AUSTIN ENERGY'S TARIFF PACKAGE:	§	
2015 COST OF SERVICE STUDY	§	**BEFORE THE CITY OF AUSTIN**
AND PROPOSAL TO CHANGE BASE	§	**IMPARTIAL HEARING EXAMINER**
ELECTRIC RATES	§	

INDEPENDENT CONSUMER ADVOCATE'S
RESPONSE TO AUSTIN ENERGY'S FIRST REQUEST FOR INFORMATION

Pursuant to § 7.3(c)(I) of the Procedural Rules for the Initial Review of Austin Energy's Rates, the Independent Consumer Advocate ("ICA") hereby timely responds to Austin Energy's First Request for Information:

Respectfully submitted,

John B. Coffman
Independent Consumer Advocate

Submitted this date: May 10, 2016

CERTIFICATE OF SERVICE

The forgoing filing has been served upon all of the email addresses contained on the official Service List for this proceeding as found on the website for the Office of the City Clerk's website on this 10th day of May, 2016.

Request for Information 1-1 from Austin Energy: Please provide supporting calculations, models, and workpapers for all rate numbers, tables, and exhibits within the testimony.

Answer: ICA provides a PDF file attachment containing workpapers and supporting documents for Mr. Johnson's direct testimony. Subsequent to filing testimony, Mr. Johnson discovered an error in the modified cost of service study model. The effect of the error does not change any conclusions, but it will require errata for certain schedules and texts in the testimony. The attached workpapers include the corrected versions of affected schedules. Separately, ICA will provide Excel workbooks, in native format, containing the two modified versions of the Austin Energy cost of service model. ICA will also provide the excel spreadsheets in native format associated with the PDF attachment.

In addition, Mr. Johnson's direct testimony references reports which can be downloaded from the following web addresses:

2014 ERCOT State of the Market Report

https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf

Regulatory Assistance Project, Charging for Distribution Utility Service: Issues in Distribution Rate Design, Prepared for NARUC

http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724

Edison Foundation, Benefits of Smart Meters

http://www.edisonfoundation.net/iei/Documents/IEE_BenefitsofSmartMeters_Final.pdf

Sponsored by: Clarence Johnson

Clarence Johnson

Direct Testimony

Workpapers & Related Documents

Schedule G-10
Comparison of Cost of Service and Current Rates

No.	Description	Reference	Total Company	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW
			(A)	(B)	(C)	(D)	(E)	(F)
1	**Current Rates and Test Year Fuel and Pass-Through Costs**							
2	Rate Revenue (excluding CAP; after billing adj)	WP G-10.1	$ 1,235,103,056	$ 472,182,438	$ 31,440,214	$ 283,772,562	$ 239,265,138	$ 46,440,686
3								
4	Adjusted Cost of Service	Schedule G-6	$ 1,196,178,825	$ 464,372,702	$ 30,893,019	$ 246,157,382	$ 234,668,693	$ 45,957,441
5								
6	Under/(Over) Recovery	Line 4 - 2	$ (38,924,231)	$ (7,809,736)	$ (547,196)	$ (37,615,180)	$ (4,596,445)	$ (483,245)
7								
8	Required Increase/(Decrease) in Rate Revenue		-3.2%	-1.7%	-1.7%	-13.3%	-1.9%	-1.0%
9								
10								
11	**Current Base, Fuel and Pass-Through Rates**							
12	Rate Revenue (excluding CAP; after billing adj)		$ 1,214,066,043	$ 462,426,897	$ 32,190,585	$ 291,023,250	$ 230,692,602	$ 47,675,638
13								
14								
15	**Proposed Rates and Projected (Estimated) Fuel and Pass-Through Costs**							
16	Rate Revenue (excluding CAP; after billing adj)	Schedule H-5.3	$ 1,166,309,563	$ 451,852,198	$ 31,153,060	$ 268,208,348	$ 225,437,148	$ 42,224,120
17		& WP G-10.2						
18	Base COS with Estimated Pass-Through Costs	Schedule G-9 & G-7	$ 1,146,501,373	$ 446,786,389	$ 29,902,408	$ 235,338,997	$ 224,533,676	$ 44,151,745
19		& WP G-10.2						
20	Under/(Over) Recovery	Line 18 - 16	$ (19,808,190)	$ (5,065,809)	$ (1,250,652)	$ (32,869,351)	$ (903,472)	$ 1,927,625
21								
22	Below/(Above) Cost of Service		-1.7%	-1.1%	-4.2%	-14.0%	-0.4%	4.4%
23	Required Increase/(Decrease) in Revenue Under Proposed Rates		-1.7%	-1.1%	-4.0%	-12.3%	-0.4%	4.6%
24								
25	**Increase/(Reduction)**							
26	Current with Test Year Fuel and Pass-Throughs to Proposed Rates		$ (68,793,492)	$ (20,330,240)	$ (287,154)	$ (15,564,214)	$ (13,827,990)	$ (4,216,566)
27	**Current Base, Fuel and Pass-Through Rates to Proposed Rates**		**$ (47,756,480)**	**$ (10,574,699)**	**$ (1,037,525)**	**$ (22,814,902)**	**$ (5,255,454)**	**$ (5,451,519)**
28	*above includes estimated pass-through cost impacts (e.g., over/under balances applied to pass-through rates)*							

Schedule G-10

Primary Voltage ≥ 3 < 20 MW (G)	Primary Voltage ≥ 20 MW (H)	Transmission Voltage (I)	Transmission Voltage ≥ 20 MW @ 85% aLF (J)	Service Area Street Lighting (K)	City-Owned Private Outdoor Lighting (L)	Customer-Owned Non-Metered Lighting (M)	Customer-Owned Metered Lighting (N)	Total (O)
$ 52,461,814	$ 90,462,004	$ 2,164,516	$ 13,602,284	$ -	$ 2,898,555	$ 109,617	$ 303,227	$ 1,235,103,056
$ 53,487,672	$ 98,579,143	$ 1,755,615	$ 15,754,556	$ -	$ 4,036,463	$ 139,192	$ 376,946	$ 1,196,178,825
$ 1,025,858	$ 8,117,139	$ (408,901)	$ 2,152,272	$ -	$ 1,137,907	$ 29,576	$ 73,719	$ (38,924,231)
2.0%	9.0%	-18.9%	15.8%		39.3%	27.0%	24.3%	-3.2%
$ 45,846,212	$ 86,739,183	$ 2,130,434	$ 12,253,293	$ -	$ 2,705,231	$ 100,589	$ 282,129	$ 1,214,066,043
$ 45,929,568	$ 83,744,440	$ 2,144,754	$ 12,547,007	$ -	$ 2,704,431	$ 98,532	$ 265,958	$ 1,166,309,563
$ 51,086,226	$ 93,646,025	$ 1,675,568	$ 14,887,638	$ -	$ 3,993,492	$ 132,982	$ 366,226	$ 1,146,501,373
$ 5,156,659	$ 9,901,585	$ (469,187)	$ 2,340,631	$ -	$ 1,289,061	$ 34,450	$ 100,268	$ (19,808,190)
10.1%	10.6%	-28.0%	15.7%		32.3%	25.9%	27.4%	-1.7%
11.2%	11.8%	-21.9%	18.7%		47.7%	35.0%	37.7%	-1.7%
$ (6,532,246)	$ (6,717,564)	$ (19,762)	$ (1,055,278)	$ -	$ (194,124)	$ (11,085)	$ (37,269)	$ (68,793,492)
$ 83,356	**$ (2,994,743)**	**$ 14,321**	**$ 293,713**	**$ -**	**$ (800)**	**$ (2,057)**	**$ (16,171)**	**$ (47,756,480)**

Schedule G-10
Comparison of Cost of Service and Current Rates

No.	Description	Reference	Total Company	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW
			(A)	(B)	(C)	(D)	(E)	(F)
1	**Current Rates and Test Year Fuel and Pass-Through Costs**							
2	Rate Revenue (excluding CAP; after billing adj)	WP G-10.1	$ 1,234,701,609	$ 474,062,283	$ 31,458,282	$ 283,339,669	$ 238,491,828	$ 46,257,714
3								
4	Adjusted Cost of Service	Schedule G-6	$ 1,217,227,310	$ 475,622,876	$ 31,259,261	$ 249,588,917	$ 237,774,156	$ 46,552,743
5								
6	Under/(Over) Recovery	Line 4 - 2	$ (17,474,299)	$ 1,560,593	$ (199,021)	$ (33,750,752)	$ (717,673)	$ 295,029
7								
8	Required Increase/(Decrease) in Rate Revenue		-1.4%	0.3%	-0.6%	-11.9%	-0.3%	0.6%
9								
10								
11	**Current Base, Fuel and Pass-Through Rates**							
12	Rate Revenue (excluding CAP; after billing adj)		$ 1,214,066,043	$ 462,426,897	$ 32,190,585	$ 291,023,250	$ 230,692,602	$ 47,675,638
13								
14								
15	**Proposed Rates and Projected (Estimated) Fuel and Pass-Through Costs**							
16	Rate Revenue (excluding CAP; after billing adj)	Schedule H-5.3	$ 1,166,309,563	$ 451,852,198	$ 31,153,060	$ 268,208,348	$ 225,437,148	$ 42,224,120
17		& WP G-10.2						
18	Base COS with Estimated Pass-Through Costs	Schedule G-9 & G-7	$ 1,167,899,745	$ 458,201,165	$ 30,275,395	$ 238,842,522	$ 227,698,444	$ 44,758,833
19		& WP G-10.2						
20	Under/(Over) Recovery	Line 18 - 16	$ 1,590,182	$ 6,348,967	$ (877,665)	$ (29,365,826)	$ 2,261,296	$ 2,534,713
21								
22	Below/(Above) Cost of Service		0.1%	1.4%	-2.9%	-12.3%	1.0%	5.7%
23	Required Increase/(Decrease) in Revenue Under Proposed Rates		0.1%	1.4%	-2.8%	-10.9%	1.0%	6.0%
24								
25	**Increase/(Reduction)**							
26	Current with Test Year Fuel and Pass-Throughs to Proposed Rates		$ (68,392,045)	$ (22,210,085)	$ (305,222)	$ (15,131,321)	$ (13,054,680)	$ (4,033,595)
27	**Current Base, Fuel and Pass-Through Rates to Proposed Rates**		**$ (47,756,480)**	**$ (10,574,699)**	**$ (1,037,525)**	**$ (22,814,902)**	**$ (5,255,454)**	**$ (5,451,519)**
28	*above includes estimated pass-through cost impacts (e.g., over/under balances applied to pass-through rates)*							

Schedule G-10

Primary Voltage ≥ 3 < 20 MW (G)	Primary Voltage ≥ 20 MW (H)	Transmission Voltage (I)	Transmission Voltage ≥ 20 MW @ 85% aLF (J)	Service Area Street Lighting (K)	City-Owned Private Outdoor Lighting (L)	Customer-Owned Non-Metered Lighting (M)	Customer-Owned Metered Lighting (N)	Total (O)
$ 52,185,478	$ 89,945,727	$ 2,146,390	$ 13,517,421	$ -	$ 2,884,834	$ 108,555	$ 303,428	$ 1,234,701,609
$ 54,188,915	$ 99,923,374	$ 1,777,803	$ 15,969,971	$ -	$ 4,046,523	$ 141,145	$ 381,627	$ 1,217,227,310
$ 2,003,437	$ 9,977,647	$ (368,586)	$ 2,452,550	$ -	$ 1,161,689	$ 32,590	$ 78,199	$ (17,474,299)
3.8%	11.1%	-17.2%	18.1%		40.3%	30.0%	25.8%	-1.4%
$ 45,846,212	$ 86,739,183	$ 2,130,434	$ 12,253,293	$ -	$ 2,705,231	$ 100,589	$ 282,129	$ 1,214,066,043
$ 45,929,568	$ 83,744,440	$ 2,144,754	$ 12,547,007	$ -	$ 2,704,431	$ 98,532	$ 265,958	$ 1,166,309,563
$ 51,797,652	$ 95,011,689	$ 1,697,687	$ 15,106,947	$ -	$ 4,003,510	$ 134,935	$ 370,966	$ 1,167,899,745
$ 5,868,084	$ 11,267,249	$ (447,067)	$ 2,559,940	$ -	$ 1,299,079	$ 36,403	$ 105,008	$ 1,590,182
11.3%	11.9%	-26.3%	16.9%		32.4%	27.0%	28.3%	0.1%
12.8%	13.5%	-20.8%	20.4%		48.0%	36.9%	39.5%	0.1%
$ (6,255,911)	$ (6,201,287)	$ (1,636)	$ (970,414)	$ -	$ (180,403)	$ (10,023)	$ (37,470)	$ (68,392,045)
$ 83,356	**$ (2,994,743)**	**$ 14,321**	**$ 293,713**	**$ -**	**$ (800)**	**$ (2,057)**	**$ (16,171)**	**$ (47,756,480)**

ICA Proposed Distribution of Revenue Decrease

	Total Retail	Residential	S1	S2	S3	P1	P2
Base Revenue	631,878,463	257,323,175	19,088,191	155,631,706	116,217,584	19,269,437	22,527,463
kWh Percent	100%	34%	2%	22%	21%	4%	5%
Rev Decrease	$ (41,076,503)	$ (14,131,615)	$ (852,538)	$ (8,991,392)	$ (8,745,596)	$ (1,780,688)	$ (2,211,103)
	-6.5%	-5.5%	-4.5%	-5.8%	-7.5%	-9.2%	-9.8%

	P3	T1
Base Revenue	33,982,914	1,328,468
kWh Percent	10%	0.2%
Rev Decrease	$ (4,289,024)	$ (74,546)
	-12.6%	-5.6%

Notes:
Assumes $2.08 Mil rev increase for T2 for calculation purposes.
No rate change for lighting classes.

