussed in my direct testimony and maintain its financial integrity. The rate increase reflects a modest 2.61% overall increase which mitigates the impact on members. Trico believes that the proposed increase strikes the correct

balance between maintaining the financial health of the Cooperative and limiting the impact on members.

Q. HAS A BILL IMPACT ANALYSIS BEEN PROVIDED IN THE SETTLEMENT AGREEMENT?

A. Yes. Schedules H-4.0 through H-4.11 included in Attachment A to the Settlement Agreement provide the bill impact analysis for all rate schedules. The average Residential customer with monthly kWh consumption of 837 kWh will see an increase of $2.05 per month or 1.75%.

Q. PLEASE DESCRIBE THE BASE COST OF POWER INCLUDED IN THE SETTLEMENT?

A. The proposed base cost of power in the settlement is $0.081711 per kWh as originally proposed by TRICO. The proposed base power cost is calculated on Schedule H-2.1.1 in the filing and is based on the adjusted test year purchased power. The adjusted test year purchased power expense was calculated using the wholesale rates in place during 2015 including the reduction in power cost resulting from the acquisition of Direct Assignment Facilities from Southwest Transmission Cooperative. As set forth in the Direct Testimony of Trico witnesses, acquisition of these facilities provides a financial benefit to Trico members. Staff had supported inclusion of those facilities in its Direct Revenue Requirement Testimony. No party has opposed their inclusion in rate base.

Q. WHAT IS THE PURPOSE OF THE PLAN OF ADMINISTRATION (POA) FOR THE WHOLESALE POWER COST ADJUSTMENT INCLUDED IN THE SETTLEMENT?

A. The purpose of the POA is to create a record describing the intended functioning of the adjustor, including how the adjustor rate is reset. The POA includes a list of the types of costs permitted to be recovered which ensures that no inappropriate costs are recovered.

Q. WHAT IS THE BASIS FOR THE CLASS REVENUE ALLOCATION INCLUDED IN THE SETTLEMENT?

A. The underlying basis for the class revenue allocation is the cost of service analysis provided in the rate filing. Staff witness Ranelle Paladino endorsed Trico's cost of service study in her direct testimony. The class revenue allocation using the rates agreed to in the settlement is shown on Schedule H-1.0 included in Attachment A of the Settlement Agreement. The class revenue allocation in the Settlement Agreement reflects Trico's originally proposed class revenue allocation updated to include the additional rate case expense.

Q. PLEASE DESCRIBE THE RATE DESIGN FOR RESIDENTIAL INCLUDED IN THE SETTLEMENT.

A. The settlement rate for Residential is a three-part rate design that includes a monthly basic service charge, a demand charge and an energy charge. The proposed Basic Charge is $24 which is a $9 increase from the existing $15 Basic Charge.

Q. PLEASE DESCRIBE THE BASIS FOR THE BASIC SERVICE CHARGE FOR RESIDENTIAL MEMBERS.

A. The customer component of expense associated with the distribution wires for the Residential class as reflected on Schedule G-6.0, page 1, is $31.83 per month. The customer component of expense reflects Trico's cost of having the service available before any energy is actually sold to the customer. As an electric cooperative serving in rural Arizona, Trico's customer density (number of customer served per mile) is low in comparison to the investor owned utilities in the state. This means that Trico's average investment required per customer is higher, and thus the fixed customer related costs of providing service are higher in comparison to the investor owned utilities.

Increasing the Basic Charge to a level closer to the actual customer cost of providing service results in a more cost based recovery in the rate that reduces the subsidy between customers that exists in the current rate. The increased Basic Charge provides a more equitable recovery of fixed customer related costs from low use customers and helps to reduce the lost fixed costs created by customers with installed DG. The proposed settlement Basic Charge of $24 is consistent with the Basic Charge for many other electric cooperatives in the region as reflected in the table below:

Arizona	
Sulphur Springs Valley Electric Cooperative, Inc.*	$25.00
Navopache Electric Cooperative, Inc.**	$24.84
Garkane Energy	$22.00
Mohave Electric Cooperative, Inc.**	$25.60
Colorado	
San Luis Valley Electric Cooperative, Inc.	$29.75

Empire Electric Association, Inc.	$30.73
K.C. Electric Assocation, Inc. - Town	$25.00
K.C. Electric Assocation, Inc. - Rural	$30.00
Gunnison County Electria Association	$28.00
Delta Montrose Electric Association	$25.00
Grand Valley Power	$30.00
Yampa Valley Electric Association	$24.50
Mountain Parks Electric, Inc.	$29.00
Poudre Valley Rural Electric Association	$24.50
Morgan County Rural Electric Association	$28.00
Highline Electric Association	$28.17
Mountain View Electric Association	$34.50
New Mexico	
Northern Rio Electric Cooperative, Inc.	$24.00
Otero County Electric Cooperative, Inc.	$26.00
Rio Grande Electric Cooperative, Inc.	$35.00
Roosevelt County Electric Cooperative, Inc.	$25.00
Springer Electric Cooperative, Inc.	$25.60

*Open rate case pending order. Proposed customer charges are supported by staff.
**Pending completion of alternate streamline rate application

Q. PLEASE DESCRIBE THE DEMAND RATE ELEMENT OF THE RATE DESIGN FOR RESIDENTIAL MEMBERS.

A. The Demand Charge is set at $0.00 per billing kW. The billing kW is defined as the highest 15-minute interval demand in the month. This is the same measurement of demand used by Trico in all of its other demand billed rates. The purpose of this initial demand charge is for use in educating the membership about demand rates and to provide Trico the necessary time to ensure that all customers are metered appropriately and the billing systems are in place to effect the billing of demand to each customer. Having the demand component in rates – and included in the Trico billing system – is important because it will accurately capture billing determinants for future rate cases. From a rate design perspective, this will allow for more accurate assessments of the impacts of any changes to the amount recovered by the various rate elements.

The majority of Trico's Residential customers currently have metering installed that will accommodate demand metering. However, there are some customers whose meters will need to be updated to allow for demand metering. In addition, Trico will need to work with its billing provider to program the demand rate into the billing software and be able to show the billing demand kW and charge on the monthly bill. Trico will be able to have these changes accomplished and in place within six months of a decision in this proceeding.

Should Trico decide to apply a measurable demand charge in its next rate case, the demand charge will not be more than $2 per kW per month subject to the terms of the agreement. The implementation of the demand charge will provide a mechanism for the recovery of fixed distribution demand costs based on the maximum monthly peak demand established by the customer. This is the most fair and equitable method of recovering fixed costs that are based on the size of the facilities required to provide service. As evidenced by the initial $0/kW charge and the commitment to hold the first measurable demand charge to $2/kW, it is Trico's intent to transition to a rate with a demand charge slowly. The demand billing kW to be shown on the customer's bill is an important component of the educational effort that will be undertaken with Trico members to demonstrate how demand rates work and what members can do to take full advantage of this rate design.

Q. IS THE ADDITION OF A DEMAND CHARGE IN THE RESIDENTIAL AND GENERAL SERVICE RATE OVERLY COMPLICATED AND CONFUSING?

A. Not at all. The demand charge is simply one additional billing component based on the customer's maximum peak consumption in a monthly billing period. Demand rates have been utilized for many years for commercial and industrial customers with great success. One of the primary reasons that demand rates have not been utilized in Residential rates is that the metering was not available due to the cost of installing demand meters. Another reason is that residential customers used to be relatively homogenous. As utilities like Trico have converted to more modern meters with demand metering capability, demand rates are now an option, particularly as the usage patterns of its members become more diverse. Other electric cooperatives have instituted demand rates for residential members, such as Mid-Carolina Electric Cooperative, Inc. in South Carolina.

The application of demand rates will require a period of customer education to familiarize members with how the rate works but the concept is not a difficult one to understand and manage. While the primary objective of adding the demand rate component is to provide an equitable recovery of fixed distribution demand costs from all customers, there are opportunities for members to manage their loads to minimize the maximum peak demand and thus lower their monthly bills.

Q. PLEASE DESCRIBE THE RATE DESIGN FOR THE GS 1 (SINGLE PHASE) AND GS 1 (THREE PHASE) RATE CLASSES?

A. The rate design for the GS 1 rates is also a three-part rate that includes a basic charge, demand charge and energy charge. The Basic Charge is $27.00 for the GS 1 (Single Phase) class and $35.00 for the GS 1 (Three Phase). The increase in the basic charge for these classes is also $9 and is supported by the cost of service study. The Demand Charge is set at $0.00 per kW and will function the same as the demand charge in the Residential rate.

Q. ARE THE PROPOSED INCREASES IN THE CUSTOMER CHARGE EXCESSIVE OR UNREASONABLE?

A. No. The increase in the customer charge is $9 per month. Under the proposed rates, the customer charge will continue to be considerably lower than the customer component of expense identified in the cost of service study for these rate classes. As my Direct Testimony explains, the issue of lost fixed costs created by customers with installed DG is significant and can only be effectively mitigated by changing the rate design to include higher fixed charges and revising the net metering policy. The larger basic service charge also helps address fixed cost recovery issues with seasonal or vacant homes. The change in the customer charge is a necessary step in reducing the subsidy between customers caused by the existing rate design. Additional rate changes will be required by Trico in the future to move the customer charge to a level where full recovery of the customer component of cost is achieved. A gradual approach to the resolution of this issue is not in the interest of the majority of Residential member consumers of Trico. The maximum increase

possible for any Residential customer under the proposed settlement rates is $9 per month.

Q. WHY DOES THE SETTLEMENT INCLUDE A PROVISION TO FREEZE THE EXISTING RESIDENTIAL TIME-OF-USE RATE?

A. The current wholesale pricing structure from AEPCO, Trico's primary power supplier, includes a fixed charge for capacity that does not vary based on the volume or the timing of energy consumed. As a result of this pricing structure, Trico's Residential Time-of-Use rate is not an effective rate and does not provide customers a meaningful opportunity to reduce costs while at the same time reducing the costs incurred by the cooperative. It is not in the best interest of the member, for Trico to allow new customers to take service on this rate. In fact, the settlement agreement includes a provision that will revise the applicability in the rate to indicate that the rate will be eliminated in the next rate filing. Freezing the rate is the first step in providing ample notice to members that the rate will be eliminated.

Q. WHAT IS THE RATE DESIGN FOR THE REMAINING CLASSES IN THE SETTLEMENT AGREEMENT?

A. The GS2, GS3, GS4 and other tariffs are as proposed by Trico in the original application, updated to reflect the additional revenue requirement associated with the increase in rate case expense. The basic charge in the GS2 and GS3 rate class have also been revised to reflect the same basic charge included in the GS 1 rate class to be consistent with the existing rate design structure. Rate Schedules IS1 and IS 2 are being combined into one rate schedule and will be frozen as of the

date of the decision in this docket because these rates are the same and like the TOU rates, there is no justifiable cost reduction that results from interruption of load.

Q. PLEASE DESCRIBE THE PROVISIONS OF THE SETTLEMENT AGREEMENT WITH RESPECT TO NET METERING?

A. The Agreement stipulates that the existing Net Metering Tariff will be frozen and will be available only to members whose DG interconnection agreement applications were received on or before May 31, 2016. This grandfathering of the existing Net Metering Tariff will allow existing DG customers to continue receiving the existing treatment with respect to compensation for DG energy including banking and payment at the full retail rate. The grandfathering of the Net Metering Tariff for existing customers will continue until a decision in Trico's next rate case with the expectation that grandfathering will continue for the remaining term of the member's interconnection agreement or for 20 years, whichever is shorter. This provides a sufficient time period for the customer to recover their investment in DG facilities.

There will be no net metering provision or banking of exported DG energy for new members applying for interconnection after May 31, 2016. For these members, a new DG Energy Export Tariff will apply as a rider. This rider provides for the purchase of all excess energy generated by a member's DG system and delivered back to Trico at a rate of $0.0770 per kWh. Any credit amount will be provided to the member on a monthly basis with any credit balance carried forward to the

following billing period. Any credit balance remaining at year-end will be paid to the member at that time.

Q. HOW WAS THE $0.0770 PER KWH EXPORT RATE DETERMINED?

A. The export rates is a compromise amount that is equivalent to the power supply portion of the energy charge for the first tier of the proposed RS1 rate. The first block of the RS 1 rate is 800 kWh. The average RS 1 customer has 836 kWh monthly consumption and a median consumption of 750 kWh per month. Thus, the power supply component for the first block is fairly representative for the average residential customer. The $0.0770 per kWh export rate also reflects a compromise amount that is roughly halfway between Trico's avoided cost (wholesale fuel and energy) of $0.03662 per kWh and the full first block RS1 retail rate of $0.11293.

Q. DOES THE SETTLEMENT AGREEMENT PROVISION WITH REGARD TO NET METERING STILL MITIGATE THE INEQUITABLE RECOVERY OF FIXED COSTS FROM TRICO MEMBERS?

A. Yes, but only about half of what Trico had originally proposed. The elimination of the banking of kWh and the reduction in the export rate from full retail to $0.0770 per kWh will reduce the subsidy provided by other members caused by net metering and reduce the level of lost fixed cost caused by customers with installed DG. **Exhibit DWH – S1** is an updated version of Exhibit DWH – 8 which was originally filed with my direct testimony. Exhibit DWH – S1 provides a calculation of the lost fixed cost associated with serving a DG customer under Trico's existing Residential rate and existing net metering policy and the Original,

Amended and Settlement proposed rates and proposed export rate. The analysis also reflects the actual PV System data on line 6 provided from the sample of Trico DG customers. On Line 10 of Exhibit DWH – S1, the analysis shows that the lost fixed costs for the average DG customer under Trico's existing rate and existing net metering policy is $89.91 per customer per month. Trico's originally proposed Residential rate in conjunction with the originally proposed net metering policy reduced that lost fixed cost subsidy to $34.55 per customer per month (over a $50 per month reduction in the subsidy). The proposed rate in Trico's amended filing reduced the lost fixed cost further to $32.64 per customer per month. The proposed settlement rate in conjunction with the increased basic service charge and proposed export rate will result in a lost fixed cost from new DG customers of $60.27 per customer per month (a $29 per month reduction in the subsidy). While the reduction in lost fixed costs is not as much as Trico had originally proposed, the settlement rates and export rate do provide a meaningful reduction in the lost fixed cost subsidy and result in more equitable recovery of Trico's fixed costs.

Also provided as **Exhibit DWH – S2** is a calculation of the lost fixed cost recovery for the grandfathered DG customers. While the proposed Residential rate and proposed Export Rate for new DG customers provides a measurable reduction in the lost fixed costs (as demonstrated on Exhibit DWH – S1), the existing grandfathered DG customers served on the existing Net Metering tariff will continue to create a significant lost fixed cost situation. The proposed Residential rate with the increased customer charge does provide some mitigation in the lost fixed cost but only a small reduction from the lost fixed cost of $89.91 per month under the existing rate and NM policy to $81.72 per month under the settlement

rate and existing NM policy. The change in the grandfathered date to May 31, 2016 increased the number of grandfathered DG customers by 359 which also increased the amount of the lost fixed costs.

Q. DOES THE EXPORT RATE PROVIDE A REASONABLE VALUE FOR THE EXCESS ENERGY PRODUCED BY MEMBERS WITH DG?

A. Yes. As I have noted, Trico has higher fixed costs than typical IOU utilities and therefore the Trico member saves more per DG kWh offset – even though the cost of a DG system is not higher for the Trico member. This can result in a quicker "payback" period for Trico members than in lower cost utility areas. The typical DG customer in Trico's service area consumes only about 40% of the generation produced from the DG facility and exports the remaining 60% of generation to TRICO. Therefore a new DG customer would be effectively compensated on a per kWh basis for the DG energy produced under the settlement rates at a value of $0.09137 per kWh for all DG energy produced calculated as follows:

DG energy consumed compensated at full retail = 40% x $0.11293 = $0.04517
Excess energy delivered to Trico at export rate = 60% x $0.07700 = $0.04620
Average compensation for DG energy = $0.09137

This level of compensation per kWh is significant as it is essentially equivalent to the total energy component of the Tucson Electric Power (TEP) Residential rate and adders that is provided to DG customers in conjunction with TEP's net metering policy. Therefore, under the Settlement Agreement, the payback period for Trico members will still be equivalent to residential customers in TEP's service

area. Maintaining parity with TEP with respect to the total compensation provided to new DG customers is very important to ensure that neither utility is perceived as providing a greater value for DG customer installations than the other.

Q. PLEASE DESCRIBE THE PROVISIONS IN THE SETTLEMENT REGARDING THE FILING OF TRICO'S NEXT RATE CASE?

A. The signatories to the agreement agree that Trico's next rate case will utilize a test-year no earlier than the 12-month period ending June 30, 2018. This will allow Trico the opportunity to conduct the member outreach and demand-rate education program with its members and to gather and track the demand data necessary to implement the demand charge component of the rate. To ensure there is a gradual transition to the full implementation of the demand rate, Trico has agreed to limit the demand charge implemented in its next rate case to no more than $2 per kW. Trico has also agreed to provide as part of its next application the following; a) a study of the impact of billing demand on a 15-minute interval versus a 60-minute interval; and b) discuss customer usage and demand profile to the extent available.

Q. WHAT ADDITIONAL PROVISIONS ARE INCLUDED IN THE SETTLEMENT AGREEMENT?

A. Trico's purchase of Direct Assignment Facilities will not be completed until late 2016 or early 2017. As part of the settlement agreement, the parties agree that Trico will provide as a compliance filing a notice of the completion of the acquisition of the DAF's.

The parties agree that the depreciation rates used by Trico in its application are reasonable and should be approved.

The parties agree that Trico will revise its DG interconnection agreements for leased and owned systems to incorporate language that customers may be charged a return trip fee for a return trip to inspect installations where the return trip is due to a customer installer issue. This change is necessary to mitigate the costs of providing the service.

The parties agree that the Trico's Rules and Regulations shall be revised as set forth in Attachment D of the settlement agreement. The modifications to the Rules and Regulations are needed to meet current operational needs and provide a better alignment with customer needs and ultimately provide better customer service. The Direct Testimony of Ms. Cathers provided a discussion of the proposed changes to the Rules and Regulations. No party opposed those changes, although Staff had some suggested modifications to the changes that Trico has agreed to and that are reflected in Attachment D to the settlement agreement.

Q. ARE THE TERMS OF THE AGREEMENT IN THE PUBLIC INTEREST?

A. Yes. The terms of the agreement provide a reasonable resolution to the issues in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Exhibit DWH – S1

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE

			Existing Rate	Original Proposed Rate Proposed Export Rate	Amended Proposed Rate Proposed Export Rate	Settlement Rate Settlement Export Rate
1	Energy Charge (Includes WPCA)		$ 0.121161	$ 0.117600	$ 0.112800	$ 0.112930
2	Purchased Power Energy Cost	Schedule G-6.0, Page 1 of 8	$ 0.030795	$ 0.030795	$ 0.030795	$ 0.030795
3	Purchased Power Demand Cost	Schedule G-6.0, Page 1 of 8	$ 0.049487	$ 0.049487	$ 0.049487	$ 0.049487
4	Remainder: Distribution Wires Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040879	$ 0.037318	$ 0.032518	$ 0.032648
	Lost Fixed Cost Calculation:					
5	Total Residential DG Customers at TY Adjusted		1,262	1,262	1,262	1,262
6	Monthly kWh Produced by 6.51 kW AC PV System (Estimated)	Based on Actual Sample Data	995	995	995	995
7	PV System kWh Compensated at Full Retail		995	398	398	398
8	Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 49.24	$ 19.70	$ 19.70	$ 19.70
9	Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 40.67	$ 14.85	$ 12.94	$ 12.99
10	Total Lost Fixed Costs - Monthly	L8 + L9	$ 89.91	$ 34.55	$ 32.64	$ 32.69
11	Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,361,667	$ 523,264	$ 494,333	$ 495,116

12	Monthly Energy Export (60% of Estimated PV generation)	597.0
13	Lost Fixed Costs Associated with Export (L12 x ($0.0770 export rate - $0.030795 PP energy))	$ 27.58
14	Total Lost Fixed Costs - Monthly L10 + L13	$ 60.28
15	Total Lost Fixed Costs Annual	$ 912,854

Exihibit DWH - S1

Exhibit DWH – S2

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE- GRANDFATHERED CUSTOMERS

			Existing Rate	Original Proposed Rate Existing NM Tariff	Amended Proposed Rate Existing NM Tariff	Settlement Rate Existing NM Tariff
1	Energy Charge (Includes WPCA)		$ 0.121161	$ 0.117600	$ 0.112800	$ 0.112930
2	Purchased Power Energy Cost	Schedule G-6.0, Page 1 of 8	$ 0.030795	$ 0.030795	$ 0.030795	$ 0.030795
3	Purchased Power Demand Cost	Schedule G-6.0, Page 1 of 8	$ 0.049487	$ 0.049487	$ 0.049487	$ 0.049487
4	Remainder: Distribution Wires Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040879	$ 0.037318	$ 0.032518	$ 0.032648
	Lost Fixed Cost Calculation:					
5	Total Residential DG Customers as of May 31, 2016		1,621	1,621	1,621	1,621
6	Monthly kWh Produced by 6.51 kW AC PV System (Estimated)	Based on Actual Sample Data	995	995	995	995
7	PV System kWh Compensated at Full Retail		995	995	995	995
8	Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 49.24	$ 49.24	$ 49.24	$ 49.24
9	Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 40.67	$ 37.13	$ 32.36	$ 32.48
10	Total Lost Fixed Costs - Monthly	L8 + L9	$ 89.91	$ 86.37	$ 81.60	$ 81.72
11	Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,749,019	$ 1,680,097	$ 1,587,194	$ 1,589,710

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

Reply Testimony of David Hedrick

In Support of Settlement Agreement

on Behalf of

Trico Electric Cooperative, Inc.

August 15, 2016

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EXHIBITS

DWH-R1 COMPARISON OF FIXED DISTRIBUTION COST RECOVERY FOR THE RESIDENTIAL RATE – EXISTING, SETTLEMENT AND EQUIVALENT MINIMUM BILL RATE

BACKGROUND AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David W. Hedrick and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. ARE YOU THE SAME DAVID HEDRICK THAT PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REPLY TESTIMONY?

A. I will provide additional testimony on behalf of Trico with regard to:

1. The testimony provided by EFCA witness Monsen regarding a minimum bill rate design;
2. The testimony provided by EFCA witness Monsen regarding the proposed demand rate;
3. The concerns raised by intervener Mr. Hall; and
4. A discussion of demand rates at other electric cooperatives.

Q. EFCA WITNESS MONSEN RECOMMENDS THE COMMISSION REJECT THE PROPOSED SETTLEMENT AND DIRECT TRICO TO ADOPT A "MINIMUM MONTHLY BILL THAT IS TRUED UP ANNUALLY FOR RESIDENTIAL CUSTOMERS THAT IS REVENUE NEUTRAL RELATIVE TO ITS CURRENT FIXED CHARGE. ALTERNATIVELY, THE COMMISSION SHOULD DIRECT TRICO TO REDUCE ITS MONTHLY FIXED CHARGE TO

$10/CUSTOMER/MONTH AS RECOMMENDED BY SWEEP." WHAT IS YOUR RESPONSE?

A. Mr. Monsen's recommendation entirely ignores the evidence by Trico in this proceeding. That evidence includes:

1. A fixed distribution wires customer cost component for the Residential class of $31.83/customer/month as reflected on Schedule G-6.0, Page 1 of 8. The fixed distribution wires customer component is discussed in both my direct testimony and testimony provided in support of the settlement.
2. The significant level of lost fixed cost recovery from DG customers caused in part by an existing fixed charge that is too small and an existing energy charge that includes too much of the fixed costs of providing service. The lost fixed cost recovery issue was addressed in my direct testimony and my testimony provided in support of the settlement.

One of the major objectives of Trico in this rate proceeding was to address the lost fixed cost recovery issue and to provide more equitable recovery of those fixed costs. Trico's originally proposed rate design and ultimately the rates reflected in the settlement agreement, address the lost fixed cost issue by increasing the recovery of fixed cost with a larger customer charge and a lower energy charge. Mr. Monsen's minimum bill recommendation would increase rather than decrease the level of lost fixed costs by reducing the amount of fixed costs recovered in the fixed component of the rate and increasing the amount of fixed costs recovered in the energy charge.

The minimum bill approach is a step backward with regard to rate design. Most utilities are seeking to structure their rates to decouple the commodity component of cost from the fixed component of cost, and this is particularly important for rural utilities with higher fixed costs of service. However, Mr. Monsen recommends that Trico do the opposite and include more of the fixed costs in the energy charge of the rate. The effect of such a rate design is to significantly reduce the amount of fixed distribution costs recovered from lower use customers and shift that recovery of costs to customers with higher consumption.

Attached as Exhibit DWH –R1 is a comparison of the billing for the Residential class under the Existing rate, the Settlement rate and an equivalent Minimum Bill rate as proposed by Mr. Monsen at various consumption levels. The equivalent Minimum Bill rate produces the same revenue for an average customer at 837 kWh. The analysis shows that while the Settlement rate provides for an increase in the contribution to fixed distribution costs at the lower consumption levels, the minimum bill rate approach significantly reduces the recovery of fixed distribution costs at the lower consumption levels. The minimum bill approach would also significantly lower the overall bill for lower consumption level customers. It is clear that a minimum bill rate design does not provide an appropriate and equitable recovery of costs and would increase the level of lost fixed costs resulting from a higher level of fixed costs included in the energy rate.

Q. DO YOU AGREE WITH MR. MONSEN'S CONTENTION THAT THE PROVISION OF 15-MINUTE INTERVAL DATA TO THE CUSTOMER IS NECESSARY TO IMPLEMENT A DEMAND RATE FOR TRICO?

A. No. First and foremost, the demand rate structure's purpose is to provide the most equitable and appropriate recovery of fixed demand related costs in a rate component that is based on a customer's contribution to those demand related costs. Those demand related costs are most equitably recovered based on a customer's peak demand contribution. Demand rates with a billing demand based on the maximum non-coincident peak (NCP) kW in a monthly billing period have been utilized by utilities (including Trico) for commercial and industrial customers for decades and have been very effective in recovering demand related costs and providing the appropriate price signal to the customer. Demand rates have not been utilized for Residential primarily because the metering was not in place to provide the monthly NCP kW. That is no longer the case as Trico now has metering to capture the required NCP kW data.

The Settlement Agreement reflects a very reasonable proposal to transition to a three-part Residential rate which includes a demand charge based on the maximum demand established by the customer in a monthly billing period. The 15-minute interval used for metering is the same interval used for all of Trico's other demand billed customers. While the initial charge for demand is set at $0.00 per kW, the customer will be provided the billing demand data on the monthly bill showing the maximum demand kW reading for the month as well as the date and time that it occurred. In Trico's next rate case, the billing demand data for a full twelve-month period will be used to calculate a demand charge to provide a partial

recovery of the demand related costs of providing service should the analysis reflect that a demand rate is prudent. The Settlement Agreement includes a provision that the monthly demand charge in the next case, if Trico proposes to include a demand charge, will be no greater than $2 per kW. Again, the intent of the rate is to recover demand related costs based on the maximum demand established by the customer.

While the primary objective of transitioning to a three-part rate with a demand component is the fair and equitable recovery of fixed costs, the demand rate structure does provide opportunity for customers to exercise efficient energy consumption and reduce the maximum monthly demand. As part of the program to educate members on the purpose and operation of the demand rate, customers will be advised that their maximum monthly billing demand is the sum of all energy consuming devices for the peak hour in the month. For individual residential customers, the highest peak demand in a monthly billing period will occur at the time when the major energy consuming devices in the household are operating simultaneously. One of the first steps to reducing the monthly peak demand is to stagger the use of major energy consuming devices such as air conditioning, dishwashers, clothes dryers and other devices to the extent possible. Providing the member with after the fact 15-minute interval demand data for all hours of the month as recommended by Mr. Monsen is not needed for the customer to make a determination which of its major energy consuming devices are operating at the same time.

The transition to a demand rate as proposed in the Settlement Agreement provides the opportunity to educate members on how the demand rate works and how members can efficiently utilize their use of the distribution grid that Trico is providing. The proposed demand rate is not a time differentiated demand rate nor is intended to be utilized as a peak shaving program. The demand rate is intended to recover a portion of the distribution wires capacity costs which are a fixed cost of providing service based on the capacity required to provide service. Trico's wholesale (power and transmission) capacity costs are also fixed and do not vary based on consumption. Therefore, there is no cost basis for designing a demand rate that differentiates the cost based on time. To the extent a member can manage the operation of the major energy consuming devices in their household they can achieve a reduction in their demand billing.

Q. COULD RESIDENTIAL MEMBERS WITH INSTALLED DG BENEFIT FROM A THREE PART DEMAND RATE?

A. Yes. To the extent that a member with installed DG reduces the maximum monthly peak demand by the use of their DG system, the member would see a lower demand billing under at three-part demand rate. Given the continued arguments made by EFCA and other solar advocates that the capacity value of solar DG is not being adequately recognized, it is hard to understand why these groups are working so hard to deny DG customers the ability to utilize a demand rate structure that would provide them the ability to avoid fixed demand costs through the use of their DG facility.

Q. HAVE OTHER COOPERATIVES ACROSS THE COUNTRY IMPLEMENTED DEMAND RATES?

A. Yes. Several cooperatives across the country have implemented demand rates and others are in the process of implementing demand rates. The following list is not meant to be all-inclusive, but provides known cooperatives that currently have a residential demand rate in effect:

Butler Rural Electric Cooperative Association, Inc., Kansas
Cobb Electric Membership Corporation, Georgia
Grayson Rural Electric Cooperative, Inc., Kentucky
Howard Electric Cooperative, Inc., Missouri
Intermountain Rural Electric Association, Colorado
Mid Carolina Electric Cooperative, Inc., South Carolina
Sun River Electric Cooperative, Inc., Montana
Traverse Electric Cooperative, Inc., Minnesota

In addition to the list above there are a few others that I am aware of that are in various stages of evaluation and proposing residential demand rates:

Central Rural Electric Cooperative, Inc., Oklahoma (Effective: January 2017)
Kay Electric Cooperative, Inc., Oklahoma
Platte-Clay Electric Cooperative, Inc., Missouri (Effective: November 2016)

Q. HOW DO YOU RESPOND TO MR. MONSEN'S RECOMMENDATION THAT TRICO DEVELOP A DEMAND BILLING PILOT PROGRAM BEFORE IMPLEMENTING A DEMAND CHARGE?

A. The Settlement Agreement reflects a transition to a demand rate structure that provides all of the components that Mr. Monsen identifies for a pilot program but is applicable to all customers. The intent is to transition a to rate structure that is applicable to all customers but do so in a manner that provides ample opportunity to educate members and minimize customer impact. There is no need for a pilot

program to assess customer acceptance and provide member education as those will be accomplished in the transition plan proposed in the Settlement.

Q. MR. MONSEN CONTENDS IN HIS TESTIMONY THAT THE $0.077 PER KWH EXPORT RATE DOES NOT INCLUDE TRANSMISSION COSTS. IS THIS CORRECT?

A. No. The $0.077 per kWh export rate is the **total** power supply component for the first block of the proposed settlement Residential rate. As an electric distribution cooperative that purchases all of its wholesale power, the power supply component includes both the power supply capacity and energy costs as well as the transmission costs. The export rate reflects the full amount of transmission costs incurred by Trico to provide service

Q. MR. ROBERT HALL RECOMMENDS MAINTAINING A $15 CUSTOMER CHARGE BASED ON HIS UNDERSTANDING OF THE COST COMPONENTS THAT SHOULD BE INCLUDED IN THE RATE. HOW DO YOU RESPOND?

A. Mr. Hall correctly states on page 8 beginning on line 4, "Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." However, Mr. Hall does not include all of the customer related costs that are generally recognized components of the customer charge. Schedule G-6.0 of the Cost of Service Study reflects the following monthly customer cost components:

Distribution Customer Costs	$17.20
Metering	$ 5.23

Meter Reading	$ 0.98
Customer Records	$ 6.33
Customer Service	$ 1.27
Revenue Related	$ 0.82
Total Customer Costs	$31.83

Mr. Hall does not include the distribution customer costs in his calculation of the justifiable customer charge, yet these are fixed operating and capital costs that vary with the number of customer regardless of the power consumption. The distribution customer costs are recognized as customer related costs. These costs are reflected in more detail on Schedule G-6.1, page 3 of the Cost of Service Study. The distribution customer costs consist of 60% of the 1-Phase extension line costs, a portion of the transformer costs and a portion of the service drop costs. These are the costs of having Trico's infrastructure in place to serve the customer's minimum load before any energy is provided to the customer.

The proposed Residential customer charge of $24 per month included in the Settlement Agreement is still well below the customer cost of providing service of $31.83 identified in the cost of service study.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit DWH – R1

TRICO ELECTRIC COOPERATIVE, INC.

COMPARISON OF FIXED DISTRIBUTION COST RECOVERY FOR THE RESIDENTIAL RATE - EXISTING, SETTLEMENT AND EQUIVALENT MINIMUM BILL RATE

			Monthly kWh Consumption							
		Rate	0	50	100	300	500	837	1000	3000
Existing Rate										
Customer Charge		$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00
Power Supply (Including WPCA)	All kWh	0.083073	$ -	$ 4.15	$ 8.31	$ 24.92	$ 41.54	$ 69.53	$ 83.07	$ 249.22
Distribution	All kWh	0.038600	$ -	$ 1.93	$ 3.86	$ 11.58	$ 19.30	$ 32.31	$ 38.60	$ 115.80
Total			$ 15.00	$ 21.08	$ 27.17	$ 51.50	$ 75.84	$ 116.84	$ 136.67	$ 380.02
Total Contribution to Fixed Distribution Costs			$ 15.00	$ 16.93	$ 18.86	$ 26.58	$ 34.30	$ 47.31	$ 53.60	$ 130.80
Settlement Rate										
Customer Charge		$ 24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00	24.00
Power Supply (Including WPCA)	First 800 kWh	$ 0.07700	-	3.85	7.70	23.10	38.50	64.45	61.60	61.60
	Excess kWh	$ 0.08700	-	-	-	-	-	3.22	17.40	191.40
Distribution	All kWh	$ 0.03593	-	1.80	3.59	10.78	17.97	30.07	35.93	107.79
Total			24.00	29.65	35.29	57.88	80.47	121.74	138.93	384.79
Total Contribution to Fixed Distribution Costs			24.00	25.80	27.59	34.78	41.97	54.07	59.93	131.79
Equivalent Minimum Bill Rate										
Power Supply (Including WPCA)	First 800 kWh	$ 0.07700	-	3.85	7.70	23.10	38.50	64.45	61.60	61.60
	Excess kWh	$ 0.08700	-	-	-	-	-	3.22	17.40	191.40
Distribution	All kWh	$ 0.06459	-	3.23	6.46	19.38	32.30	54.06	64.59	193.77
Minimum Bill		$ 15.00	15.00	7.92	0.84	-	-	-	-	-
Total			15.00	15.00	15.00	42.48	70.80	121.73	143.59	446.77
Total Contribution to Fixed Distribution Costs			15.00	11.15	7.30	19.38	32.30	54.06	64.59	193.77

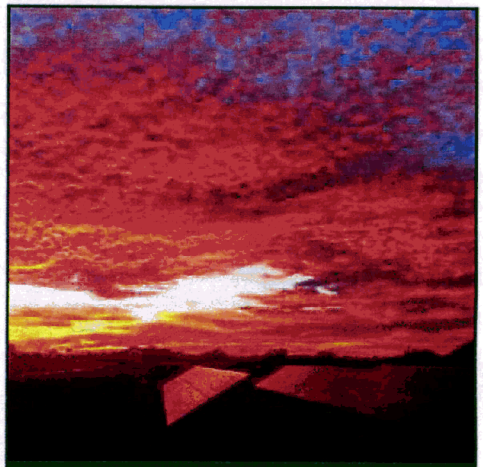
Rate case settlement to address solar costs

Trico has reached a tentative Settlement of its rate case with the Staff of the Arizona Corporation Commission (ACC). The Settlement is subject to the approval of the ACC following a hearing, which begins on August 17, 2016. The ACC may approve, deny or change the terms agreed to by Trico and the Staff.

If the Settlement is approved, the way you are billed will change to more fairly share the costs of the electric grid that is used by everyone, including Members with solar generation:

- **The monthly customer charge that everyone pays, including solar Members, would increase from $15 to $24; and the energy rate would decrease for the first 800 kWh, resulting in about a $2 increase in the average monthly bill.**
- **For Members who submit rooftop solar applications after May 31, 2016, solar generated in excess of the Member's own needs will be purchased by Trico at the rate of 7.7 cents per kWh. Members who applied on or before May 31, 2016 would be grandfathered under the existing net metering tariff.**
- **Trico will provide residential Members with demand information on their bill, but is NOT implementing demand rates in this rate case.**

Your Trico Board of Directors believes this is a reasonable solution that will continue to promote the development of solar within Trico's service area while helping reduce the cost to non-solar Trico Members. For more information, call us at (520) 744-2944 or visit **trico.coop**.



"2012 Cooperative of the year"
– Solar Electric Power Association

TRICO ELECTRIC COOPERATIVE, INC
A Touchstone Energy® Cooperative

This institution is an equal opportunity provider and employer.

EXHIBIT
Trico-8
ADMITTED

EXHIBIT
Trico-9
ADMITTED

https://trico.smarthub.coop/?useOpenId=true#usage:VVNF | Welcome to the Transaction M... | SmartHub - Usage Explorer

TRICO ELECTRIC COOPERATIVE, INC.
A Touchstone Energy® Cooperative
The power of human connections

Log Out | Home | Help | Pay Now » | Report An Outage

Home | Billing & Payments | My Profile | My Usage | Notifications | Contact Us | Search | Have a Question? Get Help. »

- My Usage
- Usage Explorer
- Average Usage
- Planning
- Usage Comparison
- Usage Management

« Daily Usage

Hourly Usage

View Usage For: ☑ 054036757

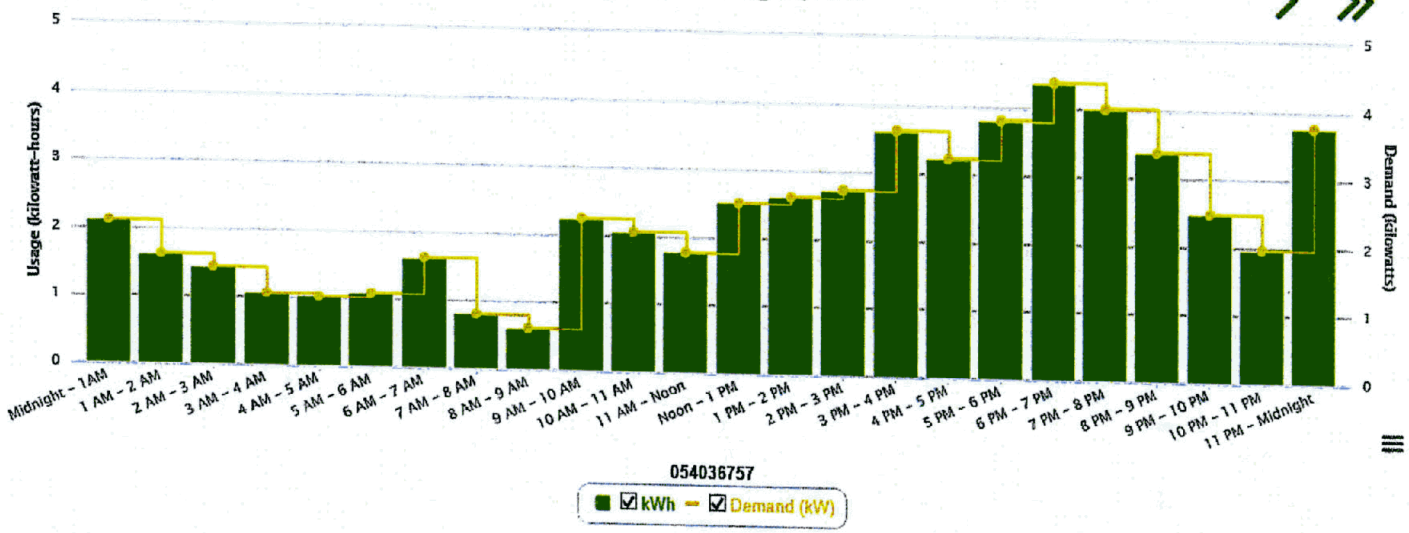
View Graph By: ◉ Usage

View Usage Type: kWh and Demand (

View Temperature: ☐ Average

Select an Account/Service Location to View: [redacted]

Usage for Mon Aug 15, 2016



Green Button Download My Data

Usage	
Meter:	054036757
High Usage:	4.36
Low Usage:	0.59
Average Usage:	2.33
Total Usage:	55.8

Weather	
Average Temperature:	88° F
High Temperature:	98° F
Low Temperature:	77° F

Like

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

E-27

CUSTOMER GENERATION PRICE PLAN FOR RESIDENTIAL SERVICE

Effective: April 2015 Billing Cycle
Includes Temporary Reduction to the Environmental Programs Cost Adjustment Factor
and the Fuel and Purchased Power Adjustment Mechanism
EFFECTIVE JULY 2016 – AUGUST 2016 BILLING CYCLE

AVAILABILITY:

The E-27 Price Plan is subject to equipment availability, as determined in SRP's sole discretion.

APPLICABILITY:

Service under this price plan is limited to residential customers with on-site generation who do not purchase all of their energy requirements from SRP. Participation in this plan is required for all such customers, except for those customers who originally installed the on-site generation at a residence on or before December 8, 2014, or who (i) by such date, either delivered to SRP a fully-executed contract for the installation of the on-site generation or had an SRP Residential Solar Electric Program Application for the on-site generation pending with SRP, and (ii) interconnect the generating facility with SRP's electrical grid by February 26, 2016. If a customer meets this exception, that customer will be exempt from required participation in this plan, for service at the residence where the system was originally installed, until the later of (a) March 31, 2025, or (b) the date that is 20 years after the date on which SRP initially interconnected the generating facility on which the exemption is based to SRP's electrical service grid. The foregoing exemption will run with the property, such that it will apply to the initial customer of record for the residence (meaning the person(s) in whose name(s) the account is held) and any subsequent customer of record for that same residence.

This plan is applicable to a single family house, a single unit in a multiple family house, a single unit in a multiple apartment, a manufactured housing unit, or other residential dwelling, where the on-site generation is installed. Service is supplied through one point of delivery and measured through one meter. Service under this price plan excludes resale, sub-metering and standby uses.

ACCESSIBILITY:

Equipment used to provide time-of-use service must be physically accessible to SRP personnel without prior notice.

CHARACTER OF SERVICE:

Sixty hertz alternating current at approximately 120/240 volts, single-phase. SRP, in its sole discretion, may provide three-phase service, at not more than 120/240 volts.

CONDITIONS:

A. On-peak hours from May 1 through October 31 consist of those hours from 1 p.m. to 8 p.m., Monday through Friday, Mountain Standard Time, excluding the holidays listed in Condition B below. On-peak hours from November 1 through April 30 consist of those hours from 5 a.m. to 9 a.m. and from 5 p.m. to 9 p.m., Monday through Friday, Mountain

Published: June 23, 2016

EXHIBIT
Tyco-10
ADMITTED

Standard Time, excluding the holidays listed in Condition B below. All other hours are off-peak.

B. The following holidays are off-peak: New Year's Day (observed), Memorial Day (observed), Independence Day (observed), Labor Day, Thanksgiving Day and Christmas Day (observed).

C. Metering will be such that kilowatts (kW) and kilowatt-hours (kWh) can be related to time-of-use.

D. A customer assigned to this price plan is required to maintain service under this price plan for the duration of the time the customer uses on-site generation and does not purchase all of their energy requirements from SRP.

E. A customer requiring additional interconnection, metering, or other equipment beyond what is necessary for SRP to provide basic service applicable under this price plan must pay SRP for the costs of such additional equipment.

F. Applicable monthly charges or credits may be converted to daily amounts. The amounts would be annualized and then converted to daily charges or credits.

G. The kWh delivered to SRP shall be subtracted from the kWh delivered from SRP for each billing cycle. If the kWh calculation is net positive for the billing cycle, SRP will bill the net kWh to the customer under this price plan. If the kWh calculation is net negative for the billing cycle, SRP will credit customer for the net kWh at the retail per-kWh price under this price plan. For the purposes of this calculation, excess generation will be tracked by time-of-use period.

PRICE PER METER:

Monthly Service Charge

	Amp Service 0-200	Amp Service 200+
Billing, Collections	$2.69	$2.69
Meter	$2.10	$2.10
Competitive Customer Service	$11.01	$11.01
Distribution Facilities	$16.64	$29.64
Total	$32.44	$45.44

(Continued on next page)

On-Peak per kW Charges

SUMMER	First 3 kW	Next 7 kW	All Add'l kW
Distribution Delivery	$2.70	$4.83	$9.58
Transmission Delivery	$1.93	$3.51	$6.66
Transmission Cost Adjustment	$0.00	$0.00	$0.00
Ancillary Services 1-2	$0.09	$0.18	$0.35
System Benefits	$0.09	$0.18	$0.34
Environmental Programs Adjustment	$0.77	$1.38	$2.62
Competitive Customer Service	$0.00	$0.00	$0.00
Energy (Generation)	$2.45	$4.55	$8.22
Total	$8.03	$14.63	$27.77

SUMMER PEAK	First 3 kW	Next 7 kW	All Add'l kW
Distribution Delivery	$2.79	$5.05	$10.40
Transmission Delivery	$2.57	$4.77	$9.11
Transmission Cost Adjustment	$0.00	$0.00	$0.00
Ancillary Services 1-2	$0.13	$0.25	$0.49
System Benefits	$0.12	$0.21	$0.36
Environmental Programs Adjustment	$0.70	$1.31	$2.53
Competitive Customer Service	$0.00	$0.00	$0.00
Energy (Generation)	$3.10	$5.90	$10.67
Total	$9.41	$17.49	$33.56

WINTER	First 3 kW	Next 7 kW	All Add'l kW
Distribution Delivery	$0.31	$0.52	$0.98
Transmission Delivery	$0.96	$1.56	$2.68
Transmission Cost Adjustment	$0.00	$0.00	$0.00
Ancillary Services 1-2	$0.06	$0.11	$0.19
System Benefits	$0.08	$0.15	$0.21
Environmental Programs Adjustment	$0.72	$1.09	$1.84
Competitive Customer Service	$0.00	$0.00	$0.00
Energy (Generation)	$1.42	$2.25	$3.84
Total	$3.55	$5.68	$9.74

(Continued on next page)

Per kWh Charges

SUMMER	On-Peak All kWh	Off-Peak All kWh
Ancillary Services 3-6	$0.0022	$0.0003
Energy (Generation)	$0.0169	$0.0073
Fuel and Purchased Power	$0.0295	$0.0295
Total	$0.0486	$0.0371

SUMMER PEAK	On-Peak All kWh	Off-Peak All kWh
Ancillary Services 3-6	$0.0026	$0.0003
Energy (Generation)	$0.0312	$0.0125
Fuel and Purchased Power	$0.0263	$0.0263
Total	$0.0601	$0.0391

WINTER	On-Peak All kWh	Off-Peak All kWh
Ancillary Services 3-6	$0.0012	$0.0003
Energy (Generation)	$0.0198	$0.0167
Fuel and Purchased Power	$0.0220	$0.0220
Total	$0.0430	$0.0390

Summer is defined as the May, June, September and October billing cycles. Summer Peak is defined as the July and August billing cycles. Winter is defined as the November through April billing cycles.

ANCILLARY SERVICES:

Ancillary services provided include:

1) Scheduling, System Control and Dispatch Service
2) Reactive Supply and Voltage Control from Generation Sources Service
3) Regulation and Frequency Response Service
4) Energy Imbalance Service
5) Operating Reserve – Spinning Reserve Service
6) Operating Reserve – Supplemental Reserve Service

Direct access customers must secure Ancillary Services 3-6 from an alternative energy supplier or from SRP under the terms and conditions outlined in SRP's Open Access Transmission Tariff.

MINIMUM BILL:

The Monthly Service Charge.

DETERMINATION OF DEMAND IN KILOWATTS:

The billing demand is the maximum thirty-minute integrated kW demand occurring during the on-peak periods of the billing cycle, as measured by the meter.

ADJUSTMENTS:

A. SRP may increase or decrease the price for Fuel and Purchased Power based on changes in the average cost of fuel and purchased power. The price for Fuel and Purchased Power is calculated for the summer and winter season based on the projected cost of fuel and purchased power, adjusted for the actual over- or under-collection of fuel and purchased power revenues relative to fuel and purchased power expenses from prior periods.

B. SRP may adjust the Transmission Cost Adjustment Factor to recover transmission related costs or charges incurred by SRP resulting from standardized wholesale market designs, regional transmission organizations or related activities.

C. SRP may increase or decrease the Environmental Programs Cost Adjustment Factor based on changes in the cost of providing energy efficiency, renewable energy and other environmental programs. The price for Environmental Programs is calculated based on the projected cost of the programs, adjusted for the actual over- or under-collection of the programs relative to expenses from prior periods.

D. SRP will increase or decrease billings under this price plan in proportion to any taxes, fees, or charges (excluding federal or state income taxes) levied or imposed by any governmental authority and payable by SRP for any services, power, or energy provided under this price plan.

RULES AND REGULATIONS:

A. Service under this price plan and all associated riders shall be in accordance with the terms of SRP's Rules and Regulations, as they may be amended or revised by SRP from time to time. Failure by a customer to comply in all material respects with SRP's Rules and Regulations may result in SRP terminating electric service to the customer.

B. For direct access customers, service under this price plan is in accordance with the terms of SRP's Direct Access Program, as set forth in the Rules and Regulations, including any amendments.

SPECIAL RIDERS:

A. Limited-income customers may qualify for a discount under the Economy Discount Rider.

B. Customers with medical life support equipment may qualify for a discount under the Medical Life Support Equipment Discount Rider, if and to the extent that rider is available for participation by such customers.

C. Customers who wish to support the development of renewable energy may elect to participate in the Renewable Energy Credit Pilot Rider.

D. Customers who wish to support the development of solar energy may elect to participate in the Residential Community Solar Pilot Rider, if and to the extent that rider is available for participation by such customers.

E. Customers may be eligible to participate in SRP's Renewable Energy Service Pilot Rider.

Snell & Wilmer
L.L.P.
LAW OFFICES

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Phoenix, Arizona 85004-2202
602.382.6000
602.382.6070 (Fax)
www.swlaw.com

EXHIBIT
S-1
ADMITTED

ORANGE COUNTY
PHOENIX
RENO
SALT LAKE CITY
TUCSON

Michael W. Patten
(602) 382-6339
mpatten@swlaw.com

August 4, 2016

RECEIVED
AUG - 5 2016
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

BY E-MAIL & HAND DELIVERY

Matthew Laudone
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Re: Trico Electric Cooperative, Inc. General Rate Case
Docket No. E-01461A-15-0363

Dear Mr. Laudone:

Enclosed please find Trico Electric Cooperative, Inc.'s responses to Staff's Tenth Set of Data Requests.

Please let me know if you have any questions.

Very truly yours,

Snell & Wilmer

Michael W. Patten

MWP:jh

Enclosures

cc: Rick Lloyd (w/ Enclosures)
Connie Fitzsimmons (w/ Enclosures)

STAFF'S TENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
AUGUST 4, 2016

STF 10.1 Please provide a comparison of the NEM banking and netting provisions now in effect on customer classes (using an average size system for each class) with the banking and netting provisions of the Settlement Agreement on customer classes using the average system size of each customer class.

RESPONSE: See the Testimony of David Hedrick in Support of the Settlement Agreement, Exhibit DWH-S1 and Exhibit DWH-S2 for the comparison of the residential customer class current and Settlement Agreement, for new DG and grandfathered DG customers, attached for reference. In order to provide the comparison of the other customer classes (non-residential), Trico will require additional time, as we have only 18 non-residential DG customers that have a full year of data, and each have unique load characteristics, such that a determination of an "average system size" will not provide a meaningful analysis of the class, so we are working to provide the analysis for each individual customer.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.2 Please provide Trico's analysis as to how solar customers will be impacted as a result of the Settlement Agreement. Please discuss all provisions that will or could impact solar customers.

RESPONSE: See the response to STF 10.1 for the comparison of current net metering provisions to that of the Settlement Agreement. The proposed settlement energy rate in conjunction with the increased customer charge and proposed DG Energy Export Tariff will result in lost fixed grid costs from new residential DG customers in the amount of $60.27 per customer per month. That represents a $29 per month reduction in the credit subsidy from that provided under the current rates. For grandfathered residential net metering customers proposed residential energy rate with the increased customer charge does provide some mitigation in the lost fixed cost but only a small reduction from the lost fixed cost of $89.91 per month under the existing rate and NM policy to $81.72 per month under the settlement rate and existing NM policy (about an $8 per month reduction in the credit subsidy from the current rates).

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.3 Why is Trico's status as a cooperative important with respect to these issues?

RESPONSE: Electric cooperatives were originally conceived of and financed through New Deal legislation adopted to promote rural electrification. That is, to bring electricity to those areas of the Country that were not economically viable for investor owned utilities to serve. The mission of electric cooperatives today continues to be to provide reliable power at an affordable cost to areas that cannot be served economically by investor owned entities. That historical background serves as the basis for two significant differences between electric distribution cooperatives and investor owned utilities.

First, because there are no external investors or shareholders, distribution cooperatives are owned and governed exclusively by their Members – the customers they serve. Members elect a Board of Directors from the membership, and the Board (who are each Members themselves) is charged with running the cooperative for the benefit of the Members, in the best interest of the Members. Margins produced through the business operations of a distribution cooperative are allocated to the capital accounts of the Member-owners. There are no third-party investors or stockholders who receive a return outside of the cooperative's customers.

Second, and perhaps more significant from a ratemaking standpoint, the fact that electric distribution cooperatives serve areas that are not economically viable for investor owned utilities underscores that the cost of service for rural electric cooperatives is invariably higher than that of investor owned utilities. By way of illustration, Trico serves approximately 10 Members per mile of distribution line, which is a small fraction of the customers per mile of line served by the State's investor owned utilities (e.g. more urban utilities have about 50 to 100 customers per mile of line). Fewer people per mile of line means that Trico's fixed cost per Member are significantly higher than for customers of more highly concentrated more urban utilities. Higher fixed costs typically equate to higher rates, and Trico's rates continue to be higher than those of Arizona investor owned utilities. Higher fixed costs per

Member also result in comparatively more lost fixed costs when Members generate power under a Net Metering tariff, and a higher amount of subsidy to distributed solar generation Members who are credited for excess power at the retail rate. For that reason, Trico believes a "one-size-fits-all" policy relating to compensation or credit for power produced through distributed generation is not appropriate.

See also response to STF 10.11.

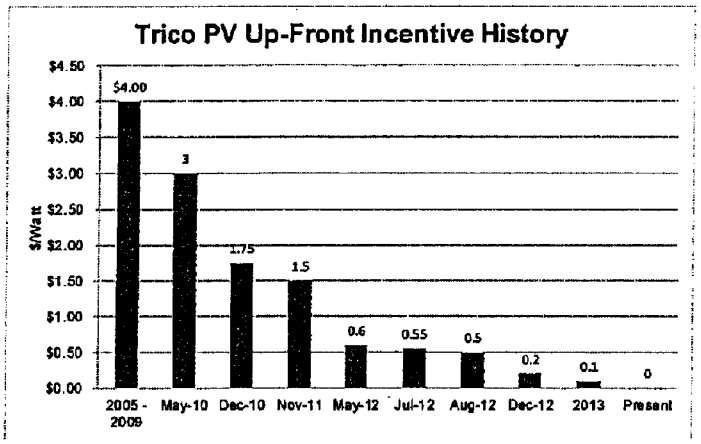
RESPONDENT: Vincent Nitido, CEO/General Manager

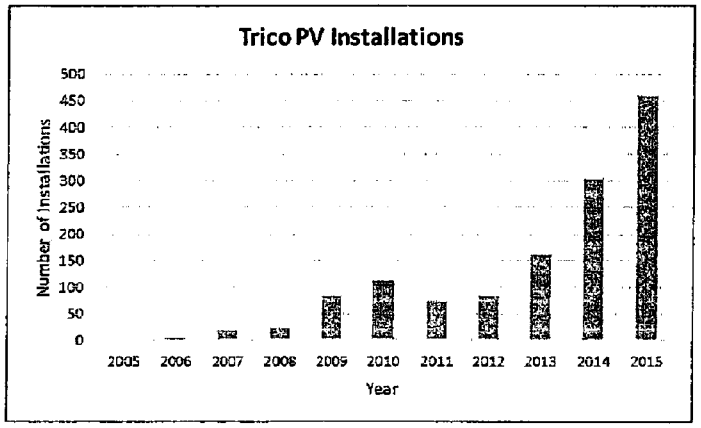
STF 10.4 Does Trico believe that the Settlement Agreement will negatively impact the ability of solar companies to do business in its service area? How does the impact differ for purchase versus leased systems? Please explain your responses in detail.

RESPONSE: No, Trico does not believe that the Settlement Agreement will negatively impact the ability of solar companies to do business in its service area. Utilizing the $0.077/kWh export rate under the Settlement Agreement and the average DG export percentage of 60% for Trico's service territory (utilizing actual data from 354 current Trico DG members), the Settlement Agreement produces an average credit of $0.091417/kWh from base rates (not including additional benefits such as avoided sales taxes). That is higher than Tucson Electric Power Company's (TEP's) current full net metering retail credit (summer first block) of $ 0.091311/kWh. By all accounts, rooftop DG is continuing to increase in the TEP service territory. Trico's comparatively higher fixed costs and associated higher retail rates provide more value for net metered DG in its service territory. The proposed DG Energy Export Tariff should also have the effect of incenting DG customers to size their systems to used more energy on-site, which will result in savings under the Settlement Agreement closer to that experienced under the current rate structure, because the greater the percentage of DG energy that is used on-site, the more the effective credit increases. Solar witnesses in other dockets have claimed that DG energy exports are often as low as 30%. If that is the case, the average base rate energy credit would be $0.10213/kWh under the Settlement Agreement.

Second, if history is an indication, a gradual reduction in solar DG subsidies by Trico will not result in a significant reduction in the deployment of DG in the service territory. Trico, like other Arizona electric utilities, first reduced, then eliminated up-front incentives for rooftop solar DG as the cost of DG systems reduced and the efficiency of solar panels increased over time. Notwithstanding the elimination of up-front incentives, which averaged $15,000 per DG member, the deployment of rooftop DG has continued to escalate. The fact that Trico is now receiving several times more DG interconnection applications each month

than it did three years ago suggests a modest reduction in the subsidies paid by Trico members for rooftop DG as proposed under the Settlement Agreement is appropriate and would not result in a significant reduction in the deployment of rooftop DG in the Trico service territory, see charts below. Even though the "payback" period for rooftop systems may increase slightly under the Settlement Agreement as compared to today's payback period, the payback period may still be shorter than it was in the near past. PV prices have been decreasing over the past years.





Please see also the Testimony of Vincent Nitido in Support of the Settlement Agreement.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.5 For rooftop PV systems installed in Trico's service territory, what is the percentage of the systems that are leased by residential customers? What is the percentage of the systems that are purchased? Please provide annual data from 2009 to 2015.

RESPONSE:

Year	% Leased	% Owned
2009	0%	100%
2010	0%	100%
2011	11%	89%
2012	67%	33%
2013	70%	30%
2014	61%	39%
2015	60%	40%

RESPONDENT: Karen Cathers, Chief Operating Officer

STAFF'S TENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
AUGUST 4, 2016

STF 10.6 How many rooftop solar systems has Trico received interconnections requests for after May 31, 2016?

RESPONSE: Trico has received 68 applications after May 31, 2016 through August 2, 2016, (65 residential and 3 commercial).

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.7 Please describe Trico's service in geographical, economic and demographic terms.

RESPONSE: Trico provides services to the rural areas around the metropolitan Tucson that includes three counties (Pima, Santa Cruz and Pinal) which stretches from north of Tucson south to the Arizona/Mexico border. Trico has a very dispersed service area that extends over 3,600 square miles and includes over 3,700 miles of distribution lines, which corresponds to only about 10 Members per mile of line (e.g. more urban utilities have about 50 to 100 customers per mile of line). Trico's Members are more than 95% residential (98% residential and small commercial). Trico's Members are largely rural and many have low incomes particularly those on tribal lands (i.e. Trico provides service to portions of the Pascua Yaqui Tribe and the Tohono O'odham Tribe). Trico has several large retirement communities in its service area with newer more affluent homes and it is in these areas that the majority of the rooftop residential DG is located.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.8 Do you believe that the current time of use tariff is ineffective for residential customers? Please explain.

RESPONSE: Yes, currently Trico's long term wholesale power contracts charge Trico based on a single monthly energy rate which does not differ by time of day or day of the week. This means that when Members on the TOU rate receive an overall reduction in energy costs by reducing peak usage, Trico does not receive a corresponding reduction in its energy costs. Thus, in effect, the reduction in costs to the TOU Members is subsidized by other Members. With respect to the fixed cost of wholesale power Trico pays a fixed dollar amount that does not change based on usage or the time of that usage. Until such time as Trico can get time of use price signals from its power suppliers, it will not be possible for Trico to have an effective time of use tariff.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.9 Does Trico intend to propose a new TOU tariff for its residential customers? If yes, please explain. Will that tariff be effective with a demand charge? Please explain.

RESPONSE: Not as this time, please see the response to STF 10.8. Unless and until such time as Trico's long term wholesale power contracts provide more granularity at least with respect to energy charges Trico does not believe that a time of use tariff will be effective.

Trico does not believe that the existing time of use tariff would be effective with a demand charge. The demand charge proposed in the Settlement Agreement for the residential and small commercial is to provide a signal to the Member of their use of the Trico distribution facilities which corresponds to their highest monthly demand (the size of the distribution facilities needed to serve their peak demand). Because this highest demand can happen any time it could result in causing a peak to occur at a time when the Member is trying to shift its energy usage to more off-peak. This could have an outcome of the time of use Member having two signals that work against each other.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.10 Has Trico discussed the TOU issue with AEPCO? Please summarize the nature of the discussions you have had.

RESPONSE: Yes, one of the suggestions that Trico has made is for AEPCO to modify its systems and billing such that it could bill its Members on an hourly energy basis. We understand that this change could require some extensive modifications to AEPCO billing system and cost accounting, and we believe that may need to be accomplished through an AEPCO rate case.

RESPONDENT: Karen Cathers, Chief Operating Officer

STF 10.11 Describe Trico's system compared to UNSE's system (or other Arizona Utilities' systems) and how this impacts the successful use of TOU.

RESPONSE: Trico does not have an integrated distribution, transmission and power supply in one company like UNSE/TEP or Arizona Public Service Company (APS). As discussed in the response to STF 10.8, Trico is billed through several contracts for its power based on a single monthly energy rate and a fixed dollar charge for capacity. With respect to power supply Trico currently gets no benefit from usage at different times of the day or week or season.

Trico currently purchases transmission from APS, TEP and Arizona Electric Power Cooperative (AEPCO). Some of these transmission service agreements are point to point with a set reserve capacity which does not differ if we use less, however the majority of the transmission service agreements are for network service which is billed based on Trico's load ratio share of each system total cost at the time of each of the systems peaks. Each of these transmission systems have peaks at different times and it would be virtually impossible to design an effective retail rate signal based on a transmission demand charge. In an integrated utility the concept is a system peak occurs which is at the same time for at least the power supply and transmission system which if reduced could save or defer the need for new generation and/or transmission facilities. In a distribution cooperative like Trico where we acquire power supply and transmission from others it is much more difficult to quantify or even have any impact on the systems of others (e.g. even if Trico did reduced costs for APS's transmission system it is very unlikely that Trico would ever directly see any of those savings which could then be passed through to the Trico retail Members).

In addition, because Trico load is 95% residential, its distribution system peaks most often on the weekends rather than during the week as most urban utilities with more substantial commercial load. This makes an effective distribution system time of use rate difficult for residential Members who would typically want to have weekends as off-peak times.

STAFF'S TENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
AUGUST 4, 2016

RESPONDENT: Karen Cathers, Chief Operating Officer

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE

			Existing Rate	Original Proposed Rate Proposed Export Rate	Amended Proposed Rate Proposed Export Rate	Settlement Rate Settlement Export Rate
1	Energy Charge (Includes WPCA)		$ 0.121161	$ 0.117600	$ 0.112800	$ 0.112930
2	Purchased Power Energy Cost	Schedule G-6.0, Page 1 of 8	$ 0.030795	$ 0.030795	$ 0.030795	$ 0.030795
3	Purchased Power Demand Cost	Schedule G-6.0, Page 1 of 8	$ 0.049487	$ 0.049487	$ 0.049487	$ 0.049487
4	Remainder: Distribution Wires Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040879	$ 0.037318	$ 0.032518	$ 0.032648
	Lost Fixed Cost Calculation:					
5	Total Residential DG Customers at TY Adjusted		1,262	1,262	1,262	1,262
6	Monthly kWh Produced by 6.51 kW AC PV System (Estimated)	Based on Actual Sample Data	995	995	995	995
7	PV System kWh Compensated at Full Retail		995	398	398	398
8	Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 49.24	$ 19.70	$ 19.70	$ 19.70
9	Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 40.67	$ 14.85	$ 12.94	$ 12.99
10	Total Lost Fixed Costs - Monthly	L8 + L9	$ 89.91	$ 34.55	$ 32.64	$ 32.69
11	Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,361,667	$ 523,264	$ 494,333	$ 495,116
12	Monthly Energy Export (60% of Estimated PV generation)					597.0
13	Lost Fixed Costs Associated with Export (L12 x ($0.0770 export rate - $0.030795 PP energy))					$ 27.58
14	Total Lost Fixed Costs - Monthly L10 + L13					$ 60.28
15	Total Lost Fixed Costs Annual					$ 912,854

Exihibit DWH - S1

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE- GRANDFATHERED CUSTOMERS

			Existing Rate	Original Proposed Rate Existing NM Tariff	Amended Proposed Rate Existing NM Tariff	Settlement Rate Existing NM Tariff
1	Energy Charge (Includes WPCA)		$ 0.121161	$ 0.117600	$ 0.112800	$ 0.112930
2	Purchased Power Energy Cost	Schedule G-6.0, Page 1 of 8	$ 0.030795	$ 0.030795	$ 0.030795	$ 0.030795
3	Purchased Power Demand Cost	Schedule G-6.0, Page 1 of 8	$ 0.049487	$ 0.049487	$ 0.049487	$ 0.049487
4	Remainder: Distribution Wires Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040879	$ 0.037318	$ 0.032518	$ 0.032648
	Lost Fixed Cost Calculation:					
5	Total Residential DG Customers as of May 31, 2016		1,621	1,621	1,621	1,621
6	Monthly kWh Produced by 6.51 kW AC PV System (Estimated)	Based on Actual Sample Data	995	995	995	995
7	PV System kWh Compensated at Full Retail		995	995	995	995
8	Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 49.24	$ 49.24	$ 49.24	$ 49.24
9	Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 40.67	$ 37.13	$ 32.36	$ 32.48
10	Total Lost Fixed Costs - Monthly	L8 + L9	$ 89.91	$ 86.37	$ 81.60	$ 81.72
11	Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,749,019	$ 1,680,097	$ 1,587,194	$ 1,589,710

EXHIBIT
Number S-2
ADMITTED

STF 6.3

Rate Design: In the application as part of the testimony for Vincent Nitido on page 16, Mr. Nitido details the reasons Trico isn't proposing a demand rate for DG customers. Staff believes a demand rate for residential and general service customers may be a way to alleviate some of the fixed costs that are not being recovered with the current rate design.