Base Revenue CCOS Results With ICA Recommendation

	Total Retail	Residential	S1	S2	S3	P1	P2	P3
Base Revenue	631,878,463	257,323,175	19,088,191	155,631,706	116,217,584	19,269,437	22,527,463	33,982,914
Cost of Service	$ 592,954,232	$ 249,513,439	$ 18,540,995	$ 118,016,525	$ 111,621,139	$ 18,786,193	$ 23,553,322	$ 42,100,053
Difference	$ (38,924,231)	$ (7,809,736)	$ (547,196)	$ (37,615,180)	$ (4,596,445)	$ (483,245)	$ 1,025,858	$ 8,117,139
Req Incr (Decr)	-6.2%	-3.0%	-2.9%	-24.2%	-4.0%	-2.5%	4.6%	23.9%

	T1	T2	Street L.	Outdoor L.	Cust. L.	Meter L.
Rate Revenue	1,328,468	$ 6,122,357	$ -	$ 3,454,600	$ 74,193	$ 251,849
Cost of Service	$ 919,567	$ 6,122,357	$ -	$ 3,454,600	$ 74,193	$ 251,849
Difference	$ (408,901)	$ 2,152,272	$ -	$ 1,137,907	$ 29,576	$ 73,719
Req Incr (Decr)	-30.8%	54.2%		49.1%	66.3%	41.4%

Filed Rev Requirement With ICA Allocation Changes

INCLUDES FUEL, PASS-THROUGHS

	Total Retail	Residential	S1	S2	S3	P1	P2	P3
Rate Revenue	1,234,701,609	474,062,283	31,458,282	283,339,669	238,491,828	46,257,714	52,185,478	89,945,727
Cost of Service	1,217,227,310	475,622,876	31,259,261	249,588,917	237,774,156	46,552,743	54,188,915	99,923,374
Difference	(17,474,299)	1,560,593	(199,021)	(33,750,752)	(717,673)	295,029	2,003,437	9,977,647
Req Incr (Decr)	-1.4%	0.3%	-0.6%	-11.9%	-0.3%	0.6%	3.8%	11.1%

	T1	T2	Street L.	Outdoor L.	Cust. L.	Meter L.	Total
Rate Revenue	$ 2,146,390	$ 13,517,421	$ -	$ 2,884,834	$ 108,555	$ 303,428	1,234,701,609
Cost of Service	$ 1,777,803	$ 15,969,971	$ -	$ 4,046,523	$ 141,145	$ 381,627	1,217,227,310
Difference	$ (368,586)	$ 2,452,550	$ -	$ 1,161,689	$ 32,590	$ 78,199	(17,474,299)
Req Incr (Decr)	-17.2%	18.1%		40.3%	30.0%	25.8%	-1.4%

Comparison of Uncollectibles Among Utilities

		customers	per customer
EPE Uncollectible	1,923,398	306046	$ 6.28
SPS Uncollectible	2,661,033	251659	$ 10.57
ETI Uncollectible	4,887,120	578693	$ 8.45
AE Uncollectible*	16,054,751	436499	$ 36.78

* test year adjusted

AE Uncollectible at ICA Recommendaion 23.36775

Uncollectible Expense Workpaper

		Uncollectibles	(000's)	Revenues	Rev/Unc. Rate
*	2015	$ 8,463			
	2014	$ 20,863		1,234,701	1.6897%
	2013	$ 17,257		1,183,865	1.4577%
	2012	$ 3,483		1,081,609	0.3220%
	2011	$ 3,546		1,122,609	0.3159%
	2010	$ 4,166		1,030,130	0.4044%
	2009	$ 3,649		1,032,397	0.3534%
	2008	$ 2,093		1,069,822	0.1956%
a.	Avg Rate (08 - 14)				0.6770%
b.	Avg Rate (10 - 14)				0.8379%

		Reduction from Request
AE Requested Revenues	1217227	
a. Uncollectible Cost	8240.279	7814.472316
b. Uncollectible Cost	10199.66	5855.093547

*unaudited

Requested Amount 16054.751

Customer Rev Req		92,284,573
Customer GFT		13,285,402
Percentage GFT		14.4%
A&G Expense		15,850,197
Total Customer Expense		53,822,999
Percentage A&G		29.4%
Customer minus meters, services	$	48,926,951
without GFT	$	42,077,178

ICA Residential Customer Charge Calculation

Meters	$	13,569,411
Customer Accounting	$	24,600,367
Customer Service	$	9,572,309
Meter Reading	$	14,741,815
Uncollectible	$	-
Key Accounts	$	12,461
Services	$	(195,771)
Exclude GFT from Exp.	$	(6,849,773)
Exclude A&G Expense	$	(12,202,382)
Total	$	43,248,437
Residential Bills		4,626,216
	$	9.35

	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total
kWh %	34.4%	2.1%	21.9%	21.3%	4.3%	5.4%	10.4%	0.2%						
Rev Reduction	$ (14,131,615)	$ (852,538)	$ (8,991,392)	$ (8,745,596)	$ (1,780,688)	$ (2,211,103)	$ (4,289,024)	$ (74,546)						$ (41,076,503)
													Check	(41,076,503)
	0.336539897	0.02030291	0.214127132	0.208273577	0.042406519	0.052656714	0.102141738	0.0017753	0.97822378					
	34.4%	2.1%	21.9%	21.3%	4.3%	5.4%	10.4%	0.2%	100.0%					

ICA Decr.	$	(38,924,231)
T2 Incr.	$	2,152,272
Rev Spread	$	(41,076,503)

Non Nuclear Decommissioning ($/kW)

	AE	PUC Approved	Difference	Percent
Decker	38	17	21	55%
FPP	50	39	11	22%
Sand Hill	39	20	19	49%

	Requested Expense	Reduction	Allowed	
Decker	$ 14,000,000	$ 7,736,842	$ 6,263,158	
FPP	$ 3,750,000	$ 825,000	$ 2,925,000	$ 9,188,158
Sand Hill	$ 1,692,308	$ 824,458	$ 867,850	0.31666667
Total	$ 19,442,308	$ 9,386,300	$ 10,056,008	0.48277704

Outside City Discount
000's

Res	5493	94.4%
Sec 10-300	207	3.6%
Sec 300	107	1.8%
Pri 1	5	0.1%
Pri 2	5	0.1%
	5817	100.00%

AELIC 8-1

Development of BIP-R

Replacement Cost of AE Installed Generation

	gas-steam	coal	nuclear	CT	wind	solar	total
Plant Cost ($2014)	$ 1,065,816,000	$ 1,662,690,000	$ 2,146,400,000	$ 301,950,000	$ 52,757	$ 13,192,719	$ 5,190,101,475
	20.5%	32.0%	41.4%	5.8%	0.0%	0.3%	100.0%
MW Capacity	1048	570	400	450			
cost / kW $2014	$ 1,017.00	$ 2,917.00	$ 5,366.00	$ 671.00			
<u>Compare to AE's Version of BIP</u>			**Rev Requirements (hundred thousands)**				
	116.1	160.9	149.7	54.3		6.6	$ 487.60
	23.8%	33.0%	30.7%	11.1%	0.0%	1.4%	100.0%
	$ -						

	BIP-R	AE's Version
Base	73.6%	65.1%
Intermediate	20.5%	23.8%
Peak	5.8%	11.1%
	100.0%	100.0%

Non-CT Gas Units

	Installed Capacity	Ratio	TY Net Plant	Ratio	Cap Factor 2014	Weighted Avg. Cap Factor
Sand Hill	322	31%	$ 126,678	79%	42%	33%
Decker	726	69%	$ 34,301	21%	6%	1.3%
Total	1048		$ 160,979			34%

DEVELOP BIP-R ALLOCATION FACTORS

	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total
12 CP (ERCOT)	41.9%	2.1%	21.6%	18.7%	3.4%	3.6%	7.2%	0.1%	1.2%	0.1%	0.0%	0.0%	0.0%	100.0%
Energy	33.7%	2.0%	21.4%	20.8%	4.2%	5.3%	10.2%	0.2%	1.8%	0.3%	0.1%	0.0%	0.0%	100.0%
4CP (ERCOT)	43.5%	1.9%	21.6%	18.2%	3.7%	3.2%	6.7%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	100.0%
Avg & Peak (12 CP)adj revenue/cost relationship	35.31%	2.04%	21.45%	20.41%	4.07%	4.94%	9.61%	0.15%	1.66%	0.24%	0.08%	0.01%	0.02%	100.0%

Development of Base Intermediate Peak-R

	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total
Weighted Factors	73.6%													
Base	24.79%	1.50%	15.77%	15.34%	3.12%	3.88%	7.52%	0.13%	1.30%	0.21%	0.07%	0.01%	0.02%	73.6%
Weighted Factors	20.5%													
Intermediate														
Weighted Energy	2.35%	0.14%	1.50%	1.45%	0.30%	0.37%	0.71%	0.01%	0.12%	0.02%	0.01%	0.00%	0.00%	7.0%
Weighted Demand	5.68%	0.28%	2.93%	2.54%	0.46%	0.49%	0.97%	0.01%	0.17%	0.01%	0.00%	0.00%	0.00%	13.6%
Weighted 12 CP (Sum)	8.03%	0.42%	4.42%	3.99%	0.75%	0.86%	1.69%	0.02%	0.29%	0.03%	0.01%	0.00%	0.00%	20.54%
Weighted Factors	5.8%													
Peak	2.53%	0.11%	1.26%	1.06%	0.21%	0.19%	0.39%	0.00%	0.07%	0.00%	0.00%	0.00%	0.00%	5.82%
														100.0%
BIP Factors	35.35%	2.03%	21.45%	20.39%	4.09%	4.93%	9.60%	0.15%	1.66%	0.24%	0.08%	0.01%	0.02%	100.0%

Sum of Base Intermediate Peak Allocators

Development of BIP-N

	gas-steam	coal	nuclear	CT	wind	solar	total
Net Plant	$ 162,337,740	$ 243,946,317	$ 379,337,058	$ 129,210,443	$ 52,757	$ 10,471,188	$ 925,355,503
Ratio	17.5%	26.4%	41.0%	14.0%	0.0%	1.1%	100.0%
MW Capacity	1048	570	400	450			
cost / kW	$ 154.90	$ 427.98	$ 948.34	$ 287.13			
		Ratios Based on AE Version of BIP					
Rev Req	116.1	160.9	149.7	54.3		6.6	$ 487.60
Ratio	23.8%	33.0%	30.7%	11.1%	0.0%	1.4%	100.0%

	BIP-N Version	AE Version
Base	68.5%	65.1%
Intermediate	17.5%	23.8%
Peak	14.0%	11.1%
	100.0%	100.0%

Non-CT Gas Units

	Installed Capacity	Ratio	Net Plant	Ratio	Cap Factor 2014	Wtd. Cap Factor
Sand Hill	322	31%	$ 126,678	79%	42%	33%
Decker	726	69%	$ 34,301	21%	6%	1.3%
Total	1048		$ 160,979			34%

BIP-N Allocation Factors

	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total
12 CP (ERCOT)	41.9%	2.1%	21.6%	18.7%	3.4%	3.6%	7.2%	0.1%	1.2%	0.1%	0.0%	0.0%	0.0%	100.0%
Energy	33.7%	2.0%	21.4%	20.8%	4.2%	5.3%	10.2%	0.2%	1.8%	0.3%	0.1%	0.0%	0.0%	100.0%
4CP (ERCOT)	43.5%	1.9%	21.6%	18.2%	3.7%	3.2%	6.7%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	100.0%
Development of Base Intermediate Peak														
Base	68.5%													
Weighted Factors	23.05%	1.39%	14.67%	14.27%	2.90%	3.61%	7.00%	0.12%	1.21%	0.19%	0.07%	0.01%	0.02%	68.5%
Intermediate	17.5%													
Weighted Energy	2.01%	0.12%	1.28%	1.24%	0.25%	0.31%	0.61%	0.01%	0.11%	0.02%	0.01%	0.00%	0.00%	6.0%
Weighted 12 CP	4.86%	0.24%	2.50%	2.17%	0.39%	0.42%	0.83%	0.01%	0.14%	0.01%	0.00%	0.00%	0.00%	11.6%
Total Weighted Fctr	6.86%	0.36%	3.78%	3.41%	0.64%	0.73%	1.44%	0.02%	0.25%	0.03%	0.01%	0.00%	0.00%	17.54%
Peak	14.0%													
Weighted Factors	6.08%	0.26%	3.01%	2.55%	0.51%	0.45%	0.94%	0.00%	0.17%	0.00%	0.00%	0.00%	0.00%	13.96%
BIP Factors	35.99%	2.01%	21.46%	20.22%	4.06%	4.79%	9.38%	0.14%	1.62%	0.22%	0.08%	0.01%	0.02%	100.0%

Adjustment to Avg. & Peak

$ 942	Adv CC cost/kw
$ 632	Adv CT cost/kw
67%	CT/CC Ratio
20.2%	Cost Adjustment
(30.1% X 20.2%)	

25,788,000	ERCOT 12 CP
2,149,000	Monthly Average
13,156,355,000	Annual Energy
1,501,867	Average Demand
69.9%	12 CP load factor
79.8%	adjusted load factor

30.1%	Peak Ratio
20.2%	Peak Ratio As Adjusted

	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total	
Develop Substation & Transformer Allocator															
Summer Net Energy	37.88%	1.82%	20.83%	19.33%	4.51%	4.59%	8.95%	0.17%	1.60%	0.20%	0.09%	0.01%	0.02%		80.18%
Sec. Summer KwH	47.245%	2.274%	25.976%	24.113%						0.247%	0.107%	0.014%	0.023%	100.000%	
Pri Summer KwH	38.563%	1.856%	21.203%	19.682%	4.591%	4.675%	9.111%			0.202%	0.088%	0.011%	0.019%	100.000%	98.23%
Pri 12 NCP	42.46%	2.18%	21.40%	18.69%	3.41%	3.98%	7.13%	0.00%	0.00%	0.44%	0.17%	0.02%	0.13%		
67/33 Primary	41.17%	2.07%	21.34%	19.02%	3.80%	4.21%	7.79%	0.00%	0.00%	0.36%	0.14%	0.02%	0.09%	100.000%	
Net Plant:															
Station Equipment	130913	(Primary Allocator is 67% 12 NCP and 33% Summer Energy based on ratio of Station Equip. to Total Primary)													
Total Primary	401934														0.996665
Ratio	32.6%														
Develop Meter Allocator															
Wtd. Meters	77.732%	12.906%	7.981%	0.615%	0.207%	0.038%	0.006%	0.377%	0.126%	0.000%	0.000%	0.000%	0.012%	100.000%	
Production Demand	35.351%	2.027%	21.449%	20.393%	4.090%	4.927%	9.601%	0.150%	1.659%	0.239%	0.083%	0.012%	0.020%		
Prod dem, excl. lighting	35.469%	2.034%	21.520%	20.461%	4.104%	4.943%	9.633%	0.151%	1.664%				0.020%	100.000%	
60/40 allocation	60.827%	8.557%	13.397%	8.553%	1.766%	2.000%	3.857%	0.287%	0.741%	0.000%	0.000%	0.000%	0.015%	100.000%	
(Meter Allocator is 60% Wtd. Meters and 40% Production Demand without lighting)															0.136332
															0.863668
Develop Customer Service Allocator															
Rev Requirement	39.864%	2.690%	19.948%	18.847%	3.698%	4.292%	7.938%	0.143%	1.268%	0.951%	0.320%	0.011%	0.031%	100.000%	
Customers	88.320%	6.463%	3.997%	0.263%	0.023%	0.004%	0.001%	0.001%	0.000%	0.002%	0.911%	0.000%	0.014%	100.000%	
50/50 Allocation	64.092%	4.576%	11.972%	9.555%	1.861%	2.148%	3.969%	0.072%	0.634%	0.476%	0.616%	0.006%	0.022%	100.000%	
Key Account Assign.	0.43%	8.11%	13.24%	50.56%	5.12%	14.52%	4.44%	1.79%	1.79%	0.00%	0.00%	0.00%	0.00%	100.000%	
Customer Serv. Alloc.	55.18%	5.07%	12.15%	15.30%	2.32%	3.88%	4.04%	0.31%	0.80%	0.41%	0.53%	0.00%	0.02%	100.000%	

Miscellaneous Calculations

Meters: Determine Meter Reading Component

Smart Meter Cases				
Total Benefits Mil. NPV	307.9	286.9	296.6	
Meter Reading Benefit	154.3	102.9	128.6	Avg.%
	50%	36%	43%	43%

Installed Manual Meter	48	20.2%
Installed AMI Meter	190	79.8%
total	238	100.0%
source: ICA 3-8		

Smart Meter Incremental Cost
80%
Benefits Other Than Meter Reading Avoidance
40%

Center Point Economic Development Comparison		
jCenterPoint 2010 Economic Development Expense	$	2,418,560
CenterPoint Base+TCRF Revenues	$	1,446,504,000
Percent of Revenues		0.1672%
Austin Energy Economic Development	$	9,090,429
Total Electric Revenues	$	1,180,456,000
Percent of Revenues		0.7701%
H-5.3 and H 5.4		

6

Capacitor Application

Capacitors provide tremendous benefits to distribution system performance. Most noticeably, capacitors reduce losses, free up capacity, and reduce voltage drop:

- *Losses; Capacity* — By canceling the reactive power to motors and other loads with low power factor, capacitors decrease the line current. Reduced current frees up capacity; the same circuit can serve more load. Reduced current also significantly lowers the I^2R line losses.
- *Voltage drop* — Capacitors provide a voltage boost, which cancels part of the drop caused by system loads. Switched capacitors can regulate voltage on a circuit.

If applied properly and controlled, capacitors can significantly improve the performance of distribution circuits. But if not properly applied or controlled, the reactive power from capacitor banks can create losses and high voltages. The greatest danger of overvoltages occurs under light load. Good planning helps ensure that capacitors are sited properly. More sophisticated controllers (like two-way radios with monitoring) reduce the risk of improperly controlling capacitors, compared to simple controllers (like a time clock).

Capacitors work their magic by storing energy. Capacitors are simple devices: two metal plates sandwiched around an insulating dielectric. When charged to a given voltage, opposing charges fill the plates on either side of the dielectric. The strong attraction of the charges across the very short distance separating them makes a tank of energy. Capacitors oppose changes in voltage; it takes time to fill up the plates with charge, and once charged, it takes time to discharge the voltage.

On ac power systems, capacitors do not store their energy very long — just one-half cycle. Each half cycle, a capacitor charges up and then discharges its stored energy back into the system. The net real power transfer is zero. Capacitors provide power just when reactive loads need it. Just when a motor with low power factor needs power from the system, the capacitor is there to provide it. Then in the next half cycle, the motor releases its excess energy, and the capacitor is there to absorb it. Capacitors and reactive loads of ferroresonance concerns. Most three-phase banks are connected grounded-wye on four-wire multigrounded circuits. Some are connected in floating wye. On three-wire circuits, banks are normally connected as a floating wye.

Most utilities also include arresters and fuses on capacitor installations. Arresters protect capacitor banks from lightning-overvoltages. Fuses isolate failed capacitor units from the system and clear the fault before the capacitor fails violently. In high fault-current areas, utilities may use current-limiting fuses. Switched capacitor units normally have oil or vacuum switches in addition to a controller. Depending on the type of control, the installation may include a control power transformer for power and voltage sensing and possibly a current sensor. Because a capacitor bank has a number of components, capacitors normally are not applied on poles with other equipment.

Properly applied capacitors return their investment very quickly. Capacitors save significant amounts of money in reduced losses. In some cases, reduced loadings and extra capacity can also delay building more distribution infrastructure.

6.1 Capacitor Ratings

Capacitor units rated from 50 to over 500 kvar are available; Table 6.2 shows common capacitor unit ratings. A capacitor's rated kvar is the kvar at rated voltage. Three-phase capacitor banks are normally referred to by the total kvar on all three phases. Distribution feeder banks normally have one or two or (more rarely) three units per phase. Many common size banks only have one capacitor unit per phase.

IEEE Std. 18 defines standards for capacitors and provides application guidelines. Capacitors should not be applied when any of the following limits are exceeded (IEEE Std. 18-2002):

- 135% of nameplate kvar
- 110% of rated rms voltage, and crest voltage not exceeding $1.2\sqrt{2}$ of rated rms voltage, including harmonics but excluding transients
- 135% of nominal rms current based on rated kvar and rated voltage

Capacitor dielectrics must withstand high voltage stresses during normal operation — on the order of 2000 V/mil. Capacitors are designed to withstand overvoltages for short periods of time. IEEE Std. 18-1992 allows up to 300 power-frequency overvoltages within the time durations in Table 6.3 (without transients or harmonic content). New capacitors are tested with at least a 10-sec overvoltage, either a dc-test voltage of 4.3 times rated rms or an ac voltage of twice the rated rms voltage (IEEE Std. 18-2002).

U.S. Energy Information Administration

Annual Energy Outlook 2015

Release Date: April 14, 2015 | **Next Release Date:** June 2016 | correction | full report

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015

Release date: June 3, 2015

This paper presents average values of levelized costs for generating technologies that are brought online in 2020[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2015* (AEO2015) Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while LCOE is a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.

A related factor is the ***capacity value***, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of LCOE across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments. The avoided cost is divided by average annual output of the project to develop the "levelized" avoided cost of electricity (LACE) for the project.[4] The LACE value may then be compared with the LCOE value for the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology and represents the potential revenue available to the project owner from the sale of energy and generating capacity. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on ***portfolio diversification.*** While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations.

The LCOE values shown for each utility-scale generation technology in Table 1 and Table 2 in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.1%[5]. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2015 reference case, 3 percentage points are added to the cost of capital when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning.[6] The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Although the capital and operating components do not incorporate the production or investment tax credits available to some technologies, a subsidy column is included in Table 1 to reflect the estimated value of these tax credits, where available, in 2020. In the reference case, tax credits are assumed to expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. As noted above, the LCOE (and also subsequent LACE) calculations presented in the tables apply only to the utility-scale use of those technologies.

In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. Projected capacity factors for these resources in the AEO 2015 or other EIA analyses will not necessarily correspond to these levels.