1. If Staff were to recommend Trico implement an optional or mandatory three-part rate for residential and general service customers, what would Trico suggest that rate design look like for each rate class?

2. How would system peaks factor into a three-part rate for Trico? Would weekends need to be included in the calculation of the peak kW since Trico's system peak typically happens on the weekend?

3. If an optional or mandatory three-part rate was implemented for Trico, would Trico also want to adjust the TOU rates/time periods? What changes would be suggested, if any?

4. Customer education would be a key component in the implementation of a voluntary three-part rate for residential and general service customers. Please estimate the possible level of expense Trico would incur to educate customers about the use of a three-part rate.

5. Given the fact that meters will need to be replaced, the billing system would have to be modified slightly, and customer education would need to happen, what would be the earliest that Trico would want to implement an optional three part rate for residential and general service customers?

RESPONSE:

Responses to each question below:

1. If Staff were to recommend that Trico implement an optional or mandatory three-part rate for residential and general service customers, Trico suggests that the three-part rate would be mandatory (not optional) and the demand rate would be small initially until customers/members had an opportunity understand the new rate. Trico does not believe that optional demand rates would be effective as only customers/members who would easily benefit from the rate design would opt to take part. Trico would want to analyze

the test year residential and small commercial demand data to develop the magnitude of the initial demand rate.

2. Trico would suggest to bill the demand rate at the time of the customer/member monthly peak not on a Trico system peak. Trico may benefit long term from all customers/members moving toward a better overall load factor, but Trico does not see a direct benefit in moving the Trico system peak a few hours earlier or later in the day as would be encouraged under a TOU demand rate.

3. Trico would not want to implement TOU demand rates but would rather suggest demand rates billed at the time of the customer/member monthly peak. This design is similar to what Trico has currently for its commercial customers that have demand rates.

4. Trico agrees that customer education would be a key component in the implementation of a three-part rate for residential and small general service customers. Trico would plan to contract with an outside firm the customer education program and would need to complete a request for proposals to get an estimate of the possible level of expense.

5. Given the fact that meters will need to be replaced, the billing system would have to be modified slightly, and customer education would need to happen, the earliest that Trico would want to implement three part rates for residential and general service customers would be January 1, 2018.

RESPONDENT: Karen Cathers, Chief Operating Officer

EXHIBIT
S-3
ADMITTED

TRICO
ELECTRIC COOPERATIVE, INC.

A Touchstone Energy® Cooperative

December 14, 2015

Mr. Patrick F. Ledger
Chief Executive Officer
Southwest Transmission Cooperative, Inc.
1000 S. Highway 80
Benson, AZ 85602

RE: SALE OF DIRECT ASSIGNMENT FACILITIES

Dear Mr. Ledger:

Over the past several years, Southwest Transmission Cooperative, Inc. (SWTC) and Trico Electric Cooperative, Inc. (Trico) (the "Parties") have discussed the purchase by Trico of certain Direct Assignment Facilities (DAFs), which SWTC installed, financed and classified as DAFs for Trico (Trico DAFs) in accordance with network transmission service agreements entered into by the Parties (Network Agreements).

The purpose of this letter (Letter Agreement) is to document the understanding of the Parties with respect to the SWTC sale of the Trico DAFs to Trico.

The Network Agreements do not preclude a mutually agreeable sale to Trico of DAFs. On October 23, 2015, Trico made a rate filing with the Arizona Corporation Commission (Trico Rate Case). Trico has requested that the closing date (Closing Date) of the purchase of the Trico DAFs occur concurrent with the effective date of approval of the Trico Rate Case, which is expected to be on or about January 1, 2017.

The Parties have discussed the conveyance of the Trico DAFs by SWTC to Trico at a price equal to the greater of: i) the value of the total outstanding debt associated with the Trico DAFs, plus any plant in service financed by general funds associated with the Trico DAFs: or ii) at depreciated net book value of the Trico DAFs as of the date of sale.

Since the first Trico DAF went into service, the Parties have worked to formalize and finalize the billing and accounting for the Trico DAFs. The Parties are now close to finalizing accounting reports for the Trico DAFs and revising the billing which will result in a final true-up of the costs and will include adjustments to reflect any additional plant in service at the time of the Closing Date.

As reflected on the SWTC bills to Trico, the Trico DAFs include the following, with billed costs to Trico as of February 2015, subject to billing and accounting true-up as discussed herein:

DAF	Plant Start Date	Installed Costs	Depreciation As Billed	Depreciated NBV Cost
1 Thornydale	11/30/2001	$ 1,349,963.32	$ 553,199.46	$ 796,763.86
2 Valencia	1/31/2003	$ 1,063,002.33	$ 310,262.10	$ 752,740.23
3 Oracle Junction	10/31/2004	$ 393,980.31	$ 78,175.72	$ 315,804.59
4 Avra Valley	11/30/2004	$ 347,053.63	$ 97,403.93	$ 249,649.70
5 Three Points	11/30/2004	$ 241,895.01	$ 58,362.98	$ 183,532.03
6 Sandario	5/31/2006	$ 1,410,975.83	$ 327,836.45	$ 1,083,139.38
7 Saddlebrooke Ranch	5/24/2007	$ 3,920,910.36	$ 750,397.70	$ 3,170,512.66
8 Bicknell	11/1/2008	$ 2,152,353.20	$ 320,671.65	$ 1,831,681.55
TOTAL		$ 10,880,133.97	$ 2,496,309.99	$ 8,383,823.99

Based on the current as billed data, the estimated depreciated net book value of all the Trico DAFs as of January 1, 2017 will be approximately $7,825,000, which the Parties will modify based on the final accounting true-up.

Therefore, until otherwise modified in writing by agreement of the Parties, the Parties agree to the following:

1) The Parties shall complete the accounting and billing true-up of costs for each Trico DAF and agree on final adjustments to Trico DAF billings, which shall establish the original installed cost and depreciated net book value for each Trico DAF.

2) The Parties shall prepare an agreement for the purchase by Trico of the Trico DAFs from SWTC, the terms and conditions of which shall include, but not be limited to, the following:

   a) The purchase shall occur and be effective on the Closing Date, which shall be the effective date of the Trico Rate Case or such other date as the Parties may agree.

   b) On the Closing Date, Trico shall make a onetime payment to SWTC for the Trico DAFs in the amount of the greater of the following at the Closing Date: i) the outstanding loan balance associated with the Trico DAFs, plus any plant in service financed by general funds, less a negotiated adjustment agreed to by the Parties; or ii) the amount of the depreciated net book value of the Trico DAFs. Such sales price shall be subject to any requisite lienholder or trustee approval.

   c) Before the Closing Date, SWTC will seek any necessary release of lien to facilitate the sale as of Closing Date. On the Closing Date, SWTC shall convey all of its right, title and interest in the Trico DAFs to Trico, free and clear of all liens and encumbrances, including but not limited to those of the RUS, its successors and assigns; and, Trico shall thereafter assume ownership and control of the Trico DAFs, except as otherwise provided herein.

d) On the Closing Date, in accordance with the Network Agreements, if any Trico DAF facilities and equipment to be purchased and owned by Trico is installed on land owned or controlled by SWTC, then SWTC and Trico shall enter into a License Agreement, as defined in the Network Agreements.

e) As soon as practicable after the execution of this Letter Agreement, the Parties shall review and determine whether the land rights, easements and leases associated with Trico DAFs can be assigned to Trico. In the event any such land rights, easements and leases are determined to be non-assignable, the Parties will work in good faith to determine alternatives that provide Trico with access to the equipment and facilities that it owns as a result of its purchase of the Trico DAFs.

f) To the extent required the Parties shall work cooperatively to assign any contract rights and obligations associated with the Trico DAFs from SWTC to Trico as part of the sale.

3) In accordance with the Network Agreements, the Parties shall prepare and enter into an operations and maintenance agreement (O&M Agreement) to be effective on the Closing Date, pursuant to which SWTC will perform the operations and maintenance work on the portion of the former Trico DAFs operating at 115 kV and above and for any equipment that directly connects to physical system facilities owned by SWTC. As agreed by SWTC and Trico, the O&M Agreement shall provide that SWTC shall charge Trico the actual costs to operate and maintain such portions of the purchased equipment and facilities.

Please confirm your agreement with the foregoing by signing two originals of this Letter Agreement in the space provided below. Please return one original to me for Trico's files. Trico looks forward to working with SWTC and continuing our partnership.

Sincerely,

Vincent Nitido
CEO/General Manager

Accepted for:

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

By: _____
Patrick F. Ledger
Its: Chief Executive Officer

Date: Jan. 5, 2016

Snell & Wilmer
L.L.P.
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EXHIBIT
S-4
ADMITTED

ORANGE COUNTY
PHOENIX
RENO
SALT LAKE CITY
TUCSON

Michael W. Patten
(602) 382-6339
mpatten@swlaw.com

April 15, 2016

BY E-MAIL & HAND DELIVERY

Matthew Laudone
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Re: Trico Electric Cooperative, Inc. General Rate Case
Docket No. E-01461A-15-0363

Dear Mr. Laudone:

Enclosed please find Trico Electric Cooperative, Inc.'s responses to Staff's Seventh Set of Data Requests. Some of the information is confidential and is being provided pursuant to the protective agreement in this docket.

Please let me know if you have any questions.

Very truly yours,

Snell & Wilmer

Michael W. Patten

RECEIVED
APR 15 2016
LEGAL DIVISION
AZ CORP COMM

MWP:jh

Enclosures

cc: Rick Lloyd (w/ Enclosures)

FILE COPY

Snell & Wilmer is a member of LEX MUNDI, The Leading Association of Independent Law Firms.

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
APRIL 15, 2016

STF 7.1 **DAF Purchase:** As a follow-up to Staff's DR #5.4, please provide details on Trico's plans for financing the purchase of the DAFs. Does Trico intend on financing all of the purchase price or only $4 million? At a minimum, include the intended method and source of financing, how much of the purchase price will be financed, general financing terms, and the source of any other funds to be used for the purchase.

RESPONSE: Trico intends to purchase the DAFs using general funds. However, to enable funding of the DAFs using general funds, Trico anticipates that it will need to borrow more to fund its current Construction Work Plan Projects from its existing Rural Utilities Service AL8 Loan (approved and extended in Decision Nos. 70399, 73933, 74583 and 75120). Trico included borrowing an additional $4 million from its AL8 Loan in the adjusted test year Cost of Service to enable funding of the DAFs using general funds.

RESPONDENT: Karen Cathers, Chief Operating Officer

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
APRIL 15, 2016

STF 7.2 **DAF Purchase:** Please provide a copy of the purchase agreement for the DAFs between Trico and Southwest Transmission

RESPONSE: Trico and Southwest Transmission Cooperative, Inc. (now "AEPCO") have entered into a letter agreement, dated December 14, 2015 that documents the understanding of the parties with respect to the Southwest Transmission Cooperative Sale of the Direct Assignment Facilities (DAFs) to Trico. This letter agreement is attached as STF 7.2 Attachment SWTC_Trico DAF Letter Agreement. The letter agreement includes among other items the agreement by the parties to finalized the DAF costs and to enter into a sale agreement for the DAFs which would have a closing date upon the effective date of the Trico rate case approving the sale.

RESPONDENT: Karen Cathers, Chief Operating Officer

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
APRIL 15, 2016

STF 7.3 **DAFs Rate of Return:** Please provide how the Cooperative is ultimately proposing to incorporate the transfer of the DAFS into the rate increase application.

RESPONSE: The estimated amount of the Direct Assignment Facilities (DAFs) to be purchased of $7,824,026 was included as an adjustment to plant in account 353, transmission station equipment. The additional depreciation expenses associated with the facilities increases Trico's depreciation expense by $215,943 ($7,824,026 x 2.76%). It is anticipated that additional loan funds of $4 million will be incurred for the purchase at an interest rate of 3%, resulting in additional interest expense of $120,000. A total of $335,943 of additional expenses directly related to the purchase of the DAFs is included in the revenue requirement. An amount of $1,091,877 is removed from purchased power expense to reflect a reduction in AEPCO's billing to Trico since the assets will no longer be owned by AEPCO and the carrying costs will no longer be billed to Trico by AEPCO.

RESPONDENT: Rebecca Payne, Guernsey

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
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STF 7.4 **DAFs Final Cost:** Please provide Staff with the final cost including any true-ups of the DAFS.

RESPONSE: Trico is working with SWTC (now "AEPCO") on the final true-up of costs associated with the DAFs. Trico's most current cost estimate is as Trico provided in response to STF 1.7 and in STF 1.7 Attachment 1 Summary of DAF Costs, which includes a summary of the DAFs associated with each of the eight substations and the costs to date as well as a forecast estimate of the January 1, 2017 net book value. The forecasted net book value is the estimated sale price of the DAFs that Trico would ultimately pay SWTC, assuming a closing date of the sale as January 1, 2017.

RESPONDENT: Karen Cathers, Chief Operating Officer

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STF 7.5 **DAF Plant Additions:** Please provide a narrative of the methodology that Trico is proposing to account for the DAFS after the transfer to Trico.

RESPONSE: Trico's accounting methodology is governed by Rural Utility Services (RUS) regulations listed in Title 7, Subtitle B, Chapter XVII, Part 1767 of the Federal Register. Trico will use the methodology laid out by RUS in 1767.16 (e)(2), the accounting for the acquisition of electric plant.

Trico will record in a subaccount of Account 353, Transmission Station Equipment, the original cost of the DAF facilities, as recorded in AEPCO's General Ledger. Trico, will also use a subaccount of 108.5, Accumulated provision for Depreciation-Transmission Plant, the life to date depreciation balance for the DAF recorded in AEPCO's General Ledger. The difference between the 353 accounts and 108.5 accounts will be the net book value of the DAFs will reflect the net book value of the DAFs recorded in AEPCO's plant records.

RESPONDENT: Brian Fickett, Manager of Finance and Accounting

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
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STF 7.6

Age of the DAFS: Are the individual remaining lives of the DAFs included in the methodology of depreciating the DAFS? The application is showing the DAFS as added to the account 353.0 Station equipment as just one flat amount and depreciation is shown going forward at a rate of 2.76, which would allow for approximately 36 years of remaining life. Yet, the DAFS have varying individual depreciation rates prior to the transfer to Trico.

RESPONSE:

Trico plans to add the depreciated net book value of the DAFs into plant account 353.0, which will recognize the depreciation that has occurred prior to the Trico purchase. Consistent with RUS accounting regulations, Trico depreciates plant in account 353.0 on an aggregate basis at the rate of 2.76 percent annually. The individual remaining life of plant added to account 353.0 (including the DAFs) is not directly incorporated in the methodology of depreciating plant added to that account, rather the depreciated book value of the plant is reflected in the aggregate plant account.

Pursuant to the attached STF 7.6 Attachment RUS Bulletin 183-1, Depreciation Rates and Procedures, and the RUS Uniform System of Accounts, Trico depreciates plant assets using straight line depreciation on a composite basis. This methodology is also consistent with the electric utility industry standard for calculating depreciation. While the DAFs have varying remaining lives, the use of composite depreciation treats them as one asset for depreciation purposes.

Please see also the response for STF 7.5 related to the plant accounting for the DAFs.

RESPONDENT: Karen Cathers, Chief Operating Officer

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
APRIL 15, 2016

STF 7.7

Rate Schedules: The Trico rate application includes a proposed new Standard Offer Tariff for the Sunwatts Sun Farm Monthly Participation Tariff Schedule RESFM. The following questions are in regard to the proposed new tariff.

a. Is this new tariff in addition to the currently in effect Sunwatts Sun Farm Tariff Schedule RESF? What are the differences between the two tariffs?

b. Is it correct that the new program would utilize the same group of existing panels located outside the Trico headquarters building?

c. How many panels in total do you have outside the headquarters building?

d. How many of those panels are currently subscribed through the Sunwatts Sun Farm Tariff Schedule RESF?

e. How were the panels paid for initially?

f. Is output from the panels part of the purchased power costs currently charged to Trico customers?

g. Are the panels already part of plant factored into rate base?

h. How many years have the panels been producing output? What is the expected lifespan of the panels?

i. Who would be a target customer for the Sunwatts Sun Farm Monthly Participation Tariff Schedule RESFM?

j. Can customers who currently subscribe to the RESF tariff also purchase output from the RESFM tariff?

k. The tariff language for the RESFM indicates that Trico retains all of the RECs produced by the Sun Watts Sun Farm. Are the customers paid any incentive dollars for those RECs? Are the RECs counted as utility scale solar in the REST plan filing each year?

l. The proposed rate for the RESFM tariff is listed on the second page of the proposed tariff in the rate application. How were those rates calculated? Are the rates based on the cost incurred by Trico to install the Sun Watts Sun Farm? Please provide spreadsheets showing the calculation of the proposed RESFM rates.

m. What makes up the Fixed Cost Portion Energy Rate ($/kWh) on the proposed rates for the RESFM tariff?

n. How often will the RESFM rates change? Only in a rate case?

o. Why is the energy from the Solar Blocks excluded from the calculation of the PCA and the REST charges?

p. Once a customer contracts for at least 432 kWh per year (36 kWh per month), is the rate locked in for the next 20 years even if future rate cases change that rate? What happens after 20 years? Will the customer have the option to keep the same rate on the same output level or be required to contract for a specific number of solar blocks at the new rate in effect once the 20 years has passed?

q. Will the new net metering provisions apply to any excess usage from the RESFM tariff during the month?

r. Have you presumed any revenue for this proposed rate schedule in the rate application? If yes, how much and please provide the support for those revenue calculations.

s. Please provide a copy of the contractual agreement the customer signs to participate in the RESFM program.

RESPONSE: The following responds to each question:

a. Is this new tariff in addition to the currently in effect Sunwatts Sun Farm Tariff Schedule RESF? What are the differences between the two tariffs?

Yes. Trico's current SunWatts Sun Farm Tariff Schedule RESF requires participation through a one-time upfront fee. The proposed new SunWatts Sun Farm Monthly Participation Tariff Schedule RESFM would allow Trico Members to participate in Trico's SunWatts Sun Farm without having to pay an upfront fee, by purchasing panel output through a monthly solar energy charge.

b. Is it correct that the new program would utilize the same group of existing panels located outside the Trico headquarters building?

Yes. It would include panel output that has not already been contracted for by members.

c. How many panels in total do you have outside the headquarters building?

Trico Sun Farm has a total of 840 panels.

d. How many of those panels are currently subscribed through the Sunwatts Sun Farm Tariff Schedule RESF?

Trico members have purchased the energy output of 192 SunWatts Sun Farm panels.

e. How were the panels paid for initially?

The total cost of Trico's Sun Farm was $1,230,399. Trico received a grant from the Arizona Commerce Authority, through the U.S. Department of Energy's American Recovery and Reinvestment Act (ARRA) in the amount of $933,458. The remaining $296,941 was funded using Trico general funds.

f. Is output from the panels part of the purchased power costs currently charged to Trico customers?

The panel output that is not already purchased by members reduces the overall purchase power energy and overall purchase power costs.

g. Are the panels already part of plant factored into rate base?

Yes, the portion of the Sun Farm that Trico funded using general funds has been included into rate base.

h. How many years have the panels been producing output? What is the expected lifespan of the panels?

Trico's SunWatts Sun Farm went into service in July 2011. The panels are warranted to produce 80% of specified power for a period of 25 years. Trico anticipates that the panels will have a life span of 25 to 30 years.

i. Who would be a target customer for the Sunwatts Sun Farm Monthly Participation Tariff Schedule RESFM?

The target customers for the monthly Sun Farm Tariff are similar to those for Trico's current Sun Farm Tariff that requires an up-front payment except that they cannot or do not wish to have a large up-front payment. These are renters and homeowners who cannot site a solar system or who do not have the capital to fund or otherwise finance their own unit. Trico has received requests from its Members to allow participation in the program through a monthly payment option.

j. Can customers who currently subscribe to the RESF tariff also purchase output from the RESFM tariff?

Yes, if they otherwise qualify under the requirements of the tariff.

k. The tariff language for the RESFM indicates that Trico retains all of the RECs produced by the Sun Watts Sun Farm. Are the customers paid any incentive dollars for those RECs? Are the RECs counted as utility scale solar in the REST plan filing each year?

The incentive is built into the price of the panel output and reflected in their 36 kWh credit per panel per month for their purchase. Yes, Trico does count the Sun Farm as utility scale solar (or Non-Distributed Generation) for the purposes of the REST plan filings each year which is in accordance with Decision No. 72086.

l. The proposed rate for the RESFM tariff is listed on the second page of the proposed tariff in the rate application. How were those rates calculated? Are the rates based on the cost incurred by Trico to install the Sun Watts Sun Farm? Please provide spreadsheets showing the calculation of the proposed RESFM rates.

Please see the attached spreadsheet STF7.7(l) Attachment SunWatts Sun Farm Rate Calculation. A description of how the rates are calculated and the basis for the rates is included in STF7.7(l) Attachment SunWatts Sun Farm Rate Calculation in the Background sheet of the spreadsheet.

m. What makes up the Fixed Cost Portion Energy Rate ($/kWh) on the proposed rates for the RESFM tariff?

The Fixed Cost Portion Energy Rate would be those approved in the rate case for each rate class. What is in the draft RESFM tariff corresponds to the unbundled rates as proposed by Trico in its rate case filing. The Fixed Cost Portion Energy Rate includes all the fixed costs that are not included in the customer charge or in a demand rate (fixed power cost, transmission cost and distribution cost). See the attached STF 7.7(m) Attachment Unbundled Rates.

n. How often will the RESFM rates change? Only in a rate case?

The RESFM rates would change only in a rate case.

o. Why is the energy from the Solar Blocks excluded from the calculation of the PCA and the REST charges?

Trico's PCA and REST charges are applied to energy (kWh) purchased by a customer during the month. The Solar Blocks effectively reduce the amount of kWh purchased by a customer each month, and is therefore not included in the calculation of the PCA and REST charges. This mirrors the current process for the kWh not purchased by the customer through participation in Trico's Net Metering Tariff. Trico does not include the kWh generated by a customer's interconnected renewable generation system in the calculation of the PCA and REST charges.

p. Once a customer contracts for at least 432 kWh per year (36 kWh per month), is the rate locked in for the next 20 years even if future rate cases change that rate? What happens after 20 years? Will the customer have the option to keep the same rate on the same output level or be required to contract for a specific number of solar blocks at the new rate in effect once the 20 years has passed?

Yes, the rate is locked in for the next 20 years even if future rate cases change the rate. After 20 years, the customer would need to sign up to participate in the program at the rates in effect at that time.

q. Will the new net metering provisions apply to any excess usage from the RESFM tariff during the month?

Typically, customers participating in the Sun Farm do not have any excess during the month. However, if they have any excess it would simply reduce their energy at the retail rate.

r. Have you presumed any revenue for this proposed rate schedule in the rate application?

No

s. Please provide a copy of the contractual agreement the customer signs to participate in the RESFM program.

Trico has proposed that the customer will not sign a contractual agreement but rather the terms of their participation in the program are included in the SunWatts Sun Farm Monthly Participation Tariff Schedule RESFM.

RESPONDENT: Karen Cathers, Chief Operating Officer

STAFF'S SEVENTH SET OF DATA REQUESTS TO
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363
APRIL 15, 2016

STF 7.8

Rate Schedules: The Trico rate application indicates in both Karen Cathers' testimony and Rebecca Payne's testimony that Trico is proposing to combine the existing Interruptible Service for Commercial and Industrial customers (IS1) and the existing Interruptible Service for Irrigation and Water Pumping Service (IS2). The following questions are in regard to the proposed changes to the IS1 and IS2 tariffs.

a. Are there any customers currently on these rate schedules? If yes, how many are on each? Please provide the names of the interruptible customers currently on the IS1 and IS2 tariffs. In 2014, how many interruptions were required for the IS1 and IS2 customers? In 2014, did you have any occurrences of customers not interrupting when they were asked to?

b. The application indicates Trico is proposing to combine these two tariffs into one Interruptible Service (IS1) tariff and then Trico is also proposing to freeze this IS1 tariff. What interruptible schedule would you have available for new customers if you freeze the proposed IS1 tariff?

c. Are the availability and application sections of the previous IS1 and IS2 tariffs similar enough that they can be combined into one rate schedule? Why were they proposed as two rate schedules originally?

d. In Karen Cathers' testimony on page 12 lines 24-27, she indicates that "...the current tariff has proven ineffective and has not provided the anticipated benefits to Trico given our wholesale power charges are billed as a fixed charge now rather than as a demand rate. Additionally, this tariff has very labor intensive administrative requirements versus the limited benefits." Please explain further the benefits Trico hoped to gain from offering interruptible tariffs and how those are not being met as AEPCO's rates are not demand based at this point in time. Also, please explain how the interruptible tariffs are labor intensive administratively. Are they more labor intensive than the other standard offer tariffs?

e. Have the interruptible customers on the current IS1 and IS2 tariffs been notified of the possibility of the combined tariff, freezing of the tariff, and the possible rate increase?

f. In Rebecca Payne's testimony on page 21 lines 11-14, she ndicates that Trico would seek to eliminate this frozen IS1 tariff and transition customers to an applicable tariff. The proposed rate changes are to help ease that transition. What applicable tariff does Trico want to transition these customers to?

RESPONSE: Responses to each question as follows:

a) Are there any customers currently on these rate schedules? If yes, how many are on each? Please provide the names of the interruptible customers currently on the IS1 and IS2 tariffs. In 2014, how many interruptions were required for the IS1 and IS2 customers? In 2014, did you have any occurrences of customers not interrupting when they were asked to?

Yes. As of March 31, 2016 there are 23 interruptible accounts, 2 accounts on IS1 rate schedule and 21 accounts on IS2, which are held by 6 members. See STF7.8(a) Attachment IS_Rate_Schedules which includes a summary of members and the number of accounts held by each tariff.

In 2014, Trico Dispatch issued 19 interruption requests during the year. There were 103 occurrences of customers not interrupting (all or part of their load) during the time of the AEPCO peak.

b) The application indicates Trico is proposing to combine these two tariffs into one Interruptible Service (IS1) tariff and then Trico is also proposing to freeze this IS1 tariff. What interruptible schedule would you have available for new customers if you freeze the proposed IS1 tariff?

New customers depending on their load characteristics could take service under the Time-of-Day Water Pumping, Irrigation, General Service 1, 2, 3 or General Service TOU, based on if they qualify under the tariff.

c) Are the availability and application sections of the previous IS1 and IS2 tariffs similar enough that they can be

combined into one rate schedule? Why were they proposed as two rate schedules originally?

Yes. Trico does not know why two rate schedules were originally proposed.

d) In Karen Cathers' testimony on page 12 lines 24-27, she indicates that "...the current tariff has proven ineffective and has not provided the anticipated benefits to Trico given our wholesale power charges are billed as a fixed charge now rather than as a demand rate. Additionally, this tariff has very labor intensive administrative requirements versus the limited benefits." Please explain further the benefits Trico hoped to gain from offering interruptible tariffs and how those are not being met as AEPCO's rates are not demand based at this point in time. Also, please explain how the interruptible tariffs are labor intensive administratively. Are they more labor intensive than the other standard offer tariffs?

When Trico formulated the IS1 and IS2 rates its costs for generation from AEPCO were charged based on a demand rate at the time of the AEPCO monthly peak. If Trico could interrupt the IS1 and IS2 customers at the time of the AEPCO monthly peak this would result in savings. However, in 2011 (Decision No. 72055) AEPCO's rates changed such that Trico is now billed a fixed monthly charge rather than a demand rate which limits the benefit of interrupting load. The IS1 and IS2 are labor intensive because Trico must monitor the AEPCO half hour peak 24/7 and try to estimate when interruption is needed. To interrupt load each customer must be notified many of which require multiple calls to reach someone.

e) Have the interruptible customers on the current IS1 and IS2 tariffs been notified of the possibility of the combined tariff, freezing of the tariff, and the possible rate increase?

Trico has not provided any formal notification to these customers, other than the notice of the rate case filing provided to all Trico members pursuant to the Procedural Order issued in this docket, however Trico has had verbal discussions with about half of the customers.

f) In Rebecca Payne's testimony on page 21 lines 11-14, she indicates that Trico would seek to eliminate this frozen IS1

tariff and transition customers to an applicable tariff. The proposed rate changes are to help ease that transition. What applicable tariff does Trico want to transition these customers to?

Existing customers depending on their load characteristics could take service under the Time-of-Day Water Pumping, Irrigation, General Service 1, 2, 3 or General Service TOU, based on which tariff they qualify under. The majority of the accounts are irrigation or water pumping accounts and they fit under the Time-of-Day Water Pumping and Irrigation tariffs.

RESPONDENT: Karen Cathers, Chief Operating Officer

Net Metering Tariff Application

You MUST sign up to participate in the Trico Net Metering Tariff. Please review the Net Metering Tariff attached, which can also be found on Trico's website at www.trico.coop, complete the information below and return it with your application if you would like to take service under this Tariff. If you do not qualify, Trico will respond to your application by sending you a notification, which will include information regarding the reason you did not qualify.

IMPORTANT NOTICE: Trico proposed a new net metering tariff in the rate case it filed with the Arizona Corporation Commission (Commission) on October 23, 2015 in Docket No. E-01461A-15-0363. Trico requested that the proposed new Net Metering Tariff apply to Interconnection Applications received after February 28, 2015. Neither the proposed tariff nor the February 28, 2015 implementation date has been approved by the Commission at this time. In Trico's rate case, the Commission's Utilities Division Staff and/or intervenors may propose different modifications to the Net Metering Tariff which may affect your bill in other ways. The Commission is not bound by any party's proposal, and may accept, reject, or modify any proposed rate, charge or term of service. For further information, please visit Trico's website at www.trico.coop.

Please print:

Name: _____

Service Address: _____

City: _____ State: AZ Zip Code: _____

Account Number: _____

By signing below, you are indicating that you have read and understand the provisions of the Trico Electric Cooperative, Inc. Net Metering Tariff and wish to apply to take service under this tariff at this time. You further understand that if your Interconnection Application was received after February 28, 2015, you will be subject to the provisions of any New Net Metering Tariff, as approved by the Arizona Corporation Commission, upon the effective date of the New Net Metering Tariff.

_____ _____

Signature Date

Please mail or email your completed application to the following location:

Trico Electric Cooperative
Attn: SunWatts
PO Box 930
Marana, AZ 85653

OR

Sunwatts@trico.coop

EXHIBIT
S-5
ADMITTED

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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS

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

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	Docket No. E-00000J-14-0023

GALLAGHER NNEDY, P.A.
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INITIAL CLOSING BRIEF

OF

GRAND CANYON STATE ELECTRIC

COOPERATIVE ASSOCIATION, INC.

July 11, 2016

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INTRODUCTION

Grand Canyon State Electric Cooperative Association, Inc. ("GCSECA"), on behalf of its electric distribution cooperative members (the "Cooperatives"),[1] submits this Initial Closing Brief. In considering the value and cost of Distributed Generation ("DG"), GCSECA urges the Commission to adopt policies and guidelines consistent with standard ratemaking principles and flexible enough to account for each utility's unique characteristics, including structure and purpose as well as diversity in customers, geography, power sources, load, and growth potential.

In the context of the Cooperatives, the following findings are supported by the record, just, reasonable, and in the public interest:

- The appropriate method for valuing DG and determining the rate to be paid for excess DG generation is a utility-specific question;
- Rates should be set based on actual, known, measurable, and quantifiable data, not long-term forecasts or speculative benefits;
- The appropriate rate for the Cooperatives to pay for excess DG generation is their true avoided costs, which are limited to their avoided wholesale energy and fuel costs; and
- The Cooperatives should be afforded flexibility to develop rate design solutions to the cost shift caused by DG and should not be required to comply with any one-size-fits-all requirements that would impose economic and operational hardships.

[1] GCSECA's electric distribution cooperative members include Dixie Escalante Rural Electric Association, Inc.; Duncan Valley Electric Cooperative, Inc.; Garkane Energy Cooperative, Inc.; Graham County Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Sulphur Springs Valley Electric Cooperative, Inc.; and Trico Electric Cooperative, Inc.

GCSECA'S POSITION ON VALUE AND COST OF DISTRIBUTED GENERATION

GCSECA is not proposing a particular methodology for evaluating the value of DG or for conducting a general cost/benefit analysis of DG.[2] Instead, GCSECA's focus is on the potential use of a "value of DG" analysis to calculate the rate utilities must pay (via energy credits and bank refunds) for excess electricity generated by DG. To the extent that this docket endorses a methodology to be used to set a rate for excess DG generation, then the methodology should be consistent with the principles applicable to utility ratemaking.

First, the costs and benefits should be quantifiable and not based on forecasts or assumptions.[3] Forecasts, especially long-term forecasts, are valuable in the context of resource planning, but are ill-suited for calculating rates because they are based on inherently unknowable assumptions.[4] Also, incorporating long-term benefits into current rates creates an inequitable mismatch by paying today for a benefit that will not be received until the distant future, if at all.[5] That is why the Commission does not use forecasts to set utility rates, but instead insists on using actual, known, and measurable data.[6] The same standard should apply to setting the rate for excess DG generation.

Second, social or indirect benefits (such as environmental benefits, job creation, and avoided water consumption) should not be included in the rate-setting/valuation analysis. Not only are these alleged benefits speculative and difficult (if not impossible) to quantify, but such benefits are not included in the ratemaking formula for non-DG generation.[7] Therefore, the same

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[2] Hr. Tr., Vol. VI, p. 1100, l. 20 – p. 1101, l. 8.
[3] Hr. Tr., Vol. VI, p. 1100, l. 20 – p. 1101, l. 8; GCSECA-1, p. 13, l. 11 – p. 14, l. 2.
[4] Hr. Tr., Vol. X, p. 1936, l. 16 – p. 1940, l. 25.
[5] Hr. Tr., Vol. VI, p. 1049, l. 19 – p. 1051, l. 3.
[6] Hr. Tr., Vol. VI, p. 1101, l. 9 – p. 1102, l. 5; Hr. Tr., Vol. IX, p. 1770, ll. 5–13.
[7] Hr. Tr., Vol. VII, p. 1427, l. 1 – p. 1429, l. 3.

rules should apply to exclude secondary benefits from the process of setting the excess DG generation rate paid by utilities.

Finally, based on these principles, GCSECA urges the adoption of a simple methodology for calculating the excess DG rate that the Cooperatives pay; the rate should be based on the Cooperatives' true avoided costs. For the Cooperatives, it is undisputed that the only costs avoided by DG power are fuel and energy.[8] The Cooperatives do not provide their own generation, but receive their power pursuant to wholesale contracts that contain fixed charges for generation capacity.[9] As a result, any reduction in capacity requirements caused by DG does not translate into a reduction in generation capacity costs for the Cooperatives.[10] Likewise, DG does not reduce the Cooperatives' distribution costs and, instead, may result in the need for additional expenditures.[11] While it is possible that the future proliferation of DG could result in cost savings or other benefits, those benefits are not currently known, measurable, or quantifiable; therefore, they should not be included in the calculation of the rate that the Cooperatives pay for excess generation:

> [T]he value of solar is, for the co-ops, the avoided wholesale energy and fuel costs from the power supplier. We don't see any reduction in distribution costs. We don't see any reduction in transmission costs. We don't believe is it prudent that you are looking into the future to bring in some unquantifiable costs or benefits in the future periods. We think that's inconsistent with ratemaking principles at the Commission.[12]

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[8] Hr. Tr., Vol. VI, p. 1039, l. 24 – p. 1040, l. 4.
[9] GCSECA-1, p. 10, ll. 15–22.
[10] GCSECA-1, p. 10, l. 23 – p. 11, l. 5; Hr. Tr., Vol. VII, p. 1403, l. 14 – p. 1404, l. 4.
[11] GCSECA-1, p. 11, l. 8 – p. 12, l. 3.
[12] Hr. Tr., Vol. VI, p. 1076, ll. 14–22.

OTHER VALUE OF SOLAR PROPOSALS

The parties' proposals and options presented for the Commission's consideration in this docket have evolved over the course of the proceeding. The Commission's Utilities Division Staff initially proposed an avoided cost approach with the possibility of "adders."[13] At hearing, Staff suggested a second methodology – a resource comparison approach – that would establish the rate for excess DG generation using as a proxy the weighted average of the cost of PPAs and utility-owned facilities.[14] Ultimately, Staff endorsed the concept that the Commission should approve multiple methodologies and provide the parties with guidance as to which methods would be most appropriate to use in future rate cases depending on the individual utility's circumstances:

> [T]he way I am anticipating this docket goes is there would be some finding which says in rate cases going forward we would like the parties to focus on this method, or we require the parties to use this method or these two methods or these three, and maybe some discussion around when they are more applicable than others and guide the parties.
>
> What happens – I understand the purpose of this docket is to guide us so the rate cases will be more focused and they will be less – how would I say? It will narrow the discussion in cases going forward once we have the findings from this docket.[15]

GCSECA agrees with Staff that finding the appropriate method for valuing DG is a "utility specific question."[16] No single methodology will address each utility's unique circumstances. This is especially true for the Cooperatives when compared to the larger,

[13] S-2, p. 19, l. 5 – p. 20, l. 9.
[14] Hr. Tr., Vol. XIII, p. 2324, l. 12 – p. 2325, l. 1 and p. 2333, ll. 2–16.
[15] Hr. Tr., Vol. XIII, p. 2342, l. 18 – p. 2343, l. 4.
[16] Hr. Tr., Vol. XIII, p. 2352, ll. 11–14.

investor-owned, integrated utilities, and Staff admits that the different characteristics may warrant a different approach.[17]

Therefore, GCSECA joins Staff in urging the Commission to adopt a flexible approach that stresses the different circumstances and needs of each utility. However, for the reasons explained above, GCSECA opposes any proposal to establish a value of DG methodology based on long-term forecasts such as those proposed by RUCO, Vote Solar, and TASC. Moreover, several of the proposed methodologies should be rejected to the extent that they would require additional data gathering, analysis, and review that would impose economic and operational hardships on the Cooperatives.[18]

OTHER ISSUES RAISED IN THIS DOCKET

In addition to addressing the valuation methodology question, this docket touched on several related issues. Specifically, GCSECA and other parties raised concerns about the DG cost shift and current net metering policy and discussed potential rate design changes. To the extent that the Commission is inclined to address these issues in this docket, GCSECA provides the following comments.

The Cost Shift is Real

The vast majority of parties in this docket agree that the "cost shift" from DG is real. Under a rate design that recovers a major portion of a utility's fixed costs through the variable rate, fixed costs are under-recovered from DG customers due to their significant usage reduction; as a result, non-DG customers are forced to pay more than their equitable share of those fixed

[17] S-3, p. 18, ll. 1–2; Hr. Tr., Vol. VII, p. 1402, l. 11 – p. 1403, l. 13; Hr. Tr., Vol. XIII, p. 2352, l. 11 – p. 2353, l. 5.

[18] These proposals include, without limitation: Staff's various adders, including the nodal approach to calculating a transmission or distribution adder (Hr. Tr., Vol. VII, p. 1303, l. 5 – p. 1308, l. 5 and p. 1384, l. 25 – p. 1385, l. 24; Hr. Tr., Vol. XIII, p. 2327, l. 22 – p. 2328, l. 1); Vote Solar's hosting capacity analysis and smart inverter requirements (Hr. Tr., Vol. IX, p. 1618, ll. 11–20, p. 1631, l. 22 – p. 1632, l. 15, p. 1650, l. 18 – p. 1653, l. 5, and p. 1686, l. 5 – p. 1688, l. 19); and TASC's marginal cost analyses (TASC-26, p. 19, l. 23 – p. 22, l. 10; S-3, p. 13, ll. 10-15).

costs.[19] The magnitude of the cost shift varies by utility, but two of GCSECA's members have demonstrated more than $1 million in annual lost fixed costs caused by DG, which is a substantial under-recovery for rural distribution cooperatives.[20] This shift is exacerbated by the current net metering policy, which forces the Cooperatives and their non-DG members to overpay DG customers for excess generation.[21] Further, given their rural location and small size, the Cooperatives have a higher level of plant investment per customer and fewer customers to absorb the subsidies created by DG, which makes the cost shift an even bigger problem for Cooperatives.[22]

The only parties who dispute the cost shift are Vote Solar and TASC. Vote Solar disputes the existence of a cost shift based on alleged methodological flaws in APS's and TEP/UNS's cost of service studies.[23] Meanwhile, TASC takes the position that, while non-DG customers may overpay in the short-term, there is no cost shift because "over time" DG is expected to produce long-term benefit.[24] Alternatively, TASC asserts that the Commission can justify forcing non-DG customers to "live with" the cost shift because, according to TASC, there are future societal benefits that outweigh fairness and equity.[25] Given the overwhelming evidence in this docket demonstrating the reality of the DG-caused cost shift and the inequitable impact it has on non-DG customers, the Commission should reject Vote Solar and TASC's arguments to the contrary.

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[19] GCSECA-1, p. 3, l. 1 – p. 5, l. 16; APS-1, p. 21, l. 5 – p. 22, l. 2; TEP-1, p. 3, l. 24 – p. 4, l. 7; AIC-1, p. 9, l. 14 – p. 10, l. 11; RUCO-2, p. 10, ll. 7–15; Hr. Tr., Vol. VII, p. 1335, l. 20 – p. 1337, l. 10.
[20] GCSECA-1, p. 6, l. 15 – p. 8, l. 11.
[21] GCSECA-1, p. 8, l. 13 – p. 10, l. 6.
[22] GCSECA-1, p. 12, l. 6 – p. 13, l. 8.
[23] Vote Solar-8, p. 4, ll. 11–15; Hr. Tr., Vol. IX, p. 1709, l. 15 – p. 1715, l. 13.
[24] Hr. Tr., Vol. X, p. 1912, l. 11 – p. 1913, l. 3.
[25] Hr. Tr., Vol. X, p. 1923, l. 22 – p. 1924, l. 19.

One-Size-Fits-All is the Wrong Answer

Various proposals were mentioned in the docket to address the cost shift. For example, Staff recommended a transition from the current two-part rate design and net metering system to a three-part time-of-use rate design and avoided cost-based compensation for excess DG generation.[26] Other viable – and in some cases the most appropriate – options include increasing fixed costs, developing separate rate classes for DG customers, and revising net metering tariffs for new DG customers.[27]

Just as determining the appropriate valuation methodology is a utility-specific inquiry, so too is the issue of rate design and finding the best solution to the cost shift. For example, transition to a three-part rate with a demand charge requires capital investment in metering capability and billing system upgrades as well as customer outreach and education.[28] While one of GCSECA's members has demand metering in place, the transition for many of the others would be prohibitively expensive and time-consuming.[29] Accordingly, given the significant impact that DG is having on the cooperative community, the Cooperatives need flexible options and solutions, not a one-size-fits-all rate design. As the Commission and Staff have repeatedly acknowledged, the Cooperatives differ from the other Arizona electric utilities in that the Cooperatives are small, non-profit, democratically governed, and serve some of the most economically challenged areas in the state.[30] Therefore, GCSECA urges the Commission to adopt a flexible approach and allow each cooperative to address the cost shift according to its individual circumstances and the needs of its members.

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[26] S-3, p. 30, ll. 4–16 and p. 31, ll. 7–9; Hr. Tr., Vol. VII, p. 1290, ll. 20–25 and p.1339, ll. 8–12.
[27] These options are being explored in two currently-pending cooperative rate cases: Docket Nos. E-01461A-15-0363 and E-01575A-15-0312.
[28] Hr. Tr., Vol. VI, p. 1080, l. 12 – p. 1081, l. 20.
[29] Hr. Tr., Vol. VI, p. 1081, l. 23 – p. 1083, l. 1.
[30] Hr. Tr., Vol. VII, p. 1405, l. 14 – p. 1406, l. 13.

RESPECTFULLY SUBMITTED this 11th day of July, 2016.

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EXHIBIT
S-6
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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BOB STUMP
Commissioner
BOB BURNS
Commissioner
TOM FORESE
Commissioner
ANDY TOBIN
Commissioner

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

DIRECT

RATE DESIGN

TESTIMONY

OF

RANELLE PALADINO

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 1, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

Ranelle Paladino's testimony presents the results of the Utilities Division Staff's ("Staff") review of the cost of service study ("COSS"), revenue allocation, and rate design proposals in the rate case application of Trico Electric Cooperative, Inc.'s ("Trico" or "Company"). The application was filed with the Arizona Corporation Commission ("Commission") on October 23, 2015.

Taking into consideration Staff's recommendation that rate design more closely reflect actual cost of service and with Trico's ability to and interest in implementing a three-part rate (customer, demand, and energy), Staff is proposing Trico offer three-part rates and two-part rates to its residential and small commercial customers. By suggesting that Trico offer both options to customers, Staff is supporting Trico in the direction of moving fixed costs out of the variable energy rate.

Based on its review of Trico's COSS, revenue allocation, and rate design proposals, Staff's conclusions and recommendations are as follows:

CONCLUSIONS

A. Staff concludes that Trico has performed the COSS consistent with methodologies generally accepted in the industry, and developed the allocation factors appropriately.

B. Staff further concludes that the application of the COSS model is acceptable.

C. Staff also concludes that the overall revenue allocation developed by Trico is reasonable but Staff modified the allocations slightly to account for changes in billing determinants for the residential customers.

D. Staff's review of the rate design proposals submitted by Trico concludes:

1. The Residential Service Rate Schedule, Residential Time-of-Use Rate Schedule, and General Service 1 Rate Schedule rate design proposal from the Trico amendment docketed May 4, 2016, is a step in the direction of more closely recovering costs. Implementing the rate design proposal from May 4, 2016 as *mandatory* for Residential, Residential Time of Use and General Service 1 is *not* just, fair and reasonable.

2. The General Service 2 Rate Schedule, General Service 3 Rate Schedule, General Service Time-of-Use Rate Schedule, General Service 4 Rate Schedule, Water Pumping Rate Schedule, Irrigation Service Rate Schedule, Time of Day Pumping Rate Schedule, Security (Outdoor) Lighting Rate Schedule, and Street Lighting Rate Schedule rate design proposals are just, fair and reasonable.

3. The Interruptible Commercial and Industrial Rate Schedule should be combined with the Interruptible Pumping Rate Schedule into the creation of the Interruptible Service Rate Schedule.

4. The rate design proposal to combine the two existing interruptible schedules into the new Interruptible Service Rate Schedule is just, fair and reasonable.

5. The new Interruptible Service Rate Schedule should be frozen, not allowing any new customers to sign up for this rate schedule.

E. Staff concludes that the proposed change to the Schedule of Special Charges (Schedule SC) incorporating language to charge customers for return visits to inspect the installation of DG interconnections is just, fair and reasonable.

F. Staff concludes that the proposal to offer a new tariff designated as the SunWatts Sun Farm Monthly Participation Tariff (Schedule RESFM) is providing the opportunity for a segment of customers to take part in solar benefits who may have not been able to previously.

RECOMMENDATIONS

A. Based on the aforementioned conclusions, Staff recommends that the Commission accept Trico's COSS.

B. Staff also recommends the Commission accept the revenue allocation specified by Staff on page 6 of this testimony.

C. Staff recommends that the rates proposed by Trico for the General Service 2 Rate Schedule, General Service 3 Rate Schedule, General Service Time-of-Use Rate Schedule, General Service 4 Rate Schedule, Water Pumping Rate Schedule, Irrigation Service Rate Schedule, Time of Day Pumping Rate Schedule, Security (Outdoor) Lighting Rate Schedule, and Street Lighting Rate Schedule be approved.

D. Staff recommends that Trico offer both a two-part rate alternative and a three-part rate alternative for the Residential Rate Schedule, Residential Time-of-Use Rate Schedule, and the General Service 1 Rate Schedule.

E. Staff recommends that Trico implement an in-depth customer education program to familiarize residential and general service customers with demand charges and kW measurements.

F. Staff recommends approval of the Staff-proposed rates found in Exhibit RSP-2 and detailed in this testimony for the Residential Rate Schedule, Residential Time-of-Use Rate Schedule, and the General Service 1 Rate Schedule.

G. Staff recommends the combination of the Interruptible Commercial and Industrial Rate Schedule with the Interruptible Irrigation and Water Pumping Rate Schedule into one new Interruptible Service Rate Schedule.

H. Staff recommends that the new Interruptible Service Rate Schedule be frozen so no new customers can be added to the rate schedule.

I. Staff recommends that the rates proposed by Trico for the new Interruptible Service Rate Schedule be approved.

J. Staff recommends Trico notify in writing customers currently on the Interruptible Commercial and Industrial Rate Schedule of the change to the new Interruptible Service Rate Schedule. These customers should be informed of the timing and the implications of the transition.

K. Staff recommends Trico notify in writing customers currently on the Interruptible Irrigation and Water Pumping Rate Schedule of the change to the new Interruptible Service Rate Schedule. These customers should be informed of the timing and the implications of the transition.

L. Staff recommends that Trico's proposal to revise the language in the Schedule SC to allow for charges associated with return trips to inspect installations of DG interconnections if the return trip is due to a customer or DG installer issue be approved.

M. Staff recommends that Trico modify its Interconnection Agreements for leased and owned systems to incorporate language that customers may be charged a return trip fee for a return trip to inspect installations of DG interconnections.

N. Staff recommends that the proposed SunWatts Sun Farm Monthly Participation Tariff be approved.

O. Staff recommends that reporting of the revenue and expenses associated with the new SunWatts Sun Farm Monthly Participation Tariff along with the reporting of the Renewable Energy Credits ("RECs") be incorporated into the reporting process currently in place for the Renewable Energy Standards and Tariff annual plan filings for Trico.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Ranelle Paladino. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning the adjustments to billing determinants, the base cost of power and operating revenue adjustments.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01461A-15-0363?

A. Yes.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to discuss Staff's review of Trico Electric Cooperative, Inc.'s ("Trico" or "Company") Cost of Service Study ("COSS") for the rate case, and present the results of this review.

In addition, my testimony also incorporates Staff's recommendations regarding the revenue allocation and the proposed changes to Trico's rate design. My testimony also includes Staff's recommendations regarding the discontinuance of a rate schedule, the implementation of a service call fee for return visits to interconnect photovoltaic ("PV") systems and the addition of a new community solar program.

Q. Are you addressing net metering in your testimony?

A. No. I am not addressing net metering in my testimony. Net metering will be addressed in the testimony of Eric Van Epps.

COST OF SERVICE STUDY

Q. Has Trico provided a COSS?

A. Yes. Trico provided a COSS in its rate application based on the Test Year (twelve-month period ended December 31, 2014).[1] The COSS provides the individual class returns for the Company's thirteen rate schedules plus wheeling activity for two other customers.

Q. What is the purpose of preparing a COSS?

A. The purpose of preparing a COSS includes: (1) relating costs to different groups of customers based on which customers caused those costs to occur; (2) determining how to recover costs from customers within each class, (3) calculating costs of services based on how much the utility has to spend on each cost, and (4) separating costs between regulatory jurisdictions if necessary. A complete allocated COSS ultimately tries to determine the specific cost to serve each customer class and subclass.

Q. How will a COSS be used?

A. A fully allocated COSS would be used as a guideline to allocate revenue among classes. The COSS may also be used as a determinant in rate design if the purpose is to design rates based on the costs to serve each customer class.

[1] Trico Rate Application Filing Schedule G.

Q. Is there a standard COSS methodology?

A. No. There is no one right methodology for designing a COSS so the COSS should be used as a guideline for revenue allocation and designing rates.

Q. Have you reviewed the COSS model presented by Trico?

A. Yes. The COSS was provided in Trico's rate application on Schedules G-1 through G-7.1. I reviewed the allocations and developed and reviewed the answers to the Data Requests by Staff. In addition, I reviewed the test year rate base, revenues, and expenses, including the test year adjustments, in the COSS and matched them with the appropriate schedules in the application.

Q. What model was used by Trico in developing its COSS?

A. Trico utilized the services of Guernsey Engineers, Architects and Consultants ("Consultants"), out of Oklahoma City, Oklahoma. The Consultants prepared the COSS using their in-house model, named CoOPTIONS. This model was used by Trico in its last full rate case under Arizona Administrative Code ("A.A.C.") R14-2-103, Decision No. 71230 dated August 6, 2009.

Q. Did Trico adjust or normalize its usage or revenues?

A. Trico utilized a test year ending December 31, 2014. As detailed in my direct testimony on pages 2-3, Trico made three adjustments to test year billing determinants: (1) adjust the number of billed consumers to reflect the revenue collected from the customer charge divided by the customer charge, (2) adjust the billed consumers and kWh sold to show a reclassification of accounts moving from the General Service Schedule GS 3 ("GS 3") to General Service Schedule GS 4 ("GS 4") and (3) adjust residential kWh sales downward to reflect estimates of a decline in kWh attributed to the growth in net metered customers that

occurred in late 2014 and continued into 2015.[2] The adjustments to the billing determinants resulted in a reduction to test year base revenue of $1,296,163.[3]

In addition, the revenues were adjusted by the Consultants to account for the fuel bank charges during the test year, restate the Wholesale Power Cost Adjustor ("WPCA") revenue to allow for the full amount of WPCA revenue, and adjust Other Revenue for the addition of 6,657 new net metering customers paying the $3.38 net metering tariff charge. The total revenue adjustments other than base revenue resulted in an increase to adjusted test year revenue of $1,621,212. The total test year revenue adjustment was an increase in test year revenues of $325,049.[4]

Q. Did Trico make adjustments to the COSS allocation factors from the prior rate case?

A. Trico utilized similar demand, energy, and customer-based allocation factors between this COSS and the prior rate case with the exception of the allocation of Account 368 Transformers. This COSS separated Account 368 into customer-related and capacity-related costs. Staff considers this adjustment to be appropriate.

Q. What did Staff determine from its review of the COSS?

A. Staff's review of Trico's COSS determined that acceptable methods were utilized to functionalize, classify, and allocate costs. Staff has determined the COSS model appropriately calculated the components of the rate application. Staff did not fully agree with the adjustments made to test year residential billing determinants as detailed on pages 3-4 of my direct testimony filed on May 4, 2016. Staff did not agree with the lowering of residential billing determinants attributed to net metered customers. Staff is still evaluating the actual

[2] Payne Direct page 3 lines 16-26 and page 4 lines 1-3.
[3] Payne Direct page 4 line 6.
[4] Trico Rate Application Schedule A-1.0.

production data for those net metered customers supplied by Trico on April 27, 2016. If the production data support a test year adjustment to residential billing determinants, Staff may make the appropriate changes in its surrebuttal testimony to be filed on July 8, 2016. Staff did not recalculate the COSS contained in the G Schedules of Trico's rate application as this study was used as a guideline in the rate design process, and Staff didn't feel the roughly 1 percent adjustment to test year billing determinants for the residential class would materially affect the results of the COSS.

Q. Did the methods used by Trico comply with industry standards?

A. Trico utilized methodologies that are generally accepted in the utility industry for its COSS. Allocation of plant and operating expenses were assigned to the respective customer classes on the basis of demand, energy and other customer-related factors.

Q. Does Staff have a recommendation concerning Trico's COSS?

A. Staff recommends the Commission accept Trico's COSS in this case.

REVENUE ALLOCATION

Q. Please describe the revenue increase allocation?

A. Trico's rate application included a request for a revenue increase of $2,182,076 on adjusted test year revenues of $87,480,736 for a proposed revenue requirement of $89,662,812. Staff witness Mary J. Rimback in her direct testimony recommended a revenue increase of $1,972,842 on adjusted test year revenues of $87,824,867 for a Staff-proposed revenue requirement of $89,797,709. Table 1 details the adjusted test year revenue and Staff-proposed revenue increase by rate schedule.

Table 1: Staff's Proposed Revenue Allocation

Trico Rate Schedule	Test Year Adj. Rev. $*	Staff Proposed Rev. $**	% Increase
Residential	$53,263,752	$55,126,101	3.50%
Residential Time of Use	$4,428,768	$4,796,920	8.31%
GS 1	$1,764,280	$1,844,061	4.52%
GS 2	$1,814,862	$1,911,985	5.35%
GS 3	$14,967,633	$14,427,413	-3.61%
GS Time of Use	$170,535	$171,992	0.85%
GS 4	$7,239,836	$7,239,836	0.00%
Water Pumping	$462,950	$498,535	7.69%
Irrigation	$38,217	$41,231	7.89%
Time of Day Pumping	$618,859	$645,720	4.34%
Interruptible	$1,142,715	$1,176,258	2.94%
Lighting	$142,046	$147,243	3.66%
Wheeling	$149,317	$149,317	0.00%
Other Revenue	$1,621,097	$1,621,097	0.00%
Total Revenue	$87,824,867	$89,797,709	2.25%

*Total Adjusted TY Revenue detailed on RSP-1.
**Staff-Proposed Total Revenue from RSP-2.

Looking at the relative rates of return calculated in the COSS for each rate schedule illustrates which relative rates of return are negative, close to 1.0, or above 1.0. Rate increases designed to more closely recover costs to serve a rate schedule should move the relative rates of return closer to 1.0. Trico's COSS on Schedule G-1.0 illustrates that, to varying degrees, the GS 3, GS Time of Use, GS 4, and Interruptible Rate Schedules are paying more than their cost of service leading to the lower percentage increases in rates noted above. The Residential, Residential Time of Use, and GS 1 rate schedules are slightly under 1.0 leading to the moderate increase noted above. The Water Pumping, Irrigation, Time of Day Pumping, and Lighting rate schedules are paying less than their cost of service. As indicated on Schedule G-1.0, the overall system return is reported to be approximately 5.086 percent.

As can be seen on Schedule G-2.0, after incorporating the proposed revenue increase, the overall system return has increased to 6.33 percent. The proposed revenue increases also led

to an improvement of the relative rates of return of all rate schedules with a relative rate of return below 1.0 or negative.

RATE DESIGN

Q. Please describe Staff's position on Rate Design?

A. Rates are designed to collect a specific revenue requirement. The breakdown of that revenue requirement by rate schedule has been split in recovery between a fixed and a variable component for the residential, GS 1, irrigation, and water pumping rate schedules. All other rate schedules except for the lighting segment have an additional billing demand component. The lighting segment has a per-unit rate. Historical rate design, especially for the residential customer class, has allowed recovery of Trico's fixed costs partly through a customer charge and partly through a variable rate or energy charge.

Variations in usage among customers in the same class have increased for a number of reasons (including seasonal customers, vacant homes, and distributed generation ("DG")). Existing rate design does not always account for these variations in usage. Staff believes that rates should now be more closely based on the actual costs to serve each customer class. However, Staff recognizes that rate design may need to evolve gradually. One option allows for each customer to pay for the level of service they may require at any point in time through a customer charge, demand charge, and energy charge—in essence, a three-part rate. However, Staff recognizes that a change in rate design from a two-part rate to a three-part rate requires extensive education for customers to understand a demand charge and their ability to control the level of demand within their own household.

Q. Please summarize the Company's rate design proposal.

A. Trico has indicated in its rate application that the proposed rates are designed to gradually move toward better matching revenue recovery to actual cost of service.[5]

Q. What was the Company's primary concern in developing its rate design proposals?

A. Trico's application indicates the Company has requested a 2.49 percent overall increase in adjusted test year total revenue. Trico explains that this increase is necessary to address concerns over the significant changes the Company has seen in how its members use energy. Specifically, Trico's application is proposed to address increased energy conservation efforts, overall milder weather and expanded DG deployment within its service territory.[6]

Q. How did Trico propose implementing its rate design changes?

A. Trico's application proposed increases to the monthly customer charge for all rate schedules. The Company is hoping to improve revenue stability and lessen the amount of fixed costs collected in the energy charge. Specifically for the residential rate schedule, Trico proposed two-tier inclining block energy charges to incent energy conservation and lessen the impact of the increase in the customer charge on low-use customers.

On May 4, 2016, Trico filed an amendment to its application ("May 4th Amendment"). The amendment proposed a modification to the rate design that would apply to all residential and small commercial (GS 1) customers. The modified rate design incorporated a fixed monthly demand charge of $4.00 per customer based on a minimum billed demand of 2 kW at $2.00 per kW. The demand charge for any kW demand over 2 kW will be billed at $0.00 per kW. Trico indicated this would allow customers the ability to see what their demand is on a monthly basis and how changes in behavior affect the monthly kW prior to any charge being

[5] Trico Application page 4 lines 26-27.
[6] Trico Application page 2 lines 23-27.

implemented. The energy charge proposed in the modifications is slightly lower than in the original rate application.

Q. Is Trico's cost per customer analysis in Schedule G-6.0 useful in evaluating its proposed customer charges and demand charges?

A. Yes. If the goal of a restructuring of rate design is to more accurately recover fixed costs through a fixed charge, Schedule G-6.0 from the COSS is useful. Schedule G-6.0 details the monthly cost per consumer broken down into purchased power demand, purchased power energy, distribution (wires), and total customer costs (which includes such items as billing and metering).

For example, Schedule G-6.0 indicates that it costs $31.83 per month per residential customer in fixed monthly customer costs. Other fixed costs incurred for residential customers include distribution system (wires, poles, etc.) and the fixed portion of purchased power charges paid to primarily Arizona Electric Power Cooperative ("AEPCO"), Trico's generation and transmission provider, on a monthly basis. In a perfect recovery scenario, Trico would assess fixed charges which fully recover its fixed costs as shown in Table 2 below. In a practical application of rates to recover costs, Staff has considered the impact on the consumer of increased fixed charges and how to gradually recover those fixed costs.

Table 2: Trico's Total Residential Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$41.41
Distribution (Wires) Costs	$27.40
Customer Costs	$31.83
TOTAL RESIDENTIAL FIXED COSTS	$100.64

Residential

Q. Please describe the Residential Service Rate Schedule?

A. Residential Service in Trico's territory is available for residential use to private dwellings and individually metered apartments, condominiums, and similar residential units where all service is supplied at one point of delivery and where energy is metered through one meter.

Q. What changes did Trico propose for the Residential Service Rate Schedule?

A. For the Residential Service Rate Schedule, Trico's original application proposed increasing the customer charge from $15.00 to $20.00 per month. The energy charge originally was proposed to go from a flat kWh charge to an inclining block rate with two blocks. The existing energy charge is $0.1216 per kWh. The originally proposed rate for the first 800 kWh per month is $0.1176 per kWh. The originally proposed rate for usage over 800 kWh per month is $0.1276 per kWh.

The May 4th Amendment modified the rates for the Residential Service Rate Schedule. The modified rates still incorporate raising the customer charge from $15.00 to $20.00 per month. A minimum demand charge has been added assessing $2.00 per kW for the first 2 kW per month. Any kW demand over the 2 kW level will be shown on the customer's bill but will be charged a rate of $0.00 per kW to allow the customer time to familiarize themselves with kW billing. The energy charge is based on the inclining block rate of $0.1128 per kWh for the first 800 kWh per month and $0.1228 per kWh for usage over 800 kWh.

Q. Did Trico propose any other changes for the Residential Class?

A. No.

Q. Please describe the Residential Time-Of-Use ("TOU") Service Rate Schedule?

A. Residential TOU Service in Trico's territory is available for residential use in individual private dwellings and in individually metered apartments, condominiums, and similar residential units where all service is supplied at one point of delivery and energy is metered through one meter. TOU customers' rates vary for usage during on-peak time versus usage during off-peak time. For Residential TOU customers, on peak time is between 1:00 pm and 9:00 pm Monday through Friday during the months of April through October. The on-peak time during the months of November through March is 6:00 am to 10:00 am and 6:00 pm to 10:00 pm Monday through Friday.

Q. What changes did Trico propose for the Residential TOU Service Rate Schedule?

A. For the Residential TOU Service Rate Schedule, Trico's original application proposed increasing the customer charge from $19.00 to $24.00 per month. The existing on-peak energy charge was originally proposed to go from $0.1932 per kWh to $0.1979 per kWh. The existing off-peak energy charge was originally proposed to go from $0.0732 per kWh to $0.0779 per kWh.

The May 4th Amendment modified the rates for the Residential TOU Service Rate Schedule. The modified rates still incorporate raising the customer charge from $19.00 to $24.00 per month. A minimum demand charge has been added assessing $2.00 per kW for the first 2 kW per month. Any kW demand over the 2 kW level will be shown on the customer's bill but will be charged a rate of $0.00 per kW to allow the customer time to familiarize themselves with kW billing. The on-peak energy charge is proposed to increase from $0.1932 per kWh to $0.19412 per kWh. The off-peak energy charge is proposed to increase from $0.0732 per kWh to $0.07412 per kWh.

Q. What are the Residential Rate Schedule and Residential TOU Rate Schedule customer costs?

A. As discussed above in Table 2, Schedule G-6.0 illustrates for the Residential Rate Schedule the fixed purchased power costs of $41.41, fixed distribution (wires) costs of $27.40 and fixed customer costs per residential consumer of $31.83.

Table 3 below shows the fixed costs for the Residential TOU Rate Schedule.

Table 3: Trico's Total Residential TOU Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$52.16
Distribution (Wires) Costs	$31.92
Customer Costs	$37.92
TOTAL RESIDENTIAL TOU FIXED COSTS	$122.00

Q. Does Staff support the changes to the Residential Service Rate Schedule proposed by Trico?

A. Staff supports a change to the rates for the Residential Service Rate Schedule but has modified the rates.

- Staff supports implementation of both rate structures proposed by Trico (in its original application and its May 4th Amendment) as alternatives for the residential class of customers. Staff believes offering a three-part rate is another rate design option that is available to allow companies to recover fixed costs. Staff proposes offering residential customers the choice between a three-part rate which incorporates a demand charge and a two-part rate which incorporates an increase in the monthly customer charge and a higher energy charge. Possible alternatives to offer residential customers can be seen in Exhibit RSP-2. Staff assumed an average monthly demand

for the residential class of 5 kW. Staff realizes that this is merely a starting point for the creation of a demand rate and recommends the Company adjust the rates in its rebuttal testimony if it does not agree with Staff's assumptions.

- Staff supports the implementation of a three-part rate which includes no change to the customer charge, a minimum demand charge for the first 2 kW and a meaningful demand charge for any kW demand over 2 kW. At the same time, the energy charge would be reduced. Staff also supports offering a two-part rate to residential customers which incorporates a higher customer charge.

- Staff recommends that for purposes of measuring demand to be billed, Trico should utilize the non-coincident peak demand in an hour period of time. If Trico's meters measure demand on a fifteen minute interval, Trico could average the four reads for the hour to determine the peak demand in an hour period. As mentioned in Trico's May 4th Amendment, Staff agrees that is it is beneficial for Trico to add demand data to all customers' bills going forward.

- Staff recommends that Trico implement an in-depth customer education program with regard to three-part rates. Trico should spend considerable time explaining demand, how it would be measured, and what steps customers can take to affect demand. Trico should also demonstrate to customers that the implementation of a demand charge has a corresponding reduction in energy charge.