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2020

U.S. average levelized costs (2013 $/MWh) for plants entering service in 2020[1]

Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system LCOE	Subsidy[2]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.4	4.2	29.4	1.2	95.1		
Advanced Coal	85	76.9	6.9	30.7	1.2	115.7		
Advanced Coal with CCS	85	97.3	9.8	36.1	1.2	144.4		
Natural Gas-fired								
ConventionalCombined Cycle	87	14.4	1.7	57.8	1.2	75.2		
Advanced Combined Cycle	87	15.9	2.0	53.6	1.2	72.6		
Advanced CC with CCS	87	30.1	4.2	64.7	1.2	100.2		
Conventional Combustion Turbine	30	40.7	2.8	94.6	3.5	141.5		
Advanced Combustion Turbine	30	27.8	2.7	79.6	3.5	113.5		
Advanced Nuclear	90	70.1	11.8	12.2	1.1	95.2		
Geothermal	92	34.1	12.3	0.0	1.4	47.8	-3.4	44.4
Biomass	83	47.1	14.5	37.6	1.2	100.5		
Non-Dispatchable Technologies								
Wind	36	57.7	12.8	0.0	3.1	73.6		
Wind – Offshore	38	168.6	22.5	0.0	5.8	196.9		
Solar PV[3]	25	109.8	11.4	0.0	4.1	125.3	-11.0	114.3
Solar Thermal	20	191.6	42.1	0.0	6.0	239.7	-19.2	220.6
Hydroelectric[4]	54	70.7	3.9	7.0	2.0	83.5		

[1]*Costs for the advanced nuclear technology reflect an online date of 2022.*

[2]*The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2020, which include a permanent 10% investment tax credit for geothermal and solar technologies. EIA models tax credit expiration as follows: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $23.0/MWh ($11.0/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013. Up to 6 GW of new nuclear plants are eligible to receive an $18/MWh production tax credit if in service by 2020; nuclear plants shown in this table have an in-service date of 2022.*

[3]*Costs are expressed in terms of net AC power available to the grid for the installed capacity.*

[4]*As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.*

Source: U.S. Energy Information Administration, Annual Energy Outlook 2015, April 2015, DOE/EIA-0383(2015).

As mentioned above, the LCOE values shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, LCOE for incremental wind capacity coming online in 2020 ranges from $65.6/MWh in the region with the best available resources in 2020 to $81.6/MWh in regions where LCOE values are highest due to lower quality wind resources and/or higher capital costs for the best sites that can accommodate additional wind capacity. Costs shown for wind may include

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2014 (2013 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2014[4] (2013 $/kW)	Variable O&M[5] (2013 $/mWh)	Fixed O&M (2013 $/kW/yr.)	Heatrate[6] in 2014 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh
Scrubbed Coal New	2018	1300	4	2,726	1.07	1.00	2,917	4.47	31.16	8,800	8,740
Coal-Gasification Integrated Comb Cycle (IGCC)	2018	1200	4	3,483	1.07	1.00	3,727	7.22	51.37	8,700	7,450
IGCC with Carbon sequestion	2018	520	4	5,891	1.07	1.03	6,492	8.44	72.80	10,700	8,307
Conv Gas/Oil Comb Cycle	2017	620	3	869	1.05	1.00	912	3.60	13.16	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2017	400	3	942	1.08	1.00	1,017	3.27	15.36	6,430	6,333
Adv CC with Carbon sequestration	2017	340	3	1,845	1.08	1.04	2,072	6.78	31.77	7,525	7,493
Conv Comb Turbine[8]	2016	85	2	922	1.05	1.00	968	15.44	7.34	10,783	10,450
Adv Comb Turbine	2016	210	2	639	1.05	1.00	671	10.37	7.04	9,750	8,550
Fuel Cells	2017	10	3	6,042	1.05	1.10	6,978	42.97	0.00	9,500	6,960
Adv Nuclear	2022	2234	6	4,646	1.10	1.05	5,366	2.14	93.23	10,479	10,479
Distributed Generation-Base	2017	2	3	1,407	1.05	1.00	1,477	7.75	17.44	9,015	8,900
Distributed Generation - Peak	2016	1	2	1,689	1.05	1.00	1,774	7.75	17.44	10,015	9,880
Biomass	2018	50	4	3,399	1.07	1.01	3,659	5.26	105.58	13,500	13,500
Geothermal[7,9]	2018	50	4	2,331	1.05	1.00	2,448	0.00	112.85	9,516	9,516
Municipal Solid Waste Conventional	2017	50	3	7,730	1.07	1.00	8,271	8.74	392.60	14,878	18,000
Hydropower[9]	2018	500	4	2,410	1.10	1.00	2,651	5.76	15.15	9,516	9,516
Wind	2017	100	3	1,850	1.07	1.00	1,980	0.00	39.53	9,516	9,516
Wind Offshore	2018	400	4	4,476	1.10	1.25	6,154	0.00	73.96	9,516	9,516
Solar Thermal[7]	2017	100	3	3,787	1.07	1.00	4,052	0.00	67.23	9,516	9,516
Photovoltaic[7,10]	2016	150	2	3,123	1.05	1.00	3,279	0.00	24.68	9,516	9,516

[1]Online year represents the first year that a new unit could be completed, given an order date of 2014.

[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

[3]The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2014.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, solar and geothermal technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2013. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2016 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the AEO2015 cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, updated by external consultants for AEO2013. This report can be found at http://www.eia.gov/forecasts/capitalcost/. The costs were assumed to be consistent with plants that would be ordered in 2012, and learning from capacity built in 2012 and 2013 has been applied in the initial costs above. Wind capital costs were updated for AEO2015 using recent reports from trade press and reports from Lawrence Berkeley National Laboratory. Site-specific costs for geothermal were provided by the National Renewable Energy Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

Capacity Utilization Responsibility: An Alternative to Peak Responsibility

By MICHAEL S. PROCTOR

The intent of this article is to demonstrate that capacity utilization is a proper measure for determining production capacity responsibility, and that under certain assumptions, this results in allocating production capacity costs by the average and peak method.

THE purpose of this article is to show the logical fallacy involved in the argument for the use of peak responsibility as the basis for allocating the embedded cost of production plants used to generate electricity. The crux of the argument for peak responsibility is that since peak demand determines the capacity required for production plant, the cost of that plant should be allocated to customers based on their share of peak demand. The principle is one of cost causality; i.e., whatever factor(s) cause cost, those same factors should be used as the basis for allocating cost. On this principle there is no disagreement. However, there is disagreement on whether peak demand is the only causal factor for the entire production plant.

In the process of showing the fallacy involved in peak responsibility, a natural outcome is the development of a causation principle that is theoretically correct. This causation principle is called *capacity utilization responsibility.*

As one might imagine, the load data requirements for an allocation method that is correct for all possible load situations could be overly restrictive. Thus, an approximation to the correct method is developed for the case where the load can be characterized by the typical load data available: class kilowatt-hour consumption and class contribution to peak. This allocation method is called the *average and peak.*

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The Record on Peak Responsibility

As early as 1921, H. E. Eisenmenger[1] recognized that peak responsibility is not the correct measure for allocating production costs to customers. In the summary to Eisenmenger's argument against peak responsibility, he states:[2] "We see that the consumer's demand cost is an intricate function of the entire load curve of the central station and of the entire load curve of the respective consumer, not only of certain parts of those curves."

In 1956, R. E. Caywood[3] recognized potential problems that exist in the use of peak responsibility. In discussing the peak responsibility method, Caywood states:[4]

> It is obvious that this method is not entirely satisfactory because a class load at the time of the system peak might be zero, while at some other time it might be of considerable size; yet no expense would be allocated to it. Furthermore, an allocation made on the basis of today's load conditions might be widely differ-

[1] "*Central Station Rates in Theory and Practice*," by H. E. Eisenmenger, Fredrick J. Drake and Company, Chicago, Illinois, 1921, pp. 277-299.
[2] Ibid., p. 295.
[3] "*Electric Utility Rate Economics*," by R. E. Caywood, McGraw-Hill, New York, 1956, pp. 156-167.
[4] Ibid., pp. 156, 157.

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ent in the future as the result of a shift of the system peak or a shift of the peak of the load of the class itself.

In 1963, C. W. Bary[5] recognized that peak responsibility is a naive approach to allocating capacity costs. In discussing the distribution of load diversity benefits, Bary states:[6]

> The one which is farthest from meeting the requirements of the general unified theory is the so-called system peak responsibility method, which reflects the demand-cost assignment to individual components on the basis of their loads at the *time* of the system peak load. This method reflects little conceptual perception of the nature and the mutual benefits of load diversity, nor the complex laws of probability governing its behavior.

In 1970, Alfred E. Kahn[7] published his two volumes on the economics of utility regulation. While Kahn seems to support the concept of peak responsibility, it is important to keep in mind Kahn's own qualifications placed on the principle:[8]

> The principle is clear, but it is more complicated than might appear at first reading. Notice, first, the qualification: "if the same type of capacity serves all users." In fact it does not always; in consequence, as we shall see, off-peak users may properly be charged explicitly for some capacity costs. Second, the principle applies to the explicit charging of capacity costs, "as such." Off-peak users, properly paying *short-run* marginal costs [SRMC] will be making a contribution to the covering of capital costs also, if and when SRMC exceeds average variable costs. Third, the principle is framed on the assumption that all rates will be set at marginal cost [MC] (including marginal capacity costs). Under conditions of decreasing costs, uniform marginal cost pricing will not cover total costs. Lacking a government subsidy to make up the difference, privately owned utilities have to charge more than MC on some of their business. In some of these "second-best" circumstances, some (of the difference between average and marginal) capacity costs might better be recovered from off-peak than from peak users.

While the arguments against peak responsibility are well documented in the literature, this method has gained wide acceptance as an appropriate procedure for allocating embedded production plant costs to jurisdictions and customer classes. Perhaps one reason for the acceptance of peak responsibility is that both the National Association of Regulatory Utility Commissioners[9] and the American Public Power Association[10] cost allocation manuals give qualified recognition to the concept of peak responsibility. It should be noted that peak responsibility involves not only the single peak method, but also any method that uses coincident peaks; e.g., summer-winter peaks, summer month peaks, winter month peaks, and 12 coincident month peaks. Also, probabilistic methods, such as loss-of-load probability, that are based on building plant to meet peak-load distributions (load plus plant outages), should be classified as peak responsibility methods.

A second reason for general acceptance of peak responsibility is its ease of application. One generally only needs to look at demands for one to twelve hours and determine the share of demand in those few hours going to each class or jurisdiction.

A third reason for the acceptance of peak responsibility is that it seems to have a strong theoretical foundation in the peak-load pricing literature in economics. The noneconomist reads peak-load pricing in the context that all capacity costs go to the peak period, and as the quote from Kahn indicates, this is a basic misconception.

A final reason for the acceptance of peak responsibility is its intuitive appeal; i.e., peak causes capacity, therefore capacity costs should be allocated on a peak responsibility basis. It is this intuitive appeal that will be challenged in this article.

Capacity Utilization Responsibility

A basic assumption in the peak responsibility approach is that the production plant is assumed to be characterized by one type of production plant; i.e., no distinction is made between peak, intermediate, and base-load plants. In the case of a single type of plant, the total annual production capacity cost can be determined by the level of peak demand, and no matter what the load shape happens to be, if the peak demand level stays the same, the total production capacity costs also stay the same. It is this observed relationship that has led supporters of the peak responsibility allocation method to claim that peak demand causes production capacity costs.

If production capacity costs are viewed as being fixed over the year, then those fixed costs have been caused by the peak demand. However, the view that production capacity costs are fixed costs within a year, and can only vary from one year to the next places a restriction on one's view of causality. Even if there is only one type of production capacity, why should one's view of that capacity be limited to a single unit whose size is fixed by the level of peak demand? Why should not the decision as to the variable cost of production capacity be viewed as a decision made on small increments of capacity over small periods of time?

[5] "*Operational Economics of Electric Utilities*," by C. W. Bary, Columbia University Press, New York, 1963, pp. 56-64.

[6] Ibid., p. 58.

[7] "*The Economics of Regulation*," by Alfred E. Kahn, John Wiley and Sons, New York, 1970, pp. 87-122.

[8] Ibid., pp. 89, 90.

[9] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, Washington, D. C., 1973, pp. 40-53.