As indicated on Exhibit RSP-3, the estimated bill impact of the two rate options is: (1) under the two-part rate, an increase for the average usage residential customer using 837 kWh is $0.89 per month which represents a 0.76 percent increase, and (2) under the three-part rate,

an increase for the average usage residential customer using 837 kWh is $0.98 per month which represents a 0.84 percent increase.

As can be seen in Table 4 below, under the two-part rate option, Staff is proposing the residential customer charge go from $15.00 to $20.00. At the same time, Staff's proposed energy charge for Residential customers would be $0.11632 for the first 800 kWh and $0.12631 per kWh for all kWh over 800 kWh.

Table 4: Residential Service Two-Part Rates

	Existing	Staff-Proposed
Customer Charge	$15.00	$20.00
Energy Charge First 800 kWh (per kWh)	$0.12160	$0.11632
Energy Charge Over 800 kWh (per kWh)	$0.12160	$0.12631
Monthly Bill Impact for an Average Residential Customer		**$0.89**

As can be seen in Table 5 below, under the three-part rate option, Staff is proposing the residential customer charge stay at $15.00. For the first 2 kW, the minimum charge would be $2.00 per kW. For any kW over 2 kW, the proposed rate is $2.50 per kW. At the same time, Staff's proposed energy charge for Residential customers would be $0.10866 for the first 800 kWh and $0.11866 per kWh for all kWh over 800 kWh.

Table 5: Residential Service Three-Part Rates

	Existing	Staff-Proposed
Customer Charge	$15.00	$15.00
Demand Charge First 2 kW (per kW) (minimum of 2 kW)	$0.00	$2.00
Demand Charge Over 2 kW (per kW)	$0.00	$2.50
Energy Charge First 800 kWh (per kWh)	$0.12160	$0.10866
Energy Charge Over 800 kWh (per kWh)	$0.12160	$0.11866
Monthly Bill Impact for an Average Residential Customer		**$0.98**

Q. Does Staff support the changes to the Residential TOU Service Rate Schedule proposed by Trico?

A. Staff supports a change to the rates for the Residential TOU Service Rate Schedule but has modified the rates.

- Staff supports implementation of both rate structures proposed by Trico (in its original application and its May 4th Amendment) as alternatives for the residential TOU class of customers. Staff believes offering a three-part rate is another rate design option that is available to allow companies to recover fixed costs. Staff proposes offering residential TOU customers the choice between a three-part rate which incorporates a demand charge and a two-part rate which incorporates an increase in the monthly customer charge and a higher energy charge. Possible alternatives to offer residential TOU customers can be seen in Exhibit RSP-2. Staff assumed an average monthly demand for the residential TOU class of 5 kW. Staff realizes that this is merely a starting point for the creation of a demand rate and recommends the Company adjust the rates in its rebuttal testimony if it does not agree with Staff's assumptions.

- Staff supports the implementation of a three-part rate which includes no change to the customer charge, a minimum demand charge for the first 2 kW and a meaningful demand charge for any kW demand over 2 kW. At the same time, the energy charge would be reduced. Staff also supports offering a two-part rate to residential TOU customers which incorporates a higher customer charge.

- Staff recommends that for purposes of measuring demand to be billed, that Trico utilize the non-coincident peak demand in an hour period of time. If Trico's meters

measure demand on a fifteen minute interval, Trico could average the four reads for the hour to determine the peak demand in an hour period. As mentioned in Trico's May 4th Amendment, Staff agrees that is it is beneficial for Trico to add demand data to customers' bills going forward.

- Staff recommends Trico implement an in-depth customer education program with regard to three-part rates. Trico should spend considerable time explaining demand, how it is measured, and what steps customers can take to affect demand. Trico should also demonstrate to customers that the implementation of a demand charge has a corresponding reduction in energy charge.

As indicated on Exhibit RSP-3 (and in Trico's application on Schedule H-4.1), the estimated bill impact of the two rate options is: (1) under the two-part rate, an increase for the average usage residential TOU customer using 1,058 kWh is $9.90 per month which represents a 7.43 percent increase, and (2) under the three-part rate, an increase for the average usage residential customer using 1,058 kWh is $9.87 per month which represents a 7.41 percent increase.

As can be seen in Table 6 below, under the two-part rate option, Staff is proposing the residential TOU customer charge go from $19.00 to $24.00. At the same time, Staff's proposed on-peak energy charge for residential TOU customers would be $0.19790. Staff's proposed off-peak energy charge would be $0.07790 per kWh. These rates mirror what Trico proposed in its application for the residential TOU rate schedule.

Table 6: Residential TOU Service Two-Part Rates

	Existing	Staff-Proposed
Customer Charge	$19.00	$24.00
On-Peak Energy Charge (per kWh)	$0.19320	$0.19790
Off-Peak Energy Charge (per kWh)	$0.07320	$0.07790
Monthly Bill Impact for an Average Residential TOU Customer		**$9.90**

As can be seen in Table 7 below, under the three-part rate option, Staff is proposing the residential TOU customer charge remain at $19.00. For the first 2 kW, the minimum charge would be $2.00 per kW. For any kW over 2 kW, the proposed rate would be $2.50 per kW. At the same time, Staff's proposed on-peak energy charge for residential TOU customers would be $0.19180 per kWh. Staff's proposed off-peak energy charge would be $0.07170 per kWh.

Table 7: Residential TOU Service Three-Part Rates

	Existing	Staff-Proposed
Customer Charge	$19.00	$19.00
Demand Charge First 2 kW (minimum of 2 kW)	$0.00	$2.00
Demand Charge Over 2 kW	$0.00	$2.50
On-Peak Energy Charge (per kWh)	$0.19320	$0.19180
Off-Peak Energy Charge (per kWh)	$0.07320	$0.07170
Monthly Bill Impact for an Average Residential TOU Customer		**$9.87**

General Service

Q. Please describe the GS 1 Rate Schedule?

A. GS 1 service in Trico's territory is available for single and three phase service for more than one residence from a single metering point. GS 1 service is typically used for business, professional and any considerable amount of electricity used for other than domestic purposes. GS 1 customers have a monthly demand of less than 10 kW and all service is supplied at one point of delivery.

Q. What changes did Trico propose for the GS 1 Rate Schedule?

A. For the GS 1 Rate Schedule – Single Phase customers, Trico's original application proposed increasing the customer charge from $18.00 to $23.00 per month. The existing energy charge was originally proposed to go from $0.1335 per kWh to $0.1337 per kWh.

For the GS 1 Rate Schedule – Three Phase customers, Trico's original application proposed increasing the customer charge from $26.00 to $31.00 per month. The existing energy charge was originally proposed to go from $0.1335 per kWh to $0.1337 per kWh.

The May 4th Amendment modified the rates for the GS 1 Service Rate Schedule. The modified rates still incorporate raising the customer charge from $18.00 to $23.00 per month for single phase customers and from $26.00 to $31.00 per month for three phase customers. A minimum demand charge has been added assessing $2.00 per kW for the first 2 kW per month. Any kW demand over the 2 kW level would be shown on the customer's bill but would be charged a rate of $0.00 per kW to allow the customer time to familiarize themselves with kW billing. The energy charge is proposed to decrease from $0.1335 per kWh to $0.12669 per kWh.

Q. What are the GS 1 Rate Schedule customer costs?

A. Table 8 details the total GS 1 fixed costs as can be found on Schedule G-6.0.

Table 8: Trico's Total GS 1 Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$26.67
Distribution (Wires) Costs	$24.69
Customer Costs	$38.54
TOTAL GS 1 FIXED COSTS	$89.90

Q. Does Staff support the changes to the GS 1 Rate Schedule proposed by Trico?

A. Staff supports changes to the rates for the GS 1 rate schedule, but has modified the rates.

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- Staff supports implementation of both rate structures proposed by Trico (in its original application and its May 4th Amendment) as alternatives for the GS 1 class of customers. Staff believes offering a three-part rate is another rate design option that is available to allow companies to recover fixed costs. Staff proposes offering GS 1 customers the choice between a three-part rate which incorporates a demand charge and a two-part rate which incorporates an increase in the monthly customer charge and a higher energy charge. Possible alternatives to offer GS 1 customers can be seen in Exhibit RSP-2. Staff assumed an average monthly demand for the GS 1 rate schedule of 5 kW. Staff realizes that this is merely a starting point for the creation of a demand rate and recommends the Company adjust the rates in its rebuttal testimony if it does not agree with Staff's assumptions.

- Staff supports the implementation of a three-part rate which includes no change to the customer charge, a minimum demand charge for the first 2 kW and a meaningful demand charge for any kW demand over 2 kW. At the same time, the energy charge would be reduced. Staff also supports offering a two-part rate to GS 1 customers which incorporates a higher customer charge.

As indicated on Exhibit RSP-3 (and in Trico's application on Schedule H-4.2), the estimated bill impact of the two rate options is: (1) under the two-part rate, an increase for the average usage GS 1 Single Phase customer using 570 kWh is $5.07 per month which represents a 5.39 percent increase and the increase for the average usage GS 1 Three Phase customer using 871 kWh is $5.11 per month which represents a 3.59 percent increase, and (2) under the three-

part rate, an increase for the average usage GS 1 Single Phase customer using 570 kWh is $5.07 per month which represents a 5.39 percent increase while the increase for the average usage GS 1 Three Phase customer using 871 kWh is $5.08 per month which represents a 3.57 percent increase.

As can be seen in Table 9 below, under the two-part rate option, Staff is proposing the GS 1 Single Phase customer charge go from $18.00 to $23.00 and the GS 1 Three Phase customer charge go from $26.00 to $31.00. At the same time, Staff's proposed energy charge for GS 1 Single Phase and Three Phase customers would go from $0.13350 to $0.13370. These rates mirror what Trico proposed in its application for the GS 1 rate schedule.

Table 9: GS 1 Service Two-Part Rates

	Existing	Staff-Proposed
Customer Charge Single Phase	$18.00	$23.00
Customer Charge Three Phase	$26.00	$31.00
Energy Charge (per kWh)	$0.13350	$0.13370

As can be seen in Table 10 below, under the three-part rate option, Staff is proposing the GS 1 Single Phase customer charge remain at $18.00 and the GS 1 Three Phase customer charge would remain at $26.00. For the first 2 kW, the minimum charge will be $2.00 per kW. For any kW over 2 kW, the proposed rate is $2.50 per kW. At the same time, Staff's proposed energy charge for GS 1 customers would go from $0.13350 per kWh to $0.12230 per kWh for Single Phase customers and from $0.13350 per kWh to $0.12620 per kWh for Three Phase customers.

Table 10: GS 1 Service Three-Part Rates

	Existing	Staff-Proposed
Customer Charge Single Phase	$18.00	$18.00
Customer Charge Three Phase	$26.00	$26.00
Demand Charge First 2 kW (per kW) (minimum of 2 kW)	$0.00	$2.00
Demand Charge Over 2 kW (per kW)	$0.00	$2.50
Energy Charge (per kWh) Single Phase	$0.13350	$0.12230
Energy Charge (per kWh) Three Phase	$0.13350	$0.12620

Q. Please describe the GS 2 Rate Schedule?

A. GS 2 service in Trico's territory is available to single phase and three phase service regularly used for business, professional, and any considerable amount of electricity used for other than domestic purposes. GS 2 monthly billing demand is greater than 10 kW but less than 200 kW and has an average monthly load factor of 30 percent or less based on twelve months of actual consumption. All service is delivered at a single location.

Q. What changes did Trico propose to the GS 2 Rate Schedule?

A. Trico is proposing to increase the customer charge for the GS 2 rate schedule from $18.00 to $23.00 for Single Phase customers and from $26.00 to $31.00 for Three Phase customers.

Q. What are the GS 2 Rate Schedule Customer Costs?

A. Table 11 details the total GS 2 fixed costs as can be found on Schedule G-6.0.

Table 11: Trico's Total GS 2 Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$307.72
Distribution (Wires) Costs	$172.03
Customer Costs	$85.07
TOTAL GS 2 FIXED COSTS	$564.82

Q. Does Staff support the changes to the GS 2 Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the GS 2 Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Q. Please describe the GS 3 Rate Schedule?

A. GS 3 service in Trico's territory is available to single phase and three phase service regularly used for business, professional, and any considerable amount of electricity used for other than domestic purposes. GS 3 monthly billing demand is between 10 kW and 11,999 kW and all service is delivered at a single location.

Q. What changes did Trico propose to the GS 3 Rate Schedule?

A. Trico is proposing to increase the customer charge for the GS 3 rate schedule from $18.00 to $23.00 for Single Phase customers and from $26.00 to $31.00 for Three Phase customers. Trico is also proposing to increase the demand charge from $16.65 per billing kW to $18.00 per billing kW.

Q. What are the GS 3 Rate Schedule Customer Costs?

A. Table 12 details the total GS 3 fixed costs as can be found on Schedule G-6.0.

Table 12: Trico's Total GS 3 Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$1,159.46
Distribution (Wires) Costs	$542.65
Customer Costs	$162.91
TOTAL GS 3 FIXED COSTS	$1,865.02

Q. Does Staff support the changes to the GS 3 Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the GS 3 Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Q. Please describe the GS TOU Rate Schedule?

A. GS TOU service in Trico's territory is available for single and three phase service for any customer who would otherwise be eligible for service under GS 1, GS 2, or GS 3 rate schedules. All service is supplied at one point of delivery. GS TOU customers' rates vary for coincident peak kW and non-coincident peak kW.

Q. What changes did Trico propose to the GS TOU Rate Schedule?

A. Trico is proposing to increase the customer charge for the GS TOU rate schedule from $24.00 to $29.00 for Single Phase customers and from $32.00 to $37.00 for Three Phase customers.

Q. What are the GS TOU Rate Schedule Customer Costs?

A. Table 13 details the total GS TOU fixed costs as can be found on Schedule G-6.0.

Table 13: Trico's Total GS TOU Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$552.38
Distribution (Wires) Costs	$252.71
Customer Costs	$50.75
TOTAL GS TOU FIXED COSTS	$855.84

Q. Does Staff support the changes to the GS TOU Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the GS TOU Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Q. Please describe the GS 4 Rate Schedule?

A. GS 4 service in Trico's territory is available for single and three phase service for all electric service used for commercial, business, professional, and industrial peak loads in excess of 2,000 kW but not to exceed 9,999 kW supplied at one point of delivery and measured

through one meter. GS 4 customers may take delivery at multiple delivery points with one primary metering point at the Company's discretion.

Q. Did Trico propose any changes to the GS 4 Rate Schedule?

A. No.

Q. What are the GS 4 Rate Schedule Customer Costs?

A. Table 14 details the total GS 4 fixed costs as can be found on Schedule G-6.0.

Table 14: Trico's Total GS 4 Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$41,198.55
Distribution (Wires) Costs	$22,851.87
Customer Costs	$1,762.91
TOTAL GS 4 FIXED COSTS	$65,813.33

Water Pumping

Q. Please describe the Water Pumping Service Rate Schedule?

A. Water Pumping service in Trico's territory is available to all electric pump installations that are furnishing water to Customers on a commercial basis prior to the effective date of the tariff. All water pumping customers connected after the effective date would be placed on the applicable General Service tariff. All service is supplied at one point of delivery.

Q. What changes did Trico propose to the Water Pumping Service Rate Schedule?

A. Trico is proposing to increase the customer charge for the Water Pumping Service rate schedule from $18.00 to $23.00 for Single Phase customers and from $26.00 to $31.00 for Three Phase customers.

Q. What are the Water Pumping Service Rate Schedule Customer Costs?

A. Table 15 details the total Water Pumping Service fixed costs as can be found on Schedule G-6.0.

Table 15: Trico's Total Water Pumping Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$342.29
Distribution (Wires) Costs	$190.83
Customer Costs	$96.82
TOTAL WATER PUMPING FIXED COSTS	$629.94

Q. Does Staff support the changes to the Water Pumping Service Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the Water Pumping Service Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Irrigation

Q. Please describe the Irrigation Service Rate Schedule?

A. Irrigation service in Trico's territory is available for single and three phase irrigation pumping installations of 10 horsepower ("HP") or larger. This rate schedule is only applicable to farm use. All service is supplied at one point of delivery.

Q. What changes did Trico propose to the Irrigation Service Rate Schedule?

A. Trico is proposing to increase the customer charge for the Irrigation service rate schedule from $18.00 to $23.00 for Single Phase customers and from $26.00 to $31.00 for Three Phase customers. Trico is also proposing to increase the energy charge from $0.124573 to $0.142000 per kWh.

Q. What are the Irrigation Service Rate Schedule Customer Costs?

A. Table 16 details the total Irrigation fixed costs as can be found on Schedule G-6.0.

Table 16: Trico's Total Irrigation Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$323.50
Distribution (Wires) Costs	$187.95
Customer Costs	$131.24
TOTAL IRRIGATION FIXED COSTS	$642.69

Q. Does Staff support the changes to the Irrigation Service Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the Irrigation Service Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Time of Day Pumping

Q. Please describe the Time of Day Pumping Rate Schedule?

A. Time of Day Pumping service in Trico's territory is available to all water pumping installations of 10 HP or larger. All service is supplied at one point of delivery. Time of Day Pumping customers are subject to on-peak and off-peak energy and demand charges.

Q. What changes did Trico propose to the Time of Day Pumping Rate Schedule?

A. Trico is proposing to increase the customer charge for the Time of Day Pumping rate schedule from $18.00 to $23.00 for Single Phase customers and from $26.00 to $31.00 for Three Phase customers. Trico is also proposing to decrease the on-peak demand charge from $18.16 per billing kW to $16.00 per billing kW. The Company is adding a non-coincident peak demand charge of $1.75 per billing kW. The on-peak energy charge is decreasing from

$0.126900 to $0.061500 per kWh while the off-peak energy charge is decreasing from $0.061900 to $0.061500 per kWh.

Q. What are the Time of Day Pumping Rate Schedule Customer Costs?

A. Table 17 details the total Time of Day Pumping fixed costs as can be found on Schedule G-6.0.

Table 17: Trico's Total Time of Day Pumping Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$1,416.90
Distribution (Wires) Costs	$691.36
Customer Costs	$174.11
TOTAL TIME OF DAY PUMPING FIXED COSTS	$2,282.37

Q. Does Staff support the changes to the Time of Day Pumping Rate Schedule proposed by Trico?

A. Yes. Staff supports Trico's proposed changes to the rates for the Time of Day Pumping Rate Schedule as can be found in Schedule H-3.0 of Trico's application.

Interruptible

Q. Please describe the Interruptible Service Commercial and Industrial Rate Schedule?

A. Interruptible Service for Commercial and Industrial customers in Trico's territory is available for single and three phase service for any General Service customer with loads in excess of 10 kW and an average monthly load factor greater than 30 percent on an annualized basis. Interruptible service customers are subject to interruption from Trico at any time. Interruptible service customers should not override the interruption more than twice in a calendar year.

Q. Please describe the Interruptible Service Irrigation and Water Pumping Rate Schedule?

A. Interruptible Service for Irrigation and Water Pumping customers in Trico's territory is available for single and three phase service for any General Service Irrigation and Water Pumping customer with loads in excess of 10 kW and an average monthly load factor greater than 30 percent on an annualized basis. Interruptible service customers are subject to interruption from Trico at any time. Interruptible service customers should not override the interruption more than twice in a calendar year.

Q. What changes did Trico propose to the Interruptible rate schedules for Commercial, Industrial, Irrigation and Water Pumping customers?

A. Trico has proposed combining the Interruptible customers onto one tariff: the Interruptible Service Schedule IS1. Trico has also proposed freezing this new tariff so that new customers would not be able to go onto this tariff. Trico has indicated that the approved interruptible tariffs are ineffective and are labor intensive administratively. Trico has proposed migrating all twelve customers on these tariffs to other rate schedules prior to the next rate case.

Q. Did Trico propose any rate changes to the newly combined Interruptible Rate Schedule?

A. Trico is proposing to add a non-coincident peak demand charge of $1.75 per billing kW and decrease the coincident peak demand charge from $29.50 to $19.50 per billing kW. Trico is also proposing to increase the energy charge from $0.084200 per kWh to $0.087500 per kWh.

Q. What are the Interruptible Rate Schedule Customer Costs?

A. Table 18 details the total Interruptible fixed costs as can be found on Schedule G-6.0.

Table 18: Trico's Total Interruptible Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$2,172.41
Distribution (Wires) Costs	$1,017.43
Customer Costs	$206.92
TOTAL INTERRUPTIBLE FIXED COSTS	$3,396.76

Q. Does Staff agree with the changes Trico has proposed for the Interruptible rate schedules for commercial, industrial, irrigation and water pumping customers?

A. Yes. After further discovery into the activity within these two interruptible schedules, Staff agrees that the rate schedules are ineffective and are not serving the purpose for which they were designed. Staff recommends that Trico notify all twelve customers of the merging of the existing rate schedules into the new interruptible rate schedule.

Security and Street Lighting

Q. What are the Lighting class (both Security and Street) customer costs?

A. Table 19 below details the total lighting fixed costs from Schedule G-6.0 in Trico's application.

Table 19: Trico's Total Lighting Fixed Costs

Trico's Fixed Costs Categories	$
Purchased Power Costs	$85.80
Distribution (Wires) Costs	$44.53
Customer Costs	$975.87
TOTAL LIGHTING FIXED COSTS	$1,106.20

Q. Does Staff support the changes to the Security (Outdoor) Lighting Rate Schedule proposed by Trico?

A. Staff supports Trico's proposed changes to the rates for the Security (Outdoor) Lighting Service rate schedule as can be seen on Schedule H-3.0 of Trico's application.

Q. Does Staff support the changes to the Street Lighting Rate Schedule proposed by Trico?

A. Staff supports Trico's proposed changes to the rates for the Security Lighting Service rate schedule as can be seen on Schedule H-3.0 of Trico's application.

Other Tariffs

Q. Did Trico propose any changes to its Qualified Cogeneration and Small Power Production Facilities (Schedule COGEN-1) tariff?

A. No. Trico did not propose any changes to its COGEN-1 tariff.

Q. Did Trico propose any changes to its Cogeneration Qualifying Facilities (Schedule QF-1)?

A. No. Trico did not propose any changes to its QF-1 tariff.

Q. Did Trico propose any changes to its Schedule of Special Charges (Schedule SC)?

A. Yes. Trico proposed one change to the Schedule SC. Trico proposed to change the language detailing charges for return trips to inspect installations for DG interconnections. Trico does not currently charge for the first trip or return trips to inspect installations for DG interconnections. Trico is proposing to be able to charge the customer for return trips to inspect installations for DG interconnections. The $50.00 charge would be the same as what is detailed in Schedule SC currently for return trips for service calls. Staff does not believe the minimal amount of revenue which may be collected from these return trips are material enough to affect the revenue requirement.

Q. Does Staff agree with the change Trico is proposing to its Schedule of Special Charges (Schedule SC)?

A. Yes. Over the past six months, roughly 5 percent of the inspection trips were return trips. The reasons for return trips varied from inverter malfunctions and incorrect wiring to bent meter socket jaws. Staff believes the customer should be responsible for the return trip fee if the reason for the return trip is the responsibility of the customer or DG installer. Staff recommends that Trico add language to its Interconnection Applications for both leased and owned DG systems that details that a customer will be responsible for the return trip fee if a return trip is necessary during inspection of installation facilities for DG interconnection if the return trip is due to a customer or DG installer issue.

Q. Did Trico propose any new tariffs?

A. Yes. Trico proposed a new SunWatts Sun Farm Monthly Participation Tariff (Schedule RESFM).

Q. Describe the new SunWatts Sun Farm Monthly Participation Tariff.

A. Trico's SunWatts Sun Farm is located adjacent to the Trico headquarters building. The Company currently offers a program as part of its Renewable Energy Standard and Tariff program. The current program allows customers to purchase the output of PV panels from the SunWatts Sun Farm in ¼, ½, and full panel increments. The full cost is billed as a one-time up-front charge. The customer receives a credit for the energy output of the panel which is estimated to be 432 kWh per year per panel in accordance with the customer's rate schedule and the net metering tariff.

Trico has proposed the new SunWatts Sun Farm Monthly Participation Tariff to allow for customers to participate in the program who may not be able to purchase the output of the

panels as an up-front cost. The program is also beneficial to those customers who are renters and may not be able to install PV on their property. The new tariff offers customers the opportunity to purchase panel output via a monthly charge rather than an up-front cost.

Customers may purchase panel output up to but not to exceed the minimum monthly kWh energy usage in the last twelve month period. The solar energy can be purchased in blocks of 432 kWh per year or 36 kWh per month. Trico will apply the energy charge to the customer's monthly bill for a term of 20 years or until the customer cancels their participation. As can be seen in the proposed tariff sheet included in Trico's application as Exhibit KC-3 to Karen Cather's direct testimony, the energy rates applicable to the panel output varies by rate schedule and is subject to change as rates may change in future rate cases.

Staff reviewed the structure of the proposed program and the supporting workpapers detailing the pricing of the program. Staff believes the program is meeting a need that has not been addressed up to this point within Trico's service territory. The program makes use of existing panels and allows an audience to utilize solar that has not been able to previously. Staff believes the pricing of the program is reasonable. Staff recommends the approval of the SunWatts Sun Farm Monthly Participation Tariff as proposed by Trico in its application. Staff also recommends that reporting of the revenue and expenses associated with this program along with the reporting of the Renewable Energy Credits ("RECs") be incorporated into the annual reporting process currently in place for the REST plan filings.

CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding its COSS, revenue allocation, and rate design?

A. Staff's conclusions and recommendations are as follows:

Conclusions

Based on Staff's review of Trico's COSS, revenue allocation and rate design proposals, Staff concludes as follows:

A. Staff concludes that Trico has performed the COSS consistent with methodologies generally accepted in the industry, and developed the allocation factors appropriately.

B. Staff further concludes that the application of the COSS model is acceptable.

C. Staff also concludes that the overall revenue allocation developed by Trico is reasonable but Staff modified the allocations slightly to account for changes in billing determinants for the residential customers.

D. Staff's review of the rate design proposals submitted by Trico concludes:

1. The Residential Service Rate Schedule, Residential Time-of-Use Rate Schedule, and General Service 1 Rate Schedule rate design proposal from the Trico amendment docketed May 4, 2016, is a step in the direction of more closely recovering costs. Implementing the rate design proposal from May 4, 2016 as *mandatory* for Residential, Residential Time of Use and General Service 1 is *not* just, fair and reasonable.

2. The General Service 2 Rate Schedule, General Service 3 Rate Schedule, General Service Time-of-Use Rate Schedule, General Service 4 Rate Schedule, Water Pumping Rate Schedule, Irrigation Service Rate Schedule, Time of Day Pumping Rate Schedule, Security (Outdoor) Lighting Rate Schedule, and

Street Lighting Rate Schedule rate design proposals are just, fair and reasonable.

3. The Interruptible Commercial and Industrial Rate Schedule should be combined with the Interruptible Pumping Rate Schedule into the creation of the Interruptible Service Rate Schedule.

4. The rate design proposal to combine the two existing interruptible schedules into the new Interruptible Service Rate Schedule is just, fair and reasonable.

5. The new Interruptible Service Rate Schedule should be frozen not allowing any new customers to sign up for this rate schedule.

E. Staff concludes that the proposed change to the Schedule of Special Charges (Schedule SC) incorporating language to charge customers for return visits to inspect the installation of DG interconnections is just, fair and reasonable.

F. Staff concludes that the proposal to offer a new tariff designated as the SunWatts Sun Farm Monthly Participation Tariff (Schedule RESFM) is providing the opportunity for a segment of customers to take part in solar benefits who may have not been able to previously.

Recommendations

Based on aforementioned conclusions, Staff recommends:

A. Based on the aforementioned conclusions, Staff recommends that the Commission accept Trico's COSS.

B. Staff also recommends the Commission accept the revenue allocation specified by Staff on page 6 of this testimony.

C. Staff recommends that the rates proposed by Trico for the General Service 2 Rate Schedule, General Service 3 Rate Schedule, General Service Time-of-Use Rate Schedule, General Service 4 Rate Schedule, Water Pumping Rate Schedule, Irrigation Service Rate Schedule, Time of Day Pumping Rate Schedule, Security (Outdoor) Lighting Rate Schedule, and Street Lighting Rate Schedule be approved.

D. Staff recommends that Trico offer both a two-part rate alternative and a three-part rate alternative for the Residential Rate Schedule, Residential Time-of-Use Rate Schedule, and the General Service 1 Rate Schedule.

E. Staff recommends that Trico implement an in-depth customer education program to familiarize Residential and General Service customers with demand charges and kW measurements.

F. Staff recommends approval of the Staff-proposed rates found in Exhibit RSP-2 and detailed in this testimony for the Residential Rate Schedule, Residential Time-of-Use Rate Schedule, and the General Service 1 Rate Schedule.

G. Staff recommends the combination of the Interruptible Commercial and Industrial Rate Schedule with the Interruptible Irrigation and Water Pumping Rate Schedule into one new Interruptible Service Rate Schedule.

H. Staff recommends that the new Interruptible Service Rate Schedule be frozen so no new customers can be added to the rate schedule.

I. Staff recommends that the rates proposed by Trico for the new Interruptible Service Rate Schedule be approved.

J. Staff recommends Trico notify in writing customers currently on the Interruptible Commercial and Industrial Rate Schedule of the change to the new Interruptible Service Rate Schedule. These customers should be informed of the timing and the implications of the transition.

K. Staff recommends Trico notify in writing customers currently on the Interruptible Irrigation and Water Pumping Rate Schedule of the change to the new Interruptible Service Rate Schedule. These customers should be informed of the timing and the implications of the transition.

L. Staff recommends that Trico's proposal to revise the language in the Schedule SC to allow for charges associated with return trips to inspect installations of DG interconnections if the return trip is due to a customer or DG installer issue be approved.

M. Staff recommends that Trico modify its Interconnection Agreements for leased and owned systems to incorporate language that customers may be charged a return trip fee for a return trip to inspect installations of DG interconnections if the return trip is due to a customer or DG installer issue.

N. Staff recommends that the proposed SunWatts Sun Farm Monthly Participation Tariff be approved.

O. Staff recommends that reporting of the revenue and expenses associated with the new SunWatts Sun Farm Monthly Participation Tariff along with the reporting of the RECs be incorporated into the reporting process currently in place for the Renewable Energy Standards and Tariff annual plan filings for Trico.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
E-01461A-15-0363

	Billing Units	Existing Rate	Adjusted TY Revenue
1. RESIDENTIAL			
Consumers (12 month sum)	454,052	$ 15.00	$ 6,810,780
kWh	385,170,505	$ 0.12160	$ 46,836,733
Net Metering Credits			$ (27,938)
Subtotal			$ 53,619,575
PCA Revenue			$ (355,823)
Total			$ 53,263,752
2. RESIDENTIAL TOU			
Consumers (12 month sum)	33,520	$ 19.00	$ 636,880
On-Peak kWh	10,257,451	$ 0.19320	$ 1,981,740
Off-Peak kWh	25,192,421	$ 0.07320	$ 1,844,085
Subtotal	35,449,872		$ 4,462,705
PCA Revenue			$ (33,937)
Total			$ 4,428,768
3. GENERAL SERVICE (1)			
Single Phase			
Consumers (12 month sum)	16,397	$ 18.00	$ 295,146
kWh	9,355,588	$ 0.13350	$ 1,248,971
Subtotal			$ 1,544,117
PCA Revenue			$ 10,575
Total			$ 1,554,692
Three Phase			
Consumers (12 month sum)	1,465	$ 26.00	$ 38,090
kWh	1,276,535	$ 0.13350	$ 170,417
Minimum Bill			
Subtotal			$ 208,507
PCA Revenue			$ 1,081
Total			$ 209,588
Total Base			$ 1,752,624
Total PCA			$ 11,656
Total			$ 1,764,280

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
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	Billing Units		Existing Rate		Adjusted TY Revenue
4. GENERAL SERVICE (2)					
Single Phase					
Consumers (12 month sum)	1,174	$	18.00	$	21,132
First 10 kW/mo	10,522	$	-	$	-
Excess kW/mo	7,988	$	4.50	$	35,944
kWh	2,630,469	$	0.13800	$	363,005
Subtotal				$	420,081
PCA Revenue				$	2,987
Total				$	423,068
Three Phase					
Consumers (12 month sum)	1,836	$	26.00	$	47,736
First 10 kW/mo	16,933	$	-	$	-
Excess kW/mo	47,271	$	4.50	$	212,719
kWh	8,157,808	$	0.13800	$	1,125,778
Minimum Bill					
Subtotal				$	1,386,233
PCA Revenue				$	5,561
Total				$	1,391,794
Total Base				$	1,806,314
Total PCA				$	8,548
Total				$	1,814,862
5. GENERAL SERVICE (3)					
Single Phase					
Consumers (12 month sum)	1,405	$	18.00	$	25,290
Billing kW	24,980	$	16.65	$	415,925
kWh	8,879,750	$	0.08300	$	737,019
Minimum Bill					
Subtotal				$	1,178,234
PCA Revenue				$	5,436
Total				$	1,183,670
Three Phase					
Consumers (12 month sum)	3,625	$	26.00	$	94,250
Billing kW	295,946	$	16.65	$	4,927,494
kWh	104,685,742	$	0.08300	$	8,688,917
Minimum Bill					
Subtotal				$	13,710,661
PCA Revenue				$	73,302
Total				$	13,783,963
Total Base				$	14,888,895
Total PCA				$	78,738
Total				$	14,967,633

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
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	Billing Units	Existing Rate	Adjusted TY Revenue
6. GENERAL SERVICE TOU			
Consumers-1Ph (12 month sum)	60	$ 24.00	$ 1,440
Consumers-3Ph (12 month sum)	72	$ 32.00	$ 2,304
NCP Billing kW	4,649	$ 5.95	$ 27,664
CP Billing kW	1,843	$ 29.50	$ 54,369
kWh	1,296,284	$ 0.063750	$ 82,638
Subtotal			$ 168,415
PCA Revenue			$ 2,120
Total			$ 170,535
7. GENERAL SERVICE (4)			
Consumers (12 month sum)	60	$ 500.00	$ 30,000
Secondary Meters (12 month sum)	456	$ 40.00	$ 18,240
Facilities Charge			$ 422,282
NCP Billing kW-Transmission	20,400	$ 0.21	$ 4,284
NCP Billing kW-Distribution Sub	25,125	$ 1.75	$ 43,968
NCP Billing kW-Distribution Pri	176,974	$ 7.19	$ 1,272,444
NCP Billing kW-Distribution Sec		$ 7.70	$ -
P.F. Adjust.-Transmission	4,152	$ 0.21	$ 872
P.F. Adjust.-Distribution Sub	4,555	$ 1.75	$ 7,971
P.F. Adjust.-Distribution Pri	2,827	$ 7.19	$ 20,326
P.F. Adjust.-Distribution Sec		$ 7.70	$ -
kWh	101,693,786	$ -	$ -
Wholesale Power Cost			$ 5,419,450
Subtotal			$ 7,239,836
PCA Revenue			$ -
Total			$ 7,239,836
8. WATER PUMPING			
Single Phase			
Consumers (12 month sum)	132	$ 18.00	$ 2,376
kWh	186,573	$ 0.13260	$ 24,740
Subtotal			$ 27,116
PCA Revenue			$ 464
Total			$ 27,580
Three Phase			
Consumers (12 month sum)	571	$ 26.00	$ 14,846
kWh	3,143,032	$ 0.13260	$ 416,766
Minimum Bill			
Subtotal			$ 431,612
PCA Revenue			$ 3,758
Total			$ 435,370
Total Base			$ 458,728
Total PCA			$ 4,222
Total			$ 462,950

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
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	Billing Units	Existing Rate	Adjusted TY Revenue
9. IRRIGATION			
Single Phase			
Consumers (12 month sum)		$ 18.00	$ -
kWh		$ 0.124573	$ -
Minimum Bill			
Subtotal			$ -
PCA Revenue			
Total			$ -
Three Phase			
Consumers (12 month sum)	132	$ 26.00	$ 3,432
kWh	261,544	$ 0.124573	$ 32,581
Minimum Bill			$ 1,602
Subtotal			$ 37,615
PCA Revenue			$ 601
Total			$ 38,217
Total Base			$ 37,615
Total PCA			$ 601
Total			$ 38,217
10. TIME OF DAY - PUMPING			
Single Phase			
Consumers (12 month sum)	24	$ 18.00	$ 432
Billing kW - On Peak	4	$ 18.16	$ 74
kWh-On Peak	34	$ 0.12690	$ 4
kWh-Off Peak	353,742	$ 0.06190	$ 21,897
Subtotal	353,776		$ 22,407
PCA Revenue			$ 261
Total			$ 22,668
Three Phase			
Consumers (12 month sum)	327	$ 26.00	$ 8,502
Billing kW - On Peak	12,751	$ 18.16	$ 231,567
kWh-On Peak	234,052	$ 0.12690	$ 29,701
kWh-Off Peak	5,137,193	$ 0.06190	$ 317,992
Minimum Bill	5,371,245		$ 4,808
Subtotal			$ 592,570
PCA Revenue			$ 3,620
Total			$ 596,190
Total Base			$ 614,977
Total PCA			$ 3,881
Total			$ 618,859

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
E-01461A-15-0363

	Billing Units	Existing Rate	Adjusted TY Revenue
11. INTERRUPTIBLE COMMERCIAL			
Consumers - 1Ph (12 month sum)	26	$ 36.00	$ 936
Consumers - 3Ph (12 month sum)	-	$ 45.00	$ -
CP Billing kW	863	$ 29.50	$ 25,472
kWh	3,573,369	$ 0.08420	$ 300,878
Subtotal			$ 327,286
PCA Revenue			$ 3,424
Total			$ 330,710
12. INTERRUPTIBLE PUMPING			
Consumers - 1Ph (12 month sum)	-	$ 36.00	$ -
Consumers - 3Ph (12 month sum)	212	$ 45.00	$ 9,540
CP Billing kW	3,795	$ 29.50	$ 111,954
kWh	7,331,315	$ 0.08420	$ 617,297
Minimum Bill			$ 62,623
Subtotal			$ 801,414
PCA Revenue			$ 10,591
Total			$ 812,005
13. LIGHTING			
Outdoor Lighting			
Security Lights	8,129	$ 11.48	$ 93,321
150 Watt HPS	12	$ 11.31	$ 136
250 Watt HPS	60	$ 11.96	$ 718
400 Watt HPS	132	$ 12.15	$ 1,604
55 Watt LPS	55	$ 10.91	$ 600
90 Watt LPS	444	$ 10.91	$ 4,844
135 Watt LPS	96	$ 11.31	$ 1,086
100 Watt HPS	36	$ 10.98	$ 395
Additional Poles	1,157	$ 10.43	$ 12,068
Subtotal			$ 114,772

TRICO ELECTRIC COOPERATIVE, INC.
STAFF REVISED ADJUSTED TEST YEAR TOTAL REVENUE
FOR THE TWELVE MONTHS ENDING DECEMBER 31, 2014
E-01461A-15-0363

	Billing Units	Existing Rate	Adjusted TY Revenue
Street Lighting			
150 Watt HPS		$ 10.30	$ -
250 Watt HPS		$ 10.30	$ -
400 Watt HPS		$ 17.00	$ -
55 Watt LPS		$ 7.30	$ -
90 Watt LPS	600	$ 11.75	$ 7,050
135 Watt LPS	1,176	$ 10.30	$ 12,113
180 Watt LPS		$ 12.62	$ -
100 Watt HPS		$ 10.30	$ -
Wood Pole		$ 1.32	$ -
28' Metal Pole	600	$ 3.48	$ 2,088
20' - 30' Metal Pole	1,176	$ 4.15	$ 4,880
30' - 40' Metal Pole		$ 4.15	$ -
Subtotal			$ 26,131
Base Revenue			$ 140,903
PCA Revenue			$ 1,143
Total			$ 142,046
kWh Sold	539,888		
14. SALE FOR RESALE (SUPPLEMENTAL WHEELING)			
Base Revenue			$ 132,075
PCA Revenue			$ 17,242
Total	1,725,231		$ 149,317
15. TOTAL			
Total Base Revenue	681,082,312		$ 86,451,362
Total PCA Revenue			$ (247,593)
Fuel Bank			$ -
Other Revenue			$ 1,621,097
Total Revenue			$ 87,824,867

TRICO ELECTRIC COOPERATIVE, INC.
STAFF PROPOSED RATES AND PROOF OF REVENUE
E-01461A-15-0363

	Billing Units	Staff-Proposed Two-Part Rate	Revenue	% Increase	Staff-Proposed Three-Part Rate	Revenue	% Increase
1. RESIDENTIAL							
Consumers	454,052	$ 20.00	$ 9,081,040		$ 15.00	$ 6,810,780	
First 2 kW (Min of 2 kW)	908,104				$ 2.00	$ 1,816,208	
Over 2 kW*	1,362,156				$ 2.50	$ 3,405,390	
First 800 kWh/Mo.	258,064,238	$ 0.11632	$ 30,018,032		$ 0.10866	$ 28,039,970	
Excess kWh	127,106,267	$ 0.12631	$ 16,054,920		$ 0.11866	$ 15,081,794	
Net Metering Credits			$ (27,938)			$ (27,938)	
Subtotal	385,170,505		$ 55,126,054			$ 55,126,204	
PCA			$ -			$ -	
Total			$ 55,126,054	3.50%		$ 55,126,204	3.50%
2. RESIDENTIAL - TOU							
Consumers	33,520	$ 24.00	$ 804,480		$ 19.00	$ 636,880	
First 2 kW (Min of 2 kW)	67,040				$ 2.00	$ 134,080	
Over 2 kW	100,560				$ 2.50	$ 251,400	
kWh - On Peak	10,257,451	$ 0.19790	$ 2,029,950		$ 0.19180	$ 1,967,379	
kWh - Off Peak	25,192,421	$ 0.07790	$ 1,962,490		$ 0.07170	$ 1,806,297	
Subtotal	35,449,872		$ 4,796,920			$ 4,796,036	
PCA			$ -			$ -	
Total			$ 4,796,920	8.31%		$ 4,796,036	8.29%
3. GENERAL SERVICE (I)							
Single Phase							
Consumers	16,397	$ 23.00	$ 377,131		$ 18.00	$ 295,146	
First 2 kW (Min of 2 kW)	32,794				$ 2.00	$ 65,588	
Over 2 kW	49,191				$ 2.50	$ 122,978	
kWh	9,355,588	$ 0.13370	$ 1,250,842		$ 0.12230	$ 1,144,188	
Subtotal			$ 1,627,973			$ 1,627,900	
PCA			$ -			$ -	
Total			$ 1,627,973			$ 1,627,900	
Three Phase							
Consumers	1,465	$ 31.00	$ 45,415		$ 26.00	$ 38,090	
First 2 kW (Min of 2 kW)	2,930				$ 2.00	$ 5,860	
Over 2 kW	4,395				$ 2.50	$ 10,988	
kWh	1,276,535	$ 0.13370	$ 170,673		$ 0.12620	$ 161,099	
Subtotal			$ 216,088			$ 216,037	
PCA			$ -			$ -	
Total			$ 216,088			$ 216,037	
Subtotal	10,632,123		$ 1,844,061			$ 1,843,937	
Total PCA Revenue			$ -			$ -	
Total Revenue			$ 1,844,061	4.52%		$ 1,843,937	4.51%

TRICO ELECTRIC COOPERATIVE, INC.
STAFF PROPOSED RATES AND PROOF OF REVENUE
E-01461A-15-0363

	Billing Units	Staff/Trico Proposed Rates	Revenue	% Increase
4. GENERAL SERVICE (2)				
Single Phase				
Consumers	1,174	$ 23.00	$ 27,002	
First 10 kW per month	10,522	$ -	$ -	
Excess kW per month	7,988	$ 4.50	$ 35,944	
kWh	2,630,469	$ 0.14640	$ 385,101	
Subtotal			$ 448,047	
PCA			$ -	
Total			$ 448,047	
Three Phase				
Consumers	1,836	$ 31.00	$ 56,916	
First 10 kW per month	16,933	$ -	$ -	
Excess kW per month	47,271	$ 4.50	$ 212,719	
kWh	8,157,808	$ 0.14640	$ 1,194,303	
Subtotal			$ 1,463,938	
PCA			$ -	
Total			$ 1,463,938	
Subtotal	10,788,277		$ 1,911,985	
Total PCA Revenue			$ -	
Total Revenue			$ 1,911,985	5.35%
5. GENERAL SERVICE (3)				
Single Phase				
Consumers	1,405	$ 23.00	$ 32,315	
Billing kW	24,980	$ 18.00	$ 449,648	
kWh	8,879,750	$ 0.07490	$ 665,093	
Subtotal			$ 1,147,056	
PCA			$ -	
Total			$ 1,147,056	
Three Phase				
Consumers	3,625	$ 31.00	$ 112,375	
Billing kW	295,946	$ 18.00	$ 5,327,020	
kWh	104,685,742	$ 0.07490	$ 7,840,962	
Subtotal			$ 13,280,357	
PCA			$ -	
Total			$ 13,280,357	
Subtotal	113,565,492		$ 14,427,413	
Total PCA Revenue			$ -	
Total Revenue			$ 14,427,413	-3.61%
6. GENERAL SERVICE TOU				
Consumers 1 PH	60	$ 29.00	$ 1,740	
Consumers 3 PH	72	$ 37.00	$ 2,664	
NCP Billing kW	4,649	$ 5.95	$ 27,664	
CP Billing kW	1,843	$ 29.50	$ 54,369	
kWh	1,296,284	$ 0.06600	$ 85,555	
Subtotal			$ 171,992	
PCA			$ -	
Total			$ 171,992	0.85%

TRICO ELECTRIC COOPERATIVE, INC.
STAFF PROPOSED RATES AND PROOF OF REVENUE
E-01461A-15-0363

	Billing Units	Staff/Trico Proposed Rates	Revenue	% Increase
7. GENERAL SERVICE (4)				
Consumers	60	$ 500.00	$ 30,000	
Secondary Meters	456	$ 40.00	$ 18,240	
Facilities Charge		$ -	$ 422,282	
NCP Billing kW-Transmission	20,400	$ 0.21	$ 4,284	
NCP Billing kW-Distribution Sub	25,125	$ 1.75	$ 43,968	
NCP Billing kW-Distribution Pri	176,974	$ 7.19	$ 1,272,444	
NCP Billing kW-Distribution Sec	-	$ 7.70	$ -	
P.F. Adjust.-Transmission	4,152	$ 0.21	$ 872	
P.F. Adjust.-Distribution Sub	4,555	$ 1.75	$ 7,971	
P.F. Adjust.-Distribution Pri	2,827	$ 7.19	$ 20,326	
P.F. Adjust.-Distribution Sec	-	$ 7.70	$ -	
kWh	101,693,786	$ -	$ -	
Wholesale Power Cost			$ 5,419,450	
Subtotal			$ 7,239,837	
PCA Revenue			$ -	
Total			$ 7,239,837	0.00%
8. WATER PUMPING				
Single Phase				
Consumers	132	$ 23.00	$ 3,036	
kWh	186,573	$ 0.14350	$ 26,773	
Subtotal			$ 29,809	
PCA			$ -	
Total			$ 29,809	
Three Phase				
Consumers	571	$ 31.00	$ 17,701	
kWh	3,143,032	$ 0.14350	$ 451,025	
Subtotal			$ 468,726	
PCA			$ -	
Total			$ 468,726	
Subtotal	3,329,605		$ 498,535	
Total PCA Revenue			$ -	
Total Revenue			$ 498,535	7.69%
9. IRRIGATION				
Single Phase				
Consumers		$ 23.00	$ -	
kWh		$ 0.14200	$ -	
Subtotal			$ -	
PCA			$ -	
Total			$ -	
Three Phase				
Consumers	132	$ 31.00	$ 4,092	
kWh	261,544	$ 0.14200	$ 37,139	
Subtotal			$ 41,231	
PCA			$ -	
Total			$ 41,231	
Subtotal	261,544		$ 41,231	
Total PCA Revenue			$ -	
Total Revenue			$ 41,231	7.89%

TRICO ELECTRIC COOPERATIVE, INC.
STAFF PROPOSED RATES AND PROOF OF REVENUE
E-01461A-15-0363

	Billing Units	Staff/Trico Proposed Rates	Revenue	% Increase
10. TIME OF DAY PUMPING				
Single Phase				
Consumers	24	$ 23.00	$ 552	
NCP Billing kW	716	$ 1.75	$ 1,253	
Billing kW - On Peak	4	$ 16.00	$ 65	
kWh - On Peak	34	$ 0.06400	$ 2	
kWh - Off Peak	353,742	$ 0.06400	$ 22,639	
Subtotal	353,776		$ 24,511	
PCA			$ -	
Total			$ 24,511	
Three Phase				
Consumers (12-month sum)	327	$ 31.00	$ 10,137	
NCP Billing kW	36,165	$ 1.75	$ 63,289	
Billing kW - On Peak	12,751	$ 16.00	$ 204,024	
kWh - On Peak	234,052	$ 0.06400	$ 14,979	
kWh - Off Peak	5,137,193	$ 0.06400	$ 328,780	
Subtotal	5,371,245		$ 621,209	
PCA			$ -	
Total			$ 621,209	
Subtotal	5,725,021		$ 645,720	
Total PCA Revenue			$ -	
Total Revenue			$ 645,720	4.34%
11. INTERRUPTIBLE COMMERCIAL				
Consumers 1 PH (12-month sum)	26	$ 36.00	$ 936	
Consumers 3 PH (12-month sum)		$ 45.00	$ -	
NCP Billing kW	9,592	$ 1.75	$ 16,785	
CP Billing kW	863	$ 19.50	$ 16,837	
kWh	3,573,369	$ 0.08750	$ 312,670	
Subtotal			$ 347,228	
PCA			$ -	
Total			$ 347,228	
12. INTERRUPTIBLE PUMPING				
Consumers 1 PH (12-month sum)		$ 36.00	$ -	
Consumers 3 PH (12-month sum)	212	$ 45.00	$ 9,540	
NCP Billing kW	23,642	$ 1.75	$ 41,374	
CP Billing kW	3,795	$ 19.50	$ 74,003	
kWh	7,331,315	$ 0.08750	$ 641,490	
Minimum Bill			$ 62,623	
Subtotal			$ 829,030	
PCA			$ -	
Total			$ 829,030	
Subtotal			$ 1,176,258	
Total PCA Revenue			$ -	
Total Revenue			$ 1,176,258	2.94%

TRICO ELECTRIC COOPERATIVE, INC.
STAFF PROPOSED RATES AND PROOF OF REVENUE
E-01461A-15-0365

			Billing Units	Staff/Trico Proposed Rates	Revenue	% Increase
13. LIGHTING						
Outdoor Lighting						
Security Lights		53 kWh/Month	8,129	$ 12.00	$ 97,520	
	150 Watt HPS	45 kWh/Month	12	$ 11.82	$ 142	
	250 Watt HPS	75 kWh/Month	60	$ 12.50	$ 750	
	400 Watt HPS	120 kWh/Month	132	$ 12.70	$ 1,676	
	55 Watt LPS	27 kWh/Month	55	$ 11.40	$ 627	
	90 Watt LPS	27 kWh/Month	444	$ 11.40	$ 5,062	
	135 Watt LPS	45 kWh/Month	96	$ 11.82	$ 1,135	
	100 Watt HPS	30 kWh/Month	36	$ 11.47	$ 413	
Additional Poles			1,157	$ 10.90	$ 12,611	
Subtotal					$ 119,936	
Street Lighting						
	150 Watt HPS	45 kWh/Month	-	$ 10.76	$ -	
	250 Watt HPS	75 kWh/Month	-	$ 10.76	$ -	
	400 Watt HPS	120 kWh/Month	-	$ 17.77	$ -	
	55 Watt LPS	27 kWh/Month	-	$ 7.63	$ -	
	90 Watt LPS	27 kWh/Month	600	$ 12.28	$ 7,367	
	135 Watt LPS	45 kWh/Month	1,176	$ 10.76	$ 12,658	
	180 Watt LPS	54 kWh/Month	-	$ 13.19	$ -	
	100 Watt LPS	30 kWh/Month	-	$ 10.76	$ -	
Wood Pole			-	$ 1.38	$ -	
28' Metal Pole			600	$ 3.64	$ 2,182	
20' - 30' Metal Pole			1,176	$ 4.34	$ 5,100	
30' - 40' Metal Pole	Watt HPS		-	$ 4.34	$ -	
Subtotal					$ 27,307	
Subtotal			539,888		$ 147,243	
Total PCA Revenue					$ -	
Total Revenue					$ 147,243	3.66%
14. SALE FOR RESALE (SUPPLEMENTAL WHEELING)						
Base Revenue					$ 149,317	
PCA Revenue					$ -	
Total			1,725,231		$ 149,317	0.00%
					Including Staff-Proposed Two-Part Residential, Residential TOU, and GS 1	
16. TOTAL						
Subtotal			679,357,081		$ 88,176,566	
PCA Revenue					$ -	
Total Revenue					$ 88,176,566	
Other Revenue					$ 1,621,097	
Total Proposed Revenue					$ 89,797,663	2.25%
					Including Staff-Proposed Three-Part Residential, Residential TOU, and GS 1	
16. TOTAL						
Subtotal			679,357,081		$ 88,175,708	
PCA Revenue					$ -	
Total Revenue					$ 88,175,708	
Other Revenue					$ 1,621,097	
Total Proposed Revenue					$ 89,796,805	2.25%

TRICO ELECTRIC COOPERATIVE, INC.
COMPARISON OF EXISTING AND STAFF PROPOSED TWO-PART RATE
E-01461A-15-0363
RESIDENTIAL BILL IMPACT

kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge	$15.00	$20.00	$5.00	33.33%
First 800 kWh/Month	$0.121600	$0.116320	($0.005280)	-4.34%
Next 800 kWh/Month	$0.121600	$0.126310	$0.004710	3.87%
PPCA Factor, per kWh	$0.000073	$0.000000	($0.000073)	-100.00%
50	$21.08	$25.82	$4.74	22.49%
100	$27.17	$31.63	$4.46	16.42%
300	$51.50	$54.90	$3.40	6.60%
500	$75.84	$78.16	$2.32	3.06%
800	$112.34	$113.06	$0.72	0.64%
1,000	$136.67	$138.32	$1.65	1.21%
3,000	$380.02	$390.94	$10.92	2.87%
5,000	$623.37	$643.56	$20.19	3.24%
837 Average	**$116.84**	**$117.73**	**$0.89**	**0.76%**
750 Median	**$106.25**	**$107.24**	**$0.99**	**0.93%**

TRICO ELECTRIC COOPERATIVE, INC.
COMPARISON OF EXISTING RATE AND STAFF ALTERNATE DEMAND RATE
E-01461A-15-0363
RESIDENTIAL BILL IMPACT

kWh Usage	Billing kW	Existing Rate	Alternate Rate	Change	% Change
Customer Charge		$15.00	$15.00	$0.00	0.00%
First 2 kW (Minimum of 2 kW)		$0.00	$2.00	$2.00	0.00%
Excess kW		$0.00	$2.50	$2.50	0.00%
First 800 kWh/Month		$0.121600	$0.108660	($0.012940)	-10.64%
Next 800 kWh/Month		$0.121600	$0.118660	($0.002940)	-2.42%
PPCA Factor, per kWh		$0.000073	$0.000000	($0.000073)	-100.00%
50	2.00	$21.08	$31.93	$10.85	51.47%
100	2.00	$27.17	$37.37	$10.20	37.54%
300	2.00	$51.50	$59.10	$7.60	14.76%
500	2.00	$75.84	$80.83	$4.99	6.58%
800	2.00	$112.34	$113.43	$1.09	0.97%
1,000	2.00	$136.67	$137.16	$0.49	0.36%
3,000	2.00	$380.02	$374.48	($5.54)	-1.46%
5,000	2.00	$623.37	$611.80	($11.57)	-1.86%
837 Average	**2.00**	**$116.84**	**$117.82**	**$0.98**	**0.84%**
750 Median	**2.00**	**$106.25**	**$108.00**	**$1.75**	**1.65%**

TRICO ELECTRIC COOPERATIVE, INC.
COMPARISON OF EXISTING RATE AND STAFF ALTERNATE DEMAND RATE
E-01461A-15-0363
RESIDENTIAL-TOU BILL IMPACT

kWh Usage	Billing kW	On-Peak kWh	Off-Peak kWh	Existing Rate	Proposed Rate	Change	Percent Change
		29%	71%				
Customer Charge				$19.00	$19.00	$0.00	0.00%
First 2 kW				$0.00	$2.00	$2.00	0.00%
Excess kW				$0.00	$2.50	$2.50	0.00%
Energy Charge, per On-Peak kWh				$0.193200	$0.191800	($0.001400)	-0.72%
Energy Charge, per Off-Peak kWh				$0.073200	$0.071700	($0.001500)	-2.05%
PPCA Factor, per kWh				$0.000073	$0.000000	($0.000073)	-100.00%
50	2	14	36	$24.34	$35.77	$11.43	46.96%
100	2	29	71	$29.81	$41.15	$11.34	38.04%
300	2	87	213	$51.42	$62.46	$11.04	21.47%
500	2	145	355	$73.04	$83.76	$10.72	14.68%
800	2	231	569	$105.34	$115.60	$10.26	9.74%
1,000	2	289	711	$126.95	$136.91	$9.96	7.85%
3,000	2	867	2,133	$342.86	$349.73	$6.87	2.00%
5,000	2	1,445	3,555	$558.77	$562.54	$3.77	0.67%
1,058 Avg	**2**	**306**	**752**	**$133.24**	**$143.11**	**$9.87**	**7.41%**
698 Mediar	**2**	**202**	**496**	**$94.38**	**$104.81**	**$10.43**	**11.05%**

TRICO ELECTRIC COOPERATIVE, INC.
COMPARISON OF EXISTING AND STAFF ALTERNATE DEMAND RATE
E-01461A-15-0363
GENERAL SERVICE 1 BILL IMPACT

Load Factor	Billing kW	kWh Usage	Existing Rate	Proposed Rate	Change	Percent Change
Customer Charge, Single Phase			$18.00	$18.00	$0.00	0.00%
Customer Charge, Three Phase			$26.00	$26.00	$0.00	0.00%
First 2 Billing kW per month			$0.00	$2.00	$2.00	0.00%
Over 2 Billing kW per month			$0.00	$2.50	$2.50	0.00%
Energy Charge, per kWh			$0.133500	$0.122300	($0.011200)	-8.39%
Energy Charge, per kWh			$0.133500	$0.126200	($0.007300)	-5.47%
PPCA Factor, per kWh			$0.000073	$0.000000	($0.000073)	-100.00%
Single Phase						
10.00%	2.0	146	$37.50	$47.36	$9.86	26.29%
20.00%	2.0	292	$57.00	$65.21	$8.21	14.40%
30.00%	2.0	438	$76.50	$83.07	$6.57	8.59%
40.00%	2.0	584	$96.01	$100.92	$4.91	5.11%
50.00%	2.0	730	$115.51	$118.78	$3.27	2.83%
Average	**2.00**	**570**	**$94.14**	**$99.21**	**$5.07**	**5.39%**
Median	**2.00**	**349**	**$64.62**	**$72.18**	**$7.56**	**11.70%**
Three Phase						
10.00%	2.0	146	$45.50	$55.93	$10.43	22.92%
20.00%	2.0	292	$65.00	$74.35	$9.35	14.38%
30.00%	2.0	438	$84.50	$92.78	$8.28	9.80%
40.00%	2.0	584	$104.01	$111.20	$7.19	6.91%
50.00%	2.0	730	$123.51	$129.63	$6.12	4.96%
Average	**2.00**	**871**	**$142.34**	**$147.42**	**$5.08**	**3.57%**
Median	**2.00**	**546**	**$98.93**	**$106.41**	**$7.48**	**7.56%**

EXHIBIT
S-7
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN IT'S RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

DIRECT

TESTIMONY

OF

RANELLE PALADINO

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 4, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

Ranelle Paladino's testimony presents the results of the Utilities Division Staff's ("Staff") review of billing determinants used in the rate design process, the base cost of power, and operating revenue adjustments included in the rate case application of Trico Electric Cooperative, Inc. ("Trico"). The application was filed with the Arizona Corporation Commission ("Commission") on October 23, 2015.

Staff's recommendations regarding the base cost of power and associated adjustments are the following:

1. The adjustments made to test year billing determinants to adjust the number of billed consumers and the reclassification of GS3 volumes to GS4 should be accepted.

2. The adjustment made to test year billing determinants for the residential class should not be accepted. Residential test year billing determinants should equal 420,620,377 kWh.

3. The adjustment made to reduce test year purchased power costs as a result of the above noted adjustment to residential test year billing determinants should not be accepted.

4. The adjusted purchased power cost should equal $52,472,056.

5. The base cost of purchased power should be set at $0.081211 per kWh.

6. The adjustment to test year base revenue should be $633,796 resulting in an adjusted test year base revenue of $86,451,362.

7. The adjustment to test year wholesale power cost adjustor ("WPCA") revenue should be $(289,666) resulting in an adjusted test year WPCA revenue of $(247,593).

8. The adjustments to test year Fuel Bank Revenue and Other Revenue proposed by Trico should be approved.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Ranelle Paladino. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I review and analyze utility applications filed with the Commission, and prepare memoranda and proposed orders for Open Meetings. I also assist in the management of rate cases and track monthly fuel adjustor reports.

Q. Please describe your educational background and professional experience.

A. In 1992, I graduated magna cum laude from Creighton University, receiving a Bachelor of Science degree in Business Administration. In 1999, I received a Master's Degree in Business Administration from Creighton University. I have been employed by the Commission since November of 2011.

Prior to working at the Commission, I was employed by UtiliCorp United, Inc. and Aquila Energy in various departments including the Gas Supply Operations Department and the Gas Accounting Department in both a regulated and non-regulated capacity. After leaving Aquila Energy, I was employed by Northern Natural Gas, an interstate pipeline, as a Regulatory Analyst and Marketing Analyst.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01461A-15-0363?

A. Yes.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to discuss Staff's review of Trico Electric Cooperative, Inc.'s ("Trico" or "Cooperative") billing determinants used in the rate design process, the base cost of power, and operating revenue adjustments included in the rate application.

Q. Have you reviewed testimony submitted by the Cooperative in this case?

A. Yes. I reviewed the testimony of Vincent Nitido, Karen Cathers, David W. Hedrick and Rebecca A. Payne, particularly as it pertains to the scope of my testimony.

KWH BILLING DETERMINANTS ADJUSTMENT

Q. Did Trico include test year billing determinants by customer class in its rate application?

A. Yes.

Q. Did Staff review the test year billing determinants Trico included in its application?

A. Yes.

Q. Did Trico make adjustments to its test year billing determinants?

A. Yes.

Q. Did Staff review the adjustments Trico made to its test year billing determinants?

A. Yes.

Q. Please explain the adjustments Trico made to its test year billing determinants?

A. Trico included three adjustments to its test year billing determinants to: (1) adjust the number of billed consumers to reflect the revenue collected from the customer charge

divided by the customer charge, (2) adjust the billed consumers and kWh sold to show a reclassification of accounts moving from the General Service Schedule GS3 ("GS3") to General Service Schedule GS4 ("GS4") and (3) adjust residential kWh sales downward to reflect estimates of a decline in kWh attributed to the growth in net metered customers that occurred in late 2014 and continued into 2015.[1]

Q. Does Staff agree with all of the adjustments Trico made to its test year billing determinants?

A. No. Staff does not agree with all of the adjustments Trico made. Staff is in agreement with the calculation for the adjustments to the number of billed consumers and the reclassification of kWh between GS3 and GS4 rate schedules. However, Staff does not agree with Trico's third adjustment that reduced test year residential sales by approximately 5.2 million kWh attributable to the effects of Trico's customers installing roof-top photovoltaic power systems. Staff believes that Trico's method of computing the reduced sales adjustment, absent accurate metered production data, is only an estimate and does not meet the usual standard of "known and measurable" for a volumetric adjustment. In addition, Staff believes that a volumetric adjustment outside of the test year (Trico included annualized data for new net metered customers in the first few months of 2015) is not appropriate unless Trico is willing to include other adjustments to account for volumetric changes that occurred in 2015. Specifically, Staff noticed that Trico did not adjust its residential sales projections for the roughly 1,300 new residential customers which came on the system in 2015.

[1] Payne Direct page 3 lines 16-26 and page 4 lines 1-3.

Q. What is Staff's recommendation regarding Trico's adjustments to test year billing determinants?

A. Staff recommends including two of the three adjustments made to test year billing determinants. Staff does not recommend lowering residential test year kWh sales from the 420,620,377 kWh (385,170,505 kWh for residential plus 35,449,872 kWh for residential time of use) level reported on Schedule E-7.2 Page 1 of 2 in the rate application.

Q. Has Trico provided any additional data to support the level of kWh reduction to residential billing determinants which Trico indicates has occurred as a result of net metered customers?

A. Yes.

Q. What additional data has Trico provided?

A. For Staff to further consider any adjustment to residential billing determinants for the test year, Staff requested actual metered production data from net metered customers for 2014. On April 27, 2016, Trico provided metered production data for a sample of net metered customers. Staff is in the process of reviewing and analyzing this information and reserves the right to modify Staff's recommendations with regard to allowable adjustments to test year residential billing determinants in its Rate Design testimony based on this recently provided data.

BASE COST OF PURCHASED POWER

Q. What is Trico's current base cost of purchased power?

A. Currently, Trico has a base cost of power of $0.081638 per kilowatt-hour ("kWh"). This base cost of power was set in Decision No. 71230, dated August 6, 2009.

Q. Is Trico proposing to change its base cost of purchased power?

A. Yes. Trico is proposing to change its base cost of purchased power to $0.081711 per kWh.

Q. Does Staff agree with Trico's calculation of the proposed base cost of purchased power?

A. No. Staff has concerns regarding adjustments made to the Cooperative's test year billing determinants which in turn affect the purchased power cost and the kWh number used to determine the new base cost of power.

Q. Did Staff review the cost of power used by Trico in order to calculate its proposed base cost?

A. Yes. Staff compared invoices for Trico's power costs for the 2014 Test Year to those purchased power costs reported by Trico in its current filing. Staff also reviewed the adjustments to purchased power costs which represent an increase of $750,858. Staff found the proposed adjustments to the cost of power to be reasonable with the exception of the reduction to purchased power costs that resulted from the decrease in test year billing determinants for the residential class.

Q. What change to the adjusted test year purchased power cost does Staff recommend?

A. When the 5,239,334 kWh adjustment reduction is added back to the billing determinants, the purchased power costs associated with those volumes needs to be included in purchased power costs for the test year. In addition, by increasing the residential test year billing determinants, the purchased power costs that are allocated based on a load-ratio share between GS4 and non-GS4 customers also changes. The net result of the increase in residential test year billing determinants is an increase to purchased power costs of $134,897

from the adjusted test year purchased power costs filed by Trico. Staff recommends adjusted test year purchased power costs of $52,472,056.