[10] "*Cost of Service Procedures for Public Power Systems*, American Public Power Association, Washington, D. C., 1979, pp. X1-X4.

The purpose for determining the causality of production capacity costs is ultimately to determine the cost responsibility of the customers that use the production plant. While it is true that at only the time of peak is the fixed plant fully utilized, it is not true that this is the only time that the production plant provides services to the customers. A proper view of cost causality should recognize that during the peak period a greater amount of production capacity is required than at other times, but the fact that peak demand is higher should *only reflect the additional production capacity costs incurred because of the higher demand level.* Within this context production capacity is seen to be a variable cost of production in each and every hour.

A simple example can be used to illustrate the concept of treating production capacity as variable in each hour and calculating capacity responsibility based on the utilization (use) of production capacity. Consider a simplified load curve for two hours. In the first hour total demand is 50 megawatts, and in the second hour total demand is 100 megawatts. In this case 50 megawatts of production capacity is needed to meet demand in the first hour and an *additional* 50 megawatts of production capacity is needed to meet demand in the second hour. In terms of utilization of production capacity, the first and second hour share equal responsibility for the initial 50 megawatts of production capacity, while the second hour carries the full responsibility for the additional 50 megawatts. Thus the total *capacity responsibility* of each hour is given by

Hour One: $(\frac{1}{2})(50) = 25$ megawatts
Hour Two: $(\frac{1}{2})(50) + (50) = 75$ megawatts

Notice that this capacity utilization responsibility is not the same as the energy responsibility of 50 megawatt-hours for the first hour and 100 megawatt-hours for the second hour. Nor is the capacity utilization responsibility the same as would be determined by peak responsibility which would place zero megawatts on the first hour and 100 megawatts on the second hour. Moreover, using energy responsibility will understate the production capacity caused by the peak hour, while using peak responsibility will overstate the production capacity caused by the peak hour. Table 1 summarizes the results of applying these three different methods of calculating responsibility for capacity.

TABLE 1
HOURLY RESPONSIBILITIES

	Energy Responsibility	Capacity Utilization Responsibility	Peak Responsibility
Hour One	$\frac{1}{3}$	$\frac{1}{4}$	0
Hour Two	$\frac{2}{3}$	$\frac{3}{4}$	1

The final piece of information needed is the share of demand for each customer class in each hour. Suppose there are just two customers: A and B, with demands in each hour as given in Table 2.

TABLE 2
CUSTOMER LOADS

Customer	Megawatts Hour One	Share	Megawatts Hour Two	Share	Megawatt-Hours Total	Share
A	25	$\frac{1}{2}$	75	$\frac{3}{4}$	100	$\frac{2}{3}$
B	25	$\frac{1}{2}$	25	$\frac{1}{4}$	50	$\frac{1}{3}$
System	50	1	100	1	150	1

Customer A's share of hour one's demand is one-half, and hour one's share of capacity utilization responsibility is one-quarter, giving customer A a capacity utilization responsibility for hour one equal to $(\frac{1}{2})(\frac{1}{4}) = \frac{1}{8}$. Customer A's share of hour two's demand is three-quarters, and hour two's share of capacity utilization responsibility is three-quarters, giving customer A a capacity utilization responsibility for hour two equal to $(\frac{3}{4})(\frac{3}{4}) = \frac{9}{16}$. Adding customer's A's capacity utilization responsibility for both hours gives $\frac{1}{8} + \frac{9}{16} = \frac{11}{16}$. A similar calculation for customer B gives a capacity utilization responsibility of five-sixteenths.

Table 3 summarizes the capacity responsibility going to each customer using energy, capacity utilization, and peak as the basis for calculating these responsibilities.

TABLE 3
CUSTOMER RESPONSIBILITIES

Class	Energy Responsibility	Capacity Utilization Responsibility	Peak Responsibility
A	$\frac{2}{3}$	$\frac{11}{16}$	$\frac{3}{4}$
B	$\frac{1}{3}$	$\frac{5}{16}$	$\frac{1}{4}$

Notice that energy responsibility allocates too little capacity to A and too much to B, and peak responsibility allocates too much capacity to A and too little to B. Also notice that A's load factor (average energy divided by demand at peak) is below the system average, and B's load factor is above the system average. Moreover, this observation can be generalized to the principle that peak responsibility will always result in allocating too much capacity to customers (classes or jurisdictions) whose load factors are below the system average, and too little capacity to customers (classes or jurisdictions) whose load factors are above the system average. Of course, energy responsibility has the opposite result.

The Average and Peak Allocation Of Production Capacity Costs

The observations from the previous section lead to the following question: If a certain percentage of capacity is allocated based on energy responsibility and the remainder based on peak responsibility, how can that percentage be chosen so that the resulting allocations are the same as those derived using the capacity utilization method? The answer is to use the system load factor to determine the percentage of capacity to be allocated by energy responsibility. This is called the *average and peak* method and is given by the following formula:

$$\left(\begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Energy}\\\text{Responsibility}\end{matrix}\right) + \left(1 - \begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Peak}\\\text{Responsibility}\end{matrix}\right)$$

The system load factor is the ratio of average demand to peak demand. For this example it is given by:

$$\begin{aligned}\text{Average Demand} &= (150 \div 2) = 75 \text{ Mw}\\ \text{Peak Demand} &= 100 \text{ Mw}\\ \text{Load Factor} &= (75 \div 100) = 3/4\end{aligned}$$

The average and peak allocation factor for each customer is given by:

$$\begin{aligned}\text{Customer A:}\ & (3/4)(2/3) + (1/4)(3/4) = 11/16\\ \text{Customer B:}\ & (3/4)(1/3) + (1/4)(1/4) = 5/16\end{aligned}$$

While the average and peak method has only been shown to produce the same answer as the capacity utilization method for the example of this section, it can also be shown to hold for any case in which demand is characterized by two levels, that is a peak and off-peak (base) level, and the result is independent of the number of hours associated with each period; c.f., the appendix to this article.

Before arriving at any conclusions about applying the average and peak method, keep in mind two very important assumptions. First, production capacity is characterized by one type of production plant. Second, demand is characterized by two levels. Much work has and is being done to develop allocation methods that will allow these two assumptions to be relaxed. These methods are called *time-of-use* cost allocations of embedded production costs.[11] Time-of-use allocations require substantially more load data (essentially they require hourly load profiles for all classes of service). When this type of load information is not available, then the average and peak method provides a viable alternative for reflecting the capacity utilization responsibility approach to the causation of production capacity.

[11] *Time of Use Cost Allocation and Marginal Cost*, by M. S. Proctor, Missouri Public Service Commission, November, 1979.

Appendix

Average and Peak Capacity Allocation

In this appendix two basic assumptions are made. First, demand is served from a single type plant with constant capacity and running cost. Second, demand is characterized by two periods: peak demand; and base (off-peak) demand. The following definitions are used.

D_p = megawatt demand at peak
D_b = megawatt demand at base
a_p = fraction of time applied to peak demand
a_b = fraction of time applied to base demand

where $a_p + a_b = 1$; i.e., the fraction of time for base and peak demand adds up to the total amount of time serving load.

These fractions can be used to calculate both average demand (energy) and capacity utilization. The following table gives these calculations.

Period	*Average Demand*	*Capacity Utilization*
Base	$a_b D_b$	$a_b D_b$
Peak	$a D_p$	$a_p D_b + (D_p - D_b$
Total	$a_b D_b + a_p D_p$	D_p

Average demand during the base and peak periods is simply the demands of those periods times the fraction of time applied to each. The capacity utilization in the base period is simply that period's fraction of time of use of the capacity required to meet base-load demand ($a_b D_b$). The capacity utilization for the peak period is that period's fraction of time of use of the capacity required to meet base-load demand ($a_p D_b$) plus the difference between base and peak demand ($D_p - D_b$), which represents that portion of total capacity used exclusively during the peak period. When these two are added together, the total capacity utilization is given by $(a_b + a_p)D_b + D_p - D_b = D_b + D_p - D_b = D_p$.

The system load factor is the ratio of the average demand to peak demand, and is given by

$$\text{System Load Factor} = (a_b D_b + a_p D_p) \div D_p$$

Since $D_b < D_p$, it follows that $a_b D_b + a_p D_p < a_b D_p + a_p D_p = (a_b + a_p) D_p = D_p$. Thus, the system load factor is less than one. It also follows that

$$\frac{a_b D_b}{a_b D_b + a_p D_p} > \frac{a_b D_b}{D_p}$$

Thus the average demand contribution to the base period is greater than the capacity utilization contribution to the base period, and subsequently the average demand contribution to the peak period is less than the capacity utilization contribution to the peak period.

Given these basic concepts, the objective in this appendix is to show that *the average and peak method for capac-*

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ity allocation to customer classes is equivalent to the capacity utilization method no matter where the levels for α_b and α_p may occur. The following definitions are used for the customer class demand responsibilities:

β_{jp} = class j's contribution (fraction) of demand in the peak period.

β_{jb} = class j's contribution (fraction) of demand in the base period.

The table below (in frame) specifies the average demand (energy), capacity utilization and peak responsibility to demand for the j[th] class.

The average and peak method simply assumes that class contribution to energy and class contribution to peak is known. Then the system load factor is used to define the following allocation factor:

$$\left(\begin{matrix}\text{Load}\\ \text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Class Contribution}\\ \text{to Energy}\end{matrix}\right) + \left(1 - \begin{matrix}\text{Load}\\ \text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Class Contribution}\\ \text{to Peak}\end{matrix}\right)$$

Substituting into this definition the appropriate terms gives the following results:

1) (Load Factor) (Class Contribution to Energy):

$$\left(\frac{\alpha_b D_b + \alpha_p D_p}{D_p}\right)\left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}\right) = \left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p}\right)$$

2) (1 − Load Factor) (Class Contribution to Peak):

$$\left(\frac{D_p - \alpha_b D_b - \alpha_p D_p}{D_p}\right)\left(\beta_{jp}\right) = \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

3) Average and Peak (1 + 2):

$$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p} + \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

$$= \frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$$

But this gives exactly the same result as the capacity utilization method for determining class responsibility for capacity. Moreover, no matter how the peak and base periods are chosen, one needs only to determine class contribution to energy, class contribution to peak, and the system load factor in order to calculate the capacity utilization responsibility for each class of load. At the same time it is important to keep in mind the basic assumptions being made; i.e., demand is served from a single type plant and demand can properly be characterized by a peak and base load.

Method	*Base*	*Peak*	*Class Contribution*
Energy	$\beta_{jb}(\alpha_b D_b)$	$\beta_{jp}(\alpha_p D_p)$	$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}$
Capacity Utilization	$\beta_{jb}\,(\alpha_b D_b)$	$\beta_{jp}\,(D_p - \alpha_b D_b)$*	$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$
Peak	$\beta_{jb}(0)$	$\beta_{jp}\,(D_p)$	β_{jp}

*Notice that $\alpha_b D_b = (1 - \alpha_p) D_b$, so that the capacity utilization contribution to peak can be rewritten as $\alpha_p D_b + (D_p - D_b) = D_p - (1 - \alpha_p) D_b = D_p - \alpha_b D_b$.

West Valley Project Gets Extra Money

An additional $5 million of federal funding has been targeted for the West Valley demonstration project. The extra money, plus some creative managing of the design and construction of the nuclear waste solidification project at the site, could result in the conversion of the radioactive liquid there to a durable solid two years sooner than had been originally planned. Dr. William H. Hannum, project director for the U. S. Department of Energy, said recently that the additional money is being transferred to this project from another DOE activity. "The extra funding indicates the importance the Department places on the timely solidification of the liquid wastes stored here." Hannum said that about sixty engineers and nuclear technicians will be added to the project staff in the next several months.

As the first U. S. nuclear waste solidification program of its kind, the West Valley demonstration project will convert almost 600,000 gallons of highly radioactive liquid waste into a durable solid which will be transported to a federal repository for disposal. The project began in February, 1982, when DOE assumed control of the former nuclear fuel reprocessing site. The liquid waste stored there was a by-product of reprocessing from 1966 to 1972. As the prime contractor to the DOE, West Valley Nuclear Services Company, a subsidiary of Westinghouse Electric Corporation, will design, build, and operate the solidification equipment.

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant
Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

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EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
	Maintenance		
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x
	Hydraulic Power Generation Operation		
535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-
	Maintenance		
541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH),

The Connecticut Light and Power Company
Docket No. 14-05-06

Data Request OCC-07

Dated: 07/03/2014
Q-OCC-292
Page 1 of 1

Witness: **Kenneth B. Bowes**
Request from: **Office of Consumer Counsel**

Question:
What is CL&P's estimate of the percentage increase in cost of transformers arising from the recently adopted federal Department Of Energy, energy efficiency standards applied to utility transformers?

Response:
The percentage increase in cost of transformers arising from the recently adopted federal Department of Energy energy efficiency standards is approximately 24%.

GCCC Response to TIEC's 1st RFI Question No. 6 Docket No. 38339

TIEC 1-6 Please provide all workpapers used to calculation showing "18% of line transformer costs are energy-related" (at p. 30).

Response

Mr. Johnson used the following data to establish the percentage incremental capital costs associated with energy efficiency: Finley Workpaper - Capital Cost Increase for Distribution Transformers due to DOE Efficiency Requirement.xls. The efficiency-related cost increase percentage is lower for three phase transfornlers. Based upon the Company workpapers for primary transformer split and transformer allocation, Mr. Johnson determined that three phase transformers comprise approximately 70/0 to 9% of total transformer costs. See attached workpapers. Based on a weighted average calculation using Mr. Finley's workpaper cited above, this produces an energy-related percentage of 17.9% - 18.20/0. The 17.9% calculation is shown on page 104 of Mr. Johnson's testimony. The attachment to this answer includes the 18.20/0 calculation. Both calculations rounded to 18%.

Prepared by: Clarence Johnson

Sponsored by: Clarence Johnson

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Attachment to

TIEC 1-6

$20,609,363 Total 1 phase increase

Percentage of 3 PH Transformers 7.0% $17,282,817

Total Base 1 phase 1.19248

Remaining Transfomers 93.0%

Average Increase, Overhead+Padmt. 19.25%

Weighted Average 3 Phase Increase 0.3% Remainder 17.9% Weighted Average 18.2%

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

Data Requirements: This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

A Digression on System Planning with Reference to Plant Cost Allocation:

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Classification of Generation:

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17
CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average

Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.

A. Customer Account Expenses (Accounts 901 - 905)

These accounts are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts, which may be directly assigned to customer classes. Some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility, and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.

B. Customer Service and Informational Expenses (Accounts 906 - 910)

These accounts include the costs of encouraging safe and efficient use of the lity's service. Except for conservation and load management, these costs are classified customer-related. Emphasis is placed upon the costs of responding to customer uiries and preparing billing inserts.

Conservation and load management costs should be separately analyzed. These programs should be classified according to program goals. For example, a load management program for cycling air conditioning load is designed to save generation during peak hours. This program could be classified as generation-related and allocated on the basis of peak demand. The goal of other conservation programs may be to save electricity on an annual basis. These costs could be classified as generation-related and allocated on the basis of energy-usage allocation. However, if conservation costs are received through cost recovery similar to a fuel-cost recovery clause, allocating the costs between demand and energy may be too cumbersome. In such cases, the costs could be received through an energy clause. A demand-saving load management program actually saves marginal fuel costs, and therefore energy.

C. Sales Expenses (Accounts 911 - 917)

These accounts include the costs of exhibitions, displays, and advertising designed to promote utility service. These costs could be classified as customer-related, since the goal of demonstrations and advertising is to influence customers. Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot properly be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available, or allocated based upon the overall revenue responsibility of each class.

Request for Information 1-2 from Austin Energy: Please provide all case studies used within the testimony.

Answer: See ICA Response to AE 1-1. Also provided are the attached documents, which were reviewed by the ICA team while preparing the ICA party presentation.

RESIDENTIAL DEMAND CHARGES: A CONSUMER PERSPECTIVE

Note: This presentation does not reflect the views of any current or future client.

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DEMAND CHARGES

- What are we talking about here? Generally, a move to require residential customers to pay more in fixed charges and less in variable kWh charges
- Demand Rates: charge a fee that varies each month based on the customer's highest actual demand (kW)
- Increased monthly charge: charge a fixed fee that shifts some distribution costs into monthly customer charge

CURRENT TRENDS: USING LESS AND PAYING MORE

- Efficiency Programs
- Smart Meter Mandates
- Renewable Energy Mandates
- Distributed Generation and Solar PV Mandates: Net Metering Subsidy Shifted to other ratepayers
- Enhanced Storm Resiliency and Distribution Infrastructure Investments
- Transmission Costs: Federal and State
- In some states, costs of low income discount or bill assistance programs

STATES WITH PRICES THAT ARE HIGHEST ARE ALSO THOSE WITH MANDATES

- California: IOU average is 20 cents per kWh for 500 kWh usage
- Massachusetts: 16 cents per kWh
- New York: Highest prices and rates in continental U.S.

California

Electric bills differ

A survey of electricity providers, comparing October 2014 bills at different usage levels, found that the private companies charge more than municipal utilities.

	2,000 kWh	1,000 kWh	500 kWh	200 kWh
Edison	$542.99	$255.06	$97.34	$30.63
PG&E	598.05	263.86	93.11	31.50
SDG&E	723.11	311.71	116.42	34.84
Private average	**621.38**	**276.88**	**102.29**	**32.32**
Los Angeles	$344.92	$167.56	$78.88	$29.87
Sacramento	311.33	136.03	58.30	30.52
Anaheim	379.86	182.31	83.54	29.14
Burbank	347.67	162.66	75.87	29.25
Glendale	340.86	160.70	74.01	32.94
Pasadena	396.12	195.99	88.04	33.78
Riverside	363.57	171.55	81.23	39.86
Azusa	339.71	167.67	81.65	31.68
Banning	508.63	212.42	99.80	37.81
Colton	450.79	188.01	72.71	19.58
Imperial Irrigation Dist.	250.34	127.02	65.36	28.37
Vernon	179.17	91.10	47.07	20.65
Public average	**351.08**	**163.59**	**75.54**	**30.29**

Sources: Survey by Southern California Public Power Authority, San Diego Union-Tribune

Los Angeles Times

MASSACHUSETTS

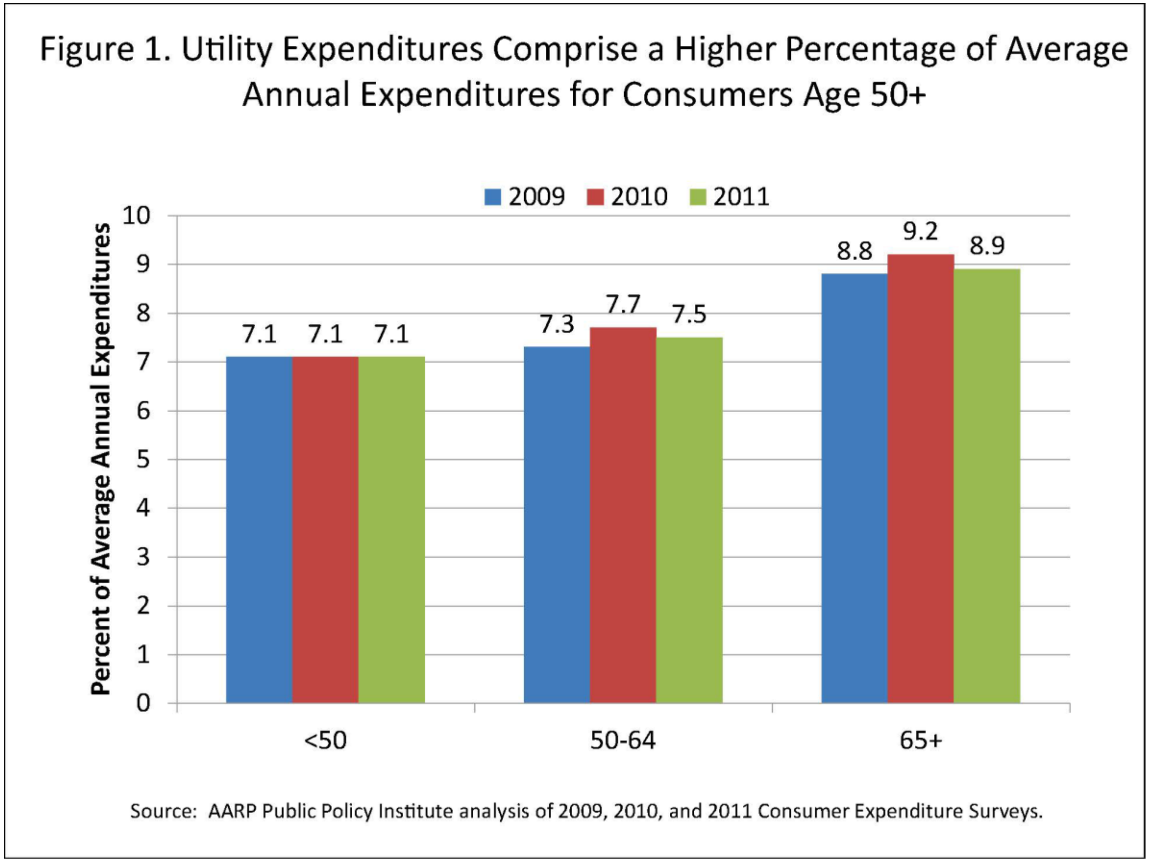
Customer Charge $4.00/month Distribution Charge *
First 600 kWh: 3.981¢/kWh
Excess of 600 kWh: 4.643¢/kWh

Transmission Charge 2.614¢/kWh Transition Charge (0.164¢)/kWh Energy Efficiency Charge 1.624¢/kWh Renewables Charge 0.050¢/kWh

* Includes: Basic Service Adjustment Factor (0.084¢), Residential Assistance Adjustment Factor 0.391¢, Storm Fund Replenishment Adjustment Factor 0.266¢, Pension/PBOP Adjustment Factor 0.244¢, Revenue Decoupling Mechanism Factor 0.179¢, Net CapEx Factor 0.223¢, Attorney General Consultant Expenses Factor 0.001¢, Solar Cost Adjustment Factor 0.007¢ and Smart Grid Distribution Adjustment Factor 0.027¢.

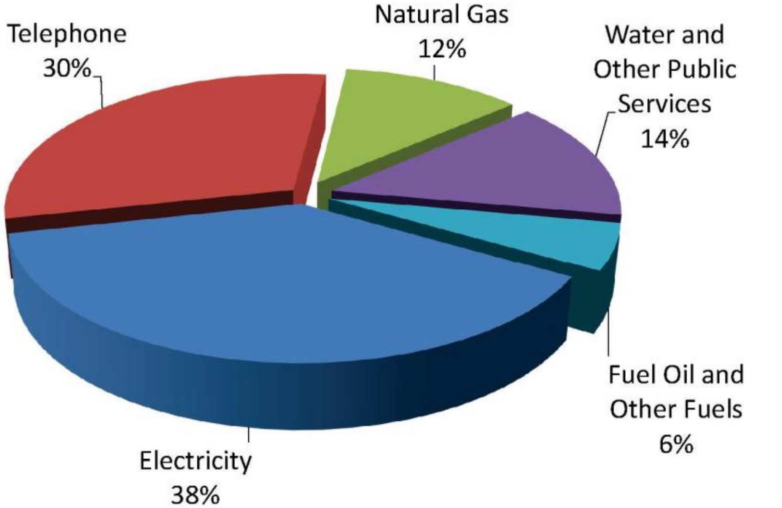
Basic Supply Charge in June 2015: 8.076 cents/kWh

Energy Expenditures: Age 50+



ELECTRICITY IS LARGEST EXPENDITURE

Figure 2. Expenditures on Electricity Comprise the largest Portion of Utility Expenditures for 50+ Consumers



Source: AARP Public Policy Institute analysis of 2011 Consumer Expenditure Survey.