Q. What is Staff's recommendation regarding Trico's base cost of purchased power?

A. Staff recommends a base cost of purchased power for Trico of $0.081211 per kWh, based on an adjusted purchased power cost (excluding GS4) of $47,052,606 and adjusted annual sales (excluding GS4) of 579,388,526 kWh.

Q. Will Staff's review of the metered data provided by Trico on April 27, 2016, affect Staff's recommendation regarding Trico's base cost of purchased power?

A. Yes. Staff reserves the right to modify Staff's recommendations with regard to base cost of purchased power if the determination is made to allow adjustments to residential test year billing determinants in its Rate Design testimony based on this recently provided data.

OTHER OPERATING REVENUE ADJUSTMENTS

Q. Did Staff make any other adjustments as a result of the recommendation to change the adjusted test year billing determinants?

A. Yes. By changing the adjusted test year billing determinants, the amount of base revenue adjustment originally calculated by Trico also changes. A portion of the base revenue adjustment proposed by Trico that reduces test year base revenue by $1,296,163 can be attributed to the base revenue tied to the 5,239,334 residential kWh reduction. By including those residential volumes, the test year base revenue adjustment Staff recommends is $633,796 leading to an adjusted test year base revenue of $86,451,362.

Changing the adjusted test year billing determinants also leads to a change in the adjustment made to the wholesale power cost adjustor ("WPCA") revenue. Trico originally proposed an

increase in the WPCA Revenue for the test year from $0 to $42,073. By including those residential volumes Trico proposed to exclude, the WPCA adjustment Staff recommends is $(289,666) leading to an adjusted test year WPCA revenue of $(247,593).

Staff agreed with the adjustments to test year fuel bank revenue and other revenue originally filed by Trico. The overall effect on operating revenues of these changes totals an increase in adjusted test year total operating revenues of $344,131.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The adjustments made to test year billing determinants to adjust the number of billed consumers and the reclassification of GS3 volumes to GS4 should be accepted.

2. The adjustment made to test year billing determinants for the residential class should not be accepted. Residential test year billing determinants should equal 420,620,377 kWh.

3. The adjustment made to reduce test year purchased power costs as a result of the above noted adjustment to residential test year billing determinants should not be accepted. The adjusted purchased power cost should equal $52,472,056.

4. The base cost of purchased power should be set at $0.081211 per kWh.

5. The adjustment to test year base revenue should be $633,796 resulting in an adjusted test year base revenue of $86,451,362.

6. The adjustment to test year WPCA revenue should be $(289,666) resulting in an adjusted test year WPCA revenue of $(247,593).

7. The adjustments to test year Fuel Bank Revenue and Other Revenue proposed by Trico should be approved.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
S-8
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

SETTLEMENT REPLY

TESTIMONY

OF

RANELLE PALADINO

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 15, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

My reply testimony addresses the direct testimony of the Energy Freedom Coalition of America's witness William A. Monsen (filed in opposition to the Settlement Agreement) regarding the proposed fixed monthly charges and the freezing of the Residential Time-of-Use Rate Schedule detailed in the Proposed Settlement. My silence as to other portions of his testimony should not be construed as agreement with them. My testimony also updates the status of the Utilities Division's review of Trico's rate case expense invoices.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Ranelle Paladino. I am an Executive Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning the adjustments to billing determinants, the base cost of power, operating revenue adjustments and rate design testimony.

Q. What is the purpose of your reply testimony in this case?

A. My reply testimony addresses the direct testimony of the Energy Freedom Coalition of America's ("EFCA") witness William A. Monsen (filed in opposition to the Settlement Agreement) regarding the proposed fixed monthly charges and the freezing of the Residential Time-of-Use ("TOU") rate schedule detailed in the Proposed Settlement docketed July 8, 2016. I also address the status of Staff's review of Trico's rate case expense invoices.

REPLY TO DIRECT TESTIMONY

Q. Did EFCA comment on the proposed fixed monthly charge in the Settlement Agreement?

A. Yes. In his direct testimony, EFCA witness William A. Monsen indicates that neither Trico nor any other party has supported the fixed monthly charges in the Settlement Agreement.[1]

[1] Monson Direct (dated July 29, 2016), p. 5 lines 16-19.

Q. Does Staff agree the fixed monthly charge in the Settlement Agreement has not been supported?

A. No. As Staff indicated in its direct rate design testimony, Trico Electric Cooperative, Inc. ("Trico") included a Cost of Service Study ("COSS") with its rate application filed on October 23, 2015. Staff's review of Trico's COSS determined that acceptable methods were utilized to functionalize, classify, and allocate costs. Staff also determined the COSS model appropriately calculated the components of the rate application.[2]

Staff further explained that the COSS detailed the monthly cost per member broken down into purchased power demand, purchased power energy, distribution (wires), and total customer costs (which includes such items as billing and metering). Specifically for residential members, the COSS illustrated that it costs $31.83 per month per residential member in fixed monthly customer costs to provide service to a residential customer. Other fixed costs incurred for residential members include distribution system (wires, poles, etc.) and the fixed portion of purchased power charges paid to primarily Arizona Electric Power Cooperative ("AEPCO"), Trico's generation and transmission provider, on a monthly basis. The COSS also illustrated that total Residential Fixed Costs per month are $100.64.[3] Staff concludes that Trico has supported through its COSS, that the fixed monthly charge of $24.00 per residential member per month in the Settlement Agreement is well under the amount contained in the COSS.

Q. Did EFCA comment on the proposed changes to the Residential TOU rate schedule in the Settlement Agreement?

A. Yes. In his direct testimony, EFCA witness Mr. Monsen indicated that Staff has not explained why it has taken a position in the Settlement Agreement recommending to freeze

[2] Paladino Direct Rate Design pg. 4 lines 19-21.
[3] Paladino Direct Rate Design pg. 9 lines 8-22.

the Residential TOU rate schedule when that recommendation is the direct opposite of the position Staff recommended in the Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") rate case, Docket No. E-01575A-15-0312.[4]

Q. Did Staff recommend in the Settlement Agreement to freeze the Residential TOU rate schedule?

A. Yes.

Q. Did Staff recommend in the SSVEC rate case to freeze the Residential TOU rate schedule?

A. No.

Q. What is the explanation for Staff's different positions on the Residential TOU rate schedules in the two recent rate cases?

A. A conclusion by Staff in one company's rate case will not necessarily carry forward into another company's rate case. Every case stands on its own merits. Each company's operations and customer base are unique with differing supply and usage characteristics.

Specifically, for the SSVEC Residential TOU rate schedule, Staff understands that the price signals may not be inherent in the current pricing structure from AEPCO. That lack of price signal does not reinforce in SSVEC's customers the need for TOU rate schedules. However, Staff also indicated that the existing Residential TOU rates are not harmful to SSVEC or the customers.[5]

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[4] Monson Direct (filed July 29, 2016) pg. 37 lines 20-22.
[5] Paladino Surrebuttal Docket No. E-01575A-15-0312 pg. 7 lines 15-17.

While Staff agrees that Trico, which also receives supply from AEPCO, lacks the price signal to reinforce the need for the TOU rate schedules, Staff disagrees with the conclusion that the existing Residential TOU rate schedule is harmless to Trico and its customers.

The Settlement Agreement proposes the implementation of a residential rate structure which incorporates a demand charge in addition to an energy charge and a monthly fixed charge. The Settlement Agreement proposes a $0 demand charge so that the residential member would have time to learn about a demand charge and how it can be a beneficial rate design for customers. Trico's existing metering infrastructure supports a demand charge based on the highest 15-minute increment during the monthly billing cycle (24 hours a day/7 days a week) not during specific peak/off-peak times. It is reasonable to anticipate that a residential customer would ultimately want to limit running all electricity consuming items at the same time and spread the electricity usage over the day and the month. Tying a 15-minute increment monthly demand charge with a residential TOU rate schedule would be sending conflicting signals to the residential customer on how to effectively control its electric bills. Staff does not support a rate structure that would harm residential customers, and Staff believes the implementation of a demand charge as proposed in the Settlement Agreement for customers on a residential TOU rate schedule would be harmful to the customer.

RATE CASE EXPENSE

Q. Did Trico adjust rate case expense for this rate case?

A. Yes. The original application filed on October 23, 2015 incorporated $150,000 of rate case expense spread over three years. As part of the Settlement Agreement, Trico requested to increase the rate case expense. Staff agreed to the increase in rate case expense with a cap at $450,000 subject to a review of the supporting invoices.[6]

[6] Ford Direct pg. 6 lines 5-9.

Q. Has Staff received copies of rate case expense invoices from Trico?

A. Yes. Staff requested copies of all rate case expense support invoices and the underlying contracts for those invoices. Staff received confidential copies of all contracts and invoices Trico had received through June 30, 2016.

Q. Did Staff have the opportunity to review all contracts and invoices provided by Trico?

A. Yes. Staff verified the invoices were in accordance with the contracts in place. Staff also verified that the invoices Trico had received through June 30, 2016 totaled approximately $400,000. Trico also indicated that it forecasted approximately $159,000 more in rate case expense before the case has a decision.

Staff agrees Trico has provided adequate support for an increase in rate case expense from $150,000 to $400,000. Staff believes, based upon the forecasts of the Cooperative, that an additional $50,000 in rate case expenses is likely. The Cooperative however should be required to provide invoices in support of this additional amount to Staff.

Q. Does this conclude your Reply Testimony in support of the Settlement Agreement?

A. Yes, it does.

EXHIBIT
S-9
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN IT'S RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

DIRECT

TESTIMONY

OF

MARY J. RIMBACK

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 4, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

Mary Rimback's testimony presents Staff's recommendations in the areas of rate base, operating revenues and expenses and revenue requirement with respect to Trico Electric Cooperative Inc.'s ("Trico" or "Cooperative") October 23, 2015 rate case application.

Trico is a certificated Arizona-based non-profit rural electric distribution cooperative. Trico provides power and energy to approximately 43,000 customers in northwest Tucson, Marana, Corona de Tucson, Sahuarita, Green Valley, Three Points, Arivaca and Sasabe. These are primarily rural areas of Pima, Pinal and Santa Cruz Counties in Arizona. Approximately 40,000 are residential customers.

Trico proposed a $2,182,076, or 2.49 percent, revenue increase, from $87,480,736 to $89,662,812. The proposed rate of return is 6.33 percent on fair value rate base ("FVRB") of $175,076,536 which results in an operating Times Interest Earned Ratio ("TIER") of 2.00, and a Debt Service Coverage Ratio ("DSC") of 1.94.

Staff recommends an increase of $1,972,842, or a 2.25 percent revenue increase, from Staff adjusted test year revenue $87,824,867 to $89,797,709. Staff recommends a 6.33 percent rate of return on fair value rate base of $175,076,536 and results in an operating TIER of 2.00 as shown on Schedule MJR-1, and a DSC of 1.87. Staff recommends the Cooperative docket as a compliance requirement, a notice of the completion of the acquisition of the Direct Assignment Facilities transaction.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Mary J. Rimback. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst III.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Accounting from Arizona State University. I am a Certified Public Accountant as recognized by the Arizona State Board of Accountancy. Since joining the Commission in June 2012, I have participated in numerous rate cases and other regulatory proceedings involving electric, water, and wastewater utilities. I have testified on matters involving regulatory accounting and auditing. Additionally, I have attended utility-related seminars sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") on ratemaking and accounting designed to provide continuing and updated education in these areas.

Q. What is the scope of your testimony in this case?

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating revenues and expenses and revenue requirement regarding Trico Electric Cooperative, Inc.'s ("Trico" or "Cooperative") application for a permanent rate increase.

Q. Who else is providing Staff testimony and what issues will they address?

A. Staff witness Richard Lloyd is presenting Staff's recommendations concerning the Cooperative's Rules and Regulations and Line Extension Policies, and Trico's adjustors. Staff witness Ranelle Paladino is presenting Staff's base cost of power recommendations and various Revenue adjustments which affect rate design and rate design recommendations. Staff witness Margaret (Toby) Little is presenting Staff's engineering analysis and recommendations.

BACKGROUND

Q. Please review the background of this application.

A. Trico is a certificated Arizona-based non-profit rural electric distribution cooperative. Trico provides power and energy to 43,050 (as of year-end 2014) customers in primarily rural areas of Pima, Pinal and Santa Cruz counties, Arizona.

Trico is a Class A Partial Requirements Member ("PRM") of Arizona Electric Power Cooperative ("AEPCO"), which generates or procures power on a wholesale basis for Trico and other member distribution cooperatives. Trico states that it converted from an All Requirements Member ("ARM") to a PRM since its last test year. Trico obtains almost all of its power from AEPCO and from other wholesale power purchases. As a PRM, Trico states that it receives a more favorable rate for power supplied by AEPCO, and it is able to purchase power requirements over and above the allocated capacity in AEPCO generating resources from any source, including AEPCO. This allows the Cooperative to access additional power supply alternatives. Effective January 1, 2015, Trico has a ten-year Power Purchase Agreement with Tucson Electric Power Company ("TEP"). Under this agreement, Trico will purchase 50MW of capacity and energy each year through 2017, and 85MW each

year thereafter until 2025. Trico is also a Class A member and network transmission customer of Southwest Transmission Cooperative ("SWTC").

Trico filed an application for a permanent rate increase on October 23, 2015, based upon a test year ending December 31, 2014. On November 30, 2015, Staff notified the Cooperative that its application met the sufficiency requirements. Trico's current rates were authorized in Decision No. 71230, dated August 6, 2009.

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. According to the Cooperative, there are four primary reasons for its rate increase application:[1]

1) Modification of how the Cooperative's fixed costs are recovered,
2) Add the acquisition of certain Direct Assignment Facilities ("DAFs") from SWTC to the Cooperative's rate base,
3) Update the Cooperative's Rules and Regulations and Line Extension Policy, and,
4) Update the Cooperative's depreciation rates for advanced metering equipment.

CONSUMER SERVICES

Q. Please provide a brief history of customer complaints received by the Commission regarding Trico.

A. A review of Consumer Services records for the time frame of January 1, 2013, through March 11, 2016, reflects twenty-six complaints have been filed.

2016 - 0 Complaints
2015 - 14 Complaints

[1] Vincent Nitido Direct Testimony, page 14, lines 7 thru 25

2014 - 9 Complaints
2013 - 3 Complaints

A breakdown of the above listed complaints is listed below as follows:

2016 Complaints	ZERO
2015 Complaints	
Billing	4
Disconnect	2
Quality of Service	4
Rates and Tariffs	1
Service	3
Total	14

2014 Complaints	
Billing	2
Disconnect	1
Quality	2
Rates and Tariffs	4
Total	9

2013 Complaints	
Billing	1
Disconnect	1
Quality	1
Total	3

One Complaint remains open pending investigation; all others have been resolved and closed. Fifty-four opinions have been filed in opposition to the application.

PUBLIC NOTICE

Q. Has the Cooperative filed its affidavit of customer notification?

A. Yes, the Cooperative filed its Affidavit of Mailing Customer Notice on January 8, 2016, advising that notice had been sent to all Trico's members, sent by first-class U.S. mail on December 28, 2015.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Cooperative's filing.

A. Trico proposed (Schedule A-2.0, docketed March 21, 2016), a $2,182,076, or 2.49 percent, revenue increase from $87,480,736 to $89,662,812. The proposed revenue requirement would result in a 6.33 percent rate of return on fair value rate base of $175,076,536 and results an operating Time Interest Earned Ratio ("TIER") of 2.00.

Q. Please summarize Staff's recommend revenue.

A. Staff recommends a $1,972,842 or a 2.25 percent revenue increase over Staff adjusted revenue of $87,824,867 to $89,797,709. Staff recommended revenue produces a 6.33 percent rate of return on fair value rate base of $175,076,536 and would result in an operating TIER of 2.00 as shown on Schedule MJR-1.

Q. What test year did Trico utilize in this filing?

A. Trico's rate filing is based on the twelve months ended December 31, 2014 ("test year").

Q. Please summarize the rate base and operating margin recommendations and adjustments addressed in your testimony for Trico.

A. Staff made no adjustment to rate base. Staff's adjustment to operating margin are consistent with the billing determinant adjustment as discussed in Ranelle Paladino's testimony.

RATE BASE

Fair Value Rate Base

Q. Did the Cooperative prepare a schedule showing the elements of Reconstruction Cost New Rate Base?

A. No, the Cooperative did not. The Cooperative's filing treats the original cost rate base the same as the fair value rate base.

Rate Base Summary

Q. Did Staff make adjustments to Trico's rate base shown on Schedules MJR-2 and MJR-3.

A. Staff made no adjustments to rate base. Staff reviewed the Cooperative's filing and found that Trico appropriately omitted construction work in progress ("CWIP") from rate base as CWIP is not used and useful. Moreover, the Cooperative appropriately omitted cash working capital from rate base as the cash working capital was not supported by a lead-lag study.

Q. Does Staff wish to make any comments regarding the Cooperative's proposed rate base adjustments?

A. Yes, Staff comments concern:

Plant Held for Future Use – Trico included $166,341 of Plant Held for Future Use in rate base. Plant held for future use is not deemed used and useful and is excluded from rate base for rate-making purposes. Staff did not adjust plant held for future use as the value in relationship to gross rate base was .07 percent or less than 1 percent of gross rate base. Staff recommends that Trico not include Plant Held for Future Use in Rate Base.

Distributed Assignment Facilities ("DAFs") – DAFs totaling $7,824,024 net of accumulated depreciation are included in Trico's proposed rate base. Trico provided Staff with a copy of a "Letter Agreement" documenting the understanding of the parties.

Q. How did the Cooperative describe the DAFs?

A. The Cooperative stated that it was in the process of acquiring DAFs from SWTC. The DAFs were defined in the service agreements between Trico and SWTC as those transmission facilities constructed and owned by SWTC, after September, 1999, that are not part of the SWTC system facilities and utilized to provide transmission service only to Trico[2].

Q. How did the Cooperative describe the current arrangement in regards to the SWTC DAFs?

A. Trico stated the carrying costs associated the SWTC DAFs are currently passed through directly to the Member that is assigned the DAFs.

Q. What category of rate base did Trico include the DAFs in the current rate application?

A. The Cooperative included the DAFs as plant account 353-Transmission Station Equipment and described the DAFs as post test year plant, rather than a future acquisition.

Q. Please discuss this distinction?

A. Post test year plant refers to plant in construction at the end of the test year, which is not yet completed. If completed, the plant will serve the existing rate payers and will be used and useful to the existing rate payers. In this instant case, the DAFs are already in use by the current rate-payers, but Trico does not own the facilities.

[2]Cathers Direct p.2, lines 17-20.

Q. Why is Trico proposing the acquisition?

A. Trico proposes that the acquisition is for the purpose of reducing the overall cost to Trico's members[3].

Q. Does the Cooperative quantify this benefit and include this benefit in the test year?

A. Yes, the benefit is included in the test year as an adjustment to test year revenues and expenses. Staff requested information on the exact adjustments and received the following response in Data Request STF 7.3.

Increased Depreciation Expense $215,943

Increased Interest Expense $120,000

Increased Revenues for Depreciation and interest expense $335,943

Decreased Purchase Power expense $1,091,877

Q. What is Staff's recommendation concerning the acquisition of the DAFs?

A. Staff recommends the Cooperative docket as a compliance requirement a notice of the completion of the acquisition of the DAFs transaction.

[3] Direct Testimony of David Hedrick p 26 lines 8-10.

OPERATING MARGIN

Operating Margin Summary

Q. What are the results of Staff's analysis of test year revenues, expenses and operating margin?

A. As shown on Schedules MJR-5 and MJR-6, Staff's analysis resulted in test year revenues of $87,824,867, expenses of $78,711,518 and operating margin after interest expense of $3,115,589. The result is an increase to test year net margin of $209,234.

Operating Margin Adjustment 1 – Net Metering, Base Cost of Power Revenue ("BCOP"), and elimination of the Wholesale Power Cost Adjustor ("WPCA") Revenue.

Base Cost of Power Revenue

Q. What is the base cost of power ("BCOP") rate and how is it calculated?

A. The BCOP rate is the portion of the base rate that recovers the test year purchased power expense. The BCOP rate is calculated by dividing the test year purchased power expense by the number of kWh's sold in the test year.

Q. For ratemaking purposes, should the revenues generated from the BCOP rate match purchased power expense?

A. Yes, the revenues generated from the BCOP rate ("BCOP revenue") should match the purchased power expense since the BCOP rate is designed to recover the test year level of purchased power expense.

Q. Is the Cooperative proposing to change its base cost of power rate?

A. Yes, the Cooperative is proposing to increase its base cost of power rate from $0.081638 per kWh (Cooperative Schedule E-7.5.1) to $ .081711 per kWh (Schedule H-2.1.1), an increase of $0.000073.

Q. What does Staff recommend?

A. Staff recommends a base cost of purchased power for Trico of $.081211 per kWh, based on an adjusted purchased power cost (excluding GS4) of $47,052,606 and annual adjusted sales (excluding GS4) of 579,388,526 kWh as shown on Schedule MJR-6. This is discussed in greater detail by Staff witness Ranelle Paladino.

Q. Did Staff adjust the Cooperative test year revenues and expenses?

A. Yes, Staff increased test year revenue in the amount of $344,131 from $87,480,736 to $87,824,867 as discussed in the testimony of Staff witness Ranelle Paladino. Staff increased test year operating expenses in the amount of $134,897 from $78,576,621 to $78,711,518 as shown on Schedule MJR4.

Q. Explain the purpose of the break-out of the total revenue from sales of electricity into components as shown on Schedules MJR-5 and MJR-6.

A. The purpose is to show the portion of revenue that is generated from base rates separately from revenue that is generated from margin revenue, and the power cost adjustor.

Q. Is it appropriate to include monies from the Cooperative's WPCA in test year operating revenues for rate making purposes?

A. No, it is not appropriate. The Cooperative's test year base rate revenue is the starting point from which to measure the amount of increase in revenue that is necessary to recover ***all*** of the Cooperative's operating expenses (including the test year Staff adjusted purchased power expense of $52,472,056) plus a return on rate base. Consequently, for rate making purposes, the revenue generated by the WPCA rate would not reflect recovery of ***any*** expense in the revenue requirement, and therefore, should be eliminated.

Further, the WPCA revenues are set using a mechanism that facilitates full recovery of all purchased power costs and is separate from that used to set base rates. The adjustor mechanism ensures that the Cooperative neither over nor under recovers purchased power cost. Moreover, the Cooperative can change the WPCA rate without a rate case based on over- or under-collections in the Cooperative's fuel bank. This means that changes in the cost of purchased power do not affect income.

Q. What is Staff recommending?

A. Staff recommends increasing test year revenues by $344,131 as shown on Schedules MJR-6.

DEBT SERVICE COVERAGE RATIO ("DSC")

Q. Did the Cooperative calculate the DSC differently than Staff?

A. Yes. The Cooperative calculated a DSC of 1.94 whereas Staff calculated a DSC of 1.87.

Q. How does Trico calculate the DSC?

A. Trico uses the DSC calculation prescribed by the National Rural Utilities Cooperative Finance Corporation ("CFC"). The CFC includes revenues derived from activities that are not a part of the Cooperative's core electric retail sales business (i.e. non-operating margin interest revenue and cash capital credit revenue). The CFC calculation is as follows:

For any calendar year add (1) Operating Margins, (2) Non-Operating Margins-Interest, (3) Interest Expense on long-term debt, (4) Depreciation and Amortization Expense, and (5) cash received from capital credits. Divide the sum so obtained by the sum of all payments of Principal and Interest on long-term debt.

Q. How does Staff's DSC calculation differ from the Cooperative's?

A. Staff's calculation is similar but excludes non-operating revenue from interest and capital credits.

Q. Why does Staff exclude non-operating revenue in its DSC calculation?

A. Non-operating revenue tends to vary from year to year. Staff's calculation measures the Cooperative's ability to make principal and interest payments based solely on the Cooperative's core operating results. Since operating results are generally more consistent than non-operating results, Staff's calculation provides a more reliable indication of ability to service debt.

Q. Is the lower 1.87 DSC Staff calculates acceptable?

A. Yes, it is.

Q. Does this conclude Staff's direct testimony?

A. Yes, it does.

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-1

REVENUE REQUIREMENT

Line No.	Description		[A] COOPERATIVE FAIR VALUE		[B] STAFF FAIR VALUE
1	Adjusted Rate Base	A:	$ 175,076,536		$ 175,076,536
2	Margin (Loss) After Interest on L.T. Debt Test Year	A:	$ 2,906,355		$ 3,115,589
3	Current Rate of Return L2/L1		1.66%		1.78%
4	Required Rate of Return		6.33%		6.33%
5a	Required Margin (Loss) Before Interest on L.T. Debt (L	A:	$ 11,086,191	1	$ 11,086,191
5b	Required Margin (Loss) After Interest on L.T. Debt	A:	$ 5,088,431		$ 5,088,431
6	Operating Margin Deficiency (L5b-L2)	A:	$ 2,182,076		$ 1,972,842
7	Gross Revenue Conversion Factor		1.00		1.00
8	**Required Revenue Increase/(Decrease) (L7*L6)**	A:	**$ 2,182,076**	1	**$ 1,972,842**
9	Adjusted Test Year Revenue	A:	$ 87,480,736		$ 87,824,867
10	**Proposed Annual Revenue (L8+L9)**		**$ 89,662,812**		**$ 89,797,709**
11	Required Increase in Revenue (%)		2.49%		2.25%
12	Depreciation and Amortization Expense	A:	$ 7,244,614		$ 7,244,614
13	Interest Expense on Long-term Debt	A:	$ 5,088,431		$ 5,088,431
14	Interest Income	A:	$ 198,590		$ 198,590
15	Principal Payments	A:	$ 4,222,676		$ 4,222,676
16	Cash Capital Credits	A:	$ 401,298	2	$ 401,298
17	TIER ((L5b+ L13)/L13)		2.00		2.00
18	DSC ((L5b+L12+L13+L14+L16)/(L13+L15) - Per Coope		1.94		N/A
19	DSC ((L5b+L12+L13)/(L13+L15) - Per Staff		N/A		1.87

References:

Column A: Cooperative Schedule A-2
Column B: Staff Schedule MJR-2 and MJR-4

[1] The Cooperative calculated this at $11,086,191, which does not calculate to a rate of return of 6.33% to on rate base of 175,076,536.

[2] Cash Capital Credits did not print in the Docketed Schedule A-2.0, but was provided to Staff in an excel file as shown in Exhibit I.

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-2

RATE BASE - ORIGINAL COST

Line No.		[A] Cooperative As Filed	[B] Staff Adjustments	[C] Staff As Adjusted
1	**Plant In Service**	$ 236,133,674	$ -	$ 236,133,674
2	Less: Accumulated Depreciatio:	68,137,427	-	68,137,427
3	**NET PLANT**	**$ 167,996,247**	**$ -**	**$ 167,996,247**
4				
5	**ADDITIONS**			
6	Materials & Supplies	$ 3,263,020	$ -	$ 3,263,020
7	Prepayments	5,493,413	-	$ 5,493,413
8	**TOTAL ADDITIONS**	**$ 8,756,433**	**$ -**	**$ 8,756,433**
9				
10	**DEDUCTIONS**			
11	Consumer Deposits	$ 1,676,144	$ -	$ 1,676,144
12		-	-	-
13		-	-	-
14		$ -	$ -	$ -
15	**TOTAL DEDUCTIONS**	$ 1,676,144	$ -	$ 1,676,144
16				
17	**RATE BASE**	$ 175,076,536	$ -	$ 175,076,536

References:

Column A: Company Schedule B-1 Column C
Column B: MJR-3
Column C: MJR Testimony

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-3

SUMMARY OF RATE BASE ADJUSTMENTS

Line No.		Intangible Plant	[A] Cooperative	[B] Adjustment	[C] Staff
1	301.00	Organization	$ 1,180		$ 1,180
2		Total	$ 1,180	$ -	$ 1,180
3					
4		**Generation Plant**			
5	340.00	Land and Land Rights	$ 32,632		$ 32,632
6	346.00	Misc Power Plant Equipment	233,216		233,216
7		Total	$ 265,848	$ -	$ 265,848
8					
9		**Transmission Plant**			
10	350.00	Land and Land Rights	$ 532,578		$ 532,578
11	353.00	Station Equipment	7,943,380	-	7,943,380
12	355.00	Poles and Fixtures	1,649,438		1,649,438
13	356.00	OH Conductors	1,138,636		1,138,636
14		Total	$ 11,264,032	$ -	$ 11,264,032
15					
16		**Distribution Plant**			
17	360.00	Land and Land Rights	$ 101,005		$ 101,005
18	362.00	Substation Equipment	14,763,594		14,763,594
19	362.12	Mt Lemmon Standby Generator	875,063		875,063
20	364.00	Poles, Towers & Fixtures	25,413,089		25,413,089
21	365.00	Conductors & Devices	24,956,937		24,956,937
22	366.00	Underground Conduit	5,823,426		5,823,426
23	367.00	Underground Conductors	81,532,300		81,532,300
24	367.10	Underground Conducor & Devices _Cable Repl	1,572,696		1,572,696
25	368.00	Transformers	27,014,136		27,014,136
26	369.00	Services	7,361,685		7,361,685
27	370.00	Meters	11,907,173		11,907,173
28	371.00	Installations on Cons. Premises	328,549		328,549
29	373.00	Street Lighting & Signal System	1,561		1,561
30		Total	$ 201,651,214	$ -	$ 201,651,214
31					
32		**General Plant**			
33	389.00	Land and Land Rights	$ 734,514		$ 734,514
34	390.00	Structures & Improvements	10,765,059		10,765,059
35	391.00	Office Furniture & Equipment	1,600,780		1,600,780
36	392.00	Transportation	5,985,727		5,985,727
37	393.00	Stores Equipment	377,529		377,529
38	394.00	Tools, Shop & Garage	696,189		696,189
39	395.00	Laboratory Equipment	1,057,434		1,057,434
40	396.00	Power Operated Equipment	876,148		876,148
41	397.00	Communications Equipment	506,810		506,810
42	398.00	Miscellaneous	179,703		179,703
43	399.00	Other Tangible Property - Generator	5,167		5,167
44		Total	$ 22,785,060		$ 22,785,060
45					
46	105.00	Plant Held for Future Use	$ 166,341	$ -	$ 166,341
47					
48		Total Classified Plant	$ 236,133,674	$ -	$ 236,133,674
49					
50		Construction Work in Progress	$ - [1]		
51					
52		Total Utility Plant in Service	$ 236,133,674	$ -	$ 236,133,674
53					
54		Accumulated Depreciation	$ (68,137,427)	$ -	$ (68,137,427)
55					
56		Total Net Plant	$ 167,996,247	$ -	$ 167,996,247
57					
58					
59					

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-4

OPERATING MARGIN - TEST YEAR AND STAFF RECOMMENDED

Line No.		[A] Cooperative Test Year	[B] Staff Test Year Adjustments	[C] Staff Test Year	[D] Staff Recommended Changes	[E] Staff Recommended
1	**Revenues**					
2	**Margin Revenue (Non-Power)**	$ 33,522,480	$ 209,234	$ 33,731,714	$ 1,972,842	$ 35,704,556
3						$ -
4	Base Cost of Power ("BCOP")	$ 46,872,329	$ 180,277	$ 47,052,606	$ -	$ 47,052,606
5	GS4 Power Revenue	$ 5,422,757	$ (3,307)	$ 5,419,450		$ 5,419,450
6	Wholesale Power Cost Adjustment Revenue ("	$ 42,073	$ (42,073)	$ -	$ -	$ -
7	Rounding	$ -	$ -	$ -	$ -	$ -
8	BCOP, GS4, and Adjustor Revenue	$ 52,337,159	$ 134,897	$ 52,472,056	$ -	$ 52,472,056
9	**Total Revenue from Sales of Electricity**	$ 85,859,639	$ 344,131	$ 86,203,770	$ 1,972,842	$ 88,176,612
10						
11	Sales for Resale _ Other	$ -	$ -	$ -	$ -	$ -
12	Other Revenues	$ 1,621,097	$ -	$ 1,621,097	$ -	$ 1,621,097
13	**Total Revenue**	$ 87,480,736	$ 344,131	$ 87,824,867	$ 1,972,842	$ 89,797,709
14						
15	**Expenses**					
16	Power Production	$ 25,326	$ -	$ 25,326	$	$ 25,326
17	Purchased Power	52,337,159	134,897	52,472,056	-	$ 52,472,056
18	Transmission of Electricity by Others	-		-		-
19	Transmission Expense O&M	5,046	-	5,046	-	5,046
20	Distribution Expense - Operations	4,909,888	-	4,909,888	-	4,909,888
21	Distribution Expense - Maintenance	1,804,667	-	1,804,667	-	1,804,667
22	Customer Accounting	2,477,823	-	2,477,823	-	2,477,823
23	Customer Service	354,456	-	354,456	-	354,456
24	Sales	305,729	-	305,729	-	305,729
25	Administrative & General	5,369,097	-	5,369,097	-	5,369,097
26	Depreciation & Amortization	7,244,614	-	7,244,614	-	7,244,614
27	Tax Expense	3,742,816	-	3,742,816	-	3,742,816
28	**Total Operating Expenses**	$ 78,576,621	$ 134,897	$ 78,711,518	$ -	$ 78,711,518
29						
30	**Operating Margins Before Interest & Other Deductions**	$ 8,904,115	$ 209,234	$ 9,113,349	$ 1,972,842	$ 11,086,191
31						
32						
33						
34	Interest L-T Debt	$ 5,088,431	-	$ 5,088,431	$ -	$ 5,088,431
35	Interest-Other	2,364	-	2,364	-	2,364
36	Other Deuctions	906,965	-	906,965	-	906,965
37	**Total**	$ 5,997,760	-	$ 5,997,760	$ -	$ 5,997,760
38						
39	**Operating Margins After Interest & Other Deductions**	$ 2,906,355	$ 209,234	$ 3,115,589	$ 1,972,842	$ 5,088,431
40						
41	**Non-Operating Margins**					
42	Interest Income	$ 198,590	$ -	$ 198,590	$ -	198,590
43	Other Margins	114,633	-	114,633	-	114,633
44	G&T Capital Credits	4,552,806	-	4,552,806	-	4,552,806
45	Other Capital Credits	464,817	-	464,817	-	464,817
46	**Total Non-Operating Margins**	$ 5,330,846	$ -	$ 5,330,846	$ -	$ 5,330,846
47						
48	**NET MARGINS**	$ 8,237,201	$ 209,234	$ 8,446,435	$ 1,972,842	$ 10,419,277
49						
50	Long-Term Debt Principal Payment	$ 4,222,676		$ 4,222,676	$ -	$ 4,222,676
51						
52	Cash Received from Retirements of Capital C	$ 401,298		$ 401,298		$ 401,298
53						

References:

Column A: Cooperatiave Schedule A-2.0
Column B: Schedule MJR-6
Column C: Column (A) + Column (B)
Column D: Schedule MJR-1
Column E: Column (C) + column (D)

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-5

SUMMARY OF TEST YEAR OPERATING ADJUSTMENTS

Line No.		[A] COOPERATIVI	[B] Net Metering, Base Cost of Power, Elimation of WPCA Revenue ADJ # 1	[C] STAFF
1	**Revenues**			
2				
3	Base Revenue (Non-Power Revenue)	$ 33,522,480	$ 209,234	33,731,714
4				
5	Base Cost of Power	$ 46,872,329	$ 180,277	$ 47,052,606
6	GS4 Power Revenue	5,422,757	(3,307)	5,419,450
7	WPCA Revenue	42,073	(42,073)	-
8	Rounding	-	-	-
9	Fuel Bank	-	-	-
10	Subtotal	52,337,159	134,897	52,472,056
11		7,943,380		
12	Other	1,621,097	-	1,621,097
13	**Total Revenue**	87,480,736	344,131	87,824,867
14				
15	**Expenses**			
16	Power Production	$ 25,326	$ -	25,326
17	Purchased Power	52,337,159	134,897	52,472,056
18	Transmission Expense O&M	5,046	-	5,046
19	Distribution Expense - Operations	4,909,888	-	4,909,888
20	Distribution Expense - Maintenance	1,804,667	-	1,804,667
21	Consumer Accounting	2,477,823	-	2,477,823
22	Customer Service	354,456		354,456
23	Sales	305,729		305,729
24	Administrative & General	5,369,097	-	5,369,097
25	Depreciation & Amortization	7,244,614	-	7,244,614
26	Tax Expense	3,742,816	-	3,742,816
27		-	-	-
28	Rounding	-	-	-
29	**Total Operating Expenses**	$ 78,576,621	$ 134,897	$ 78,711,518
30				
31	**Operating Margins Before Interest & Other Deductions**	8,904,115	209,234	9,113,349
32				
33	**Interest & Other Deductions**			-
34	Interest L-T Debt	5,088,431		5,088,431
35	Interest-Other	2,364		2,364
36	Other Deductions	906,965		906,965
37	Total	5,997,760		5,997,760
38				
39	**Operating Margin After Interest & Other Deductions**	$ 2,906,355	209,234	$ 3,115,589
40				
41	**Non-Operating Margins**			
42	Interest Income	$ 198,590	$ -	$ 198,590
43	Other Margins	114,633	-	114,633
44	G&T Capital Credits	4,552,806	-	4,552,806
45	Other Capital Credits	464,817		464,817
46	**Total Non-Operating Margins**	$ 5,330,846	$ -	$ 5,330,846
47				
48	**NET MARGINS**	$ 8,237,201	$ 209,234	$ 8,446,435

References:

Column A: Company Schedule C-1.
Column B: Column C - Column A
Column C: Staff Testimony

Trico Electric Cooperative, Inc.
Docket No.: E-01461A-15-0363
Test Year Ended: December 31, 2014

Schedule MJR-6

OPERATING MARGIN ADJUSTMENT NO. 1 - NET METERING, BASE COST OF POWER AND ELIMINATION OF WPCA

LINE NO.	DESCRIPTION	[A] Cooperative As Filed	[B] Staff Adjustments	[C] Staff
1				
2	Base Revenue (Non-Power Revenue)	$ 33,522,480	$ 209,234	$ 33,731,714
3				
4	Base Cost of Power	$ 46,872,329	$ 180,277	$ 47,052,606
5	GS-4 Base Cost of Power	$ 5,422,757	$ (3,307)	$ 5,419,450
6	Subtotal (Line 4 + Line 5)	$ 52,295,086	$ 176,970	$ 52,472,056
7	WPCA Revenue	$ 42,073	$ (42,073)	$ -
8	Total Power Revenue (Line 6 + Line 7)	$ 52,337,159	$ 134,897	$ 52,472,056
9				
10	Subtotal (Line 2 + Line 8)	$ 85,859,639	$ 344,131	$ 86,203,770
11				$ -
12	Fuel Bank	$ -	$ -	$ -
13	Other	$ 1,621,097	$ -	$ 1,621,097
14	Total Revenue (Line 10 + Line 12 + Line 13)	$ 87,480,736	$ 344,131	$ 87,824,867

References:
Column A: Schedule E-7.5 page 1
Column B: Column C - Column A
Column C: Staff Testimony

EXHIBIT
S-10
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NON-PROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASE IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS	)	DOCKET NO. E-01461A-15-0363

DIRECT

TESTIMONY

OF

MARGARET (TOBY) LITTLE

UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 4, 2016

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III. ENGINEERING REVIEW 2

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EXHIBIT

Engineering Report 1

EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

Margaret (Toby) Little's testimony presents the results of Utilities Division Staff's ("Staff") review of the rate case application ("Application") of Trico Electric Cooperative, Inc. ("Trico" or "Cooperative") filed with the Arizona Corporation Commission ("Commission") on October 23, 2015, and the results of Staff's engineering evaluation of the Cooperative's electric distribution system.

Based on its review of Trico's Application, inspection of the Cooperative's electric system, discussions with the Cooperative's staff, and responses to data requests, Staff's conclusions are as follows:

a. Trico is operating and maintaining its electrical system properly.

b. Trico is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate. The Cooperative's plant in service for the Arizona service territory is "used and useful."

c. The Direct Assignment Facilities are "used and useful" to the Cooperative's provision of service.

d. It is appropriate to assign a 12.9-year average remaining life and a corresponding depreciation rate to electronic meters and associated equipment.

e. The Cooperative has an acceptable level of system losses, consistent with the industry guidelines.

f. Trico has a satisfactory record of service interruptions in the historic period from 2010 thru 2014, reflecting a quality of service consistent with a well maintained and operated system.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Margaret (Toby) Little. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I received both my Bachelors and Master's Degrees in Electrical Engineering from New Mexico State University. I graduated with my Bachelor's Degree in July 1972, and received my Master's Degree in January 1979. My Master's Program at New Mexico State University was in Electric Utility Management. I received my Professional Engineering ("P.E.") License in the state of California in 1980.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission ("Commission") from September 2010 to February 2011 as a Utilities Contractor, was employed by the Commission from February 2011 to February 2012 an Electric Utilities Engineer, and have been a Utilities Contractor since February 2012. During this time I have performed engineering analyses for financing and rate cases, coordinated the Seventh and Eighth Biennial Transmission Assessments, reviewed utilities' load curtailment plans and summer preparedness plans, and conducted various other engineering analyses. From 1983 through 1987 I was the Supervisor of System Planning for Anchorage Municipal Light and Power, the second largest utility in Alaska. There I had overall responsibility for distribution, transmission and resource planning for the utility and supervised six electrical engineers. From 1979 through 1982 and 1987 through 1988 I worked for R.W. Beck and Associates, a nationally recognized engineering firm. There I performed many types of engineering analyses involving resource and transmission planning and worked on the engineer's reports for the financing of a major generation facility in

northern California. Prior to that, I worked in the System Planning Sections of San Diego Gas and Electric Company and Hawaiian Electric Company, where I had responsibility for short and long range distribution planning.

II. PURPOSE OF TESTIMONY

Q. As part of your assigned duties at the Commission, did you perform an analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

Q. What is the purpose of your pre-filed testimony?

A. The purpose of my testimony is to present the results of Utilities Division Staff's ("Staff") engineering evaluation of Trico Electric Cooperative's ("Trico" or "Cooperative") electric distribution system operations and planning in the state of Arizona.

III. ENGINEERING REVIEW

Q. Did you perform an engineering evaluation of Trico's electrical system?

A. Yes, I did. Based on a review of Trico's rate application ("Application"), a site visit in which I inspected parts of Trico's electric distribution system in Arizona and held discussions with members of Trico staff, and responses to data requests from Trico, I prepared an engineering report presenting my findings.

Q. Is the engineering evaluation report a part of your testimony today?

A. Yes it is. It is attached as Exhibit I.

IV. CONCLUSIONS

Q. What conclusions are derived based on Staff's engineering evaluation of Trico's electric distribution system in Arizona?

A. Staff's conclusions are as follows:

a. Trico is operating and maintaining its electrical system properly.

b. Trico is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate. The Cooperative's plant in service for the Arizona service territory is "used and useful."

c. The Direct Assignment Facilities are "used and useful" to the Cooperative's provision of service.

d. It is appropriate to assign a 12.9-year average remaining life and a corresponding depreciation rate to electronic meters and associated equipment.

e. The Cooperative has an acceptable level of system losses, consistent with the industry guidelines.

f. Trico has a satisfactory record of service interruptions in the historic period from 2010 thru 2014, reflecting satisfactory quality of service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT 1

MEMORANDUM

TO: Rick Lloyd
Public Utilities Analyst
Utilities Division

FROM: Margaret (Toby) Little
Electric Utilities Engineer
Utilities Division

THRU: Del Smith
Engineering Supervisor
Utilities Division

DATE: April 11, 2016

RE: STAFF ENGINEERING REPORT FOR THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS (DOCKET NO. E-01461A-15-0363)

GENERAL

Trico Electric Cooperative, Inc. ("Trico" or "Cooperative") submitted an application on October 23, 2015 to the Arizona Corporation Commission ("Commission") for a determination of the fair value of its utility plant and property and for increases in its rates and charges for utility service. In addition, the Cooperative is seeking approval of modifications to its rate design and net metering tariff, modifications to its Rules, Regulations and Line Extension Policy ("RRLEP"), updated depreciation rates for its metering facilities, the inclusion of Direct Assignment Facilities ("DAFs") to be acquired from Southwest Transmission Cooperative ("SWTC") in rate base as post-test year plant and for ratemaking purposes, an amendment to its Sun Watts Sun Farm Tariff, and approval for an increase in its overall revenue requirement.

ENGINEERING EVALUATION

Trico is a member-owned, non-profit, rural electric distribution cooperative headquartered in Marana, Arizona. Trico serves primarily rural areas in Pima, Pinal and Santa Cruz Counties and provides electric service to approximately 38,000 members, most of whom are residential customers. Trico is governed by a member-elected Board of Directors ("Board"), all of whom are members of Trico.

Trico is a Class A Partial Requirements Member ("PRM") of Arizona Electric Power Cooperative, Inc. ("AEPCO"), which generates or procures power on a wholesale basis for Trico

and other member distribution cooperatives. Trico is also a Class A Member and network transmission customer of SWTC. Trico obtains almost all of its power from AEPCO and from other wholesale power purchases. Trico's only generation facilities are a 1.75 MW diesel generator located in a remote area for backup purposes, and the 227 kW SunWatts Community Sun Farm located at the Cooperative's headquarters.

Trico is currently authorized to charge rates for electric service per Decision No. 71230 (August 6, 2009). The test year used in that proceeding was the 12-month period ending on December 31, 2007. The Cooperative states in its Application that the need for additional revenue is not driving this Application. Rather, it is being driven by the need to better align the rates of certain classes of Member-customers with the costs of serving them, and to address inequities among Members in the manner in which the fixed cost of providing electric service are recovered by the Cooperative. In addition, the Application seeks to incorporate facilities to be acquired from SWTC into the Cooperative's plant and rate base, to update the depreciation rate for automated metering equipment, and to amend Trico's RRLEP to provide, among other things, a reasonable allowance for line extensions.

Trico Site Visit and Facilities Inspection

Utilities Division Staff ("Staff") met with Trico Staff at its Headquarters in Marana on March 1, 2016. Representing the Engineering Division of the Commission were Margaret (Toby) Little, Nonso C-Emordi and Zach Branum. Staff met with Vincent Nitido, CEO and General Manager; Karen Cathers, Chief Operating Officer; Steve Beyer, Technical Services Manager; Ronald Brown, Manager, Electric Operations; Brian Fickett, Controller; and Janice Rast, Information Technology/Meter Services/Member Services. Steve Beyer and Ron Brown also took Staff on an inspection of various facilities. During the visit, the history of the Cooperative's operations and their organization related to customer service, planning, engineering, construction, system operations, meters, rates and maintenance were discussed. Cost, location, and reason for major construction projects as outlined in the responses to Staff data requests were discussed as well as points of delivery and source of wholesale power purchases, system loss values, operations procedures on the electric system, inspection procedures, system characteristics, and potential for growth. Metering, Line Extension policies, and the issues caused by the recent sharp increase in applications for solar Distributed Generation were also discussed.

Electric System Description

Trico's service territory is mostly within Pima County, in an area surrounding Tucson (which is served by Tucson Electric) from the northern border of the county to the Arizona/Mexico border, and from Mount Lemon in the east to the Papago Indian Reservation in the west. The Cooperative also serves small pockets of load in both southern Pinal and north central Santa Cruz Counties. With the exception of the area around Marana and a retirement community near Oro Valley, the service territory is almost exclusively rural residential.

Trico owns no generation facilities other than a 1.75 MW diesel generator located in a remote area which is exclusively used for backup and a 227 kW solar facility used for its Community Solar program.

The Cooperative has over 3,711 miles of underground and overhead distribution system lines (operated at less than 34.5 kV), approximately 31 miles of transmission lines (34.5 kV and above), and three substations at or above 69 kV. Trico is in the process of acquiring DAFs from SWTC. DAFs are defined in the service agreements between Trico and SWTC as those transmission facilities constructed and owned by SWTC after September 1999 that are not part of the SWTC system facilities and that are utilized to provide transmission service only to Trico, consistent with the Federal Energy Regulatory Commission ("FERC") applicable decisions. The current SWTC DAFs assigned to Trico include all or part of eight transmission substation delivery point facilities.

Trico receives power at eleven delivery points on their system: at Saddlebrook Ranch Substation, Oracle Junction, Marana Substation, Thornydale Substation, Avra Valley Substation, Sandario Substation, Three Points Substation, Valencia Substation, Bicknell Substation, Sahuarita Substation and New Tucson Substation. Because it serves primarily rural load, much of the distribution system is radial.

Electric System and Customer Characteristics

At year-end in 2014, Trico served 43,050 customers of which 40,717 were residential, 2,281 were commercial, and 52 were classified as "Other." The accounts classified as "Other" include all of the accounts in two irrigation districts that are served at wholesale (Avra Valley Irrigation & Drainage District and Silverbell Irrigation & Drainage District), as well as street lighting accounts; the Cooperative does not serve any industrial customers at this time.

The year-end number of services, including all classes of customers, increased from 39,688 in 2010 to 43,050 in 2014, an average annual increase of 2.11 percent.

Trico's actual Arizona system peak load and energy along with number of customers are listed below:

Historical System Characteristics

Year	Year End Number of Customers	Actual Peak Demand (MW)	Annual Demand Growth (%)	Annual Load (MWh)	Annual Load Growth (%)
2010	39,688	165.02		620,823	
2011	40,315	173.68	5.2	648,198	4.4
2012	40,926	174.10	0.2	662,418	2.2
2013	41,880	194.67	11.8	663,056	0.1
2014	43,050	182.98	(6.0)	671,676	1.3

When asked about the unexpectedly high peak demand reading in 2013, Trico staff indicated that the summer of 2013 was particularly hot. Peak demand is often dependent on weather and is not always a good indicator of actual growth on an electric system, particularly on a year to year basis; better indicators are both total annual load growth and peak demand growth averaged over several years. The average annual increase in peak demand from 2010 to 2014 for Trico was 2.7 percent; the average annual increase in annual load was 2.4 percent over the same period.

Annual System Losses

Trico's system is rural, with an average of slightly over eleven customers per mile of distribution line. As a result, losses can be expected to be greater than on an electric system with a higher customer density; long lines at a distribution voltage result in more system losses. The American Public Power Association's Distribution System Loss Evaluation Manual ("Manual") indicates that system losses of 10 percent are reasonable for a mostly rural system. Trico's annual total system losses for the last five years were:

Year	Percent System Losses
2010	4.30%
2011	4.36%
2012	3.58%
2013	6.90%
2014	4.46%

Trico's annual historic system losses average 4.72 percent for this five year period, which is well within the guidelines set forth in the Manual.

When asked about the higher than average reported losses in 2013, Trico indicated that there were two reasons for this. The first reason relates to how the losses are calculated and the impact that weather at the end of the year or the beginning of the next year has on those calculations. The second is that 2013 was the first year that Trico was in the TEP Balancing Authority and that Trico failed to reduce the total energy reported as purchased, which had the effect of increasing the reported losses. When corrected for these two anomalies, the 2013 losses would have been approximately 4.5 percent rather than 6.9 percent, which is very similar to historical losses.

Quality of Service

The outages that occur in a utility's system stem from a variety of causes and are an indicator of the quality of service to customers. Some of these causes are storm-related; others are relative to switching surges, equipment failure and planned outages. The historical data relative to Trico's distribution system outages as measured by the System Average Interruption Duration Index[1] ("SAIDI") which measures the total duration of an interruption for the average customer on an annual basis, for the period 2010 through 2014, are shown in the table below.

[1] To calculate SAIDI, each interruption during the time period is multiplied by the duration of the interruption to find the customer-minutes of interruption. The customer-minutes for all interruptions during the time period are then summed and divided by the total number of customers.

Annual System Average Interruption Duration Index in Minutes

YEAR	SYSTEM AVERAGE INTERRUPTION DURATION INDEX - MINUTES					
	Power Supplier	*Planned*	***All Other***	*Total Excluding Major Events*	***Major Events***	**All Events**
2010	3.6	0.0	**69.7**	73.3	**134.7**	**208.0**
2011	0.0	0.0	**83.1**	83.1	**21.6**	**104.7**
2012	21.6	0.0	**61.8**	83.4	**0.0**	**83.4**
2013	0.0	0.0	**44.1**	44.1	**75.7**	**119.8**
2014	14.4	0.0	**47.4**	61.8	**32.8**	**94.6**
Five-Year Average	7.9	0.0	**61.2**	69.1	**53**	**122.1**

According to the Rural Utilities Service ("RUS") Bulletins which Staff uses to judge the adequacy of a cooperative's reliability, a concern would exist when the SAIDI for "All Other" exceeds 200 minutes[2]. Trico's service quality over the five year period in terms of this metric has ranged from 44.1 minutes to 83.1 minutes with an average of 61.2 minutes, all well below the level of concern and indicating a well maintained and operated distribution system.

Distribution System Inspection

During the site visit on March 1, 2016, Staff inspected two of the major substations and portions of the transmission, sub-transmission and distribution systems, as well as facilities at Trico Headquarters. Of particular interest to Staff were the DAFs in the substations inspected.

Sandario Substation and Thornydale Substation were inspected during the site visit; both include DAFs and are delivery points. It was noted that the substations are extremely well maintained, with safety related equipment installed. Inspection included the station houses which contain controls, communication equipment, and back-up power supplies. Surveillance cameras are planned for all substations.

Trico maintains a 15 MVA mobile substation for use at any substation on the system should there be an outage on equipment within a substation. The mobile substation was on-site at

[2] As shown, outage statistics are categorized into four major causes. Power Supplier and Planned causes are separated because they represent causes over which the cooperative has virtually no control or total control, respectively, and should be analyzed separately. Major Events include outages on major event days which are days when the daily average outage minutes per customer exceed a threshold value. The threshold is determined based upon a formula specified in the RUS Bulletin 1703A-119, can change over time, and is specific to each cooperative. That leaves all other outages included in the All Other cause. All Other and Major Events are segregated to better reveal trends in daily operation in the All Other cause category that would be hidden by the large statistical effect of Major Events.

Thornydale Substation, (not energized but ready to be, should the need arise), and was found to provide an excellent back-up in the case of a substation outage. All substations have equipment that would enable the connection of the mobile sub to be made easily.

A tour of the facilities at Trico Headquarters included office and customer service facilities, supervisory control and data acquisition ("SCADA") control room, meter maintenance shop, warehouse, equipment and vehicle yard, and repair shops. All facilities were found to be well organized, clean and well maintained.

The Cooperative's routine maintenance program appears robust. It includes, but is not limited to, routine inspection of all poles with replacement as necessary; right-of-way maintenance and tree clearing as necessary; monthly substation inspections; annual oil tests on substation power transformers and reactors; line recloser, voltage regulator, line capacitor and reactor inspection and maintenance; and twice yearly infra-red inspections at substations[3]. In addition, Trico has a program of passively inspecting and analyzing the integrity of its underground cable and associated termination points to identify and repair as necessary those that may be failing or may experience a corona type discharge[4].

Trico uses technology to achieve efficiencies including automated meter reading (over power line carrier and using cell phone technology) and SCADA control of all substations on their system with a state-of-the-art SCADA control facility located at Trico Headquarters. The Cooperative uses NISC (a software program utilized by many rural electric cooperatives in the country) for billing, engineering support, software support, customer information, accounting, and Geographical Information System ("GIS") location information.

In general, the Trico electric system appears to be well planned and maintained. No deficiencies or obvious problems were observed during the inspection tour.

Direct Assignment Facilities

Under SWTC's policies, the carrying costs associated with transmission facilities constructed and owned by SWTC that are utilized to provide transmission service only to Trico (Direct Assignment Facilities or DAFs) are assigned to and paid by Trico. These costs are passed through directly to Trico's Members. The SWTC DAFs assigned to Trico include all or part of eight transmission substation delivery point facilities.

Trico has reached an agreement with SWTC whereby Trico will purchase its DAFs effective as of the date of Commission approval of the Application; Trico seeks to include the DAFs it is acquiring from SWTC into rate base as post-test year plant, which will reduce the purchased power costs associated with energy losses on those facilities.

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[3] Infra-red inspections allow a utility to check for areas of increased heat ("hot spots"), indicating equipment that may not be operating properly and potentially would need maintenance.

[4] Corona discharge is an electrical discharge brought on by the ionization of a fluid surrounding a conductor that is electrically charged. This generates gases such as ozone and nitrogen oxide, and in turn nitric oxide and nitric acid if water vapor is present. They are highly undesirable where they waste power in electrical systems.

Based on an inspection of the DAFs at Sandario and Thornydale Substation and a review of on-line diagrams for the remaining substations containing DAFs, Staff concludes that the facilities are "used and useful," to the Cooperative's provision of service. Trico stated in its application that "[a]cquiring the DAFs provides Trico with better control over the operation and maintenance expenses of those DAFs, and benefits Trico's Members because Trico will no longer pay a margin to SWTC."

Automated Metering Equipment Depreciation

Trico is seeking to adopt new depreciation rates for its advanced meters. Trico's current meter depreciation rate is based upon mechanical analog meters with an average useful life exceeding 30 years. The Cooperative's metering system is now entirely automated, using both power line carrier and cell based technologies. The industry standard for average service life of electronic meters is 15 to 20 years; Trico has conservatively chosen to use 20 years. This is the basis for the calculated 12.9 average remaining life requested in the Application.

Staff has reviewed the depreciation study done for Trico by Management Application Consulting, Inc. and has determined that an average remaining life of 12.9 years is reasonable.

Solar Rooftop Installations

In testimony[5] provided as a part of the Application as well as in discussions, Trico staff indicated that they have experienced a large increase in the number of applications for solar rooftop installations.

Staff asked the Cooperative if they have experienced any operational issues as a result of this increase in solar. They responded that they have installed a reactor on one circuit to correct the leading power factor that is the result of lack of load (due to use of distributed generation ("DG")) on an all-underground circuit.

In addition, they indicated that Trico anticipates they may encounter a need for increasing facility size on circuits with high penetrations of DG due to the fact that distributed generation installations are allowed to be sized at 125 percent of individual customer peak load. Their policy is currently that the customer installing the facility that will cause the overload be responsible for the costs associated with the upgrades. At this point they have not experienced overload on any distribution circuits.

All utilities with high penetrations of DG have, or will, experience operational issues such as those Trico has and expects to encounter. Trico has effectively managed the situations encountered and has policies in place which are expected to deal effectively with future operational issues.

[5] Vincent Nitido, pg 11

Planning and Projected System Growth

Staff reviewed the Cooperative's most recent Construction Work Plan ("CWP"), along with a list of projects over $500,000 installed and placed in-service since the last rate case. During the site visit, Staff discussed planning assumptions used in the development of their CWP. Recent system improvements, system upgrades and new construction are reasonable and appropriate, as are the assumptions used for planning purposes.

Trico provided the following projections for peak demand growth for their Arizona system over the next five year period. The projections were made using an econometric model based on assumptions and methodologies that include both historical data and projections for the economy over the next few years. The model creates low, medium and high projections for planning purposes; the following are projections in the medium range.

Year	System Peak	Percent Growth
2015	187.591 MW	2.5%
2016	193.852 MW	3.3%
2017	200.395 MW	3.4%
2018	207.213 MW	3.4%
2019	214.297 MW	3.4%

The average annual growth is projected by Trico to be slightly over three percent per year over the next five year period which is consistent with growth on the system over the past six years and projected economic conditions for the area. Based on discussions with Trico personnel, review of historical data and expectations for the Arizona economy, the projected load growth seems reasonable.

CONCLUSIONS

Based on its review of Trico's Application, inspection of the Cooperative's electric system, discussions with the Cooperative's staff, and responses to data requests, Staff's conclusions are as follows:

a. Trico is operating and maintaining its electrical system properly.

b. Trico is carrying out system improvements, upgrades and new additions to meet the current and projected load of the Cooperative in an efficient and reliable manner. These improvements, system upgrades and new construction are reasonable and appropriate. The Cooperative's plant in service for the Arizona service territory is "used and useful."

c. Staff has concluded that the DAFs are "used and useful" to the Cooperative's provision of service.

d. It is appropriate to assign a 12.9-year average remaining life and a corresponding depreciation rate to electronic meters and associated equipment.

e. The Cooperative has an acceptable level of system losses, consistent with the industry guidelines.

f. Trico has a satisfactory record of service interruptions in the historic period from 2010 thru 2014, reflecting a quality of service consistent with a well maintained and operated system.

EXHIBIT 11
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

DIRECT

RATE DESIGN

TESTIMONY

OF

ERIC VAN EPPS

EXECUTIVE CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 1, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

The Direct Rate Design Testimony of Eric Van Epps presents the results of the Utility Division Staff's ("Staff") review of the rate case application ("Application") of Trico Electric Cooperative, Inc. ("Trico" or "Company") filed with the Arizona Corporation Commission ("Commission") on October 23, 2015 and the results of Staff's evaluation of the Company's Net Metering ("NEM") proposal. Staff witness Ranelle Paladino addresses the remainder of Staff's rate design proposals.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am an Executive Consultant employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. I perform studies and provide recommendations to the Commission on matters involving electric and gas utilities.

Q. Please describe your educational background and professional experience.

A. I have bachelor's degrees in Business Administration and Political Science, specializing in international business and international politics and a degree in Sustainability with a focus on alternative energy and resources from Arizona State University. I have been employed with the Commission since January of 2013.

Q. What is the scope of your testimony in this case?

A. I will be addressing Net Metering ("NEM"), for Trico Electric Cooperative, Inc. ("Trico" or "Company").

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimonies of Company witnesses, Mr. Vincent Nitido, Ms. Karen Cathers and Mr. David Hedrick, as they pertain to NEM.

NET METERING

Q. What is Trico's proposal for changing NEM?

A. The Company has maintained its original NEM proposal, first proposed in February of 2015:

1. For energy generated by a distributed generation ("DG") Member's system that is used to serve that DG Member's load, the DG Member would continue to benefit from a full retail rate offset for that energy (i.e., no change).

2. For any *excess* energy that is delivered to Trico from the DG Member's system, Trico would provide a credit on the DG Member's bill each month for the excess generation at Trico's 2014 actual wholesale energy avoided cost rate, which is currently $0.03662 per kWh (thus, no longer rolling excess generation from the DG Member's system month to month).[1]

3. The DG Member would continue to pay Trico for any energy delivered from Trico at the tariff retail rate established in this case.

4. Trico's proposed change only affects the interval for excess energy and the credit for excess generation from the DG Member's facility.

Q. Does Staff accept the Company's proposal to change NEM?

A. No, but Staff may update its position later in this case.

[1] It is Staff's understanding the interval of measurement of excess energy would be instantaneous.

Q. Did Trico propose any grandfathering provision with its request to alter NEM?

A. Yes. Trio has proposed that its new Net Metering Tariff apply only to those members who submitted interconnection applications after February 28, 2015. All other DG Members would be grandfathered under its current Net Metering Tariff.[2]

Q. If Staff supported changes to NEM, what would be its position on NEM grandfathering?

A. Staff would be able to support grandfathering up to the date of a decision or settlement in this case. Staff would support partial grandfathering and would recognize that the topic could be revisited during each subsequent rate case by the Commission. Staff would recommend no further grandfathering of DG systems installed after an established cut-off date.

Q. Is there evidence that the Company is under-recovering fixed costs due to current DG installations?

A. Yes, because two-part rates, by definition, include fixed costs in the volumetric rate component and DG reduces kWh usage. Company witness Mr. David Hedrick has indicated that there was an under-recovery associated with the proliferation of DG systems that equated to $1,262,079 for Trico under the existing residential rate in its 2014 test year.

Q. Can Staff verify the $1,262,079 under-recovery?

A. No. The $1,262,079 under-recovery is based on assumptions that may or may not be exactly accurate. For example, the Company has production meters on its current DG customers.

[2] Trico did notice its members that there could be a change to NEM and that they may or may not be grandfathered past February 28, 2015. Staff would also note that when investing in technologies there is a fair amount of risk, one such risk is that value or profit may change over time. In this case some of a DG systems value or profit is derived from the current NEM tariff. Staff believes that Trico has provided adequate notice to its members submitting applications after February 28, 2015, that there could be a change to its NEM tariff.

The Company could use this information to more accurately depict the under-recovery attributable to DG customers between its last rate case and the test year.

Q. Has the lack of a verifiable under-recovery amount, influenced Staff's opinion in this case?

A. No. Staff believes there is a fixed cost under-recovery that can be attributable to DG systems.

Q. Given that there is a fixed cost under-recovery that can be attributable to the proliferation of DG under current NEM rules, why is Staff reluctant to make a recommendation in this case?

A. Typically, fixed cost under recoveries are resolved in the next rate case as the test year billing determinants already incorporate the reduced kWh volumes. Also, due to a number of ongoing electric cases awaiting decisions, Staff prefers to try to allow for their conclusion.

Q. Can you further explain?

A. Yes. In this case, the Company has requested a change to NEM that would rely on a substantially reduced export rate. The Company has requested that the export rate be the approved avoided cost rate of $0.03662/kWh. Although this is one option, the Commission has before it a generic docket investigating the value and cost of distributed generation, (Docket No. E-00000J-14-0023). This docket will continue to provide the Commission and Staff with information about an appropriate export rate which may or may not be the short-term avoided cost. There are various proposals in that docket which include different ways of looking at avoided cost and several different proxies for avoided cost including PPA rates and a methodology which would look at the weighted average of the utility's PPAs and owned utility scale solar revenue requirements.

Q. Does Staff have anything further to add to the Net Metering discussion?

A. Yes. Staff would like to note that there are many possible options when it comes to making adjustments to the way Net Metering currently functions. Further, Staff would like to emphasize the importance of fully understanding the impact of even minor differences between the various proposals currently being considered. It is important to understand how the mechanism and the export rate interact with one another. Variations in the billing methodologies and the export rate can have significant effects on the value to prospective solar customers and to a utility's ability to recover fixed costs. If the mechanism is only slightly changed and the export rate is decreased only slightly, a utility may see little to no improvement in its ability to recover fixed costs. On the other hand, if the mechanism is significantly changed and the export rate is low, the value to potential solar customers would be greatly reduced.

Staff believes that the inter-relationship between proposed export rates and changes to the net metering billing methodology should be evaluated together. The evaluation should include an analysis with metrics on a utility's ability to recover its fixed costs, the financial impacts for prospective solar customers, and include information on how the proposed changes would affect non-solar customers moving forward. Staff encourages Trico to put forth a more thorough evaluation of its proposed changes and their impact on customers in its rebuttal testimony.

Q. Has the Company provided any such analysis?

A. Company witness Mr. David Hedrick provided Exhibit DWH-8, which looks only at annual total lost fixed costs under three different scenarios. However, Staff disagrees with the conclusions illustrated in this study.

Q. Please Explain.

A. Exhibit DWH-8 implies that the Company's under-recovery associated with Trico's existing 1,262 DG customers would continue after new rates and changes to NEM went into effect. The Company would recover costs previously allocated to these DG customers from all other customers after new rates went into effect. Thus, the estimated $1,262,079 in under-recovered costs would be memorialized into rates based on test year volumes and as long as sales stayed the same, the Company would see recovery. Further, based on the Company's NEM proposal, the Company would likely see recovery for all energy credited at an export rate through the Company's Wholesale Power Cost Adjustor ("WPCA"). Additionally, because of the discontinuation of banking and the requirement for all kWh coming from the grid to be purchased at the retail rate, under-recovery associated with new DG customers would be drastically reduced.

Q. Do you believe Trico's filings have accounted for all of the variables associated with the changes to Net Metering it has proposed?

A. No. There are many moving parts with regard to a net metering policy direction. The NEM billing methodology (e.g., excess energy measurement interval), the export rate (e.g., how often it would change), adjustors affected by the export rate (e.g., the WPCA), cost shifts (e.g., accurate measurement), and Trico's own renewable goals are among the moving parts. Without a clear picture of all of the impacts of the changes proposed by Trico, it is difficult for Staff to make a recommendation at this time.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.

EXHIBIT 12
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

DIRECT TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

ERIC VAN EPPS

EXECUTIVE CONSULTANT II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 26, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE
DOCKET NO. E-01461A-15-0363

This testimony addresses the provisions of the Settlement Agreement regarding Net Metering, the new DG Energy Export Tariff and Grandfathering of Net Metering.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am an Executive Consultant II employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. I am responsible for the examination and verification of financial and statistical information included in electric and gas utility rate applications. In addition, I perform studies, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I have bachelors degrees in Business Administration and Political Science, specializing in international business and international politics and a degree in Sustainability with a focus on alternative energy and resources from Arizona State University. I have been employed with the Commission since January of 2013.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket E-01461-15-0363?

A. Yes.

Q. What is the scope of your testimony in this case?

A. This testimony will provide support for the Settlement Agreement ("Agreement") filed on July 8, 2016, by addressing Sections VII – IX of the Agreement regarding Net Metering, the new DG Energy Export Rider, and Grandfathering.

NET METERING

Q. What does the Agreement address with regard to Net Metering?

Section VII of the Agreement describes how Trico Electric Cooperative ("Trico" or "Cooperative") will alter its existing Net Metering tariff as well as who it will apply to going forward.

Q. Please describe how the Net Metering Tariff would change.

A. Under the Agreement, Trico would freeze its current Net Metering Tariff (Schedule NM), making the existing tariff applicable to DG interconnection applications received on or after May 31, 2016. Additionally, the Signatories have agreed to support a waiver of the Net Metering rules to the extent necessary.

Q. How will DG customers with interconnection applications received after May 31, 2016 be treated?

A. Under the Agreement, Trico would be required to create a new DG Export Tariff (Schedule NM1) which would compensate DG customers for excess energy put onto the grid. All customers who submitted interconnection applications after May 31, 2016, would go onto this new DG Export tariff in lieu of the frozen Net Metering Tariff.

NEW DG ENERGY EXPORT TARIFF

Q. What does the Agreement address with regard to the new DG Energy Export Tariff?

A. Section VIII of the Agreement describes the parameters for the new DG Energy Export Tariff.

Q. Please briefly describe the parameters of the new DG Energy Export Tariff.

A. The parameters are as follows:

- The new tariff will apply to all customers after May 31, 2016.
- The export rate will apply to all energy exported from a DG system to the grid, and compensate that DG member for their exported energy at a rate of $0.0770 per kWh.
- All energy supplied to a DG member from Trico will be charged in accordance with that member's standard rate schedule. There will be no netting or banking of excess kWh.
- If in any given month the credits received from exported energy are greater than that member's monthly bill, those credits will be carried forward to the next month. If at year-end there are remaining credits available, those credits will be paid out to the member.
- The Export rate will act as a rider in conjunction with all of Trico's rate schedules.

Q. What are the differences between the existing Net Metering Tariff Schedule NM and the new Export Energy Tariff Schedule NM1?

A. Simply stated, the difference between the aforementioned schedules deals primarily with the netting component. Under Schedule NM, DG customers are able to net excess energy produced from their DG system to offset energy consumed and taken from the grid. Further, under Schedule NM excess energy can be rolled over from month-to-month to offset future energy consumption. Schedule NM1 eliminates the netting and banking of excess kWh, and requires that all energy procured from the grid be paid for at Trico's respective retail rate, and requires that all exported energy by a DG system to the grid be credited for at $0.0770 per kWh.

Q. Why does Staff support the elimination of netting and banking?

A. Staff supports the elimination of netting and banking because they create an inequity with respect to the sale of excess energy by a DG customer. Under the existing Schedule NM,

which provides a one-for-one kWh offset, not only can a DG customer oversize a DG system to offset all consumption within a month but they can also carry forward any excess production to offset consumption in future months. DG systems can be sized in a way that is disproportionate to a customer's needs and, as a result, provide Trico with a glut of energy when the Cooperative doesn't need it and a lack of energy when it does. Further, a DG customer's ability to use the grid without paying for it, creates an under-recovery of fixed costs which in turn increases rates for all other customers.

Q. Does the Agreement help to address some of the issues you mentioned above?

A. Yes. By eliminating a DG customer's ability to net and bank, they are forced to pay for all energy they receive from the utility. Given that DG customers rely on the grid, just as all other customers do, DG customers have the same responsibility to pay for the infrastructure that allows them to have reliable power 24 hours a day. Further, the export rate allows for a DG customer to be credited or compensated for all excess energy at a rate equal to the Cooperative's Power supply cost. The disparity between the export rate and the retail rate allow the Cooperative to be compensated for the distribution portion of a customer's retail kWh rate. Essentially, under the export tariff, DG customers will be required to pay for the distribution portion of the kWh rate.

Q. Are there any additional benefits to an Export Tariff?

A. Yes. By eliminating the 1-for-1 kWh offset and creating an export energy transaction, the cost of DG energy can be realized. The utility can pass DG energy costs through its Wholesale Power Cost Adjustor ("WPCA") which in turn mitigates more of the under-recovery associated with the proliferation of DG.

Q. Have the signatories agreed to hold this rate case open for 18 months?

A. Yes. Currently, the Commission has before it an open case (Docket No. E-00000J-14-0023) investigating the value and cost of distributed generation ("VOS"). In the Agreement, Signatories agreed to hold this rate case docket open to address possible modifications to the export rate based on the conclusion of the VOS case.

GRANDFATHERING

Q. What does the Agreement address with regard to Grandfathering?

A. Section IX of the Agreement describes the parameters for Grandfathering of existing DG members.

Q. Please briefly describe the parameters of the Grandfathering agreement.

A. The parameters are as follows:

- Customers who applied for a DG interconnection on or before May 31, 2016, will be grandfathered on Schedule NM for the remaining term of the member's interconnection agreement or for 20 years, whichever is shorter.
- Grandfathering will only apply to schedule NM, not a member's standard rate schedule.
- Signatories agree to not support grandfathering for any interconnection application received after May 31, 2016.
- This agreement does not bind a future Commission.

Q. Are there any aspects of the Grandfathering provision that you wish to clarify?

A. Yes. Section 9.3 states "The Signatories agree to not support further grandfathering of the existing net metering tariffs for DG interconnection applications received after May 31,

2016." It is Staff's belief that the intent of this provision was to agree to stop any future grandfathering for any DG customer who interconnected after May 31, 2016. Staff does not favor multiple tranches of grandfathered customers with different export rates going forward. The language uses the term "existing net metering tariffs," but Staff believes that sometimes the term net metering is used to describe any DG customer receiving an incentive for excess renewable energy. However, once the net metering tariff is frozen, there will be net metered customers and export customers.

Q. Does this conclude your Direct Testimony in Support of the Settlement Agreement?

A. Yes, it does.

EXHIBIT
S-13
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTLITY SERVICE AND FOR RELATED APPROVALS.	)	DOCKET NO. E-01461A-15-0363

DIRECT TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

OF

YUE LIU

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

My Direct Testimony addresses the estimated financial net savings or net costs of purchasing or leasing a rooftop solar system from a typical Trico Electric Cooperative, Inc. ("Trico") residential customer's perspective. I provide a comparison of the net savings and net costs for a customer considering the purchase or lease of a rooftop solar system based on three different rate designs, namely, Trico's current effective Residential Service Schedule RS1 ("Existing RS1"), the proposed Residential Service Schedule RS1 in Trico's Application ("Application RS1"), and the proposed Residential Service Schedule RS1 in the Settlement Agreement ("Settlement RS1").

By modeling the bill savings under three different rate designs, Staff demonstrates that residential customers purchasing a rooftop solar system are better off under Settlement RS1 in terms of shorter payback period and higher Internal Rate of Return ("IRR"), as compared to Application RS1. Under the Settlement RS1, the IRR can reach 10.3 percent for residential customers purchasing a rooftop solar system. Although it is lower than the IRR under Existing RS1, this level of IRR is significantly higher than the annual return on a 10-year Treasury bond, which is widely accepted as a benchmark rate of return for long-term investment. The IRR is even substantially higher than the recent 10-year (2006-2015) average annual return on the S&P 500. In addition, the IRR is more than double of the mortgage rates. Therefore, purchasing a rooftop solar system would still be an economically viable investment with the adoption of Settlement RS1. Moreover, same conclusion can be drawn for residential customers leasing a rooftop solar system, even though a reduction in monthly savings would be expected compared to Existing RS1.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Yue "Nick" Liu. I am a Public Utilities Analyst III employed by the Arizona Corporation Commission ("Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background and professional experience.

A. In 2013, I graduated with high distinction from the University of Minnesota, receiving a Bachelor of Arts degree in economics, mathematics and statistics. In 2014, after working as an investment-banking analyst for one year, I enrolled in the graduate program in statistics at the University of California Berkeley and received a Master of Arts degree in 2015. Before joining the Commission in December 2015, I worked on several research projects of various disciplines as a statistical consultant, offering clients advisory services on experimental designs, sampling methodologies, data analytics and statistical inferences.

Q. Briefly describe your responsibilities as a Public Utilities Analyst III.

A. In my capacity as a Public Utilities Analyst III, I have been tasked to analyze and provide recommendations to the Commission on assigned cases.

Q. What is the scope of your testimony in this case?

A. I provide estimates of financial net savings and net costs in purchasing or leasing a rooftop solar system from the perspective of a typical Trico Electric Cooperative, Inc. ("Trico" or "Company") residential customer using a bill estimation and solar cost model I sponsor herein. Among other things, I provide a comparison of the net savings and net costs for a customer considering solar based on three different rate designs, namely, Trico's current effective Residential Service Schedule RS1 ("Existing RS1"), the proposed Residential Service

Schedule RS1 in Trico's Application ("Application RS1"), and the proposed Residential Service Schedule RS1 in the Settlement Agreement ("Settlement RS1").

Q. Please provide a summary of the three rate designs you have applied in the bill estimation and solar cost model.

A. The rates of the three rate designs mentioned above are summarized in Table 1:

	Monthly Customer Charge ($)	First 800 kWh/Month ($/kWh)	Over 800 kWh/Month ($/kWh)	WPCA Factor ($/kWh)	Monthly Data Cost ($)
Existing RS1	15.00	0.121600	0.121600	0.000073	3.38
Application RS1	20.00	0.117600	0.127600	0.000000	3.38
Settlement RS1	24.00	0.112930	0.122930	0.000000	3.38

Table 1: Summary of the three rate designs

BILL ESTIMATION AND SOLAR COST MODEL AND ASSUMPTIONS

Q. How was the bill estimation and solar cost model established?

A. The bill estimation and solar cost model was first established in the UNS Electric, Inc. ("UNSE") rate case (Docket No. E-04204A-15-0142). The final model used in Staff's direct testimony was based on the initial model and augmented by relevant revisions and improvements through Staff's internal review and best judgement.

The model used here should be viewed as Staff's model for which Staff is responsible. Staff acknowledges there is uncertainty concerning the input assumptions and, therefore, in the absolute values of the resulting estimations.

Q. What are the key assumptions used in modeling the net savings or net costs in purchasing or leasing a rooftop solar system?

A. The initial assumptions include the 1) solar system size (kW-DC); 2) solar system conversion factor (kWh-AC/kW-DC); 3) seasonal shaping of solar generation; 4) solar off-setting load at time of generation; 5) a typical residential customer kWh before solar by season; 6) related taxes and fees; 7) solar purchase cost ($/kW-DC); 8) fixed system operating and maintenance (O&M) cost ($/kW-year); and 9) applicable federal and state investment credits. The numerical values of those assumptions are listed in Schedule YL-1.

Q. Please discuss each key necessary assumption starting with the customer's solar system size (kW-DC).

A. For this assumption, Staff utilized Trico's response to Staff data requests[1] for the average residential customer and the large residential customer assuming a 90 percent offset of a customer's energy. This means the customer's DG solar system generates 90 percent of its energy requirement. Staff arrived on 5.10 kW and 6.85 kW system sizes, respectively, for average and large customers.

Q. What is the solar system conversion factor (kWh-AC/kW-DC)?

A. That assumption represents the energy kWh generation estimate per kW. Staff used 1,769 kWh annually per one kW based on the National Renewable Energy Laboratory's ("NREL") PVWatts residential solar generation profile for Tucson, AZ (TMY2). This assumption is also used in the formula for the customer's solar system size as described above.

[1] Staff to Trico 3.7

Q. What did you assume for seasonal shaping of solar generation?

A. Seasonal shaping is each season's average monthly DG solar generation as a percentage of the monthly average DG solar generation. Staff used a 105 percent summer to annual solar generation percentage and a 95 percent winter to annual solar generation percentage.

Q. What is solar off-setting load at time of generation?

A. Solar off-setting load at time of generation represents the percentage of a customer's solar production which is self-consumed at the time of generation. The balance, then, is exported. Staff used summer percentage of 44 percent and winter percentage of 37 percent.

Q. What is customer load before solar by season?

A. This is the Trico-provided customer load profile data for the average customer. Staff scaled this data on a pro rata basis for the large customer. The detailed customer usage profiles are provided in Schedule YL-2.

Q. What is the solar purchase cost assumption ($/kW-DC)?

A. This assumption is the installed purchase price to the customer. Staff used a cost of $2,750 per kW as cited in the surrebuttal testimony in the UNSE rate case.

Q. What are the taxes, fees and investment tax credit assumptions?

A. These assumptions relate to applicable avoidable taxes on electric bills and applicable investment tax credits. Staff used 10 percent as the percentage of taxes and government fees, 30 percent as the percentage of federal investment tax credit, and $1,000 per rooftop solar system as the Arizona residential solar tax credit.

Q. What is the fixed system O&M cost ($/kW-year)?

A. This is the fixed annual cost per kW for the operation and maintenance of purchased systems. Staff used $21/kW-year as the cost, assuming a system life of 33 years, based on NREL's Distributed Generation Renewable Energy Estimate of Costs (updated February 2016).

Q. Lastly, what assumptions are made on Net Energy Metering ("NEM")?

A. Under the Existing RS1, the current effective NEM is assumed, with banking and rollover for excess generation. For modeling purposes, the accumulated excess generation is represented as an average credit spread over all months, and the excess generation banked during the winter months is assumed to evenly offset summer months' energy usage. The year-end balance of excess generation is paid out to customers at Trico's avoided cost of $0.03662 per kWh.

Under Application RS1 and Settlement RS1, the proposed NEM alternative is assumed. With the proposed NEM alternative, all exported electricity from a customer to Trico is paid out each month to the customer at the avoided cost of $0.03662 per kWh and the export energy rate of $0.0770 per kWh as respectively specified in the Application and the Settlement Agreement. There is no banking or netting as provided under both scenarios.

RESULTS AND COMPARISON

Q. What evaluation measures did you select for purchasing a rooftop solar system?

A. In order to evaluate the purchasing option, the simple payback and the Internal Rate of Return ("IRR") measures were selected. The purpose of using those two measures is to capture the total financial impact of purchasing a rooftop solar system, by evaluating bill savings together with system capital cost recovery.

Q. What are the resulting simple paybacks?

A. Simple payback is a straightforward measure of how many years a customer needs to recover the initial cost of purchasing a rooftop solar system through bill savings. Table 2 below summarizes the resulting simple paybacks for an Average Customer and a Large Customer.

	Simple Payback (Years)	
	Average Customer	Large Customer
Existing RS1	8.4	8.5
Application RS1	15.9	15.7
Settlement RS1	11.4	11.4

Table 2: Resulting Simple Paybacks

Q. What is the formula of the IRR?

A. The IRR is a financial metric used to evaluate the profitability of any potential investments. The IRR is a discount rate that makes the net present value ("NPV") of all cash flows from a particular investment equal to zero. In the bill saving model, the IRR is calculated based on the formula below:

$$NPV = 0 = -C_0 + \frac{S_1}{1+IRR} + \frac{S_2}{(1+IRR)^2} + \cdots + \frac{S_{33}}{(1+IRR)^{33}},$$

Where C_0 is the total initial cost of purchasing the rooftop solar system, and $S_1, S_2, \ldots, S_{33}$ are the annual bill savings during the period of year 1, 2, …, 33 after the rooftop solar system is installed.

Q. Why is the IRR used to evaluate a customer's investment decision in purchasing the rooftop solar system?

A. Staff is using the IRR because, unlike the NPV, it does not make a numerical assumption regarding discount rate. Given different perspectives on discount rates for various

customers, using the IRR simplifies the evaluation. Generally speaking, the higher an investment's IRR, the more desirable it is to undertake the investment from the customer's perspective. Thus, the IRR can be used to rank multiple potential investments. In the bill saving model, the IRR provides an effective comparison for the financial feasibility of investing in a rooftop solar system under the four rate designs. Moreover, the IRR can also be compared against the prevailing rate of return in the securities market or accepted discount rate which are reference points for customers. For a customer considering an investment in a rooftop solar system, if the IRR for the investment is higher than his/her (publicly unknown) but accepted discount rate, the investment is economically viable.

Q. Are there additional assumptions in calculating the IRR?

A. Yes. An annual DG solar degradation rate of 0.25 percent and a lifespan of 33 years are assumed for the solar system. Moreover, an annual future utility rate escalation of 2.5 percent is assumed.

Q. How does the change of those assumptions affect the resulting IRRs?

A. The change of assumptions on annual degradation rate and annual future utility rate escalation will affect the numeric values of the resulting IRRs. However, the relative ranking among the three rate designs should be unchanged and accurate, which is the reason why the IRR is used here as an evaluation measure.

Q. What are the resulting IRRs for Average Customer and Large Customer?

A. The resulting IRRs for Average Customer and Large Customer under the four rate designs are summarized in Table 3 below:

	IRR (%)	
	Average Customer	Large Customer
Existing RS1	13.9%	13.6%
Application RS1	7.2%	7.3%
Settlement RS1	10.3%	10.3%

Table 3: Resulting IRRs

Q. Can you provide a prevailing rate of return in the securities market or a generally accepted discount rate for comparison purposes?

A. Yes. The Standard & Poor's 500 ("S&P 500") is an American stock market index based on the market capitalizations of 500 large companies with common stock listed on the NYSE or NASDAQ. The S&P 500 has a diverse constituency and is widely considered as one of the best representations of the U.S. stock market and the U.S. economy. Therefore, the return on the S&P 500 can be used as a prevailing rate of return in the securities market. In addition, the returns on a 3-month Treasury Bill ("3-month T-Bill") and a 10-year Treasury Bond ("10-year T-Bond") are generally accepted discount rates for long term and short term investments, respectively. Table 4 below summarizes the geometric averages of the annual returns on the S&P 500, the 3-month T-Bill and the 10-year T-Bond for three different time periods. The raw data of annual returns during 1928 - 2015 was retrieved from Dr. Aswath Damodaran's online database (http://pages.stern.nyu.edu/~adamodar/). Dr. Damodaran is a Professor of Finance at the Stern School of Business at New York University.

	S&P 500	3-month T-Bill	10-year T-Bond
1928-2015	9.50%	3.45%	4.96%
1966-2015	9.61%	4.92%	6.71%
2006-2015	7.25%	1.14%	4.71%

Table 4: Geometric Averages of the Annual Returns

Q. Are there any other prevailing discount rates that can be used for comparison purposes?

A. Mortgage rate is another widely used prevailing discount rate. The Primary Mortgage Market Survey ("PMMS") results provided by Freddie Mac are presented in this direct testimony. Through the PMMS, Freddie Mac surveys lenders each week on the rates, fees and points for the most popular mortgage products. Three types of mortgage products will be shown, namely 30-Year Fixed-Rate Mortgages ("30-Yr FRM"), 15-Year Fixed-Rate Mortgages ("15-Yr FRM") and 5-Year Adjustable-Rate Mortgages ("5/1-Yr ARM"). Table 5 below lists the average rates of these three mortgage products for 2005-2015.

	Mortgage Products		
	30-Yr FRM	15-Yr FRM	5/1-Yr ARM
Average Rate (2005-2015)	4.95%	4.35%	4.25%

Table 5: Average Rates of Three Mortgage Products

Q. Please summarize your findings from your analysis.

A. As shown in Table 2 and Table 3, both customers are better off under Settlement RS1 in terms of shorter payback period and higher IRR, as compared to Application RS1. Under the Settlement RS1, the IRR can reach 10.3 percent for both customers. Although it is lower than the IRR under Existing RS1, this level of IRR is significantly higher than the annual return on a 10-year T-Bond, which is generally accepted as the discount rate for long-term investment. The IRR is even substantially higher than the recent 10-year (2006-2015) average annual return on the S&P 500. In addition, the IRR is more than double of the mortgage rates. Therefore, purchasing a rooftop solar system would still be an economically viable investment with the adoption of Settlement RS1.

Q. What are the net savings under the three rate designs if a customer chooses to lease a rooftop solar system?

A. $0.09/kWh is assumed as the rooftop solar system lease rate. The monthly average net savings under the three rate designs for both customers are summarized in Table 6 below. The parentheses in the table indicate a net loss.

	Monthly Average Net Savings	
	Average Customer	Large Customer
Existing RS1	$ 29.28	$ 40.57
Application RS1	$ (12.58)	$ (14.29)
Settlement RS1	$ 5.69	$ 10.13

Table 6: Monthly Average Net Savings for Leasing

Based on the results shown above in Table 6, customers would expect net losses under Application RS1, and positive monthly savings would be achieved under both Existing RS1 and Settlement RS1. Moreover, there is a reduction in savings under Settlement RS1, however, those resulting net savings are based on the assumption of zero utility escalation, and customers would experience expanded net savings with an assumption of 2.5 percent annual utility escalation. Thus leasing a rooftop solar system could still be economically viable under the Settlement RS1 in the long haul for residential customers.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Key Assumptions

Solar system Size (kW-DC)	
Average Customer	5.10
Large Customer	6.85
Solar system conversion factor (kWh-AC/kW-DC)	1,769
Seasonal shaping of solar generation	
Summer	105% of monthly average
Winter	95% of monthly average
Solar off-setting load at time of generation	
Summer	44% of total solar kWh
Winter	37% of total solar kWh
Customer load before solar by season	See Schedule YL-2
Taxes and government fees	10%
Solar purchase cost ($/kW-DC)	2,750
Fixed system O&M cost ($/kW-year)	21
Federal investment tax credit	30%
Arizona residential solar tax credit	$1,000

Customer Profiles

	Average Customer	Large Customer
Monthly kWh	836	1,123
Solar system size kW-DC	5.10	6.85
Monthly kWh - Summer	1,037	1,392
Monthly kWh - Winter	636	853

EXHIBIT
S-A
ADMITTED

U.S. Homeowners on Clean Energy: A National Survey

2015 Poll Results
& Clean Energy Growth Trends

A Clean Energy Briefing for the C-Suite
2nd Annual Edition, March 2015

SolarCity

CLEAN EDGE

This report brought to you by **SolarCity** and **Clean Edge** in collaboration with **NASDAQ**

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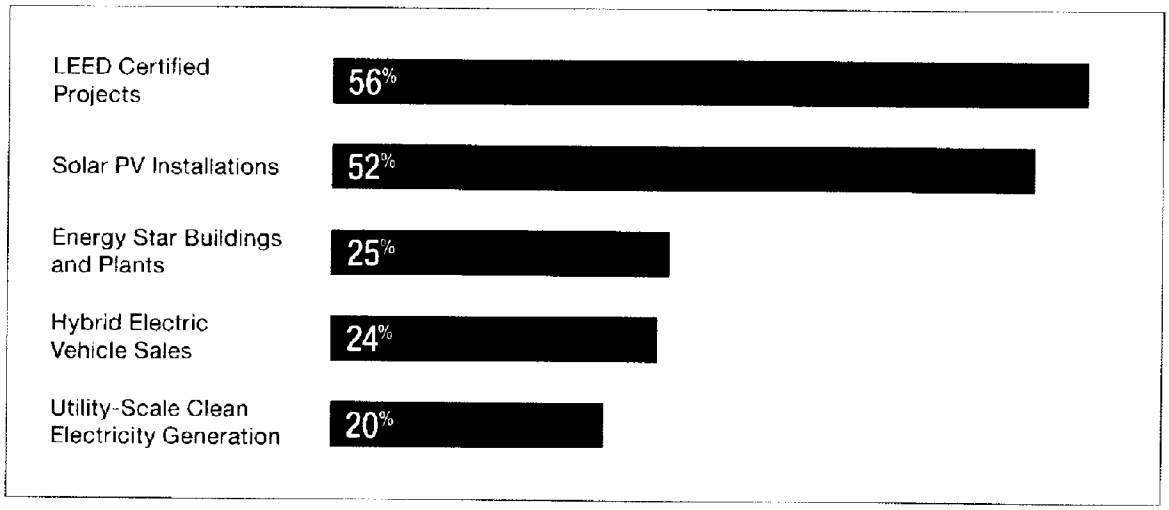
Executive Summary

In our second annual survey of U.S. homeowner purchasing trends and attitudes, we find that clean-energy products and services – including solar PV, utility-scale renewables, hybrid electric vehicles, and green buildings – continue to experience double-digit compound annual growth rates (CAGRs). Sustained double-digit growth rates for more than a decade reflect the long-term nature of this current shift to more efficient, cleaner, and environmentally friendly products and services. But don't be mistaken; as our research clearly points out, it is cost savings, much more than environmental factors, that are driving this monumental shift. Our annual survey of U.S. homeowners provides a deeper view into what's motivating these consumers, and looks at the often-nuanced reasons behind this notable transition.

11-Year Compound Annual Growth Rates (CAGRs)



Source: USGBC, IREC, Energy Star, Electric Drive Transportation Association, and EIA with Clean Edge analysis for years 2003-2013

To better understand this rapidly developing market, and the consumers behind it, SolarCity and Clean Edge commissioned a survey of U.S. homeowners by polling firm Zogby Analytics. Now in its second year, the annual survey focused on U.S. homeowners' choices and attitudes towards a range of energy technologies. 1,400 respondents were randomly selected to answer questions about renewables, energy efficiency, clean transportation, green investing, conventional energy sources, utilities, and other related topics. The purpose of the survey was to learn what homeowners know and think about clean-energy products and services and to gain insights into homeowners' purchasing decisions and attitudes.

All online surveys were completed between January 20 and January 22, 2015. Based on a confidence interval of 95%, the margin of error for the survey of 1,400 homeowners is +/- 2.7 percentage points.

Key findings from the 2015 U.S. Homeowner Survey include:

Americans Overwhelmingly Choose Solar and Wind Over Natural Gas, Nuclear, and Coal

- Half of all homeowners selected solar power as the most important energy source for America's future, and solar is the top choice across all major demographics (such as Republican, Democratic, Liberal, Conservative, North, and South).
- Wind power ranked a strong second with support of 42% of homeowners, followed by natural gas (33%) and energy efficiency (25%).
- Ranking in the middle of the pack were oil (17%), hydroelectric power (17%), waste to energy (16%), and nuclear power (14%). At the bottom were geothermal power (10%), coal (8%), and biofuels/biomass (7%).
- While solar was supported across all age groups, both natural gas and nuclear declined significantly with younger respondents. Natural gas was supported by those over 70 (43%) but dropped down significantly to 27% for those aged 18-24. Nuclear was supported by those over 70 (24%) but dropped precipitously to 8% for ages 25-34 and to just 1% for ages 18-24.

For Consumers, It Continues to be About Economics

- "Saving money" (82%) tops the list as the primary motivator influencing homeowners' decisions to purchase clean-energy products and services.
- "Reducing my environmental impact" comes in a distant second place at 34%.
- The most popular reason cited for someone's likelihood to install solar was "saving on monthly electrical bills." Nearly two-thirds (64%) said this would have the highest impact on their decision to install solar panels.
- Over the next year, the most planned clean-energy purchases by homeowners tend to be those that save money and have relatively low upfront costs, including LED light bulbs (27%), smart thermostats (12%), and Energy Star-rated hot water heaters (9%).

More than Half of Investors Consider the Social and Environmental Impacts of their Investments

- When making investment decisions, a majority of homeowners say that they consider the social/environmental impact of their investment (52%) and generally expressed an interest in "impact investments," which offer social and environmental benefits.
- Three quarters (74%) said that such investments would be compelling if they offered a "potentially higher return than other options" and 61% said such investments would be compelling if they offered "a return that is at least as good as other options."
- Profits still trump sustainability however. Interest drops significantly, to just 22%, when such investments offer "a slightly lower return than other options."
- The primary reasons given for making a personal investment with social/environmental benefits were (in order): the potential to earn higher returns than those provided by savings/CD accounts (54%); supporting the growth of American jobs (12%); and helping people switch to solar power and creating a cleaner, more sustainable future (11%).

Homeowners Back Federal Support of Clean Energy and Oppose Utility-Driven Roadblocks

- Homeowners overwhelmingly support the continuation of federal tax incentives that support the growth of the solar and wind industries (74%). Support is high across all major party affiliations, 82% for Democrats, 67% for Republicans and 72% for Independents.
- Respondents believe that utilities should not block the expansion of solar power. A strong majority (61%) oppose any utility effort to impose a rooftop solar fee for panels that are connected to the grid, while just 24% support such fees. Such opposition is stronger among rural dwellers and Republicans than city residents and Democrats.

In the following report, SolarCity and Clean Edge delve into these findings, reporting on and analyzing our second annual homeowners' survey. The report also includes a look at the high growth of clean-energy technologies over the past 11 years and a discussion of recent consumer adoption trends.

SolarCity and Clean Edge plan to release the homeowner survey annually, with the next report scheduled for early 2016.

The 2015 report is available for free download at www.cleanedge.com/reports and www.solarcity.com/insideenergy

Survey Results

Survey Overview and Methodology

SolarCity and Clean Edge, in this second annual edition, embarked on a survey of U.S. homeowners to better understand consumers' clean-energy behaviors, perceptions, and attitudes. We commissioned the polling firm Zogby Analytics to conduct an online survey of 1,400 homeowners across the U.S. The survey's purpose was to ascertain knowledge of and attitudes toward clean-energy products and services, as well as general attitudes about electric utilities, future energy options, and green investing. Thousands of U.S. adults were invited by Zogby Analytics to participate in this interactive survey. The field of participants was narrowed down to only include homeowners. Invitations were password-coded and secure so respondents could only access the survey one time. Based on a confidence interval of 95%, the margin of error for the survey of 1,400 homeowners is +/- 2.7 percentage points. All interviews were completed between January 20 and January 22, 2015.

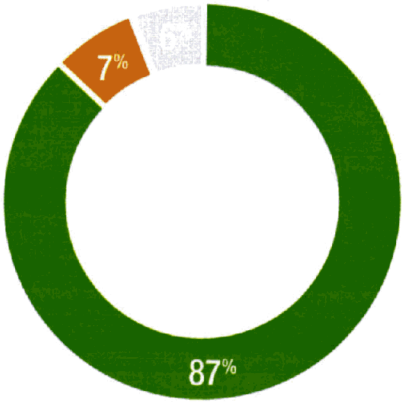
Key Findings

Following are the top findings of the survey, with supporting tables. To access the full public survey questionnaire and responses, see Appendix A on page 29.

Americans Overwhelmingly Choose Solar and Wind

Holding steady with last year's survey, nearly nine in ten Americans (87%) say renewable energy is important to the country's future. In a nation divided by so many other issues, from immigration policy to climate change, this support for renewable energy is in many ways unprecedented. Few other topics get such wide support across so many demographics.

How important is renewable energy to America's energy future?

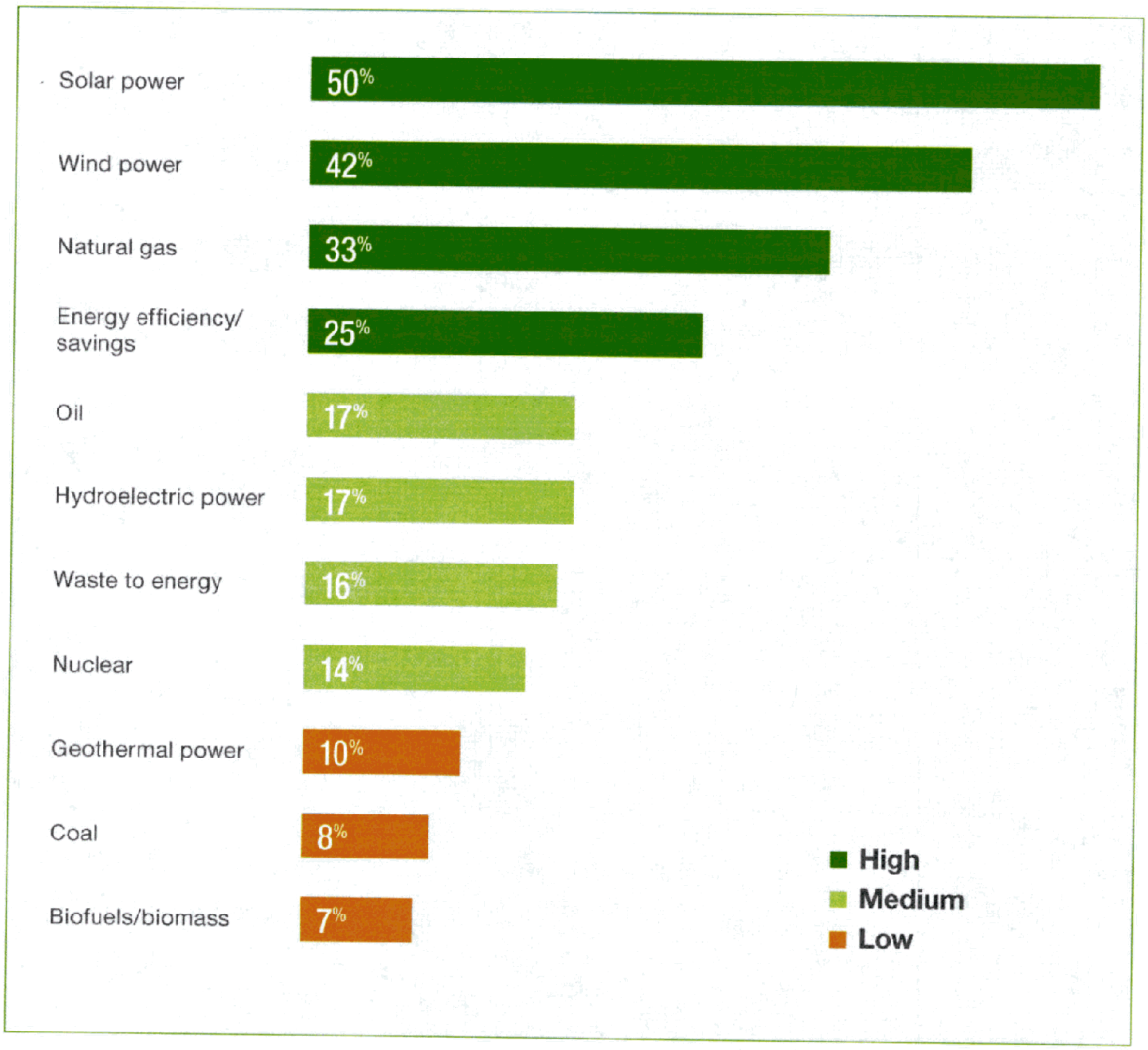


- Important
- Not Important
- Not Sure

While renewables are considered important by the vast majority of homeowners, for this year's survey we asked a new question to dig deeper into how homeowners rank the importance of both renewable and conventional sources to the nation's energy future. The results show Americans believe the nation's energy future relies first and foremost on solar and wind power, followed by natural gas and energy efficiency. At the very bottom of the pack were coal and biofuels/biomass.

50% of Americans selected solar as the most important energy source for America's future, compared to just 8% for coal

Which energy sources do you believe are most important to America's energy future? (Pick up to three)



Half of all homeowners selected solar power as the most important energy source for America's future, with solar being the top choice among all major demographics, including Republicans, Democrats, Independents, conservatives, progressives, city and rural dwellers, the young, and the elderly.

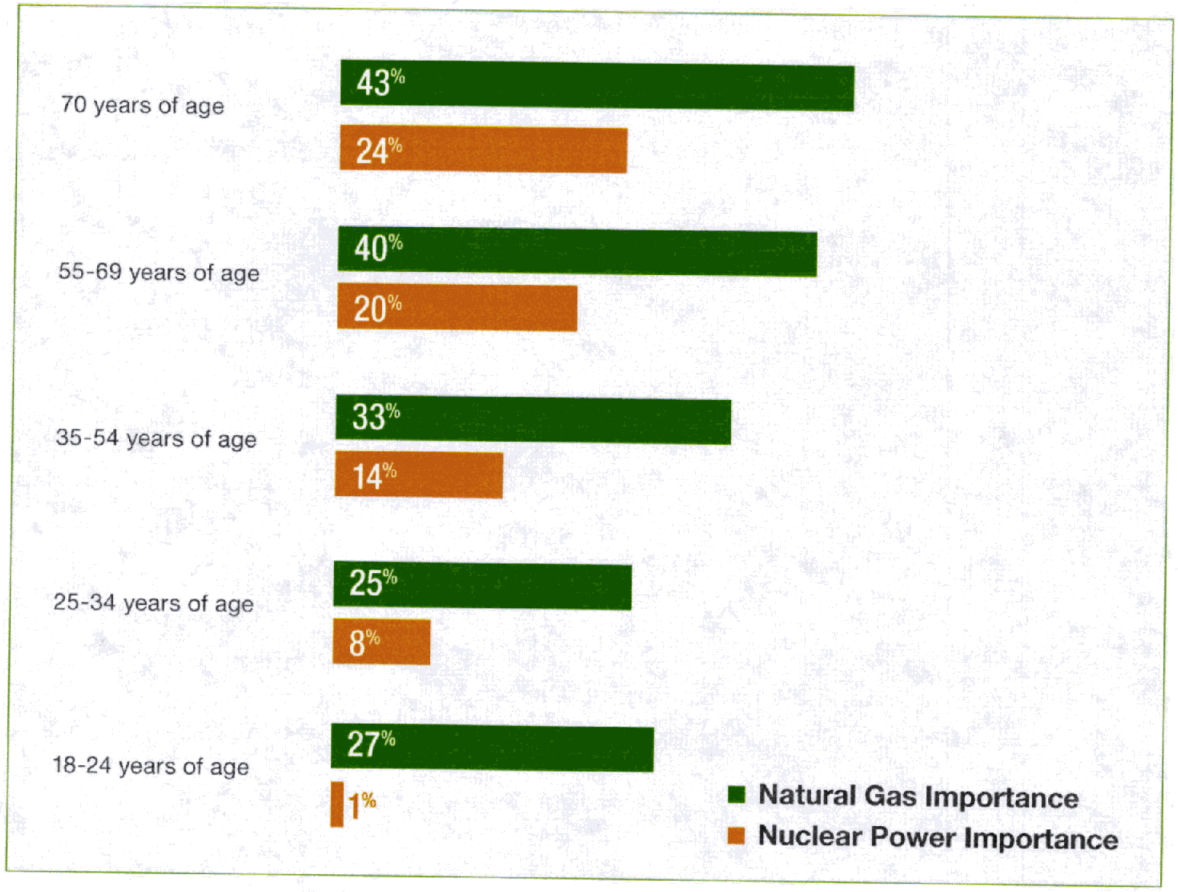
Also ranking high were wind, a strong second place with 42% support, followed by natural gas (33%) and energy efficiency (25%). The top four sources were consistent (in the same order of importance) among all regions of the country (East, South, Center Great Lakes, and West).

Ranking in the middle of the pack were oil (17%), hydroelectric power (17%), waste to energy (16%), and nuclear power (14%).

At the bottom were geothermal power (10%), coal (8%), and biofuels/biomass (7%). This reflects a very dramatic turn of fortunes for the once dominant U.S. coal industry, as well as negative perceptions surrounding a U.S. biofuels industry that currently uses corn (competing with food crops), instead of being built off of waste streams (which scored considerably higher among respondents).

One of the most striking demographic insights revolves around differences among age groups. Whereas support for solar and wind was consistently high among all age groups, natural gas and nuclear power did not maintain such support across the age spectrum. Both natural gas and nuclear power declined significantly with younger respondents. Natural gas received solid support from those over 70 years of age (43%) but dropped to 25% for 25-34 year olds and 27% for 18-24 year olds. Nuclear's decline was more notable, dropping from 24% support among those over 70 years of age to just 1% for those 18-24 years of age.

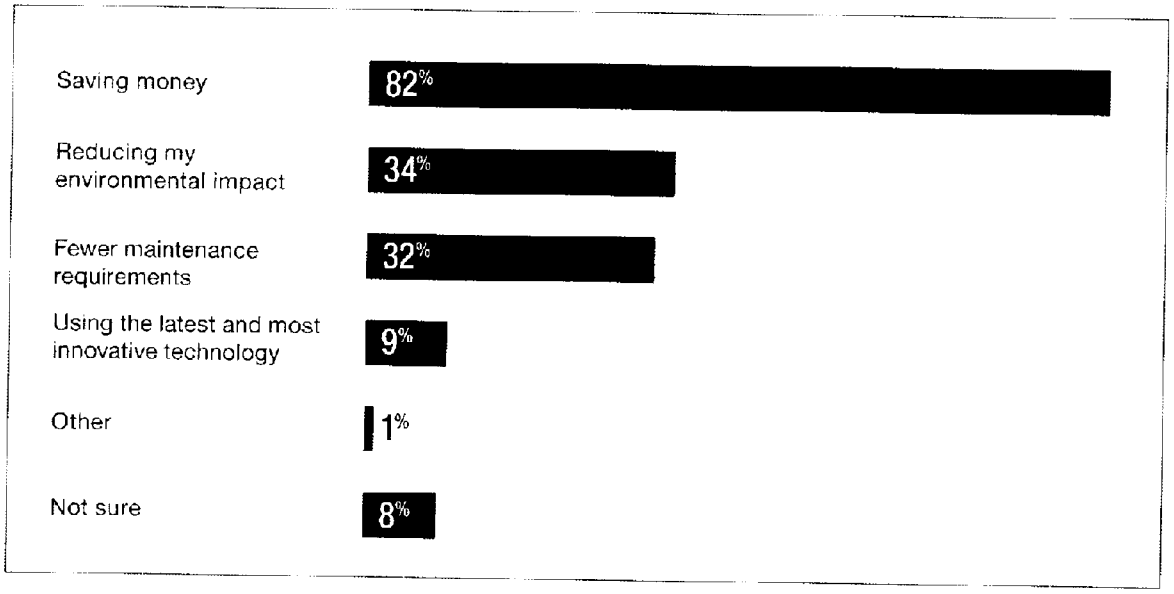
Support for natural gas and nuclear decline with younger respondents



For Consumers, it Continues to be About Economics

While survey respondents say they care about the environment, it's cost savings that truly motivate them. Similar to last year's findings, "saving money" (82%) tops the list as the primary motivator influencing homeowners' decisions to purchase clean-energy products and services. "Reducing my environmental impact" comes in a distant second at 34%.

When making decisions around purchasing clean-energy products and services, which of the following are your primary motivators? (Choose up to two)

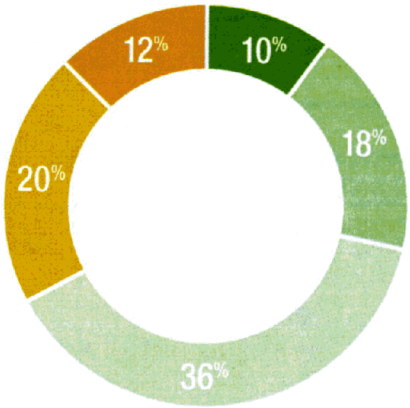


Reflecting this sentiment for questions specifically related to solar power, the most popular reason cited for someone's likelihood to install solar was "saving on monthly electrical bills." 64% said this would have the highest impact on their decision to install solar panels. It even outweighed having "to pay no upfront fees" (54%). Further down in impact were "locking in rates for 20 years" (38%) and near the bottom of reasons to install solar was "reducing my environmental impact" (35%).

This doesn't mean that homeowners don't care about the environment and their environmental impact. 65% of Americans say they consider or investigate such

factors at least sometimes when making big-ticket purchasing decisions. And 75% of respondents say they are taking at least some actions to help reduce the impact of greenhouse gas emissions. But even so, it's the promise of saving money and reducing costs that's the primary motivator for their decisions to buy clean-energy products and services.

How often do you consider or investigate the environmental impact/sustainability of big-ticket items (cars, homes, etc.) when making purchasing decisions?



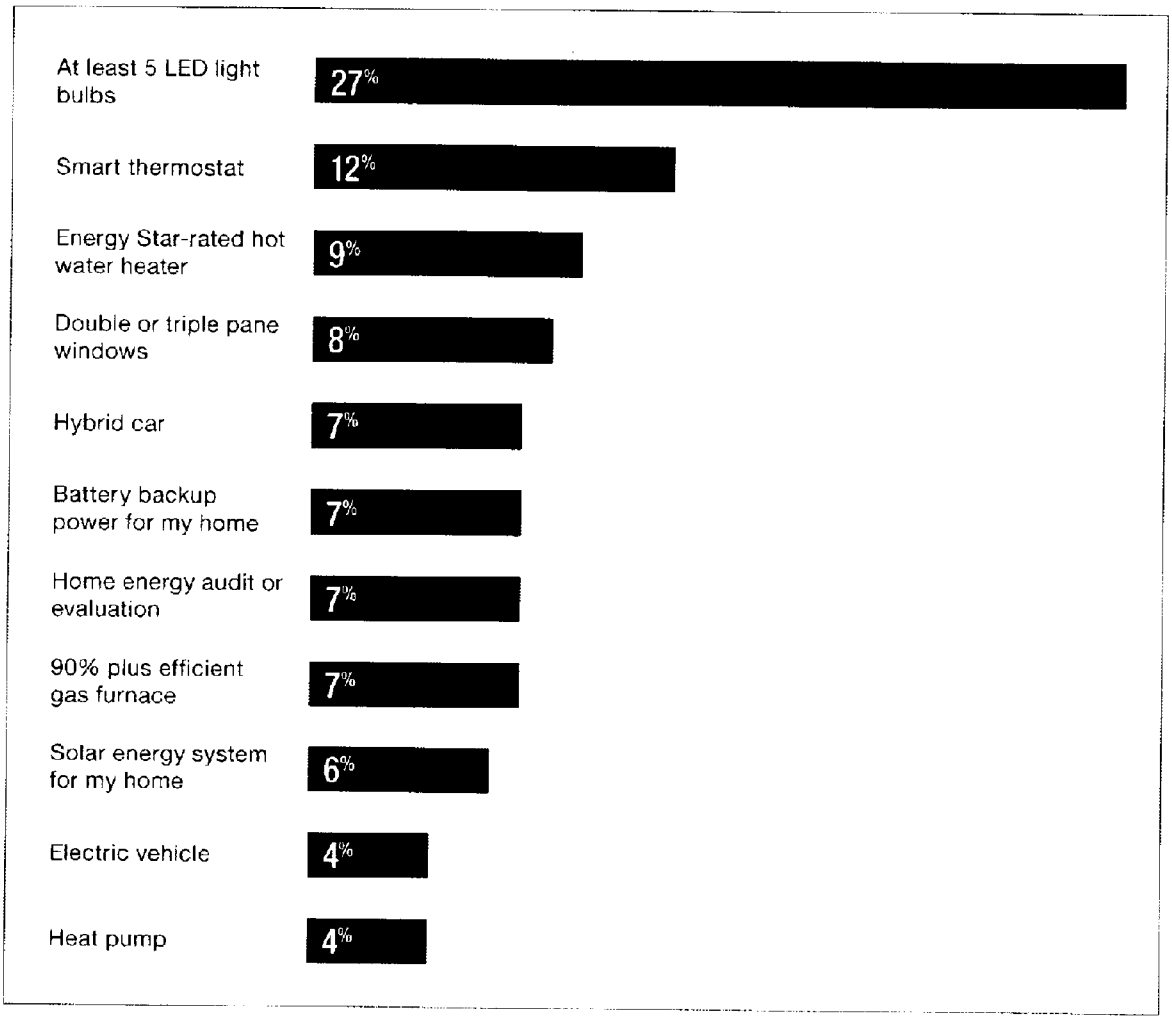
Consistent with last year's survey, the top five past clean-energy purchases, in order, were LED light bulbs (56%), Energy Star-rated hot water heaters (36%), double or triple pane windows (28%), smart thermostats (21%), and 90% efficient gas furnaces (14%). LEDs showed the greatest increase from last year's survey, up six percentage points from 50%.

Top Five Past Purchases

#1. **LED Light Bulbs (At Least 5)**
#2. **Energy Star Rated Hot Water Heater (Gas/Electric)**
#3. **Double or Triple Pane Windows**
#4. **Smart Thermostat**
#5. **90% Plus Efficient Gas Furnace**

Over the next year, the most planned clean-energy purchases by homeowners continued to be those that tend have relatively low upfront costs, including LED light bulbs (27%), smart thermostats (12%), and Energy Star-rated hot water heaters (9%). Among the other options tracked, electric vehicles and hybrids both dropped the most from last year's results. It's worth noting that the survey window corresponded with some of the lowest oil prices in recent memory, down approximately 50% from the prior year. Residential solar power systems, backup power, heat pumps, and most other clean-energy options held steady.

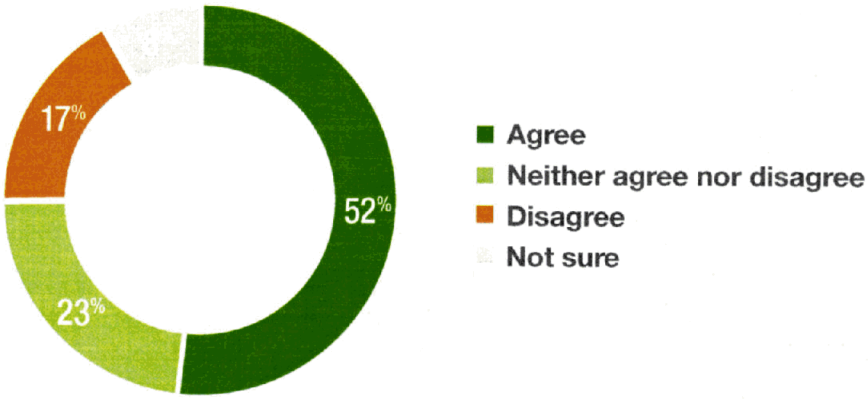
Which, if any, clean-energy purchases are you likely to make in the next year? (Choose all that apply)



More than Half of Investors Consider the Social and Environmental Impacts of their Investments

This year we added questions about what drives investors when making decisions regarding stock, bond, and CD investments. At a high level, more than half of American homeowners (52%) say that when making investment decisions they consider the social/environmental impact of their investment. They also express, at a somewhat higher percentage, an interest in "impact investments," which promise not only financial returns but social and environmental returns as well.

When making investment decisions do you agree or disagree with the following statement: *I consider the social and environmental impacts of the investment, as well as the financial return.*

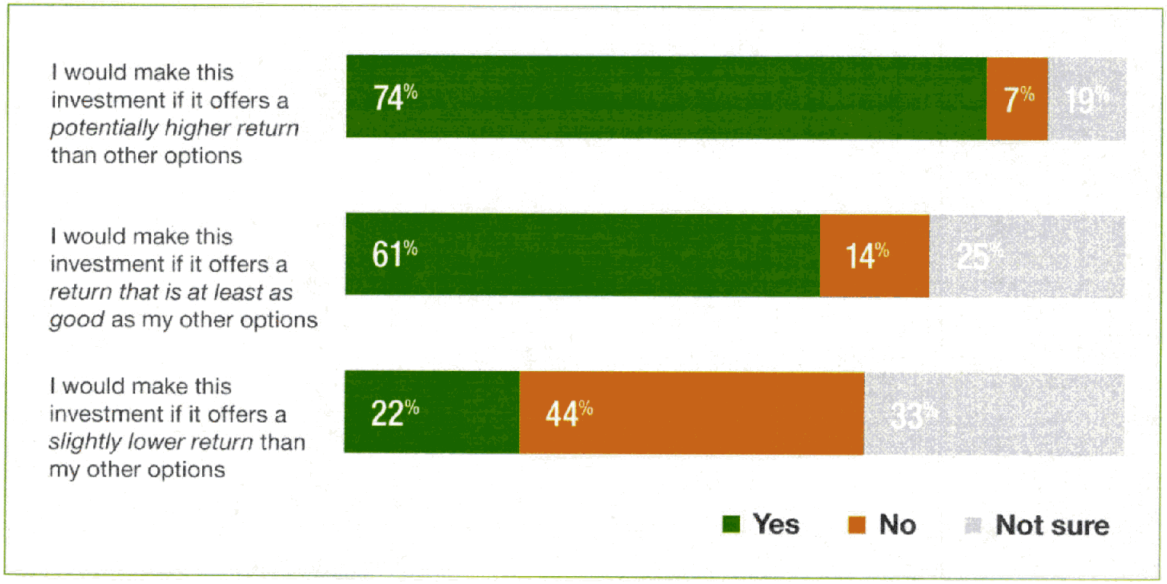


52% of homeowners say they consider the social and environmental impact of their investments

74% said that such investments would be compelling if they offered a "potentially higher return than other options" and 61% said such investments would be compelling if they offered "a return that is at least as good as other options."

But it turns out that Americans feel similarly about their investment choices as they do when it comes to buying products and services. They are interested in the environment, as long as they don't have to compromise on financial returns. In our survey, interest drops to just 22%, when such investments offer "a slightly lower return than other options."

There is a new category of investing called 'impact investing' that offers financial as well as social and environmental returns, e.g. creating jobs and helping protect the environment. Please respond 'Yes' or 'No' to the following statements:



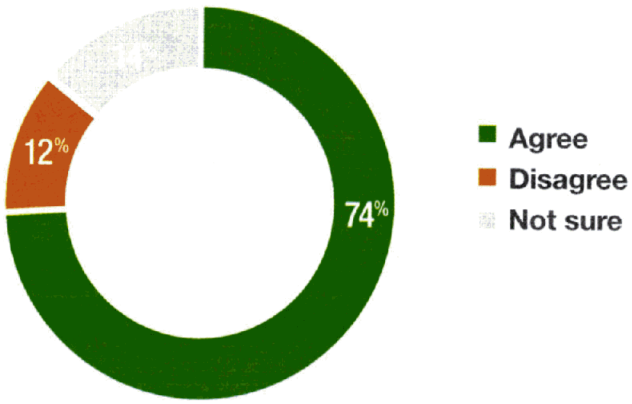
When asked for more specifics, the primary reason given for making a personal investment with social/environmental benefits is the potential to earn higher returns than those provided by savings/CD accounts (54%). That reason ranked far higher than those related to social or environmental promises, such as supporting the growth of American jobs (12%) or helping people switch to solar power and creating a cleaner, more sustainable future (11%).

As the financial services industry introduces an increasing number of clean-energy investment options, such as mutual funds, exchange traded funds, yieldcos, and bonds – and an increasing number of investors look to gain exposure to this tech-driven sector or to divest from carbon-intensive industries – tracking such sentiments and drivers will become increasingly significant.

Homeowners Back Federal Support of Clean Energy and Oppose Utility-Driven Roadblocks

While members of Congress seem divided on whether or not to extend federal incentives for clean energy, their constituents are not. Americans support the continuation of these incentives – the wind production tax credit and solar investment tax credit – by a wide margin. Indeed, our survey found that homeowners support the continuation of federal tax incentives that support the growth of the solar and wind industries by 74%, with high levels of support across all major party affiliations. 82% of Democrats support such policies, and so do two thirds (67%) of Republicans and 72% of Independents.

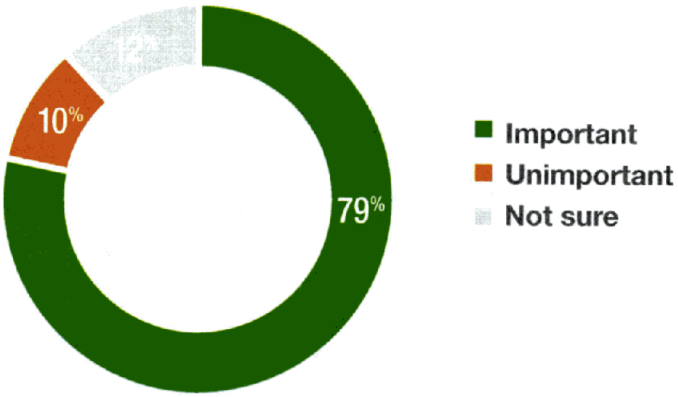
In recent years, federal tax credits have enabled both the solar and wind industries to expand, with solar and wind both more than doubling their generation over the past five years. Do you agree or disagree that the federal government should continue to offer such incentives?



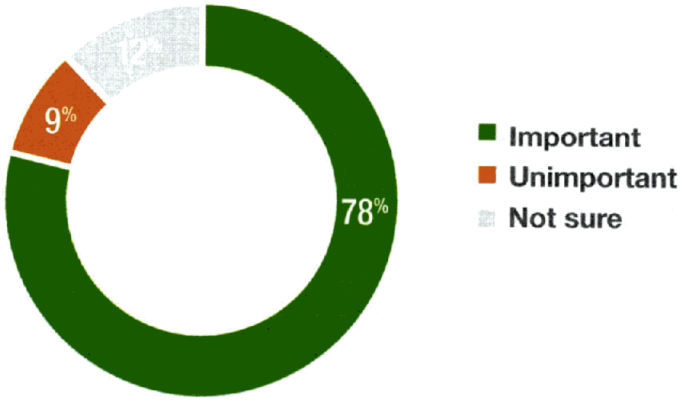
74% of U.S. homeowners back the continuation of federal tax incentives that support the growth of solar and wind

Backing up this support, 78% of respondents believe it is important that the U.S. be a global leader in developing and deploying solar energy systems and 79% believe it's important to the U.S. economy to domestically manufacture solar energy systems and solar panel components.

How important do you think it is to the U.S. economy to domestically manufacture solar energy systems, and solar panel components?

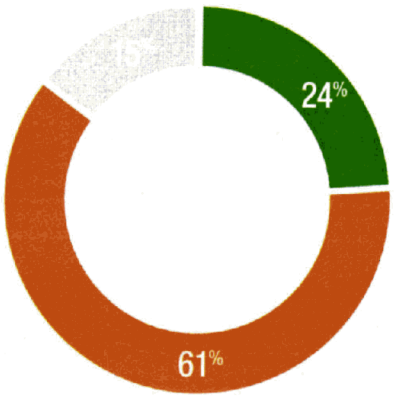


How important is it to the future of the U.S. for the nation to be a global leader in developing and deploying solar energy systems?



Last year's survey was the first to ask homeowners if they wanted choice in their electricity provider and supply, with a majority saying yes. This year, respondents echoed that desire for unfettered choice, noting that utilities should not be allowed to block the expansion of solar power. A solid majority (61%) oppose (and 43% strongly oppose) any utility effort to impose a rooftop solar fee for panels that are connected to the grid, while just 24% support (and only 8% strongly support) such fees. A similar ratio (53% to 26%) views any additional utility fee for connecting residential solar panels to the grid as a tax on solar power.

Do you support or oppose electric utility companies being able to charge an additional fee to solar powered homes and businesses?



- **Support**
- **Oppose**
- **Not sure**

Such sentiments seem to transcend geographic and political boundaries. Opposition to such fees grows stronger in rural communities (67%) than large cities (47%). And Republicans (66%) oppose utility charges for solar more than Democrats (53%).

66% Republicans

53% Democrats

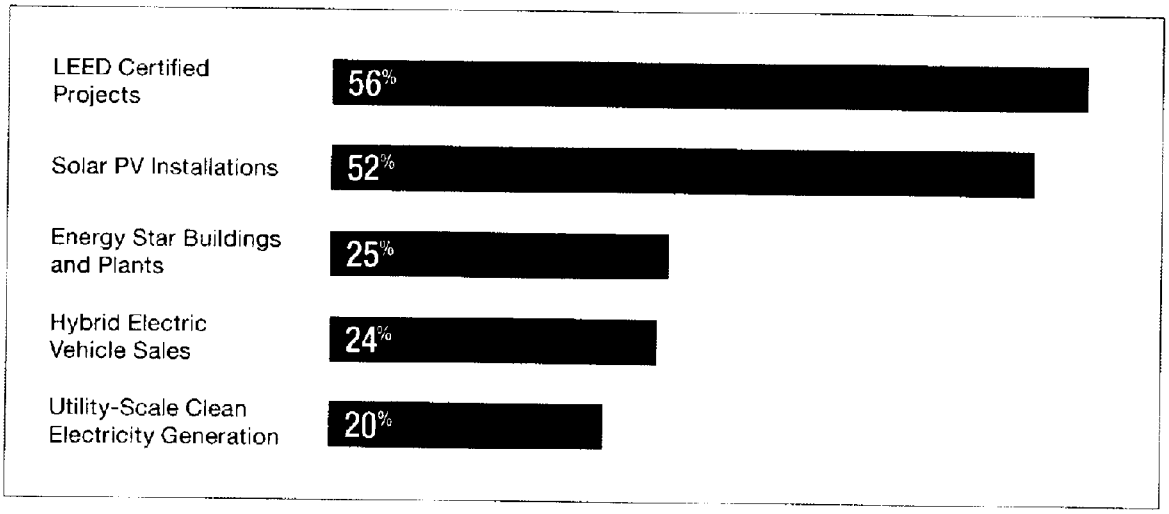
While the majority of homeowners oppose utility charges, such opposition is higher among Republicans than Democrats

U.S. Clean Energy Adoption and Growth

As highlighted in this year's survey, U.S. consumers are increasingly adopting clean-energy products that save them money while producing environmental benefits. There are a host of explanations for this shift in consumer behavior, including growing environmental concerns and improved product attributes, but foremost among the drivers are the improving economics for clean-energy products and services. We are in a period of rapid innovation that has seen the costs of everything from efficient light bulbs to solar power fall dramatically. Consumers are increasingly aware of the financial benefits that clean-energy products offer – and are taking advantage of them.

Since our first survey of U.S. homeowners one year ago, the compound annual growth rates (CAGRs) for many of the clean-tech products we track – including hybrid electric vehicles, utility-scale renewables, and solar PV – have continued to be well into the double-digits. Electric vehicles (EVs) and light-emitting diode (LED) light bulbs, with fewer years of sales data behind them, continued to maintain their astounding triple-digit CAGR paces. Across the board, these growth rates are more akin to those experienced by the smart phone and Internet sectors than those of the usually staid energy and transportation sectors.

11-Year Compound Annual Growth Rates (CAGRs)



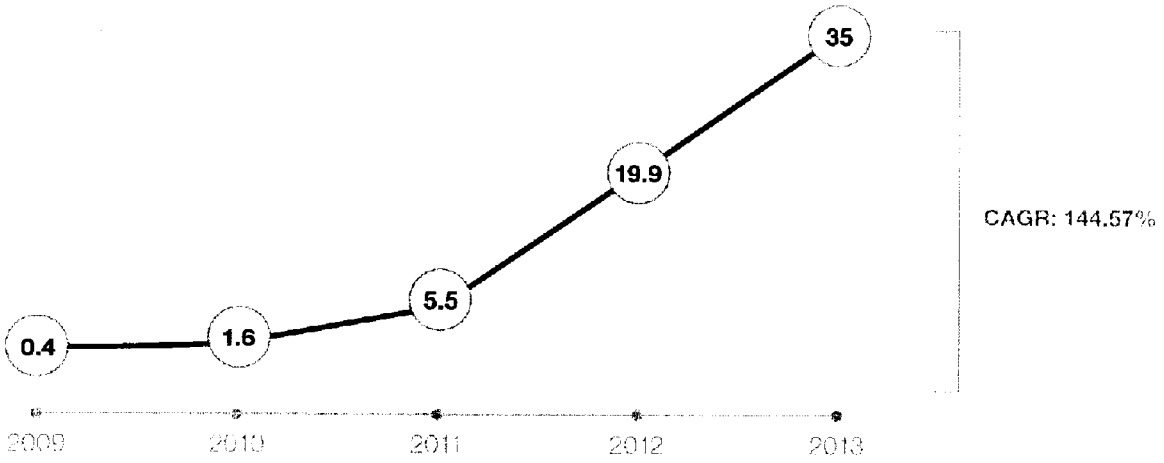
Source: USGBC, IREC, Energy Star, Electric Drive Transportation Association, and EIA with Clean Edge analysis for years 2003-2013

The following is a closer look at the rapid rise in clean-energy product adoption rates, what's driving this activity, and how the near-to mid-term might be shaping up.

A Great Leap Forward for LEDs

LED light bulbs had a banner year for growth in 2013, and three LED pioneers received the Nobel Prize in physics last year for their breakthroughs in LED lighting technology. Based on Clean Edge analysis, we estimate that installations of A-type (the most common standard size) LED bulbs in the U.S. reached 35 million in 2013, up from just below 20 million in 2012 and near zero in 2009. That represents a compound annual growth rate of 145%. While such a high growth rate isn't sustainable in the long run, we expect to see triple- and double-digit CAGRs continue in the near- to mid-term as the transition to LEDs ramps up.

Annual LED Installations: United States (A-Type Lamps, in Millions)



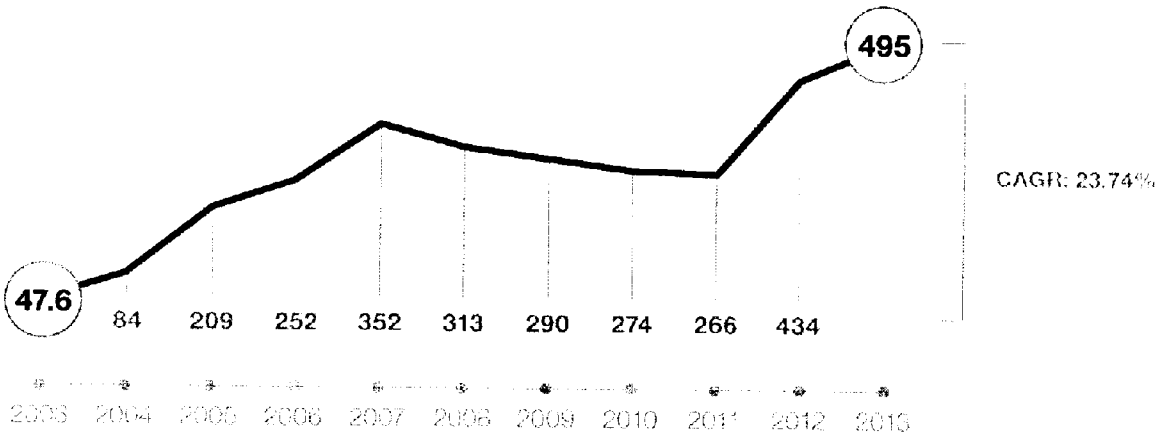
Source: Clean Edge analysis which incorporates published figures from Navigant/DOE (2009 through 2012) combined with other industry growth estimates for 2013

Consumers have benefitted greatly from improvements in the technology, quality, and costs of LED bulbs. And as we learned in last year's survey, the number one clean-energy item on homeowners' shopping lists was LEDs. That's largely because the average cost of an LED bulb has fallen from nearly $70 in 2010 to around $10 now, according to U.S. Energy Information Administration (EIA) data. The EIA forecasts further price drops, with LEDs reaching near-cost parity with CFLs by the end of this decade. In fact, some 60-watt equivalent LED bulbs from makers such as Philips and Cree are now available at less than $4 at big box retailers such as Lowe's and Home Depot. Meanwhile, across the nation, utilities and their partners continue to offer their customers incentive programs that further reduce the cost of LEDs. The Environmental Protection Agency's Energy Star program reports that LED incentives expanded from 15% of all Energy Star lighting incentives in 2013 to 19% in 2014. Coupled with the phase-out of incandescent light bulbs (the original light bulb invented by Thomas Edison), these factors should continue to spur robust growth in the LED market for years to come.