CURRENT TRENDS: RATE DESIGN IS A ZERO SUM GAME

- Whatever the level of rate charges, the entire rate design must recover the test year revenue requirement for each class. For every dollar that is recovered via fixed or demand charges, a dollar less needs to be recovered from the energy charge. The converse is also true.
- Utilities are protected with “bill stabilization,” “decoupling,” and “lost sales revenue” mechanisms OR THEY WILL FILE A RATE CASE

RETAIL COMPETITION MARKETS: 20 STATES

- Supposedly, the wholesale market sets generation supply prices and local utilities are not "in the game."
- Hah! Everyone of these states have adopted mandates for efficiency, renewable generation supply, solar PV, distributed generation and the costs are imposed on distribution system ratepayers

WHO ARE THE LOSERS?

- Whose bill will increase with demand charges or fixed monthly charges? Who pays for mandates and subsidies for efficiency and solar programs?
  - Low use customers
  - Low income and fixed income customers
  - Renters/multi-unit residents

WHO ARE THE WINNERS?

- Who are those who are likely to benefit from demand rates and higher fixed monthly charges?
  - Upper income: investments in home improvements, new technologies and appliances; income or credit rating to purchase solar
  - Better education: understand complex rate designs and bills; time and energy to learn and respond
  - Single Family Homeowner

RESIDENTIAL DEMAND CHARGES

- Is this being promoted to ensure that solar PV customers pay their fair share?
  - Consider alternative rates for solar PV customers and customers with electric vehicles

RESIDENTIAL DEMAND CHARGES

- Is this being promoted to respond to the utility “death spiral” and loss of sales revenues?
  - Where are the efficiencies and performance standards?
  - Proliferation of unregulated affiliates and mergers and acquisitions to benefit shareholders
  - The “death spiral” is highly overrated in actual fact.

SENDING THE "PROPER PRICE SIGNAL"

- First, you have to understand the "signal" being sent.
- Second, you have to have the means to respond.
- When the bill is "unbundled" and the rate tiers proliferate and the surcharges are listed, what is the "signal" and who can understand it?
- Utilities emphasize the total bill and require payment to avoid disconnection

CAN YOU UNDERSTAND THIS PRICE SIGNAL?

pepco

A PHI Company

DISTRICT OF COLUMBIA
RESIDENTIAL SERVICE
SCHEDULE R
UPDATED MARCH 6, 2015

	Billing Months of June – October 2014 (Summer)	Billing Months of November 2014 – May 2015 (Winter)	Billing Months of June – October 2015 (Summer)	Billing Months of November 2015 – May 2016 (Winter)
Generation [1]				
Minimum charge *	$ 2.28 per month	$ 2.25 per month	$ 2.38 per month	$ 2.41 per month
In excess of 30 kwh	$ 0.07207 per kwh	$ 0.07104 per kwh	$ 0.07589 per kwh	$ 0.07692 per kwh
Admin Charge **	$ 0.00400 per kwh	$ 0.00400 per kwh	$ 0.00350 per kwh	$ 0.00350 per kwh

Procurement Cost Adjustment http://www.pepco.com/my-home/choices-and-rates/district-of-columbia/tariffs/ **for monthly rate**

	Billing Months of June – October (Summer)	Billing Months of November – May (Winter)
Transmission [2]		
Minimum charge ***	$ 0.12 per month	$ 0.12 per month
In excess of 30 kwh	$ 0.00704 per kwh	$ 0.00704 per kwh
Distribution [3]		
Customer Charge Residential	$ 13.00 per month	$ 13.00 per month
Customer Charge Master Metered Apartments	$ 10.25 per month	$ 10.25 per month
First 400 kwh	$ 0.00759 per kwh	$ 0.00759 per kwh
In excess of 400 kwh	$ 0.02166 per kwh	$ 0.01512 per kwh
Delivery Tax [4]	$ 0.0070 per kwh	$ 0.0070 per kwh
Public Space Occupancy Surcharge [5]	$ 0.00205 per kwh	$ 0.00205 per kwh
Administrative Credit	http://www.pepco.com/my-home/choices-and-rates/district-of-columbia/tariffs/ **for monthly rate**	
Sustainable Energy Trust Fund [6]	$ 0.00150 per kwh	$ 0.00150 per kwh
Energy Assistance Trust Fund [7]	$ 0.0000607 per kwh	$ 0.0000607 per kwh
RADS Surcharge[8]	$ 0.000294 per kwh	$ 0.000294 per kwh
Bill Stabilization Adjustment[9]	http://www.pepco.com/my-home/choices-and-rates/district-of-columbia/tariffs/ **for monthly rate**	
Underground Project Charge[10]	$ 0.00 per kwh	$ 0.00 per kwh

* The minimum charge includes the first 30 kWh or fraction thereof of consumption. The minimum charge for the period June 2014 through May 2015 includes an administrative charge of $0.12 per month. The minimum charge for the period June 2015 through May 2016 includes an administrative charge of $0.105 per month. This charge is derived by multiplying the administrative charge in effect by the 30 kWh, the quantity assumed in the minimum charge. The administrative charge is $0.0040 per kWh from June 2014 through May 2015, and $0.00350 per kWh from June 2015 through May 2016.

** The 'Admin Charge' was previously included in the generation rate. This is not a new charge.

*** The Minimum charge includes the first 30 kWh or fraction thereof of consumption.

1 Rates are effective with Usage on and after the period as referenced above
2 Effective Usage on and after December 1, 2014
3 Effective Usage on and after April 16, 2014
4 Effective January 1, 2005
5 Effective March 1, 2014
6 Effective October 1, 2010
7 Effective Billing Month of October 2010
8 Effective Service on and after March 1, 2014
9 Effective January 1, 2010
10 Effective Usage on and after January 1, 2015

CUSTOMER UNDERSTANDING: Georgia Power Optional Residential Demand Rate

- **There are two ways to manage your bill on the Residential Demand Rate:**
- Avoid simultaneous use of major appliances. If you can avoid running appliances at the same time, then your peak demand would be lower. This translates to less demand on Georgia Power Company, and savings for you! Each month the demand resets after your meter is read.
- Shift energy usage away from the On-Peak time periods (2 PM – 7 PM, Monday – Friday, June-September, excluding holidays).
  Here are four ways to shift usage:
  - Use a programmable thermostat to increase the temperature in your home to 78-80 degrees during summer weekdays
  - Use a timer on your water heater
  - Avoid using major appliances such as washers, dryers and dishwashers during the peak time period
  - Use a timer on your pool pump so that it automatically shuts off
- **Who could benefit from the Residential Demand Rate?**
- Customers who pay attention to WHAT appliances are running and WHEN the appliances are running
- Customers who have a programmable thermostat and have timers on other appliances

COMED IN ILLINOIS:MANDATORY DEMAND CHARGES

- ComEd in Illinois has promoted legislation to move all residential customers to demand charges and has linked this proposal with new investments in Distributed Energy Resources.
- The result: ComEd's revenues guaranteed by fixed charges.
- ComEd operated a 8,000 opt out dynamic pricing pilot in 2012 that recorded no statistically valid peak load reductions or usage reductions!
- ComEd gets its mandates through legislation and without any reliance on evidentiary hearings that document costs and benefits.

DO YOU REALLY BELIEVE MOST CUSTOMERS CARE ABOUT HOURLY PRICES AND “DEMAND” FACTORS FOR THEIR APPLIANCES?

- Customers will be engaged if the options are understandable, easy to implement, automated where possible, result in measurable bill savings, and presented by a trusted advisor;
- Most Likely Success with Peak Time Rebates and Direct Load Control (“set it and forget it”)
- The market for solar PV is possible only with taxpayer and ratepayer subsidies that are not sustainable in their current form in the long run

AFFORDABLE ESSENTIAL ELECTRIC SERVICE

- Affordability is a key criterion
- One size does not fit all: What may work in Arizona in terms of generation prices, housing, climate, and customer base may not be reasonable in New York or Massachusetts
- Rate design based on average costs is not a sin!
- Consider changes from the customer’s perspective: moderation in mandates and rate design changes

RATE DESIGN PRINCIPLES

- Who are the winners and losers? Bill impacts are key to develop and consider by regulators
- Consider short term costs and long term estimated predictions; risk analysis is crucial to identify and consider since we know from experience that regulators and policy wonks do not predict the future accurately
- Can you explain it to customers without technical jargon or economic theory?
- Is it fair to lower use, low income, fixed income and multi-unit customers?
- Are you predicting generation supply cost reductions? Or other predicted benefits in performance or affordability? Who assumes the risk of achieving these benefits?

RATE DESIGN POLICIES

- Default rate design for residential customers should be flat rate
- Customer charges should reflect costs of customer specific charges and not common distribution charges
- Demand charge rates are highly unlikely to be reasonable or appropriate for vast majority of residential customers
- Offering rate options may be reasonable but should be approved only where benefits to all customers exceed the costs
- Solar PV customers should pay their fair share of distribution services and costs

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Caught in a Fix

The Problem with Fixed Charges for Electricity

Prepared for Consumers Union

February 9, 2016

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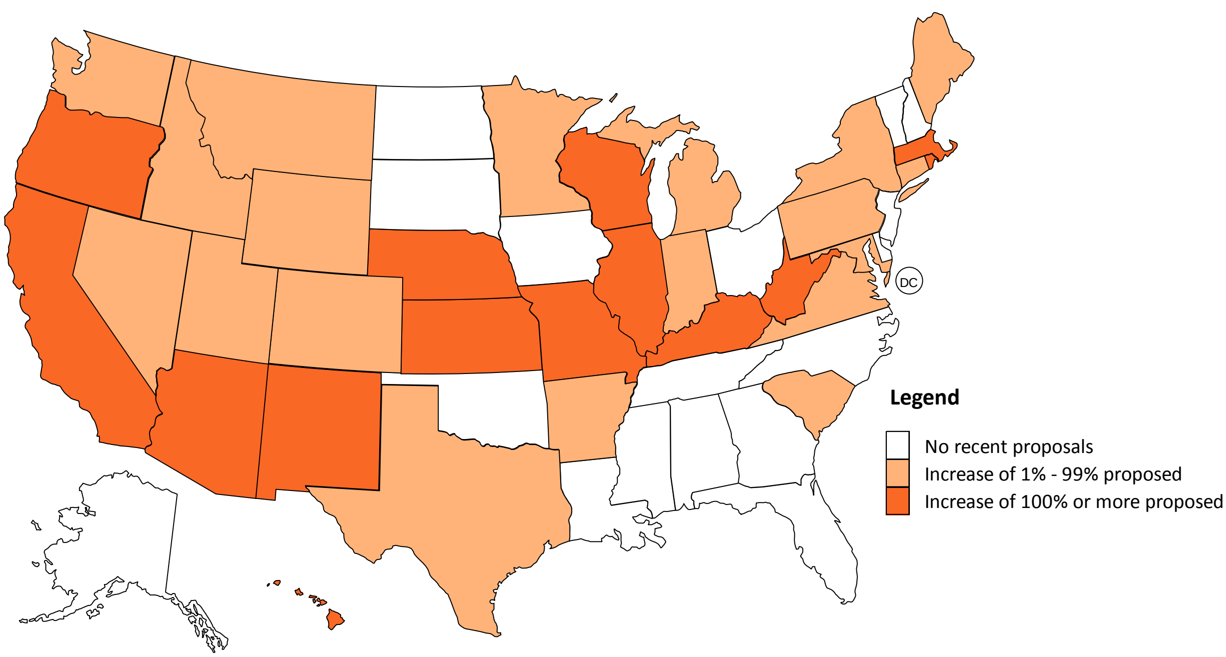
CONTENTS

EXECUTIVE SUMMARY

Recently, there has been a sharp increase in the number of utilities proposing to recover more of their costs through mandatory monthly fixed charges rather than through rates based on usage. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales (from energy efficiency, distributed generation, weather, or economic downturns) will reduce its revenues.

However, higher fixed charges are an inequitable and inefficient means to address utility revenue concerns. This report provides an overview of (a) how increased fixed charges can harm customers, (b) the common arguments that are used to support increased fixed charges, (c) recent commission decisions on fixed charges, and (d) alternative approaches, including maintaining the status quo when there is no serious threat to utility revenues.

Figure ES 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Fixed Charges Harm Customers

Reduced Customer Control. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charges reduce the ability of customers to lower their bills by consuming less energy.