Electric Vehicle Sales Begin to Mimic (and Even Surpass) the Super-Charged Growth of Hybrids

Sales of hybrid electric vehicles (HEVs) and all-electric vehicles (EVs) continued their robust growth in 2013. HEV sales approached the 500,000 mark in the U.S. for the first time, a far cry from the fewer than 50,000 sold in 2003. The CAGR over those 11 years is 24%, which is virtually unchanged from last year's report.

Hybrid Electric Vehicle Sales: United States (in Thousands)



Source: Electric Drive Transportation Association with Clean Edge analysis

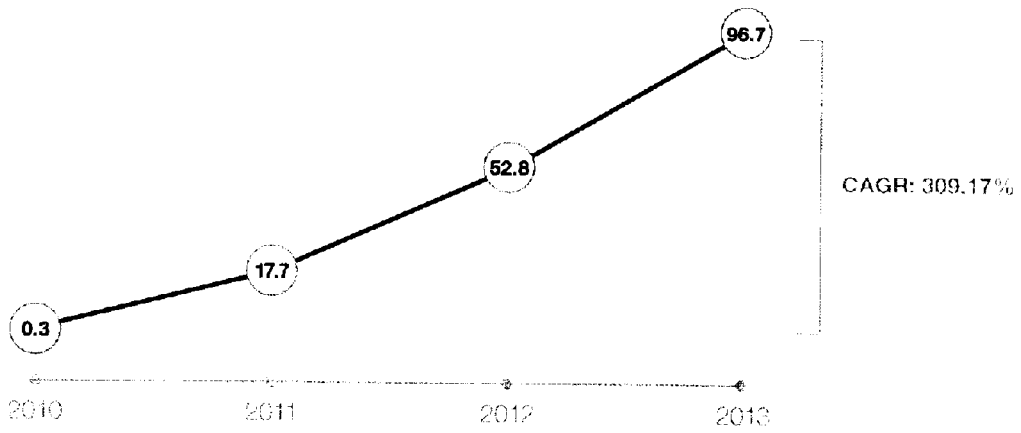
The HEV market has undergone drastic changes since the introduction of the first Toyota Prius more than a decade ago. For years, the Prius family (which now includes three models) was the undisputed king of the HEVs, commanding more than 58% of the hybrid market as late as 2012, per IHS data. In 2013, the Prius family was still the top-selling HEV at 43% in the U.S., but it had nearly 50 challengers in the marketplace. Toyota hopes to regain its former market share by introducing a revamped, sportier Prius for the 2016 model year, but with so much new competition, it may face an uphill climb.

Meanwhile, sales of hybrids' all-electric cousins continued to surge ahead. The Department of Energy reported in 2013 that EVs have surpassed the early sales growth rates of their hybrid brethren. All-electric vehicles – a category which includes plug-in hybrid, extended range, and battery EVs – nearly doubled their overall 2012 sales figure in 2013, rising to more than 96,000; as recently as 2010, less than 350 EVs were sold in the U.S. The four-year CAGR for EVs checks in at an impressive 309%.

What's driving the growth in EV sales? EVs are becoming both more visible and cheaper to buy. In fact, some consumers are skipping the intermediary hybrid

step and going straight to all-electric vehicles now that there are more options in the luxury and mid-tier categories, such as the Nissan Leaf, Chevy Volt, and Tesla Model S. EV battery prices are trending downward, and Tesla's 2014 announcement of a new battery "gigafactory" is expected to continue lowering the cost (and boosting the supply) of EVs. EVs also win points due to their safety, style, and sustainability. A federal tax credit of up to $7,500, access to carpool lanes in states such as California, and greatly expanded EV charging infrastructure have likely helped, as well.

Electric Vehicle Sales: United States (in Thousands)



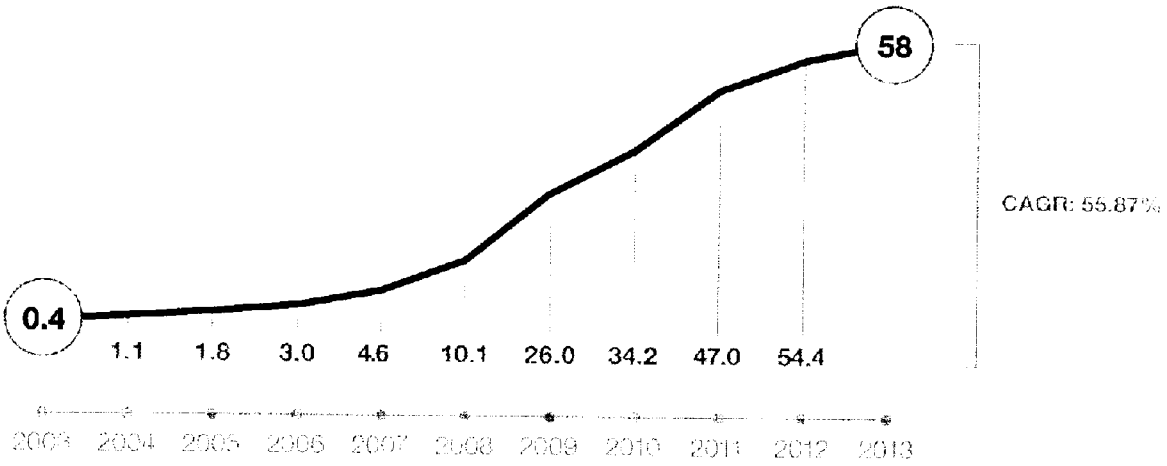
Source: Electric Drive Transportation Association with Clean Edge analysis

Still, one factor could profoundly impact the market for HEVs and EVs: the recent plummet in oil and gas prices. Perhaps not coincidentally, preliminary data for 2014 (a year in which prices tumbled for gasoline) suggests the market share of all electric vehicles has fallen for the first time since 2011. How long the low gas prices last, and what effect they will have on the hybrid and electric vehicle market, remains to be seen.

A Surge in Green Building Activity

Green building trends continued their upward momentum in 2013. More than 5,800 buildings in the U.S. became LEED-certified during the year, resulting in an 11-year CAGR of 56%. The number of buildings obtaining LEED certification has increased every year since 2003, demonstrating just how popular the rating system has become.

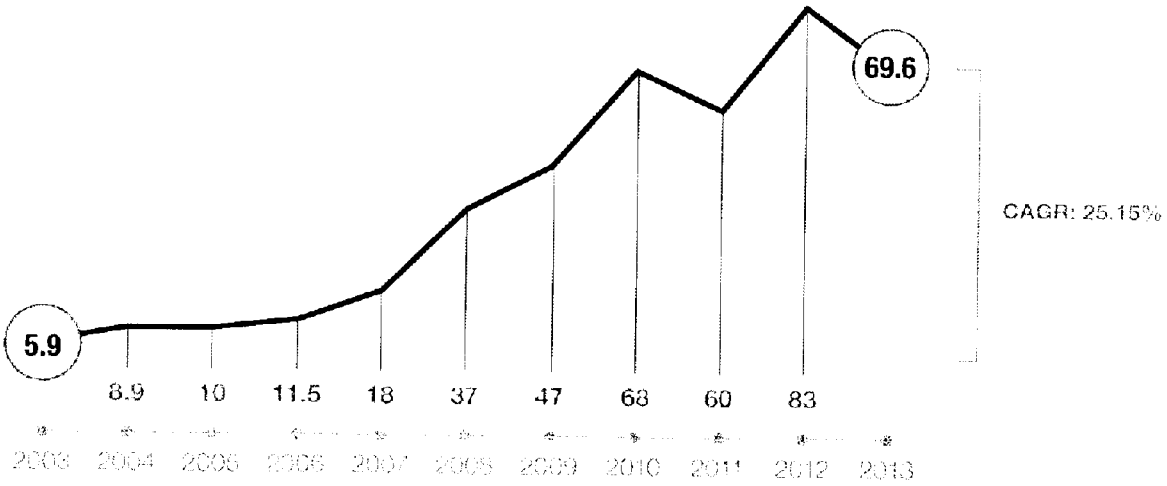
LEED Certified Projects in the United States (in Hundreds)



Source: USGBC data with Clean Edge analysis

The Energy Star program, which only tracks commercial buildings and multi-family residences and not single-family homes, has seen its building certification numbers fluctuate more in recent years. 2013 saw commercial and industrial Energy Star certifications dip to 6,960 from more than 8,300 in 2012. Over the past 11 years, though, the Energy Star program continues to have a healthy CAGR of 25%.

Energy Star Buildings and Plants in the United States (in Hundreds)



Source: Energy Star with Clean Edge analysis

Meanwhile, home building represents a leading sector in the green building field. It isn't hard to see why: the Energy Star program estimates that qualifying new homes average $300 in annual energy savings compared to typical homes, while delivering improvements in health and comfort. It's no surprise, then, that more than 77,000 new Energy Star single-family homes were built in 2013, representing almost 13% of new home market share while 47% of LEED certifications came through the LEED program's "Homes" rating system. Builders and homeowners are clearly getting the message: green building saves money in the long term.

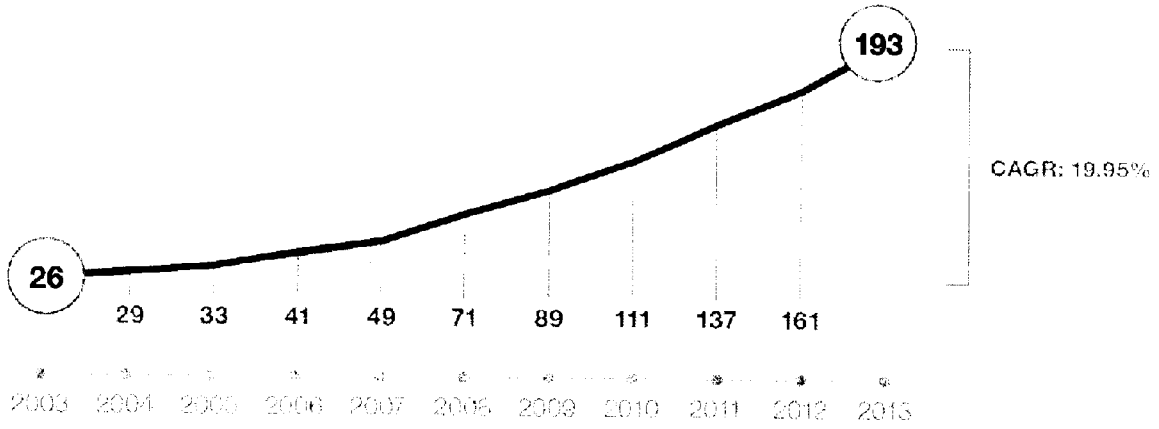
Governments are getting that message, as well. An increasing number of U.S. cities, counties, and states are requiring new public buildings to meet LEED standards. Likewise, energy benchmarking and disclosure laws for commercial buildings are gaining popularity in cities across the country.

Could net zero buildings – those that generate the same or more energy than they use – be the wave of the future? Current federal targets are for all new federal buildings to be net zero by 2030, while California and the European Union have set standards calling for all new construction to be net zero (or nearly so) by 2030 and 2020, respectively. These are ambitious goals, but they are becoming increasingly common.

Clean Electricity Continues Its Upward Trajectory

Electricity generation from renewable power sources (solar, wind, and geothermal) at the utility scale (installations of 1 MW and higher) continued to climb in 2013. These sources had a compound annual growth rate of nearly 20% during the 11-year period ended in 2013. Wind power once again led the way, producing nearly 87% of the nation's renewable electricity in 2013.

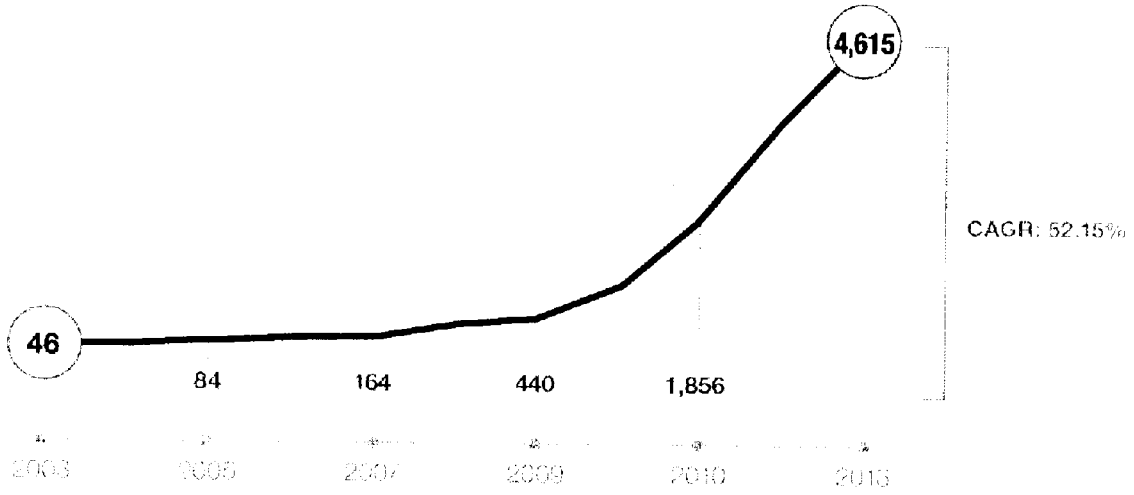
Utility Scale Clean Electricity Generation: United States (in Millions of MWh)



Source: EIA with Clean Edge analysis. EIA electricity generation data is gathered from monthly surveys of power plants with capacity of at least 1MW: sub-1MW installations do not count towards generation totals

Distributed solar PV (residential, commercial, and industrial) has also seen significant growth over the past decade, with annual grid-connected installations jumping from near zero in 2003 to more than 4.6 GW in 2013 alone, for a CAGR of 52%. In the first three quarters of 2014, residential PV installations alone were up 58% year-over-year, according to the Solar Energy Industries Association. The same study noted that more than 50% of residential PV was installed without benefit of state incentives, pointing to the continuously falling costs of PV.

Annual Grid-Connected Solar PV Installations: United States (Capacity Installed by MW-dc)



Source: IREC with Clean Edge analysis

What will the future look like? Increasingly, the U.S. electricity market is being built off of renewables, efficiency, and natural gas. Renewables, mainly wind and solar power, accounted for 50% of new utility-scale electricity generating capacity added in the U.S. in 2014—far more than the capacity added from coal and nuclear combined, and even edging out natural gas's 49%, according to data from the Federal Energy Regulatory Commission.

But threats to this progress exist. Congress has, for the time being at least, allowed the Renewable Energy Production Tax Credit to expire; meanwhile, other tax credits meant to help businesses and homeowners switch to renewables – most notably the 30% Solar Investment Tax Credit - are set to decrease or expire at the end of 2016. This threatens a slowdown in renewable capacity additions. Net metering requirements, renewable portfolio mandates, and energy efficiency standards are under attack in several states, though efforts to roll back such programs have met with limited success to date. And low oil and gasoline prices, as noted earlier, could put pressure on the markets for hybrids and EVs.

On the other hand, renewable energy costs continue to come down, making it more affordable for consumers to switch to renewable electricity. Energy storage is poised to take off; in 2013, California set a goal of 1.325 GW of energy storage by 2020. In June 2014, the EPA announced its landmark (and controversial) Clean Power Plan to significantly reduce carbon pollution in the U.S. power sector. And as noted in our homeowners' survey results, consumers continue to find increasing value in making the switch to cleaner, more efficient offerings.

As the economic, environmental, and social value proposition of clean-energy products and services intensifies, greater adoption by U.S. homeowners and consumers overall seems inevitable.

About & Disclaimer

SolarCity

SolarCity® (NASDAQ: SCTY) provides clean energy. The company has disrupted the century-old energy industry by providing renewable electricity directly to homeowners, businesses and government organizations for less than they spend on utility bills. SolarCity gives customers control of their energy costs to protect them from rising rates. The company makes clean energy easy by taking care of everything from design and permitting to monitoring and maintenance. Visit the company online at www.solarcity.com and follow the company on Facebook & Twitter.

CLEAN EDGE

Clean Edge, Inc., founded in 2000, is the world's first research and advisory firm devoted to the clean-tech sector. The firm delivers an unparalleled suite of clean-energy benchmarking services including stock indexes, utility and consumer surveys, and regional leadership tracking, providing Fortune 500s, clean-tech companies, investors, NGOs, and governments with timely research, trending analysis, and actionable insights. Managing director Ron Pernick and senior editor Clint Wilder are coauthors of the widely acclaimed business books *The Clean Tech Revolution* (HarperCollins, 2007) and *Clean Tech Nation* (HarperCollins, 2012). To keep abreast of the latest clean-tech trends, or for more information on the company, visit www.cleanedge.com.

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DISCLAIMER: Information contained in this report is not intended to be investment advice or used as a guide to investing and no recommendation is intended to be made as to any particular company in this report.

Appendix: A

Survey questionnaire, including homeowner results

Do you think that solar power today is more expensive or less expensive than the current retail rates provided by your electric utility?

	More Expensive			Same	Less Expensive			Not Sure
	Overall	Much more	Smwht. more		Overall	Smwht less	Much less	
Homeowners (%)	**38**	12	26	18	**25**	19	6	19

From your perspective, has solar energy become more or less affordable over the last three years?

	More affordable			Same	Less affordable			Not Sure
	Overall	Much more	Smwht. more		Overall	Smwht less	Much less	
Homeowners (%)	**41**	8	33	32	**10**	7	3	17

How often do you consider or investigate the environmental impact/sustainability of big-ticket items (cars, homes, etc.) when making purchasing decisions?

	Homeowners (%)
Always	10
Most of the time	18
Sometimes	37
Rarely	20
Never	12
Not sure	3

Of the following attributes, please rank which would have a "high impact" on your likelihood to install solar power on your home (rank all)

	Homeowners (%)
I save money on my monthly electricity bill	64
I pay no upfront fees for installation and equipment	54
I lock in my electricity rates for 20 years	38
By using clean energy, I can reduce my environmental impact	35

Are you more or less likely to consider environmental impact today (either of the product or the company that makes it) than you were 3 years ago?

	More Likely			Same	Less Likely			Not Sure
	Overall	Much more	Smwht. more		Overall	Smwht less	Much less	
Homeowners (%)	**47**	16	31	44	**4**	2	2	4

Which, if any, clean-energy products have you purchased? (Choose all that apply)

	Homeowners (%)
At least 5 LED light bulbs	56
Energy Star-rated hot water heater (gas or electric)	36
Double or triple pane windows	28
Smart thermostat	21
Haven't made such a purchase	16
90% plus efficient gas furnace	14
Home energy audit or evaluation	10
Heat pump	9
Hybrid car	7
Battery backup power for my home	6
Solar energy system for my home	5
Electric vehicle	3
Not sure	6

Which, if any, clean-energy purchases are you likely to make in the next year? (Choose all that apply)

	Homeowners (%)
At least 5 LED light bulbs	27
Smart thermostat	12
Energy Star-rated hot water heater (gas or electric)	9
Double or triple pane windows	8
Hybrid car	7
Battery backup power for my home	7
Home energy audit or evaluation	7
90% plus efficient gas furnace	7
Solar energy system for my home	6
Electric vehicle	4
Heat pump	4
Not sure	26

When making decisions around purchasing clean-energy products and services, which of the following are your primary motivators? (Choose up to two options)

	Homeowners (%)
Saving money	82
Reducing my environmental impact	34
Fewer maintenance requirements because of product design, longevity, and efficiency	32
Using the latest and most innovative technology	9
Other	1
Not sure	8

How important is renewable energy to America's energy future?

	Important			Not Important			Not Sure
	Overall	Very	Somewhat	Overall	Not that	Not at all	
Homeowners (%)	**87**	55	32	**7**	5	2	6

Which energy sources do you believe are most important to America's energy future? (Pick up to Three)

	Homeowners (%)
Solar power	50
Wind power	42
Natural gas	33
Energy efficiency/savings	25
Oil	17
Hydroelectric power	17
Waste to energy	16
Nuclear	14
Geothermal power	10
Coal	8
Biofuels/biomass	7
Not Sure	12

In recent years, federal tax credits have enabled both the solar and wind industries to expand, with solar and wind both more than doubling their generation over the past five years. Do you agree or disagree that the federal government should continue to offer such incentives?

	Agree			Disagree			Not Sure
	Overall	Strongly	Somewhat	Overall	Somewhat	Strongly	
Homeowners (%)	**74**	39	35	**12**	6	6	14

Please indicate if you agree or disagree with the following statement: *I would like to install solar panels on my home in the future.*

	Agree			Disagree			Not Sure
	Overall	Strongly	Somewhat	Overall	Somewhat	Strongly	
Homeowners (%)	**60**	23	37	**23**	12	11	17

Overall are you satisfied or dissatisfied with your current electric utility company?

	Satisfied				Dissatisfied				Not Sure
	Overall	Very	Satisfied	Smwht	Overall	Smwht	Dissatis-fied	Very	
Homeowners (%)	**72**	11	29	32	**24**	11	8	5	4

When making investment decisions do you agree or disagree with the following statement: I consider the social and environmental impacts of the investment, as well as the financial return.

	Agree			Neither agree nor disagree	Disagree			Not Sure
	Overall	Strongly	Smwht		Overall	Smwht	Strongly	
Homeowners (%)	**52**	17	35	23	**17**	9	8	8

There is a new category of investing called 'impact investing' that offers financial as well as social and environmental returns, e.g. creating jobs and helping protect the environment. Please respond 'Yes' or 'No' to the following statements:

I would make this investment if it offers a potentially higher return than other options.

	Homeowners (%)
Yes	74
No	7
Not sure	19

I would make this investment if it offers a return that is at least as good as my other options.

	Homeowners (%)
Yes	61
No	14
Not sure	25

I would make this investment if it offers a slightly lower return than my other options.

	Homeowners (%)
Yes	22
No	44
Not sure	34

Some electric utility companies say that they should be allowed to charge rooftop solar owners a fee for connecting their solar systems to the grid. Many solar supporters say there should be no additional fee since they are increasing the use of renewables and reducing utility company costs during peak-use periods when demand is highest and electricity prices increase. Do you support or oppose electric utility companies being able to charge an additional fee to solar powered homes and businesses?

	Support			Oppose			Not Sure
	Overall	Strongly	Somewhat	Overall	Somewhat	Strongly	
Homeowners (%)	**24**	8	16	**61**	18	43	15

Some have said that the additional fee charged by electric utility companies to solar powered homes is a 'tax' on solar power. Do you agree or disagree that this additional fee is a 'tax' on solar power?

	Agree			Disagree			Not Sure
	Overall	Strongly	Somewhat	Overall	Somewhat	Strongly	
Homeowners (%)	**53**	28	25	**26**	12	14	22

How important do you think it is to the US economy to domestically manufacture solar energy systems, and solar panel components?

	Important			Unimportant			Not Sure
	Overall	Very	Somewhat	Overall	Somewhat	Very	
Homeowners (%)	**79**	40	39	**10**	7	3	12

How important is it to the future of the US for the nation to be a global leader in developing and deploying solar energy systems?

	Important			Unimportant			Not Sure
	Overall	Very	Somewhat	Overall	Somewhat	Very	
Homeowners (%)	**78**	41	37	**9**	8	1	12

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CLEAN EDGE

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO ENERGY FREEDOM COALITION OF ARIZONA'S THIRD SET OF DATA REQUESTS DOCKET NO. E-01461A-15-0363 AUGUST 16, 2016

EFCA 3.1: Please provide workpapers supporting Staff's testimony in this docket.

RESPONSE: **Please see attached Workpapers.**

RESPONDENT: **Ranelle Paladino, Consultant, Utilities Division, Arizona Corporation Commission, 1200 West Washington, Phoenix, Arizona 85007**

EXHIBIT
tabbies
S-15
ADMITTED

SolarCity

Investor Presentation

JUNE 2016

Forward-Looking Statements

This presentation contains forward-looking statements that involve risks and uncertainties, including statements regarding SolarCity's business; our operational growth and expansion opportunities; the deployment and installation of megawatts; future bookings; financial strategies for cash generation and increasing shareholder value; forecasted cash flows from existing Energy Contracts, including related assumptions as to energy production, future operations and maintenance expenses, cancellation rates, renewal rates, default rates, amounts of renewable energy credits and other performance-based incentives, and other identified assumptions; our forecast of the value of megawatts deployed; our projections related to decreases in Cost per Watt, including our plans to decrease our sales Cost per Watt by eliminating higher cost channels, utilizing more efficient channels, and other initiatives; our goals to achieve a total Cost per Watt of $2.25 by 2017 and an installation Cost per Watt of $1.50 and sales Cost per Watt of $0.40 longer-term; the impact of proprietary technology in decreasing our installation costs; our expectations regarding future hardware and energy storage pricing, our expectations regarding the maturing efficiency of our operations centers, and our plans to vertically integrate our commercial product offerings along with related projections regarding installation efficiencies and cost savings; our plans to achieve manufacturing economies of scale and associated manufacturing cost reductions; our expectations regarding the Riverbend agreement, the development and construction of the Riverbend facility, the anticipated timing and expense related to acquisition of manufacturing equipment, and related assumptions regarding capital and operating expenses and the performance of our manufacturing operations; our goal of not owning manufacturing assets on our balance sheet; our expectations as to future regulatory and policy outcomes affecting our industry; our projections regarding the future pricing of utility-generated electricity, including as a result of infrastructure capital expenses, and assumptions related to customer savings; our liquidity and forecasted access to capital, including assumptions related to the terms of future financing (including risk premiums and interest rates), the terms and frequency of future securities offerings, the sufficiency of committed available financing, and our expectations regarding the refinancing of existing debt obligations, including our aggregation facilities and short-term Solar Bonds; our projections regarding the structure of our tax equity financing structures; the amount of megawatts that can be installed and deployed based on committed available financing; the success of our product development efforts and customer preferences, including the potential and performance of residential loan offerings, residential and commercial energy storage products, utility service offerings and other new product offerings; our assumptions regarding future tax obligations; and assumptions relating to the foregoing.

Forward-looking statements should not be read as a guarantee of future performance or results, and will not necessarily be accurate indications of the times at, or by, which such performance or results will be achieved, if at all. Forward-looking statements are subject to risks and uncertainties that could cause actual performance or results to differ materially from those expressed in or suggested by the forward-looking statements. In order to meet our projections, we will need to expand, train and retain our workforce, increase the efficiency of our sales and installation operations, and increase our existing bookings rate. Additional key risks and uncertainties include the effect of electric utility industry regulations, net metering and related policies; the availability and amount of rebates, tax credits and other financial incentives; continued confidence in our tax equity investors and lending partners in the quality of our solar assets; the availability and amount of financing from fund investors; the level of demand for our solar energy systems; the availability of a sufficient, timely, and cost-effective supply of solar panels and balance of system components in each of our geographies; our ability to expand our salesforce and increase bookings, including in new geographies; our ability to successfully integrate acquired businesses, operations and personnel; our ability to achieve manufacturing economies of scale and associated cost reductions, our expectations regarding the Riverbend agreement, the development and construction of the Riverbend facility, the anticipated timing and expense related to acquisition of manufacturing equipment, and related assumptions regarding capital and operating expenses and the performance of our manufacturing operations; the effects of existing and future tariffs and other trade barriers; changes in federal tax treatment; the retail price of utility-generated electricity or the availability of alternative energy sources; risks associated with SolarCity's rapid growth; risks associated with international expansion; the success of our product development efforts and customer preferences; risks that consumers who have executed energy contracts may seek to cancel those contracts; assumptions as to the value under energy contracts and contract renewal rates and terms, including applicable net present values, performance-based incentives, and other rebates, credits and expenses; changes in strategic planning decisions by management or reallocation of internal resources; and general market, political, economic and business conditions. You should read the section entitled "Risk Factors" in our most recent Quarterly Report on Form 10-Q and subsequent Current Reports on Form 8-K, which have been filed with the Securities and Exchange Commission, which identify certain of these and additional risks and uncertainties. We do not undertake any obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future developments or otherwise, except as otherwise required by law.

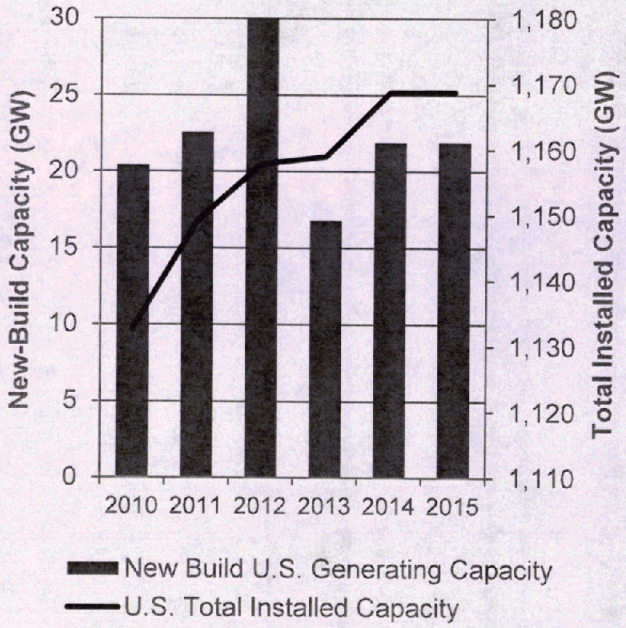
SolarCity's Vision is to Accelerate the Mass Adoption of Sustainable Energy

We believe that solar power can and will become the world's dominant source of energy, and that we can speed widespread adoption of solar power by offering products that save our customers money.

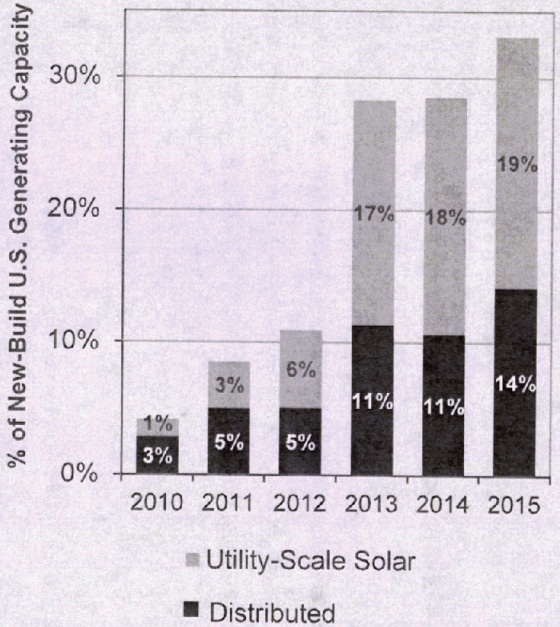
Solar Represents a Plurality of New U.S. Power Capacity

Total U.S. Installed Generating Capacity is ~1,170 GW with 15-20 GW/Yr. of New Gross Capacity since 2010
Distributed Solar Accounted for 14% of New-Build U.S. Generating Capacity in 2015 with Utility-Scale at 19%

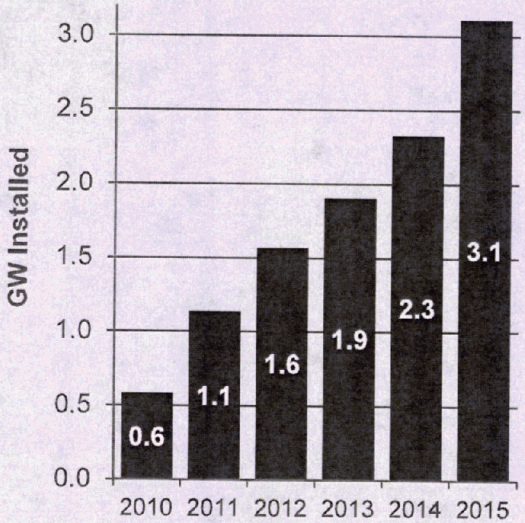
15-20 GW of New U.S. Generating Capacity per Year[1]



~14% of New U.S. Capacity was Distributed Solar in 2015[2]



U.S. Distributed Solar Grew at a 40% CAGR 2010 to 2015[3]



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Despite Continued Growth, Solar Penetration Remains Low

U.S. Solar Penetration of Both Residential and Commercial Buildings Is Below 1%

Residential Solar Is Installed on Only ~2% of Single-Family Homes in SolarCity's Primary U.S. Service Territories

	SolarCity Primary U.S. Service Territories*	Total U.S.
Total U.S. Residential Solar Installations at the End of 2015[4]	0.82M	0.90M
/ Total U.S. Single-Family Housing Units[5]	38.1M	94.0M
= Distributed Solar Penetration of U.S. Single-Family Homes	2.2%	1.0%

- Over 904k residential solar homes in the United States as of the end of 2015 with ~303k new residential installations in 2015.[4]
- 690k new single-family home permits across the Country in 2015, expanding the opportunity.[6]
- Less than 1% solar penetration of the 5.6M commercial buildings in the U.S.[7]

* Excludes Nevada.

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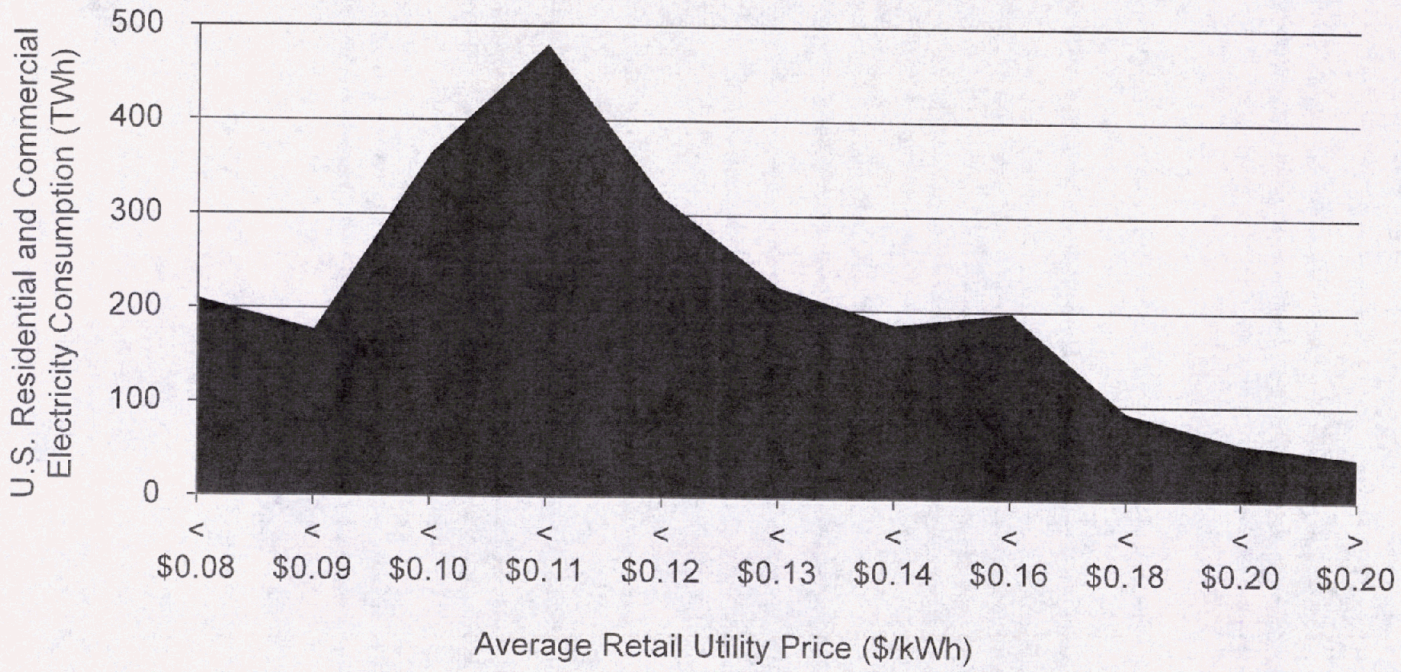
Solar Is Competitive in a Significant Portion of the U.S.

Avg. U.S. Retail Electricity Price Is ~$0.13/kWh with 583 TWh Consumed at That Price or Higher[8]
Total U.S. Residential and Commercial Electricity Sales ≥$0.13/kWh Exceeded $90 Billion in 2014



Non-SolarCity Service States: NC, FL, GA

SolarCity Service States: AZ, TX, PA, NY, CA, MD, MA, CT, HI

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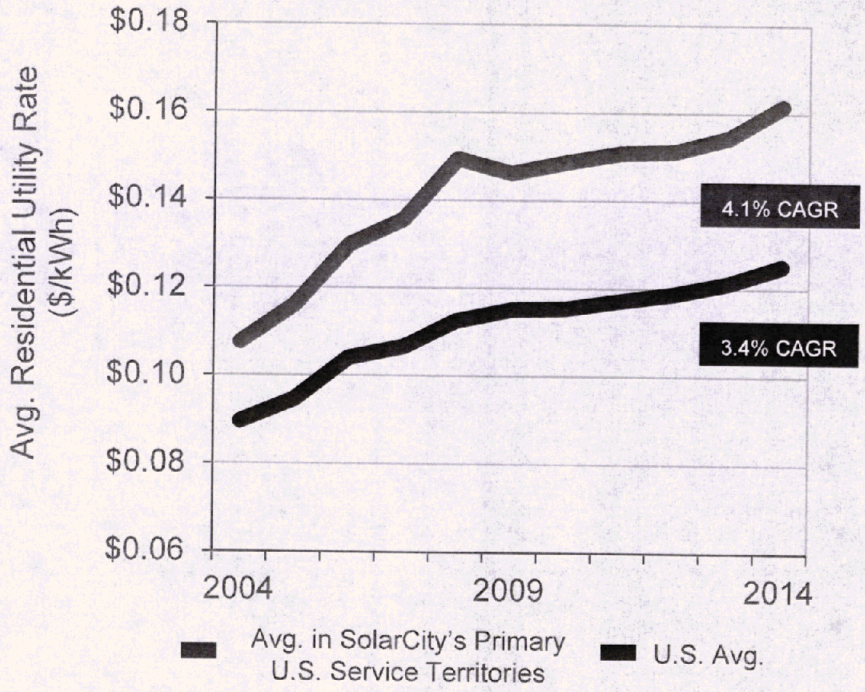
Retail Utility Rates Are Rising on Infrastructure Spending

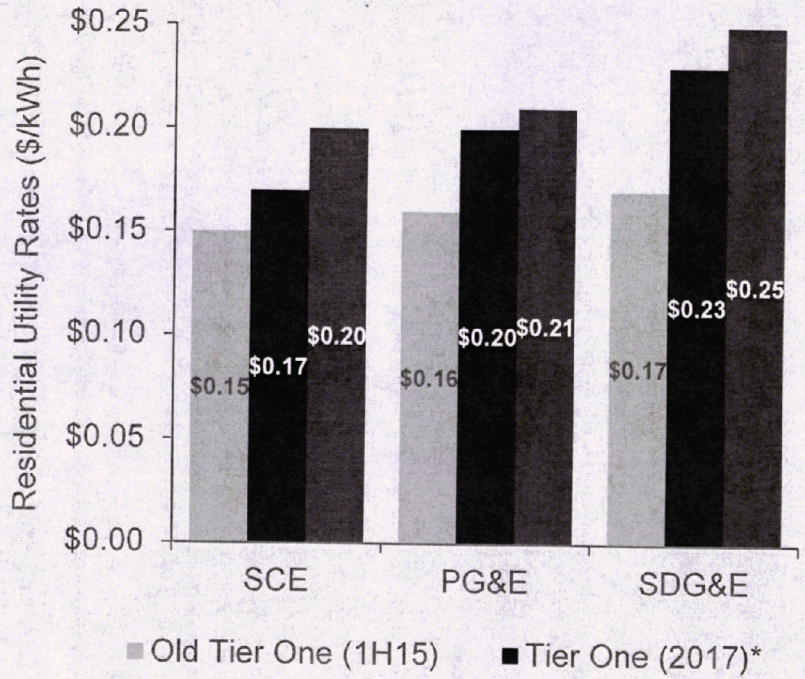
Retail Utility Rates Have Increased Despite Lower Energy Prices Due to Infrastructure Capex

CA Rate Reform Is Increasing Investor-Owned Utilities' Baseline Tier 1 Residential Rates Initially to >$0.17/kWh in 2017

Utility Rates in SolarCity Primary U.S. Service Territories Are Up 50% Since 2004[9]



New CA Rate Reform Increasing Tier One Rates[10]



* Assumes 3% Additional Annual Rate Inflation.

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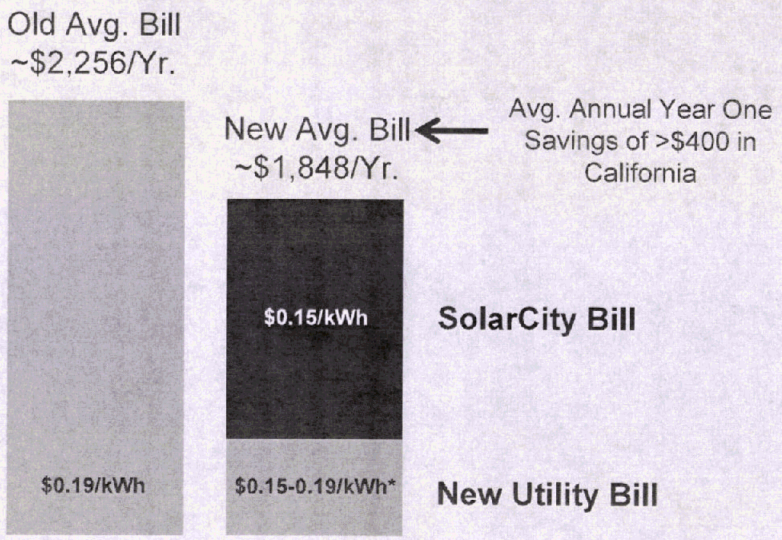
Cleaner, Lower Cost Energy

Solar PPAs and Leases Lower Customers' Energy Bills for No Initial Investment

SOLARCITY EXAMPLE OF A CALIFORNIA PPA WITH NO DOWN PAYMENT



- No upfront cost for installation required
- Solar energy paid for monthly at a lower $/kWh price than charged by the local utility
- Our solar contracts typically generate 50-90% of a customer's annual electricity needs
- Customers able to generate savings of up to 20% from Day One

* Because of tiered pricing based on usage in California, the output from solar energy systems also lowers the rate charged by the utility.

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Solar Offerings for Each Key Product Segment

	PPA	Lease	Cash Purchase	Loan
Down Payment	$0 Down Full & Partial Prepay Options	$0 Down Full & Partial Prepay Options	Outright Purchase	$0 Down
Ownership	SolarCity	SolarCity	You	You
Tax Credit(s)	×	×	✓	✓
Monthly Payments	Pay for the energy produced, with a 0-2.9% Annual Escalator	Low, Fixed with a 0-2.9% Annual Escalator	None	Fixed
Production Guarantee	×	✓	✓	✓
Energy Monitoring with MySolarCity App	✓	✓	✓	✓
Roof & System Warranty	✓	✓	✓	✓
Payment term	20 Years	20 Years	Paid in Full	10 or 20 Years

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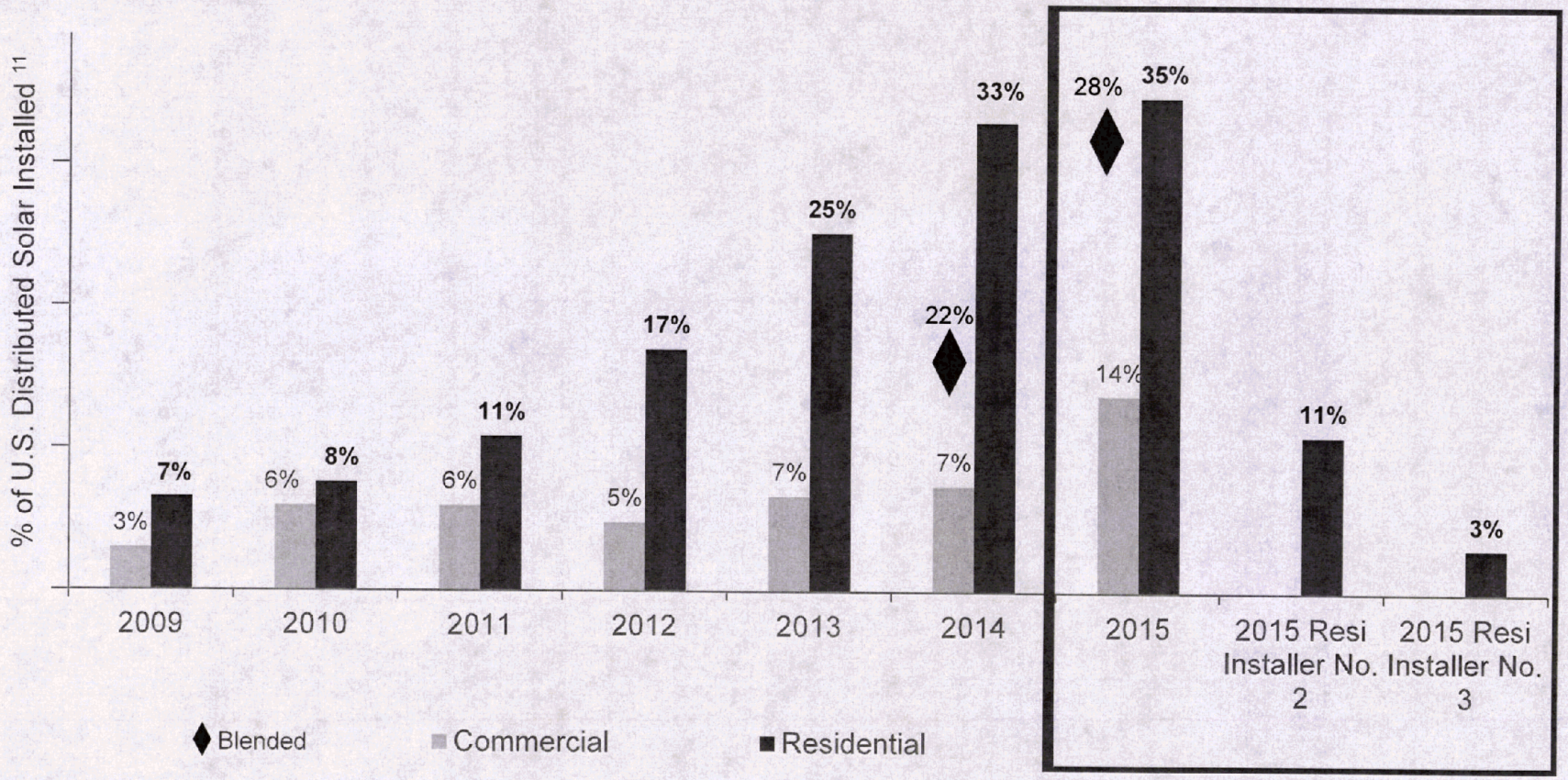
The Clear Leader in U.S. Distributed Solar Installations

SolarCity Is the Largest U.S. Residential and Commercial Solar Installer
Installed 28% of Distributed Solar, 12% of Total Solar, and 4% of New Gross Power Capacity in the U.S. in 2015



SolarCity accounted for more than 1.5% of all solar installed globally in 2015

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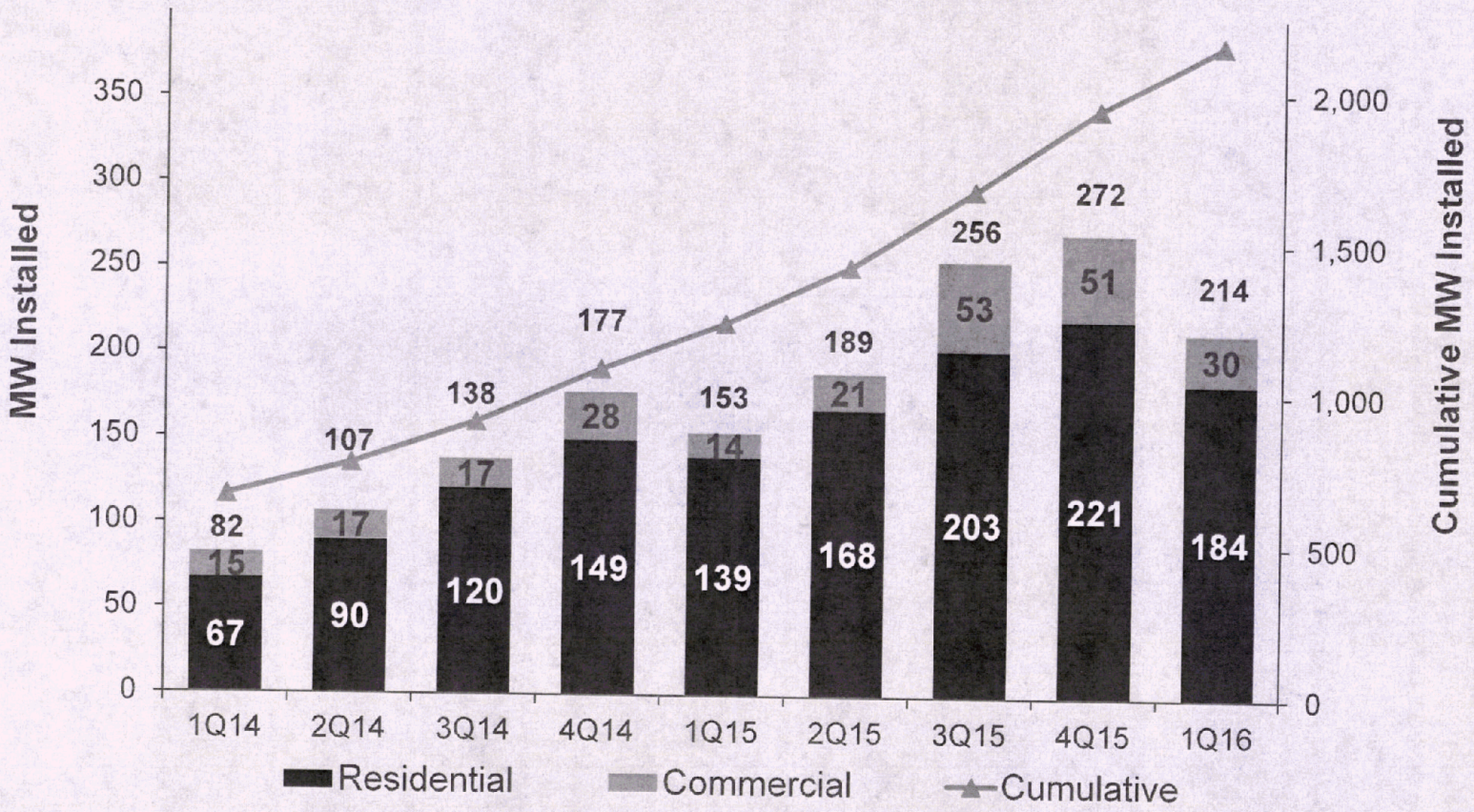
MW Installed of 870 in 2015 and 214 in Q1 2016

MW Installed Grew 40% Y/Y to 214 MW in Q1 2016 for Cumulative Total of 2.16 GW
Residential Up 32% Y/Y to 184 MW and Commercial Up 114% Y/Y to 30 MW



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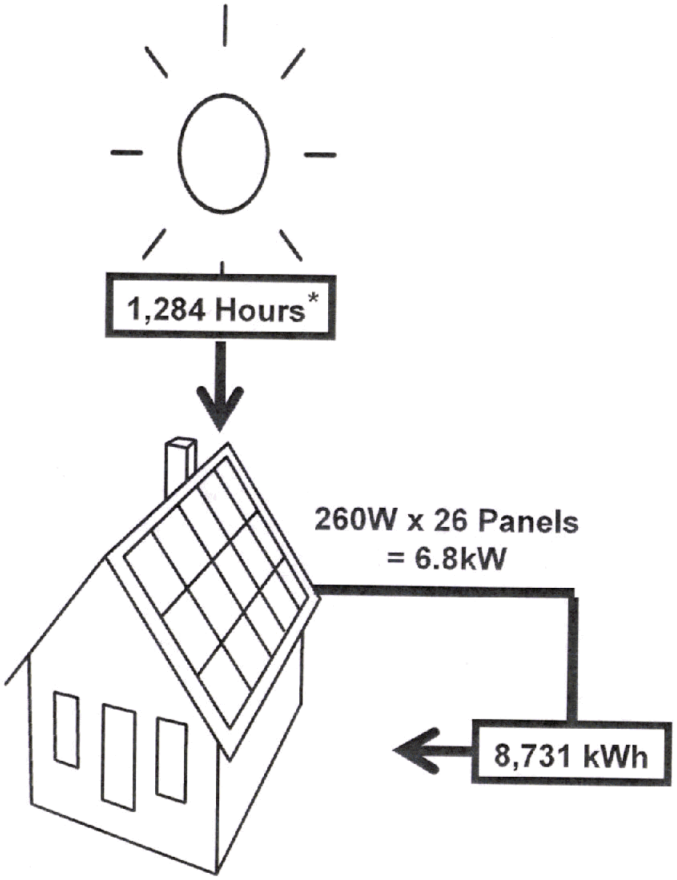
Project Cash Flow Driven by Units, Production, and Pricing



746 Avg. FICO **BILL**

Investment-grade off-taker **SREC**

	Solar Insolation	Annual hours of sunshine on the panels adjusted for tilt and azimuth
	X	
	System Size	Capacity (kW or MW)
	=	
	Annual Energy Production	Estimated kilowatt-hours (kWh) of solar energy produced in Year One
	X	
$0.12/kWh	**(Energy Contract Price**	All the energy produced by the solar system is sold to the customer at an established $/kWh price with an annual escalator (includes performance-based incentives)
+	**+**	
$0.02/kWh	**SREC Price)** *Portfolio average, e.g., $0 in California*	Certain states require electricity providers to purchase Solar Renewable Energy Certificates to meet state renewable energy portfolio standards
=	**=**	
$1,222 **(or $0.18/W)**	Energy Contract Revenue	Annual revenue is the customer bill plus payments for SRECs. Customers contract for 20 years and we expect to provide energy to the home for at least 30 years

*Average of Q1 2016 Lease/PPA Deployed; Q1 2016 average including MyPower is 1,294 hours.

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Gross Project Cash Flows (Pre-ITC) in Q1 2016

The Foundation of Our Value Creation Rests Upon the Cash Flow Stream of the Underlying Assets

Q1 2016 NPV of Lease/PPA Gross Project Cash Flows Before the Investment Tax Credit/Depreciation Was $2.21/W at a 6% Discount Rate

$/W UNIT ECONOMICS FOR THE 219 MW OF LEASES/PPAS DEPLOYED IN Q1 2016

Year		0	1	2	3	4	5	6	7	8	9	10	11*	12	13	14
Energy Production	kWh/kW		1,284	1,277	1,271	1,265	1,258	1,252	1,246	1,239	1,233	1,227	1,221	1,215	1,209	1,203
Annual Degradation	*(0.5%)*															
Contract (+PBI) Price	$/kWh		$0.12	$0.12	$0.13	$0.13	$0.13	$0.13	$0.14	$0.14	$0.14	$0.14	$0.15	$0.15	$0.16	$0.16
Annual Escalator	*2.0%*															
SREC	$/kWh		$0.02	$0.02	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
Rebates/Prepayments	$/W	$0.08														
Project Revenue	$/W		$0.18	$0.18	$0.18	$0.18	$0.18	$0.17	$0.17	$0.17	$0.18	$0.18	$0.18	$0.18	$0.19	$0.19
O&M Expenses	$/W		($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.02)	($0.18)	($0.03)	($0.03)	($0.03)
Gross Project Cash Flow	$/W	$0.08	$0.16	$0.16	$0.16	$0.16	$0.15	$0.14	$0.15	$0.15	$0.15	$0.16	$0.01	$0.16	$0.16	$0.16

Year	15	16	17	18	19	20	21*	22	23	24	25	26	27	28	29	30**
Energy Production	1,197	1,191	1,185	1,179	1,173	1,167	1,161	1,155	1,150	1,144	1,138	1,133	1,127	1,121	1,116	1,110
Annual Degradation																
Contract (+PBI) Price	$0.16	$0.17	$0.17	$0.17	$0.18	$0.18	$0.17	$0.17	$0.18	$0.18	$0.19	$0.19	$0.20	$0.20	$0.21	$0.21
Annual Escalator																
SREC																
Project Revenue	$0.19	$0.20	$0.20	$0.21	$0.21	$0.21	$0.20	$0.20	$0.20	$0.20	$0.21	$0.22	$0.22	$0.22	$0.23	$0.23
O&M Expenses	($0.03)	($0.03)	($0.03)	($0.03)	($0.03)	($0.03)	($0.15)	($0.03)	($0.03)	($0.03)	($0.03)	($0.03)	($0.04)	($0.04)	($0.04)	($0.04)
Gross Project Cash Flow	$0.17	$0.17	$0.17	$0.18	$0.18	$0.18	$0.05	$0.17	$0.17	$0.17	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20

30-Year NPV: $2.20/W

- Rebates/Prepayments: $0.08/W (upfront)
- Contracted NPV: $1.74/W (discounted at 6%)
- Renewal NPV: $0.38/W (discounted at 6%)

* Inverter replacement assumed in Year 11 at a cost of $0.15/W and in Year 21 at a Cost of $0.12/W.

** Renewal assumes SolarCity continues to provide energy to the home at a 10% discount to the utility price at the time of renewal.

Note: Excludes default rates.

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Unlevered Project Cash Flow*** in Q1 2016

In Addition, Tax Equity Enables the Monetization of the Investment Tax Credit (ITC) in Year One

Tax Equity Invests $1.65-1.80/W in Return for a Portion of Gross Project Cash Flow and Most of the 30% ITC/Depreciation

UNLEVERED PROJECT CASH FLOW OF LEASES/PPAS DEPLOYED IN Q1 2016

Year	0	1	2	3	4	5	6	7	8	9	10	11*	12	13	14	15
Gross Project Cash Flow	$0.08	$0.16	$0.16	$0.16	$0.16	$0.15	$0.14	$0.15	$0.15	$0.15	$0.16	$0.01	$0.16	$0.16	$0.16	$0.17
Tax Equity Investment	$1.60															
Tax Equity Distributions		($0.04)	($0.04)	($0.05)	($0.05)	($0.05)	($0.05)	($0.04)	($0.02)	($0.02)	($0.02)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)
Unlevered Project Cash Flow to SCTY	$1.68	$0.11	$0.11	$0.11	$0.11	$0.11	$0.10	$0.11	$0.13	$0.13	$0.14	$0.00	$0.15	$0.15	$0.15	$0.16
SCTY Share of Cash Flow		72%	72%	71%	71%	70%	68%	71%	88%	88%	88%	(64%)	93%	93%	93%	93%
Tax Equity Share of Cash Flow		28%	28%	29%	29%	30%	32%	29%	12%	12%	12%	164%	7%	7%	7%	7%

Year	16	17	18	19	20	21*	22	23	24	25	26	27	28	29	30**
Gross Project Cash Flow	$0.17	$0.17	$0.18	$0.18	$0.18	$0.05	$0.17	$0.17	$0.17	$0.18	$0.18	$0.19	$0.19	$0.19	$0.20
Tax Equity Distributions	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)	($0.01)
Unlevered Project Cash Flow to SCTY	$0.16	$0.16	$0.17	$0.17	$0.17	$0.04	$0.16	$0.16	$0.16	$0.17	$0.17	$0.17	$0.18	$0.19	$0.18
SCTY Share of Cash Flow	93%	93%	93%	93%	93%	77%	93%	93%	93%	93%	93%	93%	93%	93%	93%
Tax Equity Share of Cash Flow	7%	7%	7%	7%	7%	23%	7%	7%	7%	7%	7%	7%	7%	7%	7%

30-Year Unlevered Pre-Tax NPV: $3.45/W***

- Tax equity investment: $1.60/W (upfront)
- Rebates/Customer prepayments: $0.08/W (upfront)
- Contracted Unlevered NPV: $1.41/W
- Renewal Unlevered NPV: $0.35/W

* Inverter replacement assumed in Year 11 at a cost of $0.15/W and in Year 21 at a Cost of $0.12/W.

** Renewal assumes SolarCity continues to provide energy to the home at a 10% discount to the price at the time of renewal.

*** Unlevered Project Cash Flow Value of $3.45/W on this slide only includes Leases/PPAs; the $3.46/W reference on Slides 15, 28 and 31 includes MyPower

Note: Excludes default rates; $/Watt numbers are rounded.

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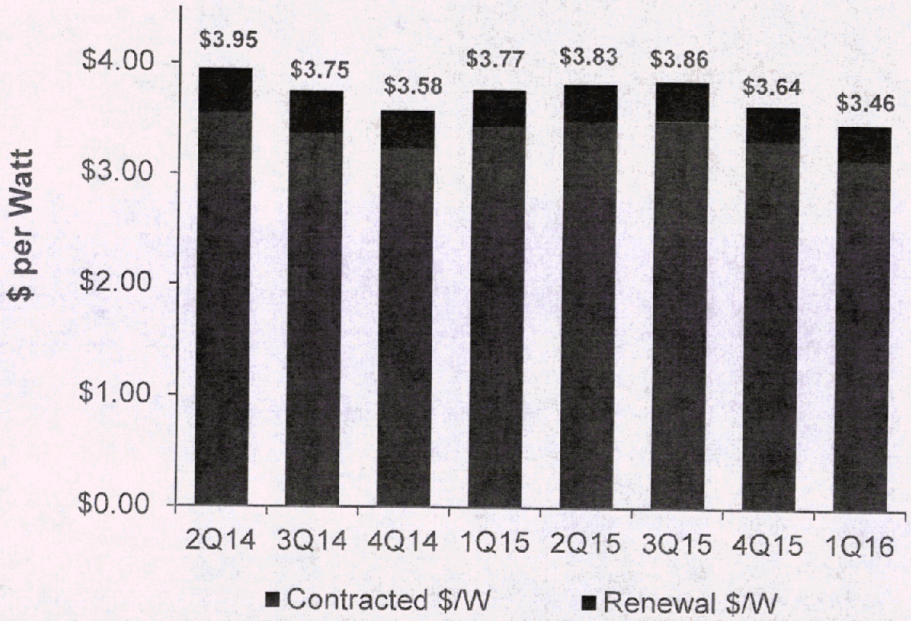
Q1 2016 Value of MW Deployed under Energy Contract at $804M*

The 30-Year Value of MW Deployed Under Energy Contracts Q1 2016 Was $804M, or $3.46/W**

Upfront Cash Receipts Accounted for $1.58/W, and Unlevered Pre-Tax NPV of Future Cash Flows Accounted for $1.88/W

VALUE OF MW DEPLOYED TO SCTY*



- MW Deployed: 245
  - Commercial represented 23% of total (up from 16% in Q4 2015 and 5% in Q3 2015)
  - 219 MW of Lease/PPA with tax equity
  - 14 MW of MyPower consumer loans with no tax equity
  - 12 MW of System Sales (excluded from Value of MW Deployed under Energy Contracts)
- Avg. Annual Energy Harvest: 1,294 kWh/kW
- Avg. Energy Contract Price: $0.12/kWh
- Blended SREC Price (5-Year Avg.): $0.01/kWh
- Avg. Energy Contract Price Escalator: 2.0%
- Tax Equity Distributions: 29% pre-flip; 7% post-flip***

$3.46/W

- Tax equity investment: $1.51/W blended (or $1.60/W ex-MyPower)
- Upfront Cash Rebates/Prepayments: $0.07/W
- Contracted Unlevered NPV: $1.55/W
- Renewal Unlevered NPV: $0.33/W

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* Represents Gross Value to SCTY at a 6% discount rate net of distributions and any additional value attributed to tax equity investment partners. Discount rate sensitivities provided in Appendix B.

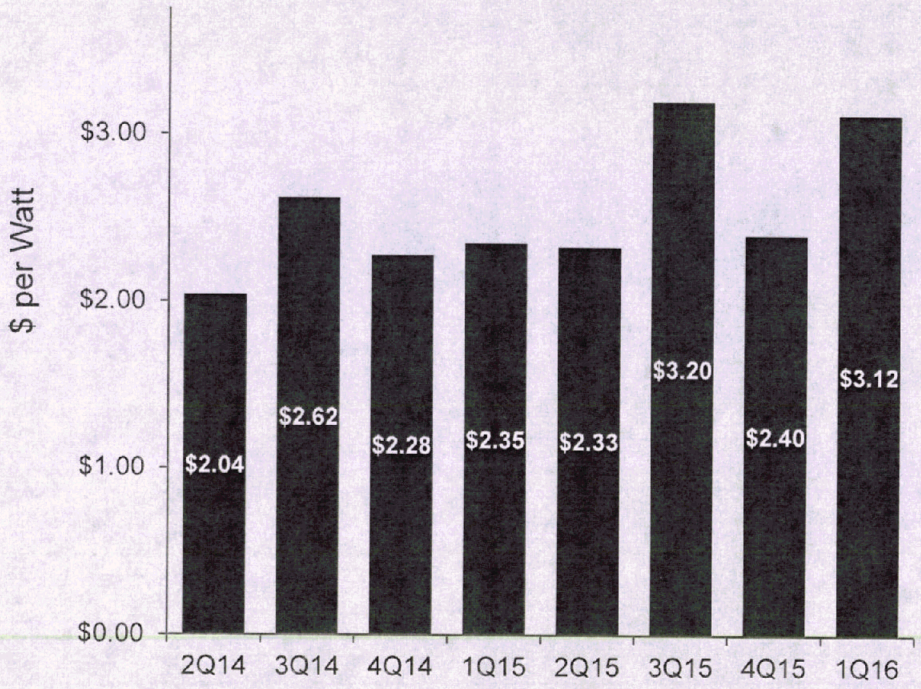
** Contracted $3.13/W (or $728M) and estimated renewal $0.33/W (or $76M).

*** Tax equity distributions based on lease/PPA cash flows only. On a blended basis including MyPower: 27% pre-flip and 7% post-flip.

Asset Financing of $3.12/W in Q1 2016

$1.1 Billion in New Project Finance Commitments Announced in Year-to-Date (With $728 Million Cash Financing Received in Q1 2016)
Available Project Financing Capacity of $714 Million (Including $478 Million of Tax Equity Capacity) at the End of Q1 2016*

ASSET FINANCING OF MW DEPLOYED UNDER ENERGY CONTRACT



- Tax Equity Investment: $1.40/W for lease/PPA MW (or $1.31/W blended including consumer loans)
  - Three new funds or upsizings
- Upfront Cash Rebates and Prepayments: $0.17/W
- Other Asset Financing: $1.64/W
  - New residential 5-year back leverage bank debt structure with BAML, KeyBank, and Silicon Valley Bank for $160M (or $0.81/W) at cost of 4.1% at the time of issuance
  - First aggregation facility dedicated solely to commercial installations for $150M (or $0.60/W); at a cost of 3.9% at the time of issuance; $35M drawn down in Q1 2016
  - New, innovative financing structure that enables upfront monetization of SRECs
  - First securitization of consumer loan product for $185M (or $2.89/W) at blended yield of 5.8%
  - Sixth securitization for $52M (for total of $3.13/W including tax equity); blended yield of 6.25% reflected temporary dislocations in debt markets

* Subsequent to the End of Q1 2016, debt pay-down from the cash equity transaction freed up an additional $151 million of aggregation facility capacity.

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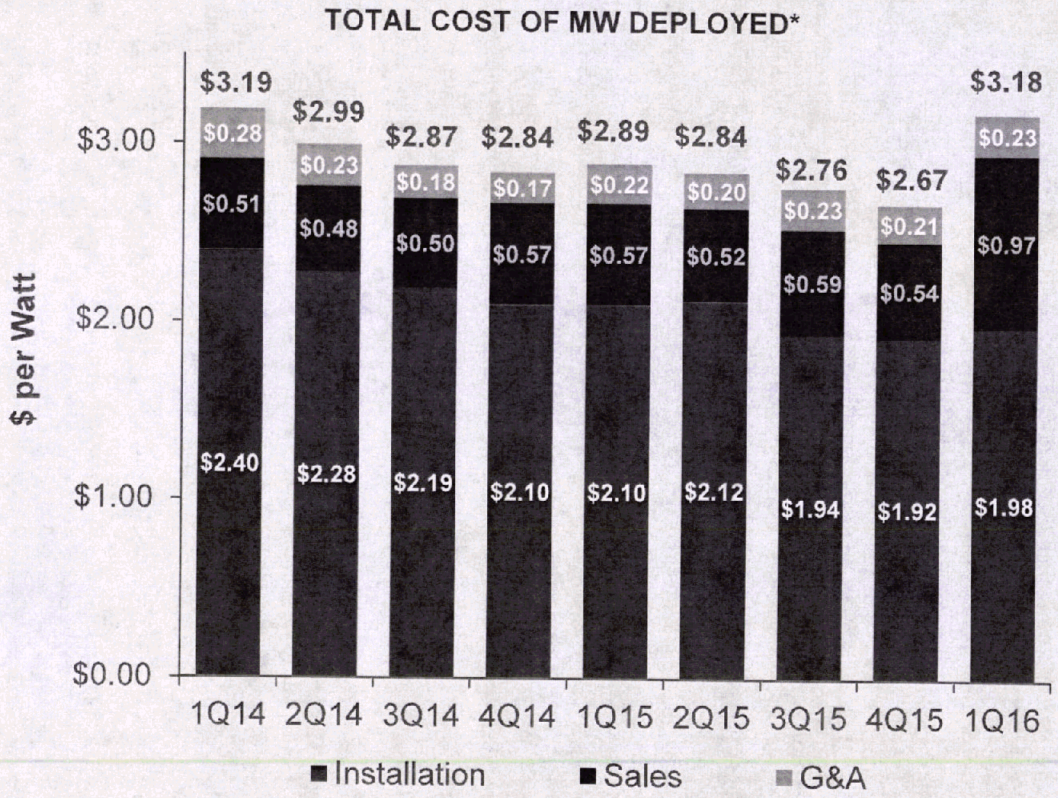
Best-in-Class Installation Costs Down 6% Y/Y

Cost per Watt Achieved New Lows in Q4 2015 as Installation Costs Achieved Original 2017 Goal One Year Ahead of Schedule
Sales Costs in Q1 2016 Affected by Temporarily Lower Bookings



- Installation Cost: Down 6% year-over-year to $1.98/W. Residential and commercial costs flat Q/Q but greater mix of higher-cost Commercial drove blended costs higher Q/Q
- Sales Cost: Up on lower volumes covering fixed costs

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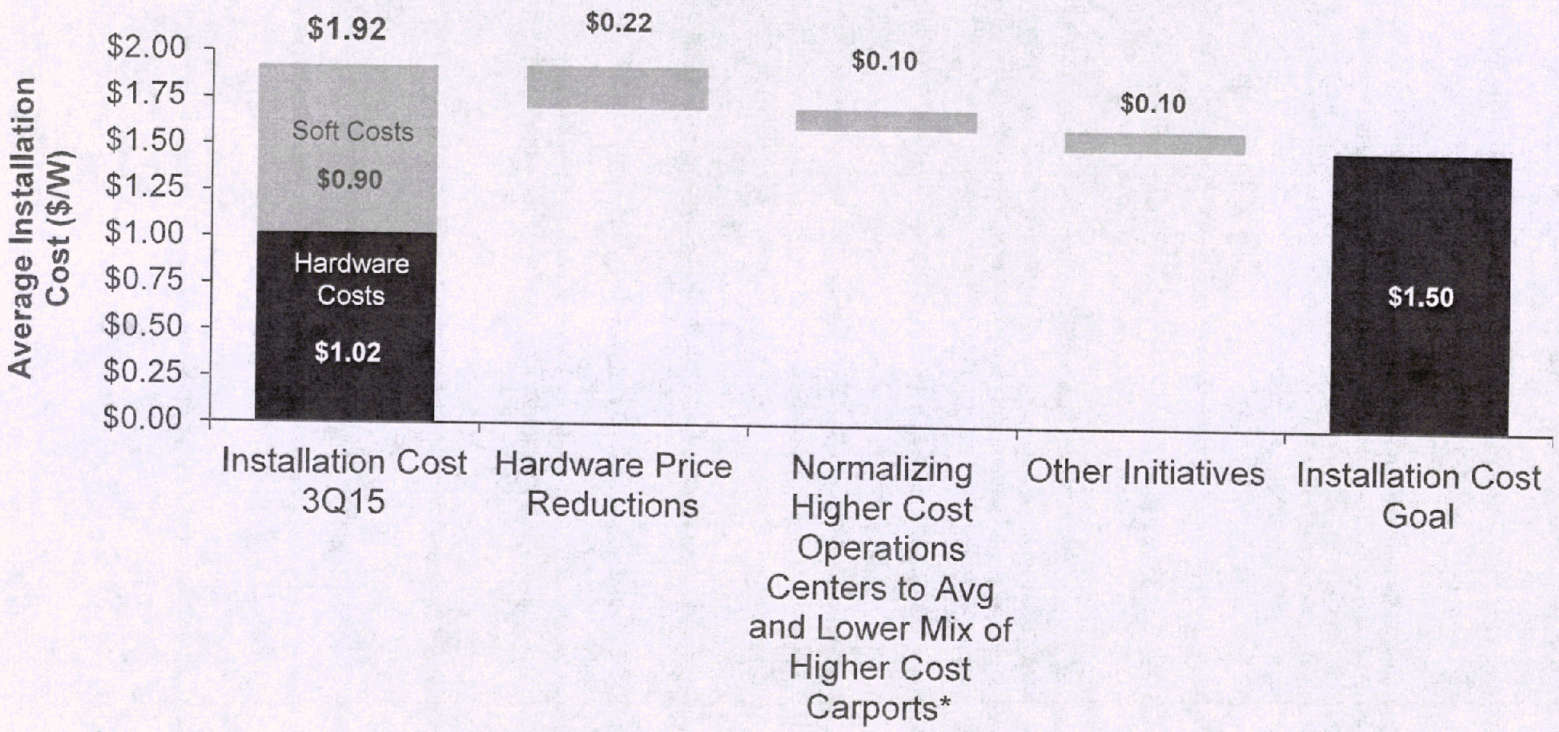
* Excludes R&D expenses and corporate capital expenditures.
Cost calculation methodology has been updated to exclude costs associated with operating the PowerCo portfolio that are now included and presented in our Recurring Cash Generation of PowerCo memo and to include cancellation costs that had not been previously included.

Reducing Installation Cost Goal to $1.50/W

Lower Hardware Prices and Soft Costs Are Each Expected to Drive ~50% of Cost Reductions



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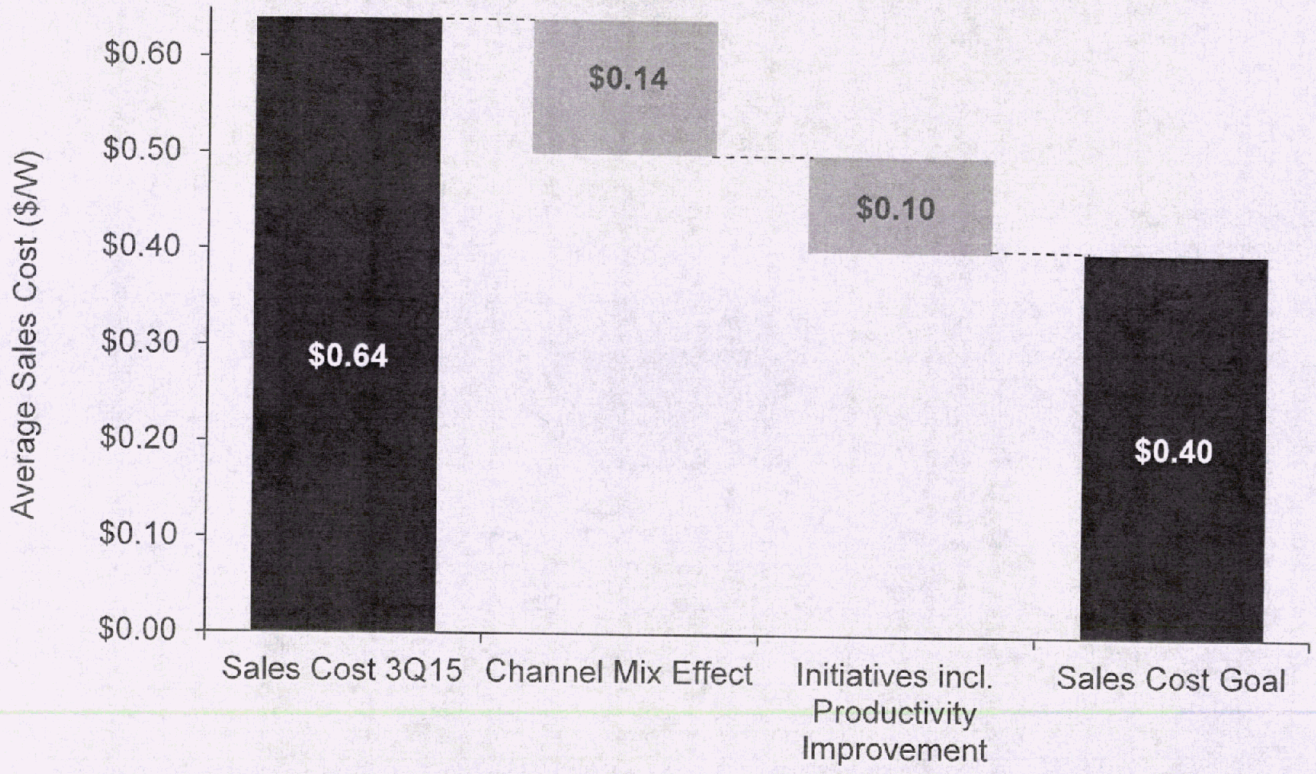
* Current economics in some states support carports but lower revenue numbers will reduce carport projects that generate enough returns.

Achieving Our Sales Cost Goal of $0.40/W

Goal Is to Reallocate Resources and Drive Productivity to Improve Cost of Acquisition



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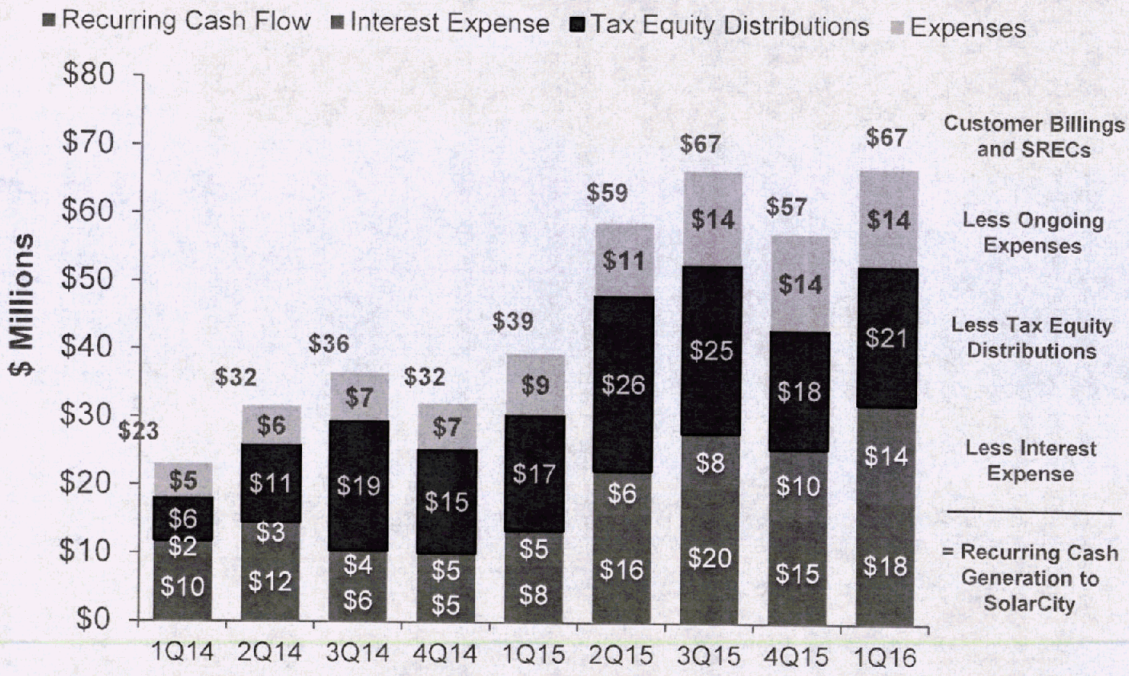
Recurring Cash Generation of PowerCo* of $69M over the Last 12 Months

Recurring Cash Generation of PowerCo Represents the Realization of Levered Project Cash Flow in Each Period
This Captures Customer Payments, SRECs, and PBIs Less Ongoing Expenses, Tax Equity Distributions, and Non-Recourse Debt Interest

RECURRING CASH GENERATION OF POWERCO**



- Customer Billings / SRECs: Billings for MW Deployed under Energy Contracts (including PBIs and SRECs)
- Ongoing Expenses: Operations & maintenance expenses
- Tax equity distributions: Contractual distributions to investors
- Interest Expense: Interest payments on all non-recourse debt (including ABS, aggregation facilities, and other back leverage)

MW Deployed under Energy Contract (EoP)	586	685	819	989	1,127	1,300	1,498	1,742	1,975

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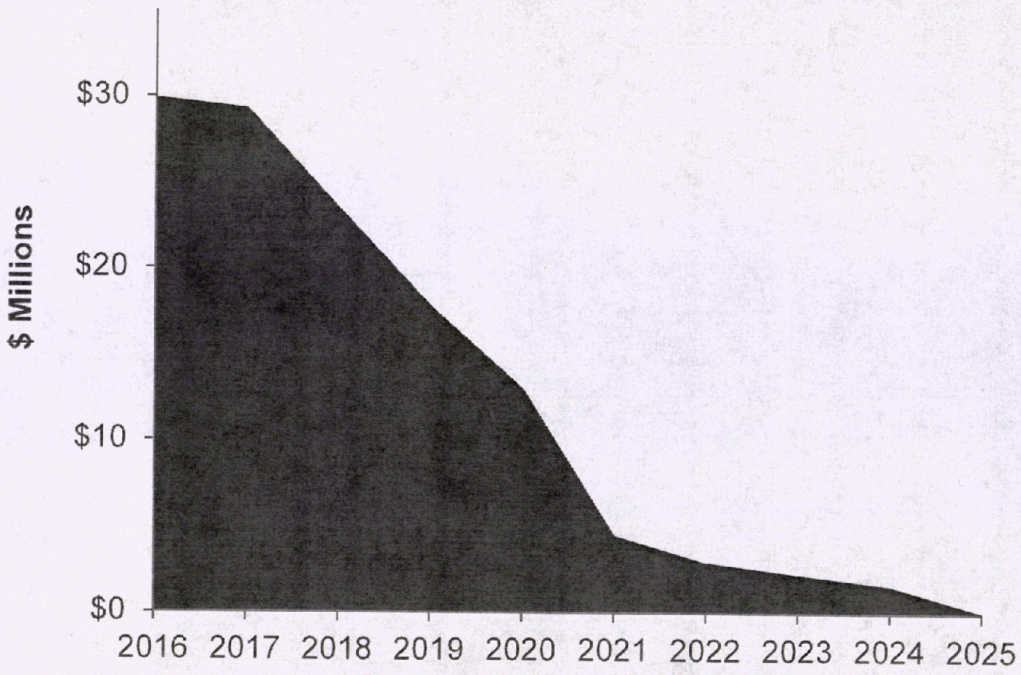
* Recurring Cash Generation of PowerCo is based on our quarterly calculation methodology, which we detail in a memo on our website.
** Excludes net upfront payments from prepayments on Energy Contracts.
.*** Excludes $10 million in prepayments (net of debt pay-down) on MyPower consumer loans.

Contracted SREC Portfolio Expected to Generate ~$122 Million over the Next 10 Years*

With 255 MW in Service and ~1,109 MWh/MW in SREC States, PowerCo Portfolio Generates ~283,000 SRECs per Year

Less Than Half of the SREC Portfolio Has Been Contracted With the Balance Still Available to Be Hedged

CONTRACTED SREC PORTFOLIO* AS OF 3/31/16 ($M)



- Solar Renewable Energy Credits (SRECs) typically represent 1 MWh of solar energy production.
- The most prominent SREC programs are based in MA, MD, and NJ.
- Energy retailers may be required to purchase SRECs in the open market to comply with Renewable Portfolio Standards in these geographical areas.
- A typical residential household generates 5-6 SRECs per year (5-6 kW system size x ~1,000-1,100 hours of sun per year) .
- Solar systems generate SRECs for 10+ years.
- SRECs are tradable securities with pricing that can be hedged (though typically only for the next 1-5 years).

NPV of Contracted SREC Portfolio at a 6% Discount Rate: $103 Million

* Represents unlevered portfolio.

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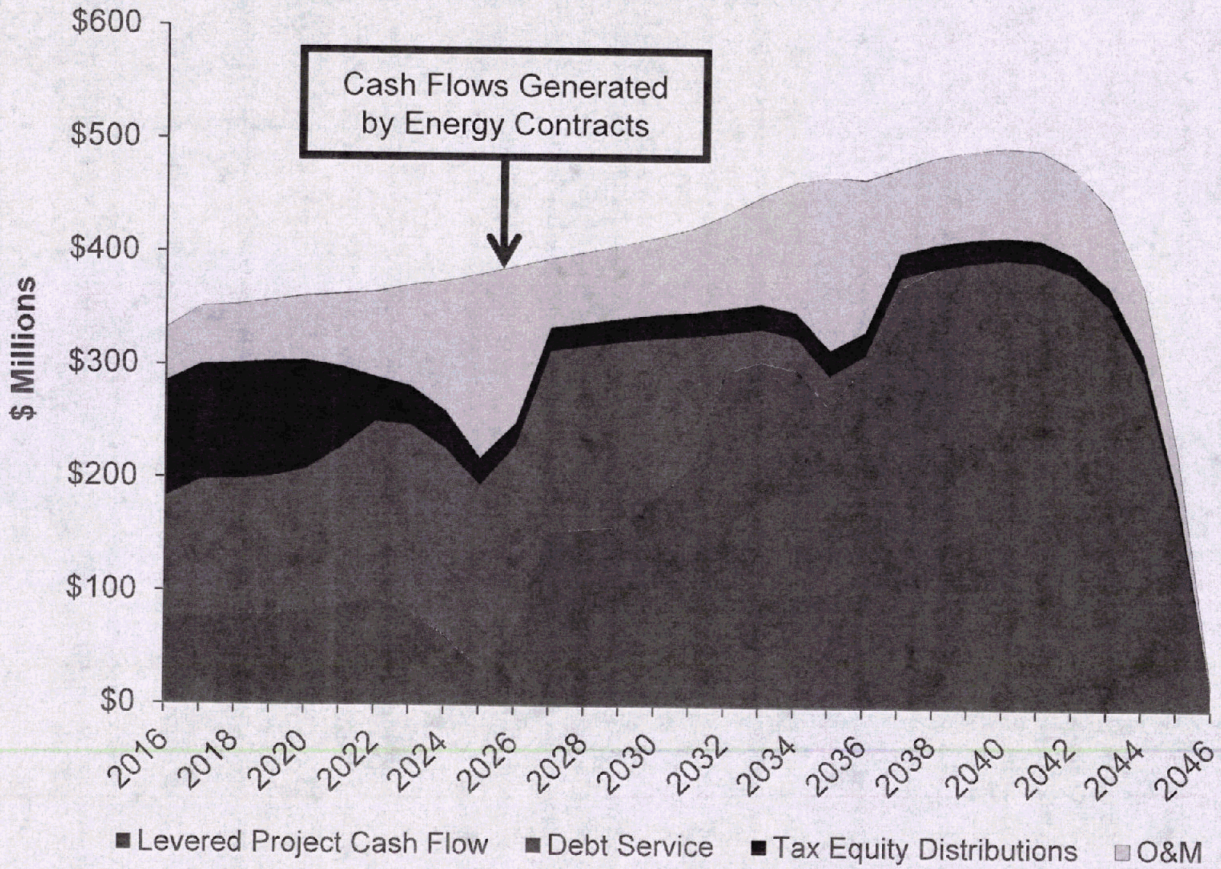
NPV of PowerCo's Unlevered Project Cash Flow (Less Debt) at $2.0B Excluding SRECs

The Pre-Tax Unlevered NPV Remaining of PowerCo's Portfolio Is Forecast at $3.6 Billion with Non-Recourse Debt at $1.6 billion
Of This Total, $2.75 Billion Is Contracted, and $0.85 Billion Is Estimated From Renewal

PowerCo Portfolio as of 3/31/15	
Cumulative Energy Contracts Deployed	2.0 GW**
Avg. Annual Energy Harvest (2016)	1,387 kWh/kW
Avg. Energy Contract Price (2016)	$0.12/kWh
Avg. Energy Contract Price Escalator	2.2%
Tax Equity % of Lease/PPA Gross Cash Flow (2016)	40%
Project Debt ($M)	$1,628
Blended Cost of Debt (%)	5.1%



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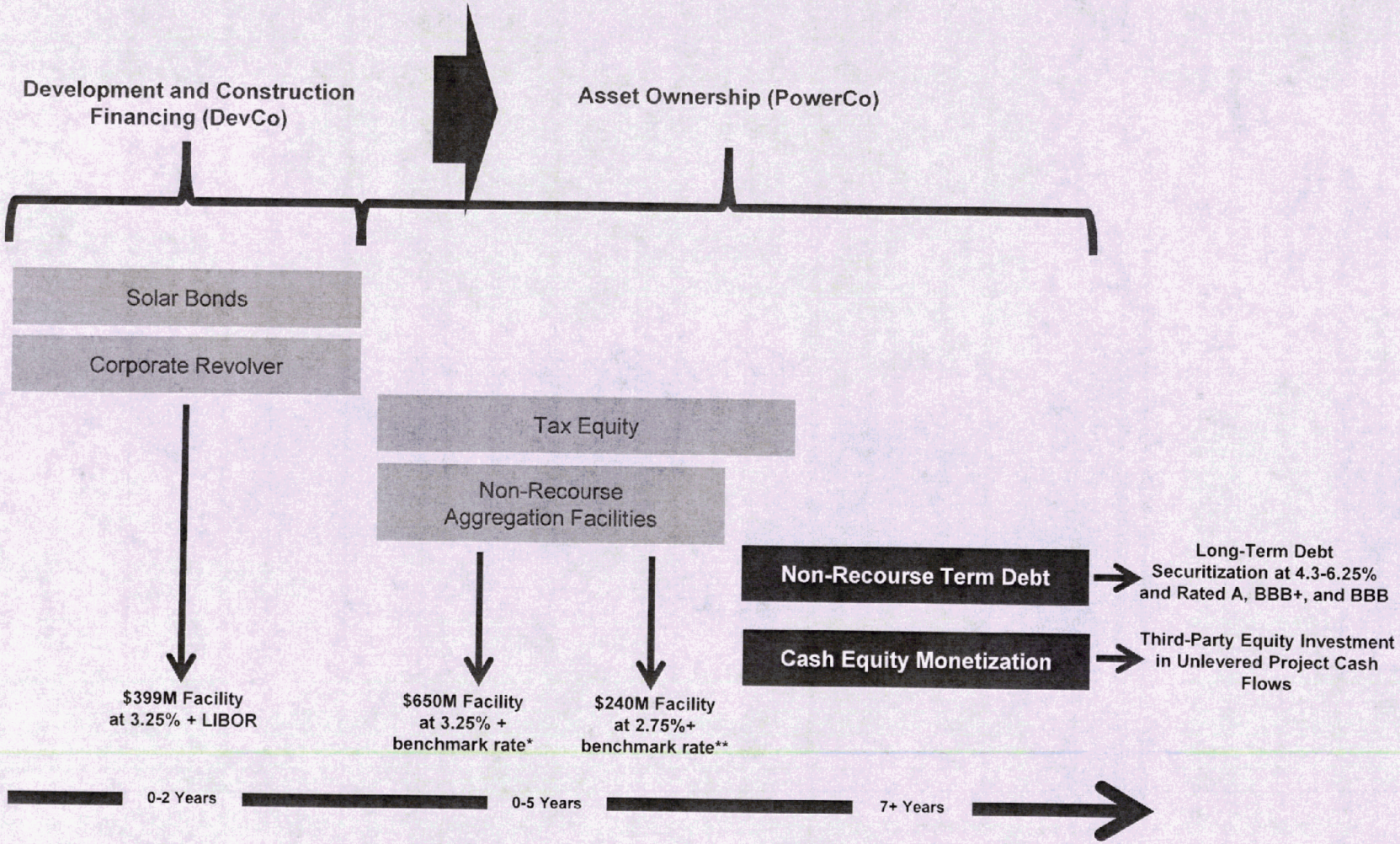
* At a 6% discount rate.
** Cumulative Energy Contracts deployed of 2.0 GW excludes 0.1 GW of System Sales deployed and includes 0.14 GW deployed of full-prepay Energy Contracts.

Strategy Targets Low Cost, Longer Term Financing



* Aggregation facility at 3.25% + 3-month or daily LIBOR, at our option.
** MyPower facility at 2.75% + applicable commercial paper rate.

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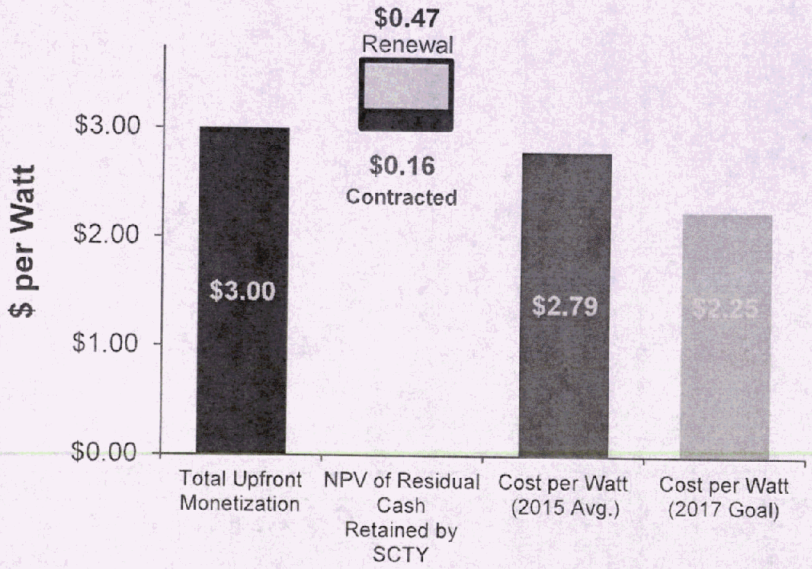
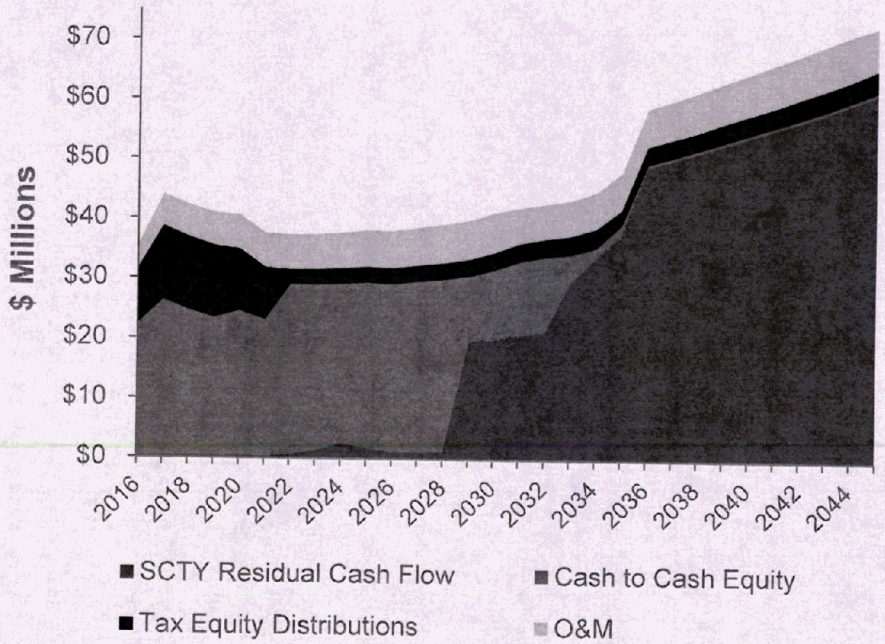
Cash Equity Transaction Generates Upfront Cash Margin while Retaining Residual Cash Flow Plus Renewal

- Closed landmark cash equity transaction in Q2 2016 that monetizes $3.25/W of residential (and $2.36/W of commercial)
- Geographically diversified portfolio:
  - State mix: 38% East Coast, 34% CA, 13% AZ, 8% NV, and 7% Other
  - Energy Harvest of 1,358 kWh/kW, blended contract price of $0.12/kWh, average annual escalator of 1.9% and includes SREC value
- Higher Commercial/Residential mix of 26%/74% (vs. cumulative deployed portfolio of 17%/83%) translates into a lower portion of contracted (vs. renewal) cash flows due to many 10-15 year commercial contracts
- SolarCity maintains customer relationship and services the asset while retaining an equity stake in a partnership flip structure (historical performance suggests potential for earlier flip)





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Balance Sheet Summary

		Remaining Term (Yrs.)	Underlying Assets	$M Outstanding at End of Q1 2016	Weighted Average Pre-Tax Cost	Payment Schedule	
PowerCo	Investment-Grade ABS Debt	7-12	418 MW	$657M	4.7%	Amortizing	Non-recourse serviced by cash flows of underlying projects
PowerCo	Aggregation Facilities and Other Project Finance*	<1-5	1,213 MW	$986M	4.0%	Revolving	Taken out with long-term financing (ABS, bank debt or cash equity)
DevCo	Revolving Credit Facility**	<1-2	Pipeline	$375M	3.7%	Revolving	Taken out with aggregation facilities and tax equity
DevCo	Vehicle Loans and Other Loans	<1-3	Vehicles	$21M	5.7%	Term	Rolling
DevCo	Solar Bonds	1-15	-	$217M	3.3%	Term	
DevCo	Convertible Debt	2-4	-	$909M	1.7%	Term	
	Cash & Investments – Unrestricted	-	-	$362M	-	-	
	MW Deployed – No Back Leverage		76				
	MW Deployed – Fully monetized		216				

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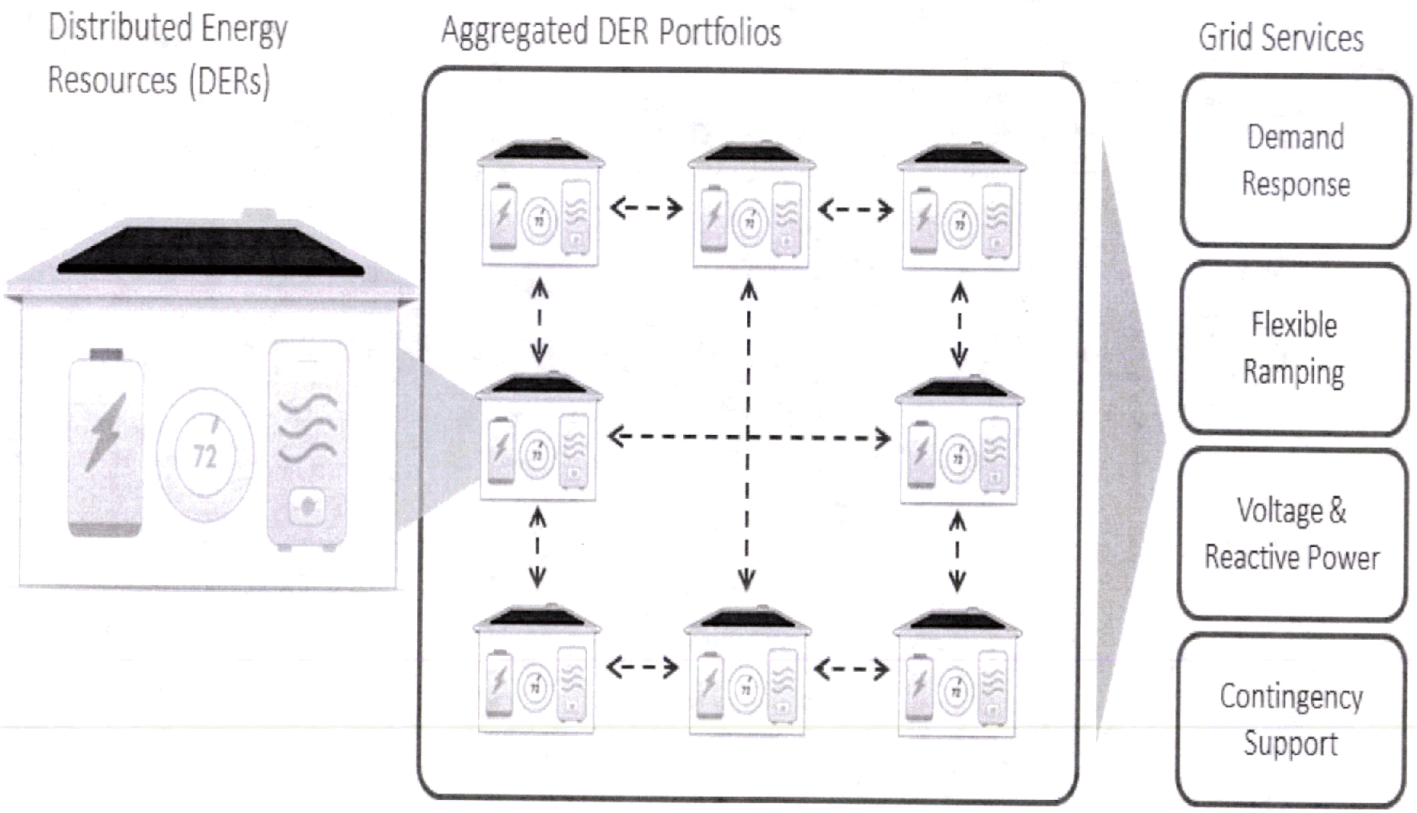
* Includes SREC financing.
** Revolver is used to fund work-in-progress of installations prior to asset financing.

The Future of the Grid

Now Offering Electricity Infrastructure Services to Utilities – a $50 Billion Annual Opportunity
A Network of Distributed Solar and Storage Systems Enables a Lower Cost, More Reliable Grid



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Conclusion

- Originating new solar installations at an annualized rate of ~1 GW
- New Energy Contracts deployed in 2015 generated value of ~$3.77 per Watt
- Built solar assets at the best cost of publicly-traded peers of ~$2.71/W in Q4 2015 with a path to $2.25/W in 2017 and ultimately $2.00/W
- Cumulative portfolio of 2.0 GW Deployed under Energy Contracts with a 30-Yr. Pre-Tax Unlevered NPV Less Debt of $2.1 billion at a 6% discount rate (including SRECs)
- Currently monetizing upfront ~2/3 of the value generated, with target to monetize enough of the cash flow in Year One to cover our upfront investment
- Investing in technology to widen our relative cost advantage and enable greater renewable capacity on existing grid infrastructure
  - Goal of not owning future manufacturing assets on balance sheet

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Quarterly Overview

Metric	Unit	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2015 Q1	2015 Q2	2015 Q3	2015 Q4	2016 Q1
SCTY Units:										
SCTY % of New U.S. Distributed Solar Capacity	%	17%	19%	25%	25%	22%	27%	32%	30%	TBD
MW Installed	**MW**	**82**	**107**	**137**	**177**	**153**	**189**	**256**	**272**	**214**
MW Deployed	MW	82	107	137	176	143	177	205	253	245
MW Interconnected	MW	83	79	113	138	160	156	203	194	228
Energy Contract Pricing of New Deployments (Yr. 1)	$/kWh	$0.12	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13	$0.12	$0.12
Annual Escalator	%	1.7%	1.9%	1.9%	1.9%	2.1%	2.1%	2.2%	2.0%	2.0%
SREC (5-Yr. Portfolio Average)	$/kWh	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.01
Energy Harvest (Yr. 1)	kWh/kW	1,425	1,416	1,406	1,402	1,404	1,379	1,352	1,347	1,294
Value Generation and Monetization (PV6):										
Contracted Value of MW Deployed in Period (PV6)	$/W	$3.68	$3.55	$3.37	$3.24	$3.44	$3.49	$3.50	$3.32	$3.13
Renewal Value of MW Deployed in Period (PV6)	$/W	$0.38	$0.40	$0.38	$0.34	$0.33	$0.34	$0.36	$0.32	$0.33
Total Value of MW Deployed in Period (PV6)	**$/W**	**$4.06**	**$3.95**	**$3.75**	**$3.58**	**$3.77**	**$3.83**	**$3.86**	**$3.64**	**$3.46**
Asset Financing in Period (including rebates)*	**$/W**	**$2.69**	**$2.04**	**$2.62**	**$2.28**	**$2.35**	**$2.33**	**$3.20**	**$2.40**	**$3.12**
Cost per Watt:**										
Sales	$/W	$0.51	$0.48	$0.50	$0.57	$0.57	$0.52	$0.59	$0.54	$0.97
Installation	$/W	$2.40	$2.28	$2.19	$2.10	$2.10	$2.12	$1.94	$1.92	$1.98
G&A	$/W	$0.28	$0.23	$0.18	$0.17	$0.22	$0.20	$0.23	$0.21	$0.23
Total Cost per Watt	**$/W**	**$3.19**	**$2.99**	**$2.87**	**$2.84**	**$2.89**	**$2.84**	**$2.76**	**$2.67**	**$3.18**
R&D Cash Expenses (Ex-Module Manufacturing)***	$M	($1.4)	($2.2)	($2.5)	($4.2)	($3.6)	($3.8)	($5.9)	($6.1)	($6.0)
Corporate Capital Expenditures	$M	($4.7)	($2.9)	($5.8)	($9.5)	($13.2)	($19.2)	($9.7)	($11.6)	($9.7)
Module Manufacturing Total Cash Committed****	$M	$-	$-	$-	($5.0)	($23.5)	($69.4)	($45.3)	($31.2)	($42.1)
Debt and Cash:										
Debt – Recourse	$M	($153.4)	($204.7)	($154.0)	($143.7)	($284.2)	($425.0)	($522.0)	($602.5)	($612.3)
Debt – Convertible	$M	($230.0)	($230.0)	($730.0)	($796.0)	($796.0)	($796.0)	($796.0)	($909.0)	($909.0)
Cash & Short-Term Investments	$M	$519.6	$405.3	$733.5	$642.7	$575.8	$489.1	$418.4	$393.9	$361.7
Current Portfolio Value										
Cumulative GW Deployed under Energy Contracts – EoP	GW	0.6	0.7	0.8	1.0	1.1	1.3	1.5	1.7	2.0
Recurring Cash Generation of PowerCo – Unlevered	$M	$11.8	$14.5	$10.4	$10.1	$13.4	$22.3	$27.9	$25.6	$32.2
Recurring Cash Generation of PowerCo – Levered	$M	$10.0	$11.7	$6.4	$5.3	$8.4	$16.0	$19.8	$15.4	$17.9
Contracted Pre-Tax Unlevered NPV Remaining (PV6)	*$M*								*$2,436*	*$2,766*
Renewal Pre-Tax Unlevered NPV Remaining (PV6)	*$M*								*$769*	*$856*
Energy Contract Pre-Tax Unlevered NPV remaining (PV6)	$M	$1,030	$1,212	$1,445	$1,735	$2,032	$2,391	$2,790	$3,205	$3,622
Debt – Non-Recourse	$M	($206)	($324)	($448)	($485)	($617)	($731)	($1,013)	($1,242)	($1,628)
PowerCo Portfolio Pre-Tax Unlevered NPV Less Debt***	**$M**	**$824**	**$888**	**$997**	**$1,250**	**$1,415**	**$1,660**	**$1,777**	**$1,963**	**$1,994**
Contracted SREC Pre-Tax Unlevered NPV Remaining (PV6)	$M									$103
SREC Financing	$M									($15M)

* Asset Financing in Period is based on our quarterly calculation methodology, which we detail in a memo on our website.
** Cost per Watt is based on our quarterly cost calculation methodology, which we detail in a memo on our website.
*** Excludes stock compensation.
**** Includes $13.1 million in cash expenditures related to the mandatory consolidation of Silevo's Chinese joint venture in Q1 2016.
***** Calculation in Q1 2016 and Q4 2015 updated based on new automated process.

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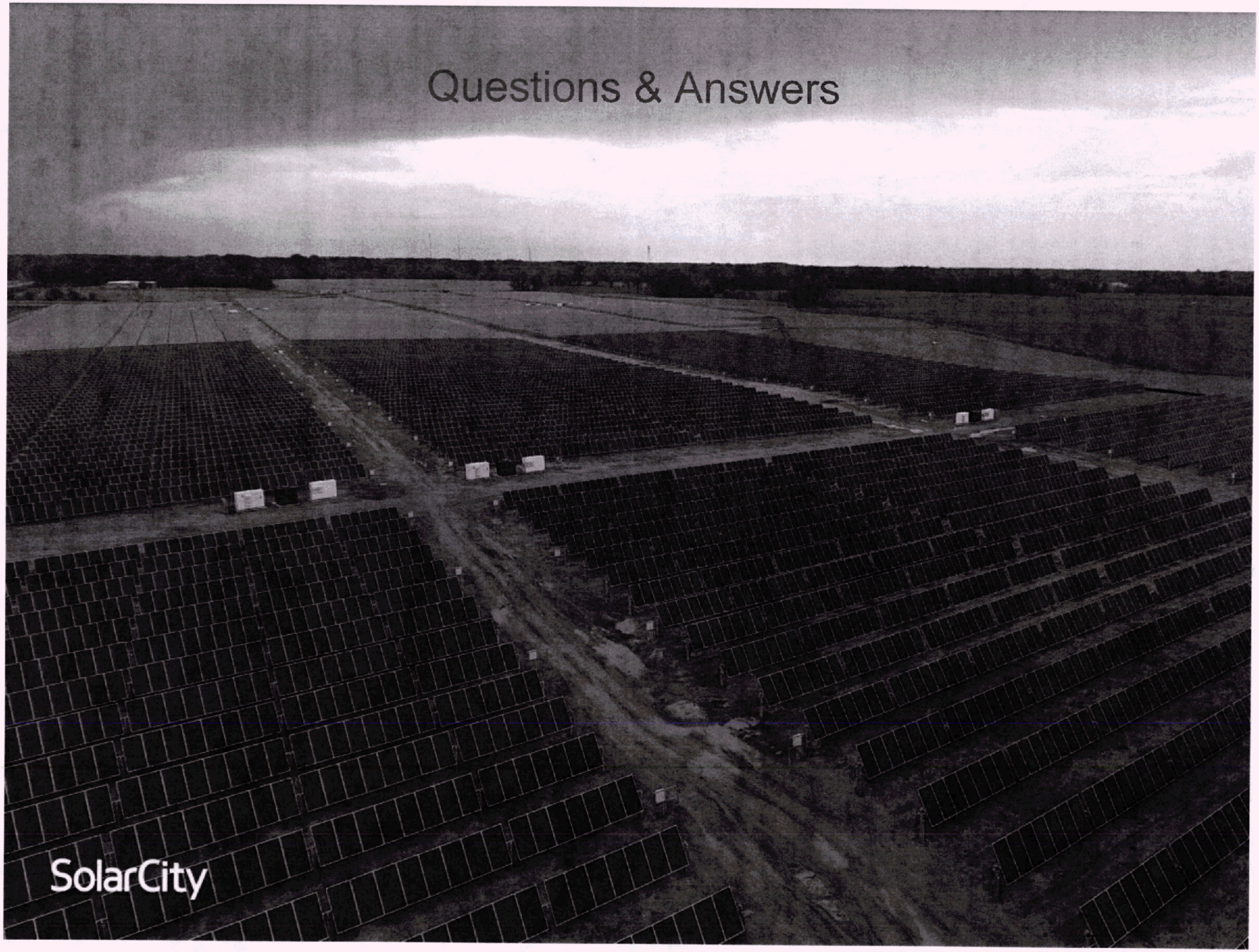
Questions & Answers



Appendix A: Tax Equity Primer

HISTORY

- The Investment Tax Credit (ITC) available under Section 48 of the IRC was extended in December 2015 to continue the existing 30% tax credit for solar systems on residential and commercial properties through December 31, 2019, before declining to 26% on December 31, 2020, 22% on December 31, 2021, and a permanent 10% effective January 1, 2022.
- While the current ITC focuses primarily on renewable energy property, various iterations of the ITC have existed since 1962, and over its history the ITC has been used by Congress to spur investment in a multitude of industries.
- ITC is part of broader General Business Credit under Section 38 that provides tax credits to various asset types, including low income housing, new markets, carbon sequestration, marginal oil wells, and dozens of other industries.

PARTNERSHIP STRUCTURE

- Partnership with SolarCity as 1% Member and Tax Equity as 99% Member
- Investment structured with projected "flip" and tenor 6.5 years
- Tax Equity partner receives the ITC, accelerated depreciation benefits and a share of cash flow
- After Tax Equity partner reaches a target IRR, their partnership interest flips down to 5% and SolarCity can exercise a buyout of the Tax Equity's interest

	% Benefit to Tax Equity Partner	
	Pre-Flip	Post-Flip
ITC / Depreciation	99%	0%
Cash Flow	30-40%	5-10%

ECONOMICS

- After-tax IRR 7% to 12%; pre-tax cash IRR 2% to 5%
- Tax Equity partner funds $1.75-1.80/W ($4.55 Fair Market Value * 30% ITC * 1.28 funding multiple)
- Return is comprised of 65% ITC, 14% depreciation, 22% cash flow

$/W	$/W	% of Return
Cash Investment in Project	**($1.77)**	
Investment Tax Credit offsetting income tax	$1.36	65%
Depreciation offsetting income tax over life of partnership	$0.29	14%
Cash Flow from project	**$0.46**	22%
Total Nominal Return	$2.11	100%

INVESTOR BASE

- Pool of sophisticated investors comprised of leading financial institutions and corporates investing for an attractive risk adjusted return
- Investor base continues to expand as asset class matures

SELECT TAX EQUITY INVESTORS

Goldman Sachs
usbancorp
JPMorgan Chase & Co.
Google
Bank of America Merrill Lynch
Direct Energy
Credit Suisse
HONDA The Power of Dreams

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Appendix B: Value of MW Deployed
Q1 2016 Sensitivities

VALUE OF MW DEPLOYED FORECAST ($M)

$M	4%	6%	8%
Contracted	$806	**$728**	$670
Renewal	$124	**$76**	$47
Total	**$930**	**$804**	**$717**

VALUE OF MW DEPLOYED FORECAST ($/WATT)

$ per Watt	4%	6%	8%
Contracted	$3.47	**$3.13**	$2.88
Renewal	$0.53	**$0.33**	$0.20
Total	**$4.00**	**$3.46**	**$3.09**

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Appendix C: PowerCo and SREC Portfolio Q1 2016 Sensitivities

POWERCO PORTFOLIO'S PRE-TAX UNLEVERED NPV REMAINING ($M)

$M	4%	6%	8%
Contracted	$3,364	**$2,766**	$2,314
Renewal	$1,336	**$856**	$556
Total	**$4,700**	**$3,622**	**$2,870**

CONTRACTED SREC PORTFOLIO PRE-TAX UNLEVERED NPV REMAINING ($M)

$M	4%	6%	8%
SREC	$109	$103	$98

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Appendix D: Footnotes

[1] FERC "Energy Infrastructure Updates" from December 2011 to December 2014 (http://www.ferc.gov/legal/staff-reports.asp).

[2] GTM Research/SEIA's "U.S Solar Market Insight Report Q2 2015" for residential and solar solar capacity and FERC "Energy Infrastructure Updates" ((http://www.ferc.gov/legal/staff-reports.asp) for all other energy capacity.

[3] GTM Research/SEIA's "U.S Solar Market Insight Report Q2 2015."

[4] GTM Research/SEIA's "U.S Solar Market Insight Report 2015 Year in Review."

[5] Single-family housing units based on data from U.S. Census American Community Survey's "Housing Units by Units in Structure and State" and assumes 1.0% annual growth in the housing stock per year through 2015. Excludes multi-family, mobile, and other housing units.

[6] U.S. Census Bureau's "Building Permits Survey by State – Annual" (http://www.census.gov/construction/bps).

[7] Commercial buildings count from EIA's 2012 Commercial Buildings Energy Consumption and commercial solar installations from GTM Research/SEIA's "U.S. Solar Market Insight Report."

[8] EIA's "2014 Utility Bundled Retail Sales" (https://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf).

[9] EIA's "Average Price by State by Provider, 1990-2014" (http://www.eia.gov/electricity/data/state).

[10] Based on filings from PG&E (http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4697-E.pdf), Southern California Edison (https://www.sce.com/NR/sc3/tm2/pdf/3268-E.pdf), and SDG&E (http://regarchive.sdge.com/tm2/pdf/2784-E.pdf) and assumes an additional 3% annual rate increases per year.

[11] GTM Research – U.S. PV Leaderboard.

Appendix E: Definitions (1/2)

"Asset Financing in Period" represents the aggregate project financing cash receipts in a period. This includes (1) Tax Equity Investment, (2) Non-Recourse Debt Proceeds, such as our aggregation and MyPower facilities and solar asset-backed loans, and (3) Upfront Cash Rebates and Prepayments. Asset Financing per Watt is a ratio of total Asset Financing in the Period divided by MW Deployed under Energy Contracts in the period, and reflects only actual cash received in a period whether or not they are specifically related to the actual MW Deployed in the period.

"Tax Equity Investment" calculated based on the total cash receipts from our tax equity investment partners captured by (a) noncontrolling interests in subsidiaries, (b) lease pass-through financing obligations and (c) amounts assigned to the monetization of investment tax credit (ITC) revenues that we record either as deferred income tax credits revenues or as liability for advances received for future ITCs. We reduce the cash receipts in a period by any refunds we make to the tax equity investment partners in that same period.

"Non-Recourse Debt Proceeds" is calculated based on all of the non-recourse project debt financing received in the period, which consists mainly of our aggregation facility debt, MyPower facility debt and solar asset-backed loans.

"Upfront Cash Rebates and Prepayments" are calculated based on the cash receipts from both (a) upfront state rebates and (b) customer prepayments received, which we consider to be a source of asset financing, in the period.

"Energy Contracts" includes all residential, commercial and government leases and power purchase agreements and consumer loan agreements pursuant to which consumers use or will use energy generated by a solar energy system that we have installed or contracted to install. For landlord-tenant structures in which we contract with the landlord or development company, we include each residence as an individual contract. For commercial customers with multiple locations, each location is deemed a contract if we maintain a separate contract for that location.

"Installed Customers" includes all locations where we have installed a solar energy system.

"Levered Project Cash Flow" represents our forecast of Unlevered Project Cash Flows after non-recourse debt service. Debt service includes both (a) Aggregation Facility debt for the first two years, based on the terms of our current facility, as well as (b) Solar Asset-Backed Loans, which we assume we issue at the end of year two to refinance the Aggregation Facility debt. We base the interest rate on the average of all four of our previous issuances and assume principal repayment over an 18-year term.

"Gross Project Cash Flow" forecast represent our estimate of the sum of total cash inflows we forecast from MW Deployed in the applicable period under Energy Contracts over the 30 year expected life of the system. This includes (a) payments that our customers are obligated to pay us over the remaining term of such contracts, (b) associated performance-based incentive (PBI) payments, (c) associated solar renewable energy credits (SRECs) that we have contracted to sell, typically representing 5 years of a total potential term of 15 years, and are net of (d) estimated operations and maintenance, insurance, administrative and inverter replacement costs, based on contractually agreed amounts as well as historic and forecasted expenses. Operations and maintenance, insurance, and administrative costs reflect our operating expenses in our funds, or are estimated at $0.021 per Watt and assumed to grow at a 2.5% inflation rate per year, and inverter replacement unit costs are estimated to decline at a (2.5%) rate per year, implying $0.15 per Watt in Year 11 and $0.12 per Watt in Year 21. Energy production is estimated to degrade at 0.5% per year. For our MyPower Energy Contracts, we use the expected cash flows over the full term of the 30-year contract, and for lease and PPA Energy Contracts with terms less than 30 years, we assume the contracts are renewed at a contract price equal to 90% of the contractual price in effect at expiration of the initial term through the remainder of the expected 30-year system life.

Appendix E: Definitions (2/2)

"MW" or "megawatts" represents the DC nameplate megawatt production capacity.

"MW Booked" represents the aggregate megawatt production capacity of solar energy systems pursuant to customer contracts that were signed (with no contingencies remaining) during the applicable period net of contracts that were cancelled during the applicable period. This metric includes solar energy systems booked under Energy Contracts (i.e. leases, PPAs, and MyPower contracts) and Direct Sales (i.e., cash). This metric also includes utility-scale and community solar energy projects for which site control and firm off-taker commitments have been obtained and feasibility of interconnection has been confirmed, the latest of which is completed during the applicable period.

"MW Deployed" represents the megawatt production capacity of solar energy systems that have had all required building department inspections completed during the applicable period. This metric includes solar energy systems deployed under Energy Contracts as well as for solar energy system direct sales.

"MW Installed" represents the megawatt production capacity of solar energy systems, for which (i) all solar panels, inverters, mounting and racking hardware, and system wiring have been installed, (ii) the system inverter is connected and a successful DC string test has been completed confirming the production capacity of the system, and (iii) the system is capable of being grid connected (including pending a utility disconnect procedure), the latest of which is completed during the applicable period. This metric includes solar energy systems deployed under Energy Contracts as well as for solar energy system direct sales. In each case in-period completion of the above criteria may be demonstrated by written verification by our President (which may include written sub-certifications).

"MW Interconnected" represents the megawatt production capacity of solar energy systems that have had all required building department inspections completed by the authority having jurisdiction and subsequently interconnected to the utility grid.

"PowerCo Portfolio" represents the cumulative MW Deployed under Energy Contracts that we have retained.

"Unlevered Project Cash Flow" represents our forecast of Gross Project Cash Flows after Tax Equity Lease/PPA Distributions for MW Deployed under Energy Contracts. "Tax Equity Lease/PPA Distributions" are based on the terms of the agreements we have in place with our tax equity investment partners for the MW Deployed in the applicable period under lease and PPA Energy Contracts. We do not use tax equity investment for our MyPower product. For tax equity investment in our lease and PPA Energy Contracts, our investment partners share in a portion of the Gross Project Cash Flow forecast received over the term of the agreement. Our estimate is not inclusive of any potential buy-out of our tax equity partners' interests in the project after Year 20.

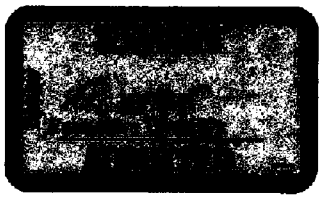
"Pre-Tax Unlevered NPV" represents the net present value at a 6% discount rate of the Unlevered Project Cash Flow forecast (Gross Project Cash Flows after Tax Equity Lease/PPA Distributions) excluding the payment of income and other taxes. This includes both "Contracted Unlevered NPV," which represents the net present value of Unlevered Project Cash Flow under contract as well as "Renewal Unlevered NPV," which represents the net present value of Unlevered Project Cash Flow forecast from renewal of our lease/PPA contracts.

"Recurring Cash Generation of PowerCo" represents the net cash flows we received or expected to receive pursuant to lease and power purchase agreements with customers, including value from solar renewable energy credits ("SRECs") after deducting the total ongoing expenses to maintain such systems and scheduled distributions to tax equity investors and interest expense.

"Value of MW Deployed" represents the sum of (1) Tax Equity Investment, (2) Upfront Cash Rebates and Prepayments, and (3) Pre-Tax Unlevered NPV.

Thank you

COMMISSIONERS
DOUG LITTLE --Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN



ARIZONA CORPORATION COMMISSION

July 20, 2016

Kevin M. Koch
2634 E. 4th St.
Tucson, Arizona 85716

VIA UNITED STATES MAIL AND EMAIL
kevin@tfssolar.com

Re: Staff's First Set of Data Requests to Kevin Koch
Docket No. E-01933A-15-0322 et al.

Dear Mr. Koch:

Please treat this as Staff's **First** Set of Data Requests to Kevin Koch, in the above-referenced matter.

For purposes of this data request set the words "Kevin Koch," "Company," "you," and "your" refer to Kevin Koch and any representative, including every person and/or entity acting with, under the control of, or on behalf of Kevin Koch. For each answer, please identify by name, title, and address each person providing information that forms the basis for the response provided.

These data requests are continuing, and your answers or any documents supplied in response to these data requests should be supplemented with any additional information or documents that come to your attention after you have provided your initial responses.

These data requests are continuing, and your answers or any documents supplied in response to these data requests should be supplemented with any additional information or documents that come to your attention after you have provided your initial responses. Please respond within ten (10) calendar days of your receipt of the copy of this letter. However, if you require additional time, please let us know.

Please provide one hard copy as well as **searchable PDF, DOC *or* EXCEL *files (via email or electronic mailing of the requested data directly to each of the following addressees via overnight delivery services to:***

(1) Rafael S. Paladino, Utilities Division, Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona 85007, rpaladino@azcc.gov.

(2) Robin R. Mitchell, Attorney, Legal Division, Arizona Corporation Commission, 1200 West Washington Street, Phoenix, Arizona 85007, rmitchell@azcc.gov.

Sincerely,

Robin R. Mitchell
Wesley Van Cleve
Brian E. Smith
Attorneys, Legal Division
(602) 542-3402

RRM:WVC:BES:mam

cc: Ranelle S. Paladino (Via Email Only)

Enclosure (Attachment to Enclosure - Via Email Only)

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
KEVIN KOCH
DOCKET NO. E-01933A-15-0322 ET AL.
JULY 20, 2016

Subject: All information responses should ONLY be provided in <u>searchable</u> PDF, DOC or EXCEL files via email or electronic media.
***For all data requests for which you do not have the information requested, please state such and skip to the next data request. Also, for responses to data requests that may be voluminous or overly burdensome, please contact the assigned analyst, Ranelle S. Paladino at 602-364-0347 to discuss.

RSP 1-1. The attached spreadsheet was originally provided by Arizona Public Service Company in the UNS Electric, Inc. rate case (Docket No. E-04204A-15-0142). The spreadsheet is intended to quantitatively capture from a residential customer's perspective their financial net savings or net costs in purchasing or leasing a rooftop solar system. Regarding the spreadsheet:

a. Please make relevant changes to reflect the residential service rate schedule of Tucson Electric Power Company ("TEP").

I have changed the spreadsheet to reflect the proposed rates for TEP as best as I can. I have made some assumptions mentioned in the spreadsheets, and due to the fact that I was modifying an existing spreadsheet I am not 100% certain I got everything right. I know, for example, that the net metering calculation for the TOU rates is not accurate.

While I have used the proposed rates from TEP, I do not support the increase of the fixed charge to $17, nor do I support the reduction from 4 tiers to 2. I would prefer a compromise of a $12 service charge and a minimum of 3 tiers for the volumetric rates.

I also think that if Net Metering is to be dismantled, the minimum solar buyback rate for the proposed volumetric rate should be $0.07/kwh, as this would result in average total solar offset rates being above $0.095/kWh, enough for a payback of 10 years or less.

As I stated in my testimony, I am also in favor of an optional demand based rate with high demand charges during the TOU period. This would provide a signal to encourage innovation in storage and load management. However, upon further reading of TEP's position, it is clear that their desire is not to provide a market signal for innovation, but to change rates to recover costs in a way that solar will not affect (so much). If this is the primary goal, I am in favor of keeping current volumetric rates and either using a buy all sell all agreement, or changing net metering so that most customers can still achieve savings of at least $0.095/kWh.

b. Please provide yellow inputs as denoted in the spreadsheet for the test year. If estimates need to be made, indicate which numbers were estimated and provide supporting assumptions. If, in some cases, a number is currently effective but TEP has proposed a different number, please cite both numbers, identifying both.

I have included a new tab for the existing rates from TEP titled IB-E(current). All other tabs reflect TEP's proposed rate structures. I could propose

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changes to each of those structures that I think could make solar a viable alternative, but have left them as proposed by TEP at this time.

c. Are there any changes that should be made to the spreadsheet to reflect a customer's financial considerations regarding whether to install rooftop distributed generation?

As mentioned above, the TOU rates would need to be modeled on an annual basis by month in order to make an accurate assessment of the Net Metering benefits.

Also, some of the assumptions will vary widely and as such, this spreadsheet cannot be used to provide them with an accurate representation of the financial considerations. This applies mostly to the fraction of energy used instantaneously, as well as the amount of demand which will be reduced by solar. These highly variable factors would affect rates based on Net Billing instead of Net Metering, and demand based rates.

RSP 1-2. Please provide any model(s) that you (or a person or entity acting for you) already created to look at financial considerations of residential customers who are or may become distributed generation customers. If possible, provide in Excel format.

I have attached the tool that I use to show customers the effect of a proposed solar installation with existing rates. It has not been modified to reflect proposed rates. It is useful for testing the payback given different electric rate offsets, which can be modified in cell "LG"B31. Different monthly energy use profiles can be entered on the "Inputs" page in order to test effects on different sized systems. This tool will not be helpful in its current form for evaluating changes to Net Metering, or demand or TOU rates. The file is called "KK existing customer savings tool."

RSP 1-3. Please identify alternative scenarios (other than an average residential customer), including any additional data inputs, that should be considered in this case.

I believe that it is important to consider the effect on lower usage customers, average usage customers, and high usage customers. And within each of these groups, I think it is important to evaluate rates based on customers who are home during the day, as well as customers who are gone at work most of the day. This would result in a minimum of 6 cases to look at for each proposed rate.

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I think it is less critical to deeply evaluate each of these conditions if there is an option available for new solar customers which would result in $0.095/kwh savings under any customer configuration, such as a buy all sell all option.

RSP 1-4. With respect to residential rooftop PV systems installed in TEP's service territory, what is the average system size in kW-DC? If possible, please provide annual data from 2009 to 2015.

I believe that TEP would be a better party to answer this question, as I only have verifiable data for TFS installations. Our average system sizes are shown below, but they only reflect installations completed each year by TFS.

2009: 4.8 kW
2010: 5.6 kW
2011: 5.9 kW
2012: 7.5 kW
2013: 6.83 kW
2014: 6.9 kW
2015: 7.4 kW

RSP 1-5. With respect to residential rooftop PV systems installed in TEP's service territory, what is the average system purchase cost in $/kW-DC? If possible, please provide annual data from 2009 to 2015.

Again, I cannot provide data for TEP service territory installations, but I can provide sample $/watt costs for TFS systems. While not an average of all of our systems, these numbers represent the cost for an average sized system with medium efficiency modules. It should be noted that part, but not all, of the price decline is related to the larger system sizes.

2009: $5.98/W
2010: $5.12/W
2011: $4.45/W
2012: $3.29/W
2013: $3.23/W
2014: $3.0/W
2015: $2.87/W

I would like to note that this incredible and consistent decline in prices is one of the real benefits of the ACC policy to support roof top solar. We have seen cost

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improvements on all levels as technology improves, installation practices become more efficient and sophisticated, and the benefits of scale are realized. I hope some compromise rate structure can be reached that allows for continued development of the roof top solar sector as a sustainable way to meet our future energy needs. Can you imagine if the electric utilities were reducing their costs and producing electricity more efficiently over time and asking for reduced rates in their rate cases? It's hard to imagine, but that is exactly what has been happening in a dramatic way in the rooftop solar industry.

ROSE LAW GROUP pc
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EXHIBIT
S-17
ADMITTED

August 5, 2016

SENT BY ELECTRONIC MAIL

Rick Lloyd
Utilities Division
Arizona Corporation Commission
rlloyd@azcc.gov

Constance Fitzsimmons
Legal Division
Arizona Corporation Commission
cfitzsimmons@azcc.gov

RE: Energy Freedom Coalition of America's Response to Staff's First Set of Data Requests/Trico Docket No. E-01461A-15-0363

Dear Mr. Lloyd and Ms. Fitzsimmons:

Pursuant to agreement between the parties, attached are EFCA's Responses to Staff's First Set of Data Requests that are due today. Thank you again for the brief extension on these response dates.

Should you have any questions or comments, please feel free to contact me directly at 480-505-3937.

Sincerely,

/s/ Court S. Rich
Court S. Rich

Attachment

cc: Maureen Scott – mscott@azcc.gov
Matthew Laudone – mlaudone@azcc.gov

ENERGY FREEDOM COALITION OF AMERICA'S
RESPONSES TO STAFF'S FIRST SET OF DATA REQUESTS
TRICO DOCKET NO. E-01461A-15-0363
AUGUST 5, 2016

Energy Freedom Coalition of America (EFCA) submits the following Responses to Arizona Corporation Commission Staff's First Set of Data Requests. These Responses are fully incorporate and restate EFCA's objections and any and all responses are made subject to such objections and do not constitute a waiver of any kind.

GENERAL OBJECTIONS

1. EFCA objects to Staff's requests to the extent they seek information and/or documents which are not relevant to any issue in this action nor reasonably calculated to lead to the discovery of admissible evidence.

2. EFCA objects to Staff's requests to the extent they are overly broad, unduly burdensome, or seek information and/or documents which go beyond the relevant scope and timeframe related to this matter. EFCA further objects to the extent a request is unduly burdensome in that the assembly and preparation of a response would require a search of information and/or documents which are of little or no benefit with respect to the issues in this matter, so that the value of the information and/or documents in the response would be far outweighed by the burden of providing such information and/or documents, especially with respect to information and/or documents which may be readily obtained by Staff from other sources.

3. EFCA objects to Staff's requests to the extent they seek information which were prepared, generated, or received in anticipation of, or after the commencement of, this matter, and/or to the extent they seek information subject to the attorney-client privilege, the work product privilege, or any other applicable privilege or protection. Should any privileged or otherwise protected information be inadvertently produced in response to the requests, such production shall not be deemed a waiver of the applicable privilege or protection.

4. EFCA objects to Staff's requests to the extent they seek information not in EFCA's possession or custody, or which EFCA does not have direct control over.

STF 1.1 Please list all of EFCA's members.

Response: EFCA objects to this request as it seeks information readily accessible to Staff through publicly available sources including the Corporation Commissions' own website. Further, the Members of EFCA were listed in the Motion to Intervene filed in this matter.

Without waiving any objections, a list of EFCA members will be provided again.

See Exhibit A; EFCA's Application for Intervention listing its members.

STF 1.2 Please describe the line of business each of the members is in, i.e., sale of solar systems, provision of support to solar homeowners, sale of solar equipment, installation, etc.

Response: EFCA objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. The business activities of EFCA members have no relevance to the Commission's task of setting just and reasonable rates.

Further EFCA member companies have different roles in the solar industry, but all companies provide goods and services to solar customers. The role of the companies is not relevant or reasonably calculated to lead to the discovery of admissible evidence.

EFCA also objects to this request as unduly burdensome because the information sought is publicly available and thus equally accessible to Staff.

STF 1.3 Please indicate which of EFCA's members are affiliated with Solar City. Please describe the nature of these affiliations.

Response: EFCA objects to this request as vague and ambiguous because the term "affiliated" is undefined and susceptible to multiple meanings. For instance, does the mere fact of common membership in EFCA implicate affiliation or does affiliation require one entity to hold a controlling interest in another? Without a definition for this term, EFCA cannot give an accurate answer.

EFCA also objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. The relationships among EFCA's members have no relevance to the Commission's task of setting just and reasonable rates.

EFCA further objects to this request as unduly burdensome. EFCA is an entity with a legal existence separate and distinct from any of its members. It does not regularly monitor the relationships among its members. It does not possess the requested information and would have to conduct extensive research and obtain information from third parties who have no obligation to provide it to respond to this request. Forcing EFCA to conduct original research and gather data it does not need to present its own position is an undue burden.

EFCA further objects to this request as overbroad, unduly burdensome, and seeking information not within the possession or control of EFCA. SolarCity is a publicly traded company and any of the other EFCA members could have pension plans, retirement plans, 401(k) plans, or profit sharing plans which have purchased shares of SolarCity on the open market as part of the investment vehicles associated with those plans. None of the investments of any EFCA member are provided to EFCA and responding to this request would require EFCA to conduct original research and gather data it does not need to present its position in this matter.

EFCA further objects to this request in that it requires EFCA to gather information, including public records, equally available to all parties. To the extent that any potential affiliation consists of one party owning a stake in another, the corporate records depositories in each members' home state may have relevant, publicly available information. Staff has as much ability to peruse these public records as EFCA, and should not burden EFCA by forcing it to research public records.

Finally, EFCA objects to this request on the grounds that affiliations or potential affiliations between or among third parties may be subject to contractual non-disclosure requirements, trade secret protection, or other business confidentiality doctrines.

STF 1.4 Please indicate which of EFCA's members are not affiliated with Solar City.

Response: EFCA objects to this request as vague and ambiguous because the term "affiliated" is undefined and susceptible to multiple meanings. For instance, does the mere fact of common membership in EFCA mean that companies are affiliated? Or does "affiliated" require one entity to hold a controlling equity stake in another? Without a definition for "affiliated" EFCA cannot provide an accurate answer.

EFCA objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. The relationships among EFCA's members have no relevance to the Commission's task of setting just and reasonable rates.

EFCA further objects to this request as unduly burdensome. EFCA is an entity with a legal existence separate and distinct from any of its members. It does not regularly monitor the relationships among its members. It does not maintain information about the relationships, if any, between its members. To respond to this request, EFCA would have to conduct extensive research and obtain information from third parties who have no obligation to provide it. EFCA is not in possession or control of the information necessary to respond to this request. Forcing EFCA to conduct original research and gather data unnecessary to the presentation of its position is an undue burden.

EFCA further objects to this request as overbroad, unduly burdensome, and requesting information not within the possession or control of EFCA. SolarCity is a publicly traded company and any of the other EFCA members could have pension plans, retirement plans, 401(k) plans, or profit sharing plans which have purchased shares of SolarCity on the open market as part of the investment vehicles associated with those plans. None of the investments of any EFCA member are provided to EFCA and responding to this request would require EFCA to conduct original research and gather data it does not need to present its position in this matter.

EFCA further objects to this request as calling for EFCA to gather information, including public records, equally available to all parties. To the extent that any potential affiliation consists of one party owning an interest in another, the corporate record depositories in each members' home state may have relevant, publicly available information. Staff has as much ability to peruse these public records as EFCA, and should not burden EFCA by forcing it to research public records.

Finally, EFCA objects to this request on the grounds that affiliations or potential affiliations between or among third parties may be subject to contractual non-disclosure requirements, trade secret protection, or other business confidentiality doctrines.

STF 1.5 Please indicate the relationship between EFCA and TASC, and any differences in their memberships.

Response: EFCA objects to this request as vague and ambiguous in that the term "relationship" is undefined and susceptible to multiple meanings. For example, does this term apply broadly, to require disclosure of any contact or dealings between EFCA and TASC, no matter how slight or how irrelevant to this matter? In the alternative, does it refer to some unspecified, but more formal arrangement? Until this term is defined, EFCA lacks the ability to answer this request accurately.

EFCA objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. No party using the name or acronym TASC has appeared in this case. TASC's membership is not relevant to this case. It has no bearing on the Commission's task to set a just and reasonable rate.

EFCA further objects to this request because it is unduly burdensome and requests information not within the possession or control of EFCA. For EFCA to respond to this request it would be necessary to obtain information from a third party. EFCA should not have the burden of obtaining information from a third party. Moreover, if Staff obtains the third-party information itself, it can compare EFCA's membership to TASC's membership through its own efforts.

Finally, EFCA objects to this request pursuant to *NAACP v. Alabama*, 357 U.S. 449 (1958) and its progeny. The Supreme Court has held that discovery of membership in a private group violates the First Amendment. EFCA objects to being forced to obtain, discover, or disclose any of TASC's First Amendment protected information.

STF 1.6 Please explain in detail how EFCA's various members are affected by the Settlement Agreement between Staff and Trico?

Response: EFCA objects to this request as vague and ambiguous because the term "affected" is undefined and susceptible to multiple meanings. Until this term is defined, EFCA cannot give an accurate answer.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. EFCA does not possess any of its member companies' business, revenue, or strategy information. None of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

Without waiving the forgoing objections and subject thereto, in response to this Request, EFCA refers Staff to the already pre-filed testimony of its witness, William Monsen regarding the impact of the proposals made in this proceeding. Further, EFCA is still evaluating the recently filed Settlement Agreement.

STF 1.7 Please explain in detail how Solar City is affected by the Settlement Agreement between Staff and Trico?

Response: EFCA objects to this request as vague and ambiguous because the term "affected" is undefined and susceptible to multiple meanings. Until this term is defined, EFCA cannot give an accurate answer.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

STF 1.8 Please provide a typical copy of Solar City's lease agreement with a solar customer.

Response: EFCA objects to this request because it requires EFCA to research and obtain publicly available information - SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's lease agreements, let alone one that may be considered "typical."

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has an obligation to provide information in its possession or under its control.

EFCA objects to this request in that the term "typical" is undefined and susceptible to multiple meanings. For example, does "typical" refer to a commercial lease or a residential lease and what criteria are to be used to determine whether a lease is "typical"? Without a definition for this term, EFCA cannot provide an accurate response to this request.

Without waiving the forgoing objections and subject thereto, and as a courtesy to Staff, counsel for EFCA entered the search terms "SolarCity Lease Sample" into the Google search engine and found a purported sample lease from SolarCity at the following address:

https://www.solarcity.com/sites/default/files/sc-contract-resi-lease-2.9.pdf

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STF 1.9 Please provide a copy of an outright purchase agreement in use by any of EFCA's members. Please also respond to this question with respect to Solar City.

Response: EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any purchase agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

STF 1.10 Do any of EFCA's members use other financing arrangements such as leases with an option to purchase; or longer term financing arrangements where the customer can pay over a period of 12-48 months and own the system? Does EFCA support use of these types of financing? Please respond to this question with respect to Solar City.

Response: EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any purchase agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA objects to this request to the extent it enquires about EFCA's position regarding financing arrangements as this request is not reasonably calculated to lead to the discovery of admissible evidence. Whether EFCA supports financing arrangements has no bearing on the Commission's obligation to set a just and reasonable rate.

STF 1.11 Do all of Solar City's solar lease agreements contain escalator clauses? Please explain your answer.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information and does not possess any copies of any SolarCity leases and without that information it cannot state whether any of SolarCity's leases contain escalator clauses.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA further objects to this request because it requires EFCA to research and obtain publicly available information. SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet google search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform.

STF 1.12 With declining costs, why do EFCA members still have an escalator clause in their agreements? Please respond to this question with respect to Solar City.

Response: EFCA objects to this request in that it assumes that the EFCA members have an escalator clause in their agreements with customers, but no evidence produced in this matter establishes that.

EFCA objects to this request in that it assumes that there has been "declining costs" experienced by EFCA members, but no evidence produced in this matter establishes that.

EFCA further objects to the phrase "declining costs" as undefined and susceptible to multiple definitions. Without a definition for this term, EFCA is unable to provide an accurate response.

EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information and thus it cannot respond whether its member companies have previously had or still have escalator clauses in their agreements with customers.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA further objects to this request because it requires EFCA to research and obtain publicly available information. SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet google search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform.

STF 1.13 How is the typical escalator clause structured in Solar City's lease agreements?

Response: EFCA objects to this request in that it assumes there is a "typical escalator clause." No facts produced establish the existence of an escalator clause or that a "typical" clause exists.

EFCA objects to this request in that the term "typical" is undefined and susceptible to multiple meanings. For example, does "typical" refer to a commercial lease or a residential lease and what criteria are to be used to determine whether a clause4 is "typical"? Without a definition for this term, EFCA cannot provide an accurate response to this request.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information or a copy of any of SolarCity's lease agreements with which to respond to this request.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

EFCA objects to this request as not reasonably calculated to lead to the discovery of admissible evidence, the structure of an escalator clause has no bearing on the Commission's obligation to set fair and reasonable rates.

Without waiving this objection, see response to 1.8.

STF 1.14 Has Solar City passed the decreases in panel costs on to its customers? Does EFCA support passing decreases in panel costs on to customers?

Response: EFCA objects to this request in that it assumes that there has been a decrease in panel costs experienced by all participants in the industry, but no evidence produced in this matter establishes that.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

EFCA objects to this request to the extent it enquires about EFCA's position regarding passing purported decrease in panel costs onto EFCA's member's customers as this request is not reasonably calculated to lead to the discovery of admissible evidence. Whether EFCA supports financing arrangements has no bearing on the Commission's task to set a just and reasonable rate.

STF 1.15 Please provide your entire analysis that indicates that the Settlement Agreement between Staff and Trico adversely affects EFCA member's future business in TRICO's service territory.

Response: EFCA objects to this request to the extent it assumes that EFCA has stated that the settlement agreement between Staff and Trico adversely affects EFCA members' future business in Trico's service territory. EFCA has not taken this position, EFCA's position has been that the settlement agreement will make rooftop solar more expensive for customers.

Without waiving the forgoing objections and subject thereto, EFCA refers Staff to the already pre-filed testimony of its witness, William Monsen who has offered testimony regarding the impacts of the Settlement Agreement on ratepayers. Further, EFCA is still evaluating the recently filed Settlement Agreement.

STF 1.16 Over the life of a lease agreement, please indicate what the owner/lessee of a typical 7 kW system pays? Please use Solar City as an example. Please provide the same information for the owner/lessee of a typical 7 kW system under the Settlement Agreement.

Response: EFCA objects to the term "typical" owner/lessee as this term is undefined and susceptible to multiple definitions. There is no context in this request for EFCA to evaluate what Staff considers a "typical" customer.

EFCA objects to this request as overly broad and lacking sufficient specificity with which EFCA can respond to this request, including the financing terms applicable to the customer, the customer's location, when the lease/purchase was made, the length of the lease, etc.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

STF 1.17 What is the impact of netting and banking under the Commission's current net metering rules on the value that a solar customer receives? Please use Solar City as an example.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

Without waiving the forgoing objections and subject thereto, EFCA avers that under the current net metering rules netting and banking ensures that customers are fairly compensated for their generation and the associated benefits that they provide to Trico's system.

STF 1.18 What is the impact of netting and banking under the Settlement Agreement on the value that a solar customer receives? Please use Solar City as an example.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

Without waiving the forgoing objections and subject thereto, EFCA avers that under the settlement, the netting and lack of banking does not provide customers with fair compensation for their generation and the associated benefits that they provide to Trico's system. In addition, EFCA points staff to the pre-filed testimony of its witness, William Monsen. Further, EFCA is still considering the recently filed Settlement Agreement and Mr. Monsen may further address this issue in his forthcoming August 12, 2016 testimony.

STF 1.19 Please provide a copy of all data requests that you have sent and/or received from other parties in this docket. Please provide copies of all of your responses to other parties' data requests. Please also provide copies of all responses received from other parties received in response to your data requests. These requests are ongoing and should be supplemented with any additional data requests and responses.

Response: **Please see the dropbox link for data requests EFCA has sent to other parties in this docket:**

EFCA's First Set of Data Requests to Freeport-AECC;
EFCA's First Set of Data Requests to Pima County;
EFCA's First Set of Data Requests to Robert Hall;
EFCA's First, Second, Third, Fourth, Fifth, Sixth and Seventh Set of Data Requests to Trico.

Please see the dropbox link for data requests EFCA has received in this docket and any responses provided to date:

Staff's First Set of Data Requests
Trico's First and Second Set of Data Requests

EXHIBIT A

ORIGINAL

INTERVENTION

Arizona Corporation Commission
DOCKETED
JAN 15 2016
DOCKETED BY

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RECEIVED

2016 JAN 15 P 4: 45

AZ CORP COMMISSION
DOCKET CONTROL

Court S. Rich AZ Bar No. 021290
Rose Law Group pc
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Direct: (480) 505-3937
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Attorney for Intervenor, Energy Freedom Coalition of America

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE	BOB STUMP	BOB BURNS	TOM FORESE
ACTING CHAIRMAN	COMMISSIONER	COMMISSIONER	COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC, AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	**DOCKET NO. E-01461A-15-0363** **THE ENERGY FREEDOM COALITION OF AMERICA'S APPLICATION FOR LEAVE TO INTERVENE**

Pursuant to A.A.C. R14-3-105, the Energy Freedom Coalition of America ("EFCA") hereby makes its Application for Leave to Intervene (the "Application") in the above captioned proceeding (the "Proceeding").

EFCA is a solar energy advocacy association. EFCA's membership is made up of solar companies including, Silevo, Inc., Zep Solar, LLC, SolarCity Corporation, and NRG Energy, Inc. These companies are important stakeholders in Arizona's rooftop solar industry. EFCA's members are responsible for thousands of residential, school, church, government and commercial solar installations in the Arizona. Together, EFCA's members have brought hundreds of jobs and many tens of millions of dollars of investment to Arizona's cities and towns.

EFCA is entitled to intervene because EFCA and its members are directly and substantially affected by the Proceeding and EFCA's intervention will not unduly broaden the issues presented. In support of this Application, EFCA submits the following information.

I. EFCA is Directly and Substantially Affected

In the Proceeding, Trico Electric Cooperative, Inc. ("Trico") seeks to alter rate structures for solar customers and end the policy of net metering in its service territory, all of which will negatively impact EFCA members.

II. EFCA's Intervention can Assist the Commission

EFCA is uniquely well positioned to offer insight to assist the Commission in its evaluation of the issues in the Proceeding.

III. EFCA's Intervention Will Not Broaden This Proceeding

Granting EFCA intervenor status will not unduly broaden the issues or prejudice other parties to the Docket.

Service of all documents or pleadings should be made to EFCA counsel at the following address:

Court S. Rich
Rose Law Group pc
7144 E. Stetson Drive, Suite 300
Scottsdale, Arizona 85251

Respectfully submitted this 15th day of January, 2016.

Court S. Rich
Rose Law Group pc
Attorney for Intervenor EFCA

Original and 13 copies filed on this 19th day of January, 2016 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Copies of the foregoing sent by electronic and regular mail to:

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EXHIBIT
S-18
ADMITTED

August 4, 2016

SENT BY ELECTRONIC MAIL

Rick Lloyd
Utilities Division
Arizona Corporation Commission
rlloyd@azcc.gov

Constance Fitzsimmons
Legal Division
Arizona Corporation Commission
cfitzsimmons@azcc.gov

RE: Energy Freedom Coalition of America's Objections to Staff's First Set of Data Requests/Trico Docket No. E-01461A-15-0363

Dear Mr. Lloyd and Ms. Fitzsimmons:

Pursuant to agreement between the parties, attached are EFCA's objections to Staff's First Set of Data Requests that are due today. EFCA will provide substantive responses, subject to these objections, tomorrow, August 5, 2016. Thank you again for the brief extension on these response dates.

Should you have any questions or comments, please feel free to contact me directly at 480-505-3937.

Sincerely,

/s/ Court S. Rich
Court S. Rich

Attachment

cc: Maureen Scott – mscott@azcc.gov
Matthew Laudone – mlaudone@azcc.gov

ENERGY FREEDOM COALITION OF AMERICA'S
OBJECTIONS TO STAFF'S FIRST SET OF DATA REQUESTS
TRICO DOCKET NO. E-01461A-15-0363
AUGUST 4, 2016

Energy Freedom Coalition of America (EFCA) submits the following Objections to Arizona Corporation Commission Staff's First Set of Data Requests:

GENERAL OBJECTIONS

1. EFCA objects to Staff's requests to the extent they seek information and/or documents which are not relevant to any issue in this action nor reasonably calculated to lead to the discovery of admissible evidence.

2. EFCA objects to Staff's requests to the extent they are overly broad, unduly burdensome, or seek information and/or documents which go beyond the relevant scope and timeframe related to this matter. EFCA further objects to the extent a request is unduly burdensome in that the assembly and preparation of a response would require a search of information and/or documents which are of little or no benefit with respect to the issues in this matter, so that the value of the information and/or documents in the response would be far outweighed by the burden of providing such information and/or documents, especially with respect to information and/or documents which may be readily obtained by Staff from other sources.

3. EFCA objects to Staff's requests to the extent they seek information which were prepared, generated, or received in anticipation of, or after the commencement of, this matter, and/or to the extent they seek information subject to the attorney-client privilege, the work product privilege, or any other applicable privilege or protection. Should any privileged or otherwise protected information be inadvertently produced in response to the requests, such production shall not be deemed a waiver of the applicable privilege or protection.

4. EFCA objects to Staff's requests to the extent they seek information not in EFCA's possession or custody, or which EFCA does not have direct control over.

ENERGY FREEDOM COALITION OF AMERICA'S
OBJECTIONS TO STAFF'S FIRST SET OF DATA REQUESTS
TRICO DOCKET NO. E-01461A-15-0363
AUGUST 4, 2016

STF 1.1 Please list all of EFCA's members.

Response: EFCA objects to this request as it seeks information readily accessible to Staff through publicly available sources including the Corporation Commissions' own website. Further, the Members of EFCA were listed in the Motion to Intervene filed in this matter.

Without waiving any objections, a list of EFCA members will be provided again.

STF 1.2 Please describe the line of business each of the members is in, i.e., sale of solar systems, provision of support to solar homeowners, sale of solar equipment, installation, etc.

Response: EFCA objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. The business activities of EFCA members has no relevance to the Commission's task of setting just and reasonable rates.

Further EFCA member companies have different roles in the solar industry but all companies provide goods and services to solar customers, so the role of each company is interconnected with others. The role of the companies is not relevant or reasonably calculated to lead to the discovery of admissible evidence.

EFCA also objects to this request as unduly burdensome because the information sought is publicly available and thus equally accessible to Staff.

STF 1.3 Please indicate which of EFCA's members are affiliated with Solar City. Please describe the nature of these affiliations.

Response: EFCA objects to this request as vague and ambiguous because the term "affiliated" is undefined and susceptible to multiple meanings. For instance, does the mere fact of common membership in EFCA implicate affiliation or does affiliation require one entity to hold a controlling interest in another? Without a definition for this term, EFCA cannot give an accurate answer.

EFCA also objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. The relationships among EFCA's members have no relevance to the Commission's task of setting just and reasonable rates.

EFCA further objects to this request as unduly burdensome. EFCA is an entity with a legal existence separate and distinct from any of its members. It does not regularly monitor the relationships among its members. It does not possess the requested information and would have to conduct extensive research and obtain information from third parties who have no obligation to provide it to respond to this request. Forcing EFCA to conduct original research and gather data it does not need to present its own position is an undue burden.

EFCA further objects to this request as overbroad, unduly burdensome, and seeking information not within the possession or control of EFCA. SolarCity is a publicly traded company and any of the other EFCA members could have pension plans, retirement plans, 401(k) plans, or profit sharing plans which have purchased shares of SolarCity on the open market as part of the investment vehicles associated with those plans. None of the investments of any EFCA member are provided to EFCA and responding to this request would require EFCA to conduct original research and gather data it does not need to present its position in this matter.

EFCA further objects to this request in that it requires EFCA to gather information, including public records, equally available to all parties. To the extent that any potential affiliation consists of one party owning a stake in another, the corporate records depositories in each members' home state may have relevant, publicly available information. Staff has as much ability to peruse these public records as EFCA, and should not burden EFCA by forcing it to research public records.

Finally, EFCA objects to this request on the grounds that affiliations or potential affiliations between or among third parties may be subject to contractual non-disclosure requirements, trade secret protection, or other business confidentiality doctrines.

STF 1.4 Please indicate which of EFCA's members are not affiliated with Solar City.

Response: EFCA objects to this request as vague and ambiguous because the term "affiliated" is undefined and susceptible to multiple meanings. For instance, does the mere fact of common membership in EFCA mean that companies are affiliated? Or does "affiliated" require one entity to hold a controlling equity stake in another? Without a definition for "affiliated" EFCA cannot provide an accurate answer.

EFCA objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. The relationships among EFCA's members have no relevance to the Commission's task of setting just and reasonable rates.

EFCA further objects to this request as unduly burdensome. EFCA is an entity with a legal existence separate and distinct from any of its members. It does not regularly monitor the relationships among its members. It does not maintain information about the relationships, if any, between its members. To respond to this request, EFCA would have to conduct extensive research and obtain information from third parties who have no obligation to provide it. EFCA is not in possession or control of the information necessary to respond to this request. Forcing EFCA to conduct original research and gather data unnecessary to the presentation of its position is an undue burden.

EFCA further objects to this request as overbroad, unduly burdensome, and requesting information not within the possession or control of EFCA. SolarCity is a publicly traded company and any of the other EFCA members could have pension plans, retirement plans, 401(k) plans, or profit sharing plans which have purchased shares of SolarCity on the open market as part of the investment vehicles associated with those plans. None of the investments of any EFCA member are provided to EFCA and responding to this request would require EFCA to conduct original research and gather data it does not need to present its position in this matter.

EFCA further objects to this request as calling for EFCA to gather information, including public records, equally available to all parties. To the extent that any potential affiliation consists of one party owning an interest in another, the corporate record depositories in each members' home state may have relevant, publicly available information. Staff has as much ability to peruse these public records as EFCA, and should not burden EFCA by forcing it to research public records.

Finally, EFCA objects to this request on the grounds that affiliations or potential affiliations between or among third parties may be subject to contractual non-disclosure requirements, trade secret protection, or other business confidentiality doctrines.

STF 1.5 Please indicate the relationship between EFCA and TASC, and any differences in their memberships.

Response: EFCA objects to this request as vague and ambiguous in that the term "relationship" is undefined and susceptible to multiple meanings. For example, does this term apply broadly, to require disclosure of any contact or dealings between EFCA and TASC, no matter how slight or how irrelevant to this matter? In the alternative, does it refer to some unspecified, but more formal arrangement? Until this term is defined, EFCA lacks the ability to answer this request accurately.

EFCA objects to this request as overbroad and not reasonably calculated to lead to the discovery of admissible evidence. No party using the name or acronym TASC has appeared in this case. TASC's membership is not relevant to this case. It has no bearing on the Commission's task to set a just and reasonable rate.

EFCA further objects to this request because it is unduly burdensome and requests information not within the possession or control of EFCA. For EFCA to respond to this request it would be necessary to obtain information from a third party. EFCA should not have the burden of obtaining information from a third party. Moreover, if Staff obtains the third-party information itself, it can compare EFCA's membership to TASC's membership through its own efforts.

Finally, EFCA objects to this request pursuant to *NAACP v. Alabama*, 357 U.S. 449 (1958) and its progeny. The Supreme Court has held that discovery of membership in a private group violates the First Amendment. EFCA objects to being forced to obtain, discover, or disclose any of TASC's First Amendment protected information.

STF 1.6 Please explain in detail how EFCA's various members are affected by the Settlement Agreement between Staff and Trico?

Response: EFCA objects to this request as vague and ambiguous because the term "affected" is undefined and susceptible to multiple meanings. Until this term is defined, EFCA cannot give an accurate answer.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. EFCA does not possess any of its member companies' business, revenue, or strategy information. None of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

STF 1.7 Please explain in detail how Solar City is affected by the Settlement Agreement between Staff and Trico?

Response: EFCA objects to this request as vague and ambiguous because the term "affected" is undefined and susceptible to multiple meanings. Until this term is defined, EFCA cannot give an accurate answer.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

STF 1.8 Please provide a typical copy of Solar City's lease agreement with a solar customer.

Response: EFCA objects to this request because it requires EFCA to research and obtain publicly available information - SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's lease agreements, let alone one that may be considered "typical."

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has an obligation to provide information in its possession or under its control.

EFCA objects to this request in that the term "typical" is undefined and susceptible to multiple meanings. For example, does "typical" refer to a commercial lease or a residential lease and what criteria are to be used to determine whether a lease is "typical"? Without a definition for this term, EFCA cannot provide an accurate response to this request.

STF 1.9 Please provide a copy of an outright purchase agreement in use by any of EFCA's members. Please also respond to this question with respect to Solar City.

Response: EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any purchase agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

STF 1.10 Do any of EFCA's members use other financing arrangements such as leases with an option to purchase; or longer term financing arrangements where the customer can pay over a period of 12-48 months and own the system? Does EFCA support use of these types of financing? Please respond to this question with respect to Solar City.

Response: EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any purchase agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA objects to this request to the extent it enquires about EFCA's position regarding financing arrangements as this request is not reasonably calculated to lead to the discovery of admissible evidence. Whether EFCA supports financing arrangements has no bearing on the Commission's obligation to set a just and reasonable rate.

STF 1.11 Do all of Solar City's solar lease agreements contain escalator clauses? Please explain your answer.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information and does not possess any copies of any SolarCity leases and without that information it cannot state whether any of SolarCity's leases contain escalator clauses.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA further objects to this request because it requires EFCA to research and obtain publicly available information. SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet google search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform.

STF 1.12 With declining costs, why do EFCA members still have an escalator clause in their agreements? Please respond to this question with respect to Solar City.

Response: EFCA objects to this request in that it assumes that the EFCA members have an escalator clause in their agreements with customers, but no evidence produced in this matter establishes that.

EFCA objects to this request in that it assumes that there has been "declining costs" experienced by EFCA members, but no evidence produced in this matter establishes that.

EFCA further objects to the phrase "declining costs" as undefined and susceptible to multiple definitions. Without a definition for this term, EFCA is unable to provide an accurate response.

EFCA objects to this request as unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent of its member companies for the purpose contemplated by this request. It does not possess any copies of any agreements between its member companies and their customers; nor does it possess any of its member companies' business, revenue, or strategy documents or information and thus it cannot respond whether its member companies have previously had or still have escalator clauses in their agreements with customers.

EFCA also objects to this request because its member companies are not parties to this proceeding. In order for EFCA to respond to this request it would be necessary to obtain discovery from each of its member companies, which is not required of a party: a party only has an obligation to provide information in its possession or under its control.

EFCA further objects to this request because it requires EFCA to research and obtain publicly available information. SolarCity maintains a sample lease agreement on its website. Staff has as much ability to conduct an internet google search as EFCA. Staff should not burden EFCA with conducting basic internet research which Staff can perform.

STF 1.13 How is the typical escalator clause structured in Solar City's lease agreements?

Response: EFCA objects to this request in that it assumes there is a "typical escalator clause." No facts produced establish the existence of an escalator clause or that a "typical" clause exists.

EFCA objects to this request in that the term "typical" is undefined and susceptible to multiple meanings. For example, does "typical" refer to a commercial lease or a residential lease and what criteria are to be used to determine whether a clause4 is "typical"? Without a definition for this term, EFCA cannot provide an accurate response to this request.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information or a copy of any of SolarCity's lease agreements with which to respond to this request.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

EFCA objects to this request as not reasonably calculated to lead to the discovery of admissible evidence, the structure of an escalator clause has no bearing on the Commission's obligation to set fair and reasonable rates.

STF 1.14 Has Solar City passed the decreases in panel costs on to its customers? Does EFCA support passing decreases in panel costs on to customers?

Response: EFCA objects to this request in that it assumes that there has been a decrease in panel costs experienced by all participants in the industry, but no evidence produced in this matter establishes that.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from SolarCity. It is not SolarCity; nor is it an agent of SolarCity for the purpose contemplated by this request. It does not possess any of SolarCity's business, revenue, or strategy information.

EFCA objects to this request because SolarCity is not a party to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from SolarCity which is not required of a party; a party only has to provide information in its possession or under its control.

EFCA objects to this request to the extent it enquires about EFCA's position regarding passing purported decrease in panel costs onto EFCA's member's customers as this request is not reasonably calculated to lead to the discovery of admissible evidence. Whether EFCA supports financing arrangements has no bearing on the Commission's task to set a just and reasonable rate.

STF 1.15 Please provide your entire analysis that indicates that the Settlement Agreement between Staff and Trico adversely affects EFCA member's future business in TRICO's service territory.

Response: EFCA objects to this request to the extent it assumes that EFCA has stated that the settlement agreement between Staff and Trico adversely affects EFCA members' future business in Trico's service territory. EFCA has not taken this position, EFCA's position has been that the settlement agreement will make rooftop solar more expensive for customers.

STF 1.16 Over the life of a lease agreement, please indicate what the owner/lessee of a typical 7 kW system pays? Please use Solar City as an example. Please provide the same information for the owner/lessee of a typical 7 kW system under the Settlement Agreement.

Response: EFCA objects to the term "typical" owner/lessee as this term is undefined and susceptible to multiple definitions. There is no context in this request for EFCA to evaluate what Staff considers a "typical" customer.

EFCA objects to this request as overly broad and lacking sufficient specificity with which EFCA can respond to this request, including the financing terms applicable to the customer, the customer's location, when the lease/purchase was made, the length of the lease, etc.

EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

STF 1.17 What is the impact of netting and banking under the Commission's current net metering rules on the value that a solar customer receives? Please use Solar City as an example.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

STF 1.18 What is the impact of netting and banking under the Settlement Agreement on the value that a solar customer receives? Please use Solar City as an example.

Response: EFCA objects to this request as overbroad and unduly burdensome and seeks information not within EFCA's possession or control. This request is aimed at the specific cost structure and economics of EFCA members and their customers. The information sought about any EFCA member company's economics or the economics of that member's customers is not within the possession or control of EFCA. EFCA is a Delaware limited liability company. It has an existence separate and distinct from its member companies. It is not an agent for its member companies for the purpose contemplated in this request. EFCA does not possess any of its member companies' business, revenue, or strategy information.

Further, none of the member companies are parties to this proceeding. In order for EFCA to respond to this request it would be necessary to conduct research, perform an investigation, and obtain discovery from each of its member companies. A party only has to provide information in its possession or under its control, none of the requested information is in EFCA's possession or control.

STF 1.19 Please provide a copy of all data requests that you have sent and/or received from other parties in this docket. Please provide copies of all of your responses to other parties' data requests. Please also provide copies of all responses received from other parties received in response to your data requests. These requests are ongoing and should be supplemented with any additional data requests and responses.

Response: No Objection.

EXHIBIT
S-19
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-0363

DIRECT TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

TERRI L. FORD

ASSISTANT DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JULY 29, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

Ms. Ford's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid and inclusive of all parties to this case. Ms. Ford explains why Staff believes this Agreement is in the public interest. In addition, Ms. Ford summarizes the different portions of the Agreement.

SECTION I - INTRODUCTION

Q. Please state your name and business address.

A. Terri L. Ford, 1200 West Washington Street, Phoenix, Arizona, 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as the Assistant Director of the Utilities Division ("Division").

Q. Please state your educational background.

A. I graduated from Loyola College in 1977 with a Bachelors Degree in Speech Pathology/Audiology and in 1978 with a Masters Degree in Speech Pathology. In 1982, I graduated from Loyola College with a Masters of Business Administration Degree.

Q. Please state your pertinent work experience.

A. From 1984 to 2006 I worked for a communications company in various product development, product management and project management roles.

From August 2007 to January 2016, I worked for the Telecom & Energy Section of the Arizona Corporation Commission Utilities Division. My responsibilities were to assign and oversee the development of Staff's evaluation and recommendations for most energy and telecom filings.

From February 2016 to the Present, I have worked as one of the two Assistant Directors of the Division. In this position, I assist the Division Director in the policy aspects of the Division. I am primarily responsible for matters dealing with telecom and energy, though I am increasingly exposed to water/wastewater issues.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to support the proposed Settlement Agreement ("Agreement"). I will also provide testimony which addresses the settlement process, public interest benefits and general policy considerations.

Q. Did you participate in the negotiations that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into five sections. Section I is this introduction, Section II provides discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV identifies and discusses the reasons why the Agreement is in the public interest and Section V addresses general policy considerations.

Q. Will there be other Staff witnesses providing testimony in this case?

A. Yes. Mr. Eric Van Epps will be providing testimony on Net Metering, Grandfathering, and the proposed New DG Energy Export Tariff. Mr. Yue "Nick" Liu will be providing testimony addressing the estimated financial net savings or net costs of purchasing or leasing a rooftop solar system from a typical Trico Electric Cooperative, Inc. residential member's perspective. In addition, all Staff witnesses that filed Direct Testimony prior to the Agreement will be available if needed.

SECTION II – SETTLEMENT PROCESS

Q. Please discuss the settlement process.

A. The settlement process was open, transparent and inclusive. All parties received notice of the settlement meeting and were accorded an opportunity to raise, discuss, and propose resolution to any issue that they desired.

Q. How many settlement meetings were held?

A. There was only one group settlement meeting relating to revenue requirement, rate design, net metering, and energy efficiency programs at which time Staff and Trico were able to come to agreement on the major terms of a settlement agreement.

Q. Who participated in the settlement meetings?

A. The following parties participated either in person or telephonically: Trico Electric Cooperative ("Trico" or "Cooperative"), Robert B. Hall, Ph.D., Pima County, the Energy Freedom Coalition of America ("EFCA"), Freeport Minerals Corporation ("Freeport"), Arizonans for Electric Choice and Competition ("AECC") and Division Staff ("Staff").

Q. Were other meetings held with the parties other than the settlement meeting?

A. Yes. These meetings were generally held at a party's request to discuss various issues in the case. Discussions were also held between the parties without Staff's participation.

Q. Once Staff and Trico reached agreement, did discussion continue with any other parties?

A. Yes, Trico and Staff continued settlement discussions with EFCA, however, ultimately the discussions were unsuccessful.

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The diverse interests included Staff, Trico, EFCA, an individual Trico member with rooftop solar, a coalition of energy consumers and a large industrial customer.

Q. How many of these parties executed the Agreement?

A. The Agreement was signed by Trico and Staff ("Signatories").

Q. Were there parties who chose not to execute the Agreement?

A. Yes. EFCA, Pima County, Freeport, AECC and Dr. Hall have chosen not to sign at this time.

Q. Why did EFCA, Pima County, Freeport, AECC and Dr. Hall not sign on to the Agreement?

A. Apart from Dr. Hall, who is opposed specifically to the increased customer charge as indicated in his testimony filed on July 20, 2016, I do not know and would not want to speculate about other intervenors.

Q. Can any party still sign on to the Settlement Agreement?

A. The Settlement Agreement provides that parties may continue to sign on by submitting a letter to the Docket along with an executed signature page.

Q. Was there an opportunity for all issues to be discussed and considered?

A. Yes, each party had the opportunity to raise and have its issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented their interests. I would characterize the discussions as candid but professional. While acknowledging that not all parties executed the Agreement, I must re-emphasize that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Would you describe the process as requiring give and take?

A. Yes, I would. As a result of the varied interests represented in the settlement process, a willingness to compromise was necessary. As evidenced in the Agreement, the Signatories compromised on what could be described as very different litigation positions.

Q. Because of such compromising, do you believe the public interest was compromised?

A. No. As I will discuss later in this testimony, I believe that the compromises made by the Signatories are just, reasonable, fair and in the public interest in that they, among other things, establish just and reasonable rates for Trico members; promote the convenience, comfort and safety, and the preservation of health, of the employees and members of Trico; and fairly and equitably resolve the issues arising from this Docket.

SECTION III – SETTLEMENT AGREEMENT

Q. Please describe Part I of the Agreement.

A. Part I is a general description of the settlement process and of the Agreement itself.

Q. Please describe Part II of the Agreement.

A. Part II describes the rate increase proposed by the Signatories. The Agreement provides for a total revenue requirement of $89,762,812, resulting in a base rate increase of 2.61 percent

over adjusted test-year retail revenues. The provisions of the Agreement result in a Times Interest Earned Ratio ("TIER") of 2.00, and a Debt Service Coverage ("DSC") of 1.87. The rate of return on fair value rate base would be 6.33 percent.

The revenue requirement included in the Agreement reflects an increase in rate case expense over the amount initially requested by Trico. The Signatories have agreed to cap the total rate case expense at $450,000, but the increase in rate case expense remains subject to Staff's review of supporting invoices. Staff is currently in the process of reviewing the available invoices.

The fair value rate base of $175,076,536 includes Direct Assignment Facilities ("DAFs") which Trico has agreed to purchase from the Arizona Electric Power Cooperative, Inc. ("AEPCO"). The purchase of the DAFs is expected to provide savings to Trico's members compared to the current leasing of the DAFs.

Q. Please describe Part III of the Agreement.

A. Part III states that the proposed overall rate increase would result in a bill impact for a residential member using the annual average of 837 kWh per month of about $2.05, or a 1.75 percent increase.

Q. Please discuss Part IV of the Agreement.

A. Part IV refers to the Wholesale Power Cost Adjustor ("WPCA"). The purpose of the WPCA is to allow Trico to recover or refund power supply costs that fluctuate between rate cases. Under the Agreement, the base cost of power would be set at $0.081711 per kWh, and the current WPCA rate would be adjusted to zero.

Although Trico has had the WPCA for many years, there is no Plan of Administration ("POA") which memorializes how the WPCA works. Therefore, the Signatories have included a proposed POA with the Agreement. The POA includes a list of eligible expenses, reporting requirements, and a description of Trico's WPCA rate adjustment process. To help avoid large monthly swings in the WPCA rate, the adjustment process contains a $2 million bank balance threshold. If the monthly WPCA bank balance equals or exceeds $2 million, Trico would adjust the WPCA rate within 60 days following the submittal of a monthly report indicating that the bank balance threshold was exceeded.

Q. Please describe Part V of the Agreement.

A. Part V states that the revenue allocation for each customer class would be as Trico proposed in its Application, although there would be a slight adjustment to the numbers as a result of the increase in rate case expense.

Q. Please describe Part VI of the Agreement.

A. Part VI describes the rate design provisions of the Agreement. The rate design provisions include the following:

- A three-part rate design would be introduced into the standard Residential rate schedule, including a customer charge, a demand charge, and energy charges.
- The existing Residential time-of use rate schedule would be frozen and may be eliminated in Trico's next rate case. Trico would provide notice to members.
- A three-part rate design would be introduced into the GS1 rate schedule, which is for General Service members with demand less than 10 kW.

- The Interruptible Service schedules IS1 and IS2 would be combined into one schedule known as IS1 that would be frozen to new members. Trico would notify members of the change.
- All other rate schedules would be as proposed by Trico in its Application, updated to reflect the revenue requirement in the Agreement, except that the monthly customer charges for the General Service schedules GS2 and GS3 would be consistent with those proposed for GS1: $27 for single-phase and $35 for three-phase.

Q. Can you explain more about the proposed three-part Residential rate schedule?

A. Yes. The three parts are a customer charge, a demand charge, and energy charges. The bundled customer charge would be set at $24 per month. The bundled energy charges would be $0.11293 per kWh for the first 800 kilowatt-hours ("kWh") each month and $0.12293 per kWh for all additional kWh. However, the demand charge would be set at zero per kilowatt ("kW"). Although there would be no rate applied to the demand, the member's peak demand would be measured as the highest 15-minute interval demand during the month, and the peak demand number would be shown on the bill within six months of the effective date of Commission approval of the Agreement.

Q. Is it the same situation for the GS1 members?

A. Yes. The introduction of demand information with a zero rate is the same for the small General Service members as for Residential members; however, the customer and energy charges are different. All proposed rates are contained on the tariffs that are attached to the Agreement.

Q. What is Part VII of the Agreement?

A. Part VII of the Agreement is on Net Metering. Staff witness Eric Van Epps will address this subject in his testimony.

Q. What is Part VIII of the Agreement?

A. Part VIII of the Agreement addresses the New DG Energy Export Tariff. Staff witness Eric Van Epps will address this subject in his testimony.

Q. What is Part IX of the Agreement?

A. Part IX of the Agreement addresses Grandfathering. Staff witness Eric Van Epps will also address this subject in his testimony.

Q. Please describe Part X of the Agreement.

A. Part X of the Agreement describes the Member Education Program that Trico will use to educate Residential and Small General Service members on demand charges because those customer classes do not currently pay demand charges in Trico's service area.

Even with a zero rate, each member's bill would indicate the date and time of the member's peak demand for the billing period. Trico's outreach and education would address, at a minimum, the nature and operation of demand charges, how members can manage their demand to reduce bills, and information on tools available to help manage demand. Educational materials would highlight technology solutions such as programmable thermostats and load controllers.

Q. Please describe Part XI of the Agreement.

A. Part XI of the Agreement provides for Trico to propose at least two demand-reduction programs in its next Energy Efficiency Implementation Plan to be filed by June 1, 2017. These demand-reduction programs should work in conjunction with the Member Education Program discussed above.

Q. Please describe Part XII of the Agreement.

A. Part XII addresses Trico's filing of its next general rate case. Trico has agreed that its next rate case would have a test year no earlier than the 12-month period ending June 30, 2018.

In regard to demand charges, Trico would use data obtained from tracking member demand following the implementation of the initial zero per kW demand rate, in order to determine an appropriate demand rate (for Residential and small General Service members) to propose in its rate case. However, the Agreement would limits the proposed demand rate to be no higher than $2 per kW for Residential and Small General Service members.

In its next general rate case application, Trico would provide a study comparing the impact of using a 15-minute interval compared to a 60-minute interval to determine billing demand.

However, the Signatories recognize that the success of a three-part rate will be largely dependent upon Trico's educational programs and its ability to help members navigate through technological options available to help control demand and energy usage. The Signatories thus expressly recognize that because the level of customer acceptance at the time of Trico's next rate case is impossible to determine now, alternative options may need to be considered in the next rate case.

Q. What is Part XIII of the Agreement?

A. Part XIII contains the following additional settlement provisions: 1) Trico would file a notice with the Commission when the acquisition of the DAFs has been completed, 2) the Signatories agree to the Trico proposed depreciation rates, 3) Trico will incorporate language into its DG interconnection agreements stating that members may be charged a fee for a return trip to inspect DG installations when the return trip is due to a member or installer issue, 4) Trico's Rules and Regulations will be revised as set forth in Attachment D of the Agreement, and 5) the energy efficiency reporting and planning requirements of A.A.C. R14-2-2409 will supplant such requirements in Decision No. 71230 and A.A.C. R14-2-213.

Q. Please describe Part XIV of the Agreement.

A. Part XIV sets forth the Signatories understanding of the Commission's independent authority in the review and consideration of the Agreement. The Signatories also recognize that Staff does not have the power to bind the Commission. This section also describes the rights of the Signatories should the Commission fail to adopt the material terms of the Agreement.

Q. Please describe Part XV of the Agreement.

A. Part XV is the legal "fine print" that describes the settlement process as a give and take, and it sets forth the role of the Signatories to support the Agreement. It also describes the Signatories legal rights with respect to the Agreement and future proceedings.

SECTION IV - PUBLIC INTEREST

Q. Is the Agreement in the public interest?

A. Yes, in Staff's opinion, the Agreement is fair, balanced, and in the public interest.

Q. Would you summarize the reasons that lead Staff to conclude that the Agreement is fair, balanced, and in the public interest?

A. This Agreement balances the interest of both Trico and its members. The significant provisions of this Agreement include:

- A modest revenue increase as proposed by Trico.
- A class revenue allocation that moves rates to levels that more closely reflect class cost.
- Updating Trico's base cost of power and the Wholesale Power Cost Adjustor rate.
- A rate design that recovers costs in a manner that better reflects how Trico incurs its costs of service.
- Introduction of a demand rate component (at a $0.00 per-kW rate) that allows for an extended period of time for member education regarding demand rates without bill impacts.
- An aggressive member education program designed to better inform member-customers of their electricity usage and technology options available that can better control their costs and usage, including access by members to Trico's Smart Hub.
- Freezing of the current Net Metering Tariff and adoption of a New DG Energy Export Tariff applicable to new DG customers.
- Grandfathering of the current Net Metering Tariff for members who had DG interconnection applications submitted by May 31, 2016, so they remain on the current Net Metering Tariff.
- Requiring Trico to propose additional demand-reduction programs for the benefit of its members and simplifying energy efficiency reporting requirements.
- An agreement that Trico's next rate case will reflect a test year no earlier than the 12-month period ending June 30, 2018.

- And, should Trico pursue Demand Charges in its next rate case, the demand charge per kW for Residential and Small General Service members will be capped at no more than $2.00.

Q. Do you believe that the Agreement results in just and reasonable rates for members?

A. Yes. Trico will receive a modest base rate increase of $2,282,076 (or approximately 2.6 percent) over adjusted test-year revenues, reflecting a total revenue requirement of $89,762,812. Upon the effective date of the new rates, the new monthly bill for a residential member, using the annual average of 837 kWh per month, will increase by approximately $2.05 from $116.84 to $118.89, which is a 1.75 percent increase. And the next rate case will reflect a test year no earlier than the 12 months ending June 30, 2018.

Q. Please discuss how the Agreement is fair to the utility.

A. The revenue recommended will provide Trico with adequate funds to provide reliable and safe service, while at the same time ensuring continued financial health of the Cooperative. Trico indicated in its Application that additional revenue, however, was not the primary purpose behind its Application. Rather, Trico was motivated by the need to better align rates of certain classes of member-customers with the cost of serving them, and to address inequities among members in the manner in which the fixed cost of providing electric service are recovered by the Cooperative.

The Cooperative stated that since 2014, it has experienced significant changes in how its members use energy. While the overall number of Trico members and the total amount of energy sold by Trico have continued to grow, increased energy conservation efforts, overall milder weather and expanded DG deployment have resulted in decreasing energy usage per residential member. The recent escalation in the number of applications to interconnect

rooftop solar DG under Trico's Net Metering Tariff has resulted in significant erosion of the Cooperative's ability to recover the fixed costs of providing electric service to its members, and inequities among its members in the payment of those fixed costs.

The proposed Settlement Agreement incorporates rate design changes to address these concerns that include Customer Charge increases to most customer classes, a shift in cost allocation that begins to reduce subsidies for residential members, freezing of the current Net Metering Tariff for existing members prior to May 31, 2016, and introduction of a New DG Energy Export Tariff for new DG customers.

Q. What was Staff's goal when it agreed to be a Signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable for both the rate payers and the Cooperative. Staff believes it has accomplished this by reviewing the facts presented and making the appropriate recommendations to the Commission for its consideration, which will balance the interest of the Cooperative and the ratepayers, by promoting the Commission's desire to ensure that the Cooperative has the tools and financial health to provide safe, adequate and reliable service while fulfilling the Commission's various policy objectives.

SECTION V – POLICY CONSIDERATIONS

Q. You have indicated that the Agreement incorporates diverse interests including those of residential customers, energy efficiency advocates, solar customers and solar advocates and large business. Please discuss how the Agreement addresses the diverse interests of these entities.

A. In the Agreement, there are specific provisions which address many of the concerns expressed by the varied and diverse interests represented in this case. For example, energy efficiency or demand-side management issues are addressed in Section XI, requiring Trico to propose at least two new demand-reduction programs in its next Energy Efficiency Implementation Plan to be filed on June 1, 2017. Overall rate design utilizes a class revenue allocation that moves rates to levels that more closely reflect cost, and is designed to recover costs in a manner that better reflects how Trico incurs its costs of service. Additionally, Trico introduces a demand rate "component" with a zero rate, which is to be coupled with an aggressive member education program designed to better inform members of their electricity usage and technology options available to assist in controlling costs and usage. Finally, grandfathering of the current Net Metering Tariff for members who had DG interconnection applications submitted by May 31, 2016, acknowledges the value and commitments of early adopters to renewable energy, recognizes that times have also changed and embraces the concept of fairness. And, the new DG Energy Export Tariff establishes an export rate for energy generated from a new DG member's system and delivered back to Trico at $0.0770 per kWh, which is a fair rate for the DG member, does not harm the financial integrity of the Cooperative and protects all rate payers.

Q. What were the major policy considerations the parties had to deal with in this Docket?

A. As Trico indicated in its Application, Trico was motivated by the need to better align rates of certain classes of member-customers with the cost of serving them, and to address inequities

among members in the manner in which the fixed cost of providing electric service are recovered by the Cooperative. That said, two of the biggest issues were rate design and the current Net Metering Tariff.

Q. Does Staff agree that Trico has adequately supported the proposed increases to Customer Charges?

A. Yes. While Staff recognizes that the proposed residential Customer Charge increases from $15.00 to $24.00 is a larger increase than in past rate cases, the Cooperative cost justified this request in its rate application. Additionally, we are collectively moving towards the recovery of fixed costs through a fixed charge. And, while Staff does recognize that increased Customer Charges can have an adverse effect on low usage customers, Trico has proposed an inclining block rate for the energy charge, which provides a lower rate for lower usage.

Q. Please describe the Cooperative's Net Metering solution proposed in its Application.

A. Trico proposed in its Application to change the credit for excess generation from the DG member's facility from the retail rate to the avoided cost rate that has been approved by the Commission (currently $0.03662 per kWh). The Cooperative proposed to provide a credit on a net metered DG member's bill each month for the excess generation. Finally, the Cooperative also proposed that DG members would no longer be able to "bank" or "net" the excess generation from their DG systems to offset the cost of future usage.

Q. What was Trico's rationale for proposing to credit excess energy from DG Members at the avoided cost rate in its Application?

A. The Cooperative stated that the avoided cost rate is a more accurate calculation of the value to Trico of the excess energy produced by the DG member's system. Trico does not believe it is a responsible use of the all members' money to pay more for energy from DG systems

that it could otherwise purchase on the wholesale market. Trico's Board believes the retail rate offset for energy that the DG Member actually uses provides an adequate subsidy and incentive to promote the continued sustainable growth of residential DG in their service territory, based on the volume of applications they have continued to receive since the proposed changes were communicated to members.

Q. How does the Agreement address Net Metering?

A. The Agreement proposes freezing the current Net Metering Tariff, so that it would be unavailable to members whose DG interconnections application is received after May 31, 2016, and introduces a new DG Energy Export Tariff. The new DG Energy Export Tariff will apply as a rider to all DG interconnection applications received after May 31, 2016. The export rate for kWh generated from a new DG member's system and delivered back to Trico ("excess energy") will be set at $0.00770 per kWh. The $0.00770 represents the equivalent of Trico's Power Supply portion of the energy change for the first tier of the proposed RSI. For new DG members, no netting or banking of kWh will occur.

Q. What was Staff's recommendation on this issue in its original Direct Testimony?

A. Staff made no recommendation in its original Direct Testimony and chose instead to await a Decision in the Cost and Value of Solar Generic Docket No. E-00000J-14-0023.

Q. Does the policy set forth in this settlement continue to support the renewable goals of this Commission?

A. Yes. The Settlement reinforces the Commission's commitment to renewable energy, specifically solar, by allowing early adopters of solar to retain the Net Metering Tariff as it currently exists. Staff witness Yue "Nick" Liu's analysis demonstrates that solar systems can still be cost effective for new solar customers. And, the Cooperative has proposed a new

option for Members to purchase energy from its Community Solar Project - the SunWatts Sun Farm. This option will not require any up-front payment and will allow Members to purchase panel output through a monthly solar energy charge. This solar energy charge will stay fixed for a 20-year term. Under this option, Members can purchase the output in whole-panel increments up to, but not exceeding, their minimum monthly kWh energy usage in the preceding 12 months.

Q. Please explain Staff's rationale for being a signatory to the Agreement which contains a different recommendation with regard to Net Metering than the recommendation offered by Staff in its original Direct Testimony.

A. The Settlement Process affords Staff the opportunity to consider "one-off" solutions for certain critical issues. In the case of Net Metering in the Trico rate case, the Cooperative has a unique set of circumstances that collectively made the proposed Settlement solution balanced and in the public interest. The Settlement Agreement also allows either Trico or Staff to seek modification of the export rate for a period of 18 months from a decision in this case, once a decision in the generic docket is entered.

Q. Does this conclude your Direct Testimony in Support of the Settlement Agreement?

A. Yes.

EXHIBIT
S-20
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC. AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILIYT SERVICE AND FOR RELATED APPROVALS	)	DOCKET NO. E-01461A-15-0363

SETTLEMENT REPLY

TESTIMONY

OF

TERRI L. FORD

ASSISTANT DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

AUGUST 15, 2016

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EXECUTIVE SUMMARY
TRICO ELECTRIC COOPERATIVE, INC.
DOCKET NO. E-01461A-15-0363

My reply testimony responds to many of the comments contained in the direct testimony of Energy Freedom Coalition of America's witness Patrick J. Quinn (filed in opposition to the Settlement Agreement). I address his comments regarding the rate design changes contained in the Settlement Agreement between Staff and Trico.

1 **INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Terri L. Ford. My business address is 1200 West Washington Street, Phoenix,
4 Arizona 85007.

5

6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed by the Arizona Corporation Commission ("Commission") as an Assistant
8 Director of the Utilities Division ("Staff").

9

10 **Q. Did you file Direct Testimony in Support of the Settlement Agreement in this case?**

11 A. Yes, I filed Direct Testimony in Support of the Settlement Agreement between Staff and
12 Trico Electric Cooperative ("Trico" or "Cooperative") on July 29, 2016.

13

14 **Q. What is the purpose of your Reply Testimony in Support of the Settlement**
15 **Agreement?**

16 A. The purpose of my Reply Testimony is to respond to some of the points made in the
17 Direct Testimony of Patrick J. Quinn filed on behalf of the Energy Freedom Coalition of
18 America ("EFCA").

19

20 **Q. Were you surprised by Mr. Quinn filing testimony in this case?**

21 A. Yes, I was. Normally, Mr. Quinn represents the Arizona Utility Ratepayers Alliance
22 ("AURA"). AURA is not an intervenor in this proceeding. Mr. Quinn is appearing on
23 behalf of EFCA.

24

RESPONSE TO TESTIMONY OF PATRICK J. QUINN

Q. What is the first point made by Mr. Quinn to which you would like to respond?

A. Mr. Quinn states that he is concerned with the "lack of notification and late timing of the important changes related to mandatory demand charges." An important point which Mr. Quinn fails to discuss until well into his testimony, is the fact that the demand charge component of the proposed three-part rate design will be set at zero ($0.00) per kW under Section VI of the Settlement Agreement until a decision is made on demand charges in the Cooperative's next rate case.

Q. What is the purpose of including a demand component on customer bills if there is no charge associated with it?

A. The purpose is to use this as an opportunity to educate customers. Our experience in other cases indicates customers may not fully understand the concept of a demand charge and how they can utilize demand rates to reduce their monthly bills. Under the Settlement Agreement, Trico is required to undertake an extensive member outreach and education program regarding demand rates. Section 10.2 of the Settlement Agreement provides that the member outreach and education will include at a minimum: (a) the nature and operation of demand rates; (b) how members can utilize demand rates to reduce monthly bills; and (c) information on tools available from Trico and third parties to help members manage demand (including Trico's Smart Hub application). In addition, each member's bill will show the date and time of the member's peak demand for the billing period. And, the Cooperative will gather critical data that may be utilized to set a demand charge in the future.

Q. Does this provision respond to one of the primary concerns raised by Mr. Quinn in his Testimony?

A. Yes, it does. At page 6 of his Direct Testimony, Mr. Quinn states the following:

> A comprehensive educational plan has to be developed that includes the ability of a consumer to get instantaneous data. Trico has not yet developed such a plan. This is absolutely necessary to avoid broadsiding customers, especially customers that are most vulnerable to increases in fixed charges like those on low or fixed incomes."

The Settlement Agreement contemplates a comprehensive educational effort before demand rates would be considered in the next rate case, coupled with individual usage data review with members.

Q. Do the provisions of the Settlement Agreement respond to other concerns raised by Mr. Quinn?

A. Yes, they do. Mr. Quinn states on page 7 of his Testimony that residential customers do not have "access to the equipment and other resources to manage demand usage." The Settlement Agreement specifically provides that Trico is required to provide educational materials that highlight technology solutions including programmable thermostats and load controllers to better manage demand charges and monthly bills.

Q. How long will this member educational program continue under the terms of the Settlement Agreement?

A. It will continue for as long as necessary and at least through the next rate case. The provisions of Section XII of the Settlement Agreement provide that Trico's next rate case will reflect a test year **no earlier** than the 12-months ending June 30, 2018. This means that there are likely to be several years of outreach and educational efforts before any form of demand rates would go into effect (if at all).

Q. Mr. Quinn attempts to make comparisons with the UNSE case. Do you believe Mr. Quinn's comparisons in this regard are accurate?

A. I believe that Mr. Quinn's comparison fails to recognize several important differences between the two cases. First, the demand component in Trico's case will be zero ($0.00 per kW) until the next rate case is resolved. Second during this time, the Settlement Agreement provides for a lengthy educational campaign before any form of demand rates would go into effect. The need for an extended educational program was discussed at the recent Open Meeting on UNSE and is consistent with the guidance provided by the Commission at that Open Meeting on the implementation of demand rates. In this case, if demand rates are adopted in Trico's next rate, they would be no higher than a modest $2.00 per kW, pursuant to Section 12.2 of the Settlement Agreement. In that next case, the Commission could also decide to leave the demand charge at $10.00.

Q. What else does Mr. Quinn's comparison fail to reflect?

A. I believe that Mr. Quinn's comparison also fails to take into account Section 12.4 of the Settlement Agreement. That Section provides:

> The Signatories recognize that the ultimate success of a three-part rate will be dependent upon the success of Trico's educational programs and its ability to help customers navigate through the technological options that are available to assist them in controlling their demand and energy usage. The Signatories recognize that alternative options may need to be considered in the next rate case.

Thus, as I stated in my Direct Testimony in Support of the Settlement Agreement, the Signatories expressly recognize that because the level of customer acceptance at the time of Trico's next rate case is impossible to determine now, alternative options may need to be considered in the next rate case.

Mr. Quinn's concern that there has been a final decision regarding the implementation of demand rates by Trico fails to take into account Section 12.4 of the Settlement Agreement.

Q. Are there other concerns that Mr. Quinn raises that you would like to address?

A. Yes. Mr. Quinn seems to be saying that there can be no changes to rate design from that filed by a company in its original application. Mr. Quinn also appears to be saying that rate design changes cannot be made in this case, because the notice did not mention "rate design." This ignores the fact that oftentimes, rate design changes, some of them significant, are proposed by Staff and intervenors in a case and adopted by the Commission.

Q. How do you respond to Mr. Quinn's concern about the basic service charge increase?

A. Mr. Quinn has concerns with the basic service charge increase of $9.00 provided in the Settlement Agreement. I would like to point out that the cost studies provided by Trico actually support a much higher basic service charge. Mr. Quinn again compares the amount of the increase in the basic service to that recently approved by the Commission in the UNSE case. This does not take into consideration other factors that are important to consider such as the overall revenue increase, which in this case was comparably small, the fact that this is a cooperative, and the unique characteristics of Trico's service area.

Q. Does this conclude your Reply Testimony in Support of the Settlement Agreement?

A. Yes, it does.

ORIGINAL

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EXHIBIT S-21 ADMITTED

BEFORE THE ARIZONA CORPORATION

COMMISSIONERS

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

Arizona Corporation Commission
DOCKETED
AUG 16 2016
DOCKETED BY

AZ CORP COMMISSION
DOCKET CONTROL
2016 AUG 16 AM 10 53

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.

DOCKET NO. E-01461A-15-0363

STAFF'S NOTICE OF ERRATA

On August 15, 2016, Arizona Corporation Commission ("Commission") Staff filed Reply Testimony in Support of the Settlement Agreement of Terri L. Ford and Ranelle Paladino. Staff has since discovered that a typographical error was made on page 4 of Ms. Ford's testimony. Specifically, at lines 11 and 12 of page 4, the following sentence, "In that next case, the Commission could also decide to leave the demand change at $10.00" should be changed to read "In that next case, the Commission could also decide to leave the demand charge at $0.00 per kW."

Staff has attached a revised page 4 which should replace the page 4 in Ms. Ford's Reply Testimony filed on August 15, 2016. Staff apologizes for any inconvenience to the ALJ and the parties.

RESPECTFULLY SUBMITTED this 16th day of August, 2016.

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On this 16th day of August, 2016, the foregoing document was filed with Docket Control as a Utilities Division Notice of Errata, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this dates or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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By: Karyn Christine
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Assistant to Maureen A. Scott

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EXHIBIT
5-22
ADMITTED

How much does a solar power system cost?

Thanks to innovations in financing, manufacturing and technology, it's now easier and more affordable to go solar. No matter which option you decide is best for you, the result will be the same: clean energy for your home and more money in your pocket for the things you really care about.

How would you like to pay for solar?

PAY AS YOU GO

PURCHASE YOUR SYSTEM

PPA

Pay for the energy produced each month at an industry-low rate. We cover installation, roof warranty and energy monitoring.

Lease

Get a low, fixed monthly payment with predictable costs and consistent savings. Choose to prepay your lease partially, or in full for added savings. We cover installation, roof warranty and energy monitoring.

	PPA	Lease	Cash purchase	Loan
Down payment	$0 DOWN, FULL & PARTIAL PREPAY OPTIONS	$0 DOWN, FULL & PARTIAL PREPAY OPTIONS	OUTRIGHT PURCHASE	$0 DOWN
Ownership	SOLARCITY	SOLARCITY	YOU	YOU
Tax credit(s)			✓	✓
Monthly payments	PAY FOR THE ENERGY PRODUCED, WITH A 0-2.9% ANNUAL ESCALATOR	LOW, FIXED WITH A 0-2.9% ANNUAL ESCALATOR	NONE	FIXED*
Production guarantee		✓	✓	✓
Energy monitoring with MySolarCity app	✓	✓	✓	✓
Roof & system warranty	✓	✓	✓	✓
Payment term	20 YEARS	20 YEARS	PAID IN FULL	10 OR 20 YEARS
	VIEW DETAILS	VIEW DETAILS	VIEW DETAILS	VIEW DETAILS

*Includes an optional 30% pre-payment by month 18

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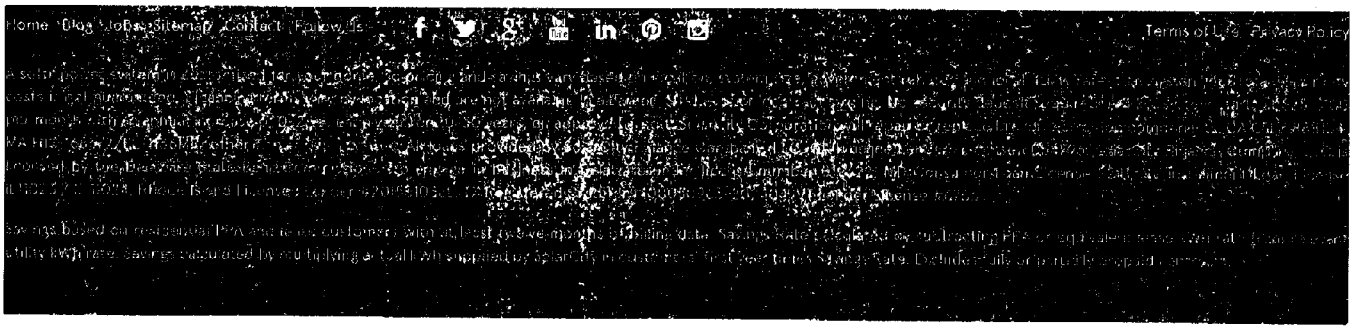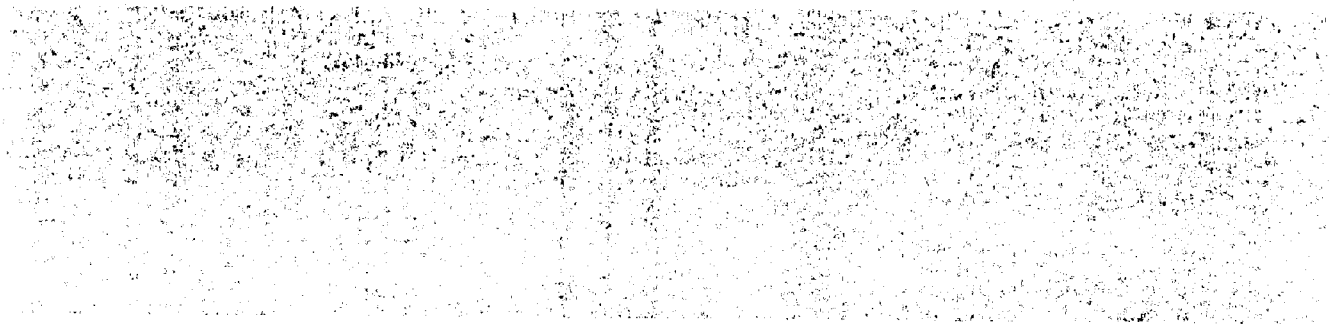
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