Low-Usage Customers Hit Hardest. Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised. There are many reasons a customer might have low energy usage: they may be very conscientious to avoid wasting energy; they may simply be located in apartments or dense housing units that require less energy; they may have small families or live alone; or they may have energy-efficient appliances or solar panels.

Disproportionate Impacts on Low-Income Customers. Data from the Energy Information Administration show that in nearly every state, low-income customers consume less electricity than other residential customers, on average. Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, fixed charges raise bills most for those who can least afford the increase.

Reduced Incentives for Energy Efficiency and Distributed Generation. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to invest in energy efficiency or distributed generation. Customers who have already invested in energy efficiency or distributed generation will be harmed by the reduced value of their investments.

Increased Electricity System Costs. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer. With little incentive to save, customers may actually increase their energy consumption and states will have to spend more to achieve the same levels of energy efficiency savings and distributed generation. Where electricity demand rises, utilities will need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

Common Myths Supporting Fixed Charges

“Most utility costs are fixed.” In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the long-term planning horizon. Over this timeframe, most costs are variable, and customer decisions regarding their electricity consumption can influence the need to invest in power plants, transmission lines, and other utility infrastructure. This longer-term perspective is what is relevant for economically efficient price signals, and should be used to inform rate setting.

“Fixed costs are unavoidable.” Rates are designed so that the utility can recover past expenditures (sunk costs) in the future. Utilities correctly argue that these sunk costs have already been made and are unavoidable. However, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be based on forward-going costs to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

“The fixed charge should recover distribution costs.” Much of the distribution system is sized to meet customer maximum demand – the maximum power consumed at any one time. For customer classes without a demand charge (such as residential customers),[1] utilities have argued that these distribution costs should be recovered through the fixed charge. This would allocate the costs of the distribution system equally among residential customers, instead of according to how much energy a customer uses. However, customers do not place equal demands on the system – customers who use more energy also tend to have higher demands. While energy usage (kWh) is not a perfect proxy for demand (kW), collecting demand-related costs through the energy charge is far superior to collecting demand-related costs through the fixed charge.

"Cost-of-service studies should dictate rate design." Cost-of-service studies are used to allocate a utility's costs among the various customer classes. These studies can serve as useful guideposts or benchmarks when setting rates, but the results of these studies should not be directly translated into rates. Embedded cost-of-service studies allocate *historical* costs to different classes of customers. However, to provide efficient price signals, prices should be designed to reflect *future* marginal costs. Rate designs other than fixed charges may yield the same revenue for the utility while also accomplishing other policy objectives, such as sending efficient price signals.

"Low-usage customers are not paying their fair share." This argument is usually untrue. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Further, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed charges are necessary to mitigate cost-shifting caused by distributed generation." Concerns about potential cost-shifting from distributed generation resources, such as rooftop solar, are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. This power is often provided to the system during periods when demand is highest and energy is most valuable, such as hot summer afternoons when the sun is out in full force. The energy from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will significantly reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

Recent Commission Decisions on Fixed Charges

Commissions in many states have recently rejected utility proposals to increase mandatory fixed charges. These proposals have been rejected on several grounds, including that increased fixed charges

[1] There are several reasons that demand charges are rarely assessed for residential customers. These reasons include the fact that demand charges introduce complexity into rates that may be inappropriate for residential customers; residential customers often lack the ability to monitor and respond to demand charges; and that residential customers often do not have more expensive meters capable of measuring customer demand.

will reduce customer control, send inefficient prices signals, reduce customer incentives to invest in energy efficiency, and have inequitable impacts on low-usage and low-income customers.

Several states have allowed utilities to increase fixed charges, but typically to a much smaller degree than has been requested by utilities. In addition, there have been many recent rate case settlements in which the utility proposal to increase fixed charges has been rejected by the settling parties. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason.

Alternatives to Fixed Charges

For most utilities, there is no need for increased fixed charges. Regulators who decide there is a need to address utility revenue sufficiency and volatility concerns should consider alternatives to increased fixed charges, such as minimum bills and time-of-use rates.

1. INTRODUCTION

In 2014, Connecticut Light & Power filed a proposal to increase residential electricity customers' fixed monthly charge by 59 percent — from $16.00 to $25.50 per month — leaving customers angry and shocked. The fixed charge is a mandatory fee that customers must pay each month, regardless of how much electricity they use.

The utility's fixed charge proposal met with stiff opposition, particularly from seniors and customers on limited incomes who were trying hard to save money by reducing their electricity usage. Since the fixed charge is unavoidable, raising it would reduce the ability of customers to manage their bills and would result in low-usage customers experiencing the greatest percentage increase in their bills. In a letter imploring the state commission to reject the proposal, a retired couple wrote: "We have done everything we can to lower our usage… We can do no more. My wife and I resorted to sleeping in the living room during the month of January to save on electricity."[2]

Customers were particularly opposed to the loss of control that would accompany such an increase in the mandatory fixed charge, writing: "If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."[3]

Unfortunately, customers in Connecticut are not alone. Recently, there has been a sharp uptick in the number of utilities that are proposing to recover more of their costs through monthly fixed charges rather than through variable rates (which are based on usage). Some of these proposals represent a slow, gradual move toward higher fixed charges, while other proposals (such as Madison Gas & Electric's) would quickly lead to a dramatic increase in fixed charges of nearly $70 per month.[4]

> *"If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."*

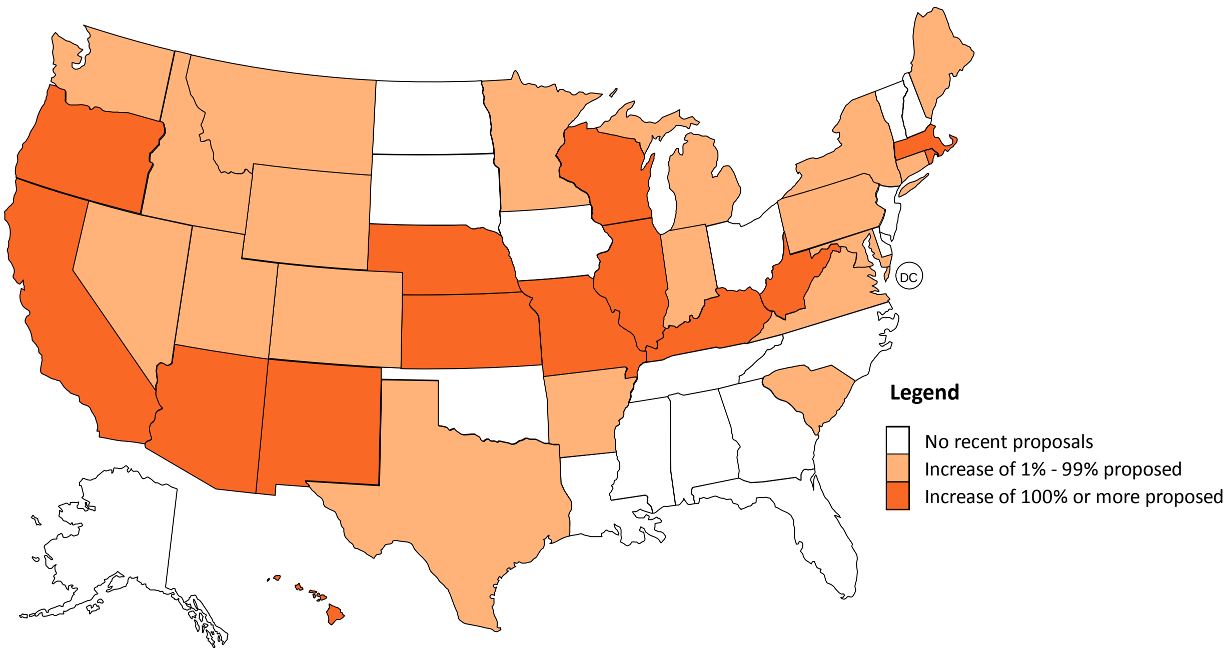
The map below shows the prevalence of recent utility proposals to increase the fixed charge, as well as the relative magnitude of these proposals. Proposals to increase the fixed charge were put forth or decided in 32 states in 2014 and 2015. In 14 of these states, the utility's proposal would increase the fixed charge by more than 100 percent.

[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[3] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

[4] Madison Gas & Electric's proposal for 2015/2016 offered a preview of its 2017 proposal, which featured a fixed charge of $68.37. Data from Ex.-MGE-James-1 in Docket No. 3270-UR-120.

Figure 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Although a fixed charge may be accompanied by a commensurate reduction in the energy charge, higher fixed charges have a detrimental impact on efficiency and equity. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales resulting from energy efficiency, distributed generation, weather, or economic downturns will reduce its revenues. However, higher fixed charges are not an equitable solution to this problem. Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

As the frequency of proposals to increase fixed charges rises, so too does awareness of their detrimental impacts. Fortunately, customers in Connecticut may soon obtain some relief: On June 30, 2015, the governor signed into law a bill that directs the utility commission to adjust utilities' residential fixed charges to only recover the costs "directly related to metering, billing, service connections and the

Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

provision of customer service."[5] However, not all policymakers are yet aware of the impacts of fixed charges or what alternatives might exist. The purpose of this report is to shed light on these issues.

Chapter 2 of this report examines the trends and drivers behind fixed charges, while Chapter 3 provides an assessment of how fixed charges impact customers. In Chapter 4, we explore many of the common technical arguments used to support these charges, and explain the flaws in these approaches. Finally, in Chapter 5, we provide an overview of some of the alternatives to fixed charges and the advantages and disadvantages of these alternatives.

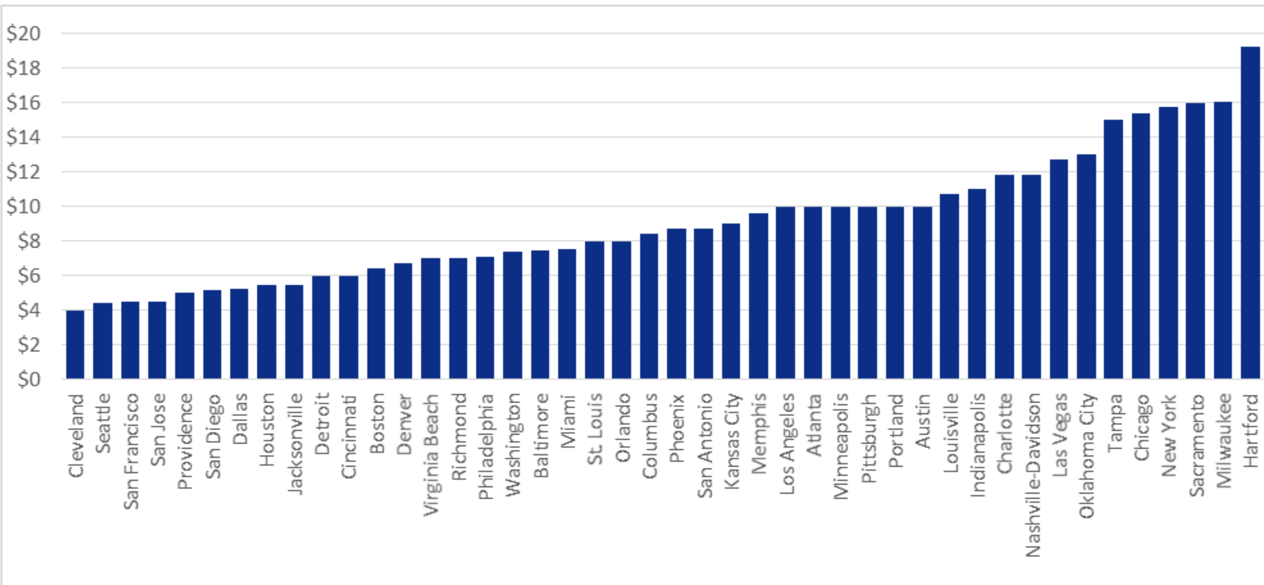
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

2. TROUBLING TRENDS TOWARD HIGHER FIXED CHARGES

What's Happening to Electric Rates?

Sometimes referred to as a "customer charge" or "service charge," the fixed charge is a flat fee on a customer's monthly bill that is typically designed to recover the portion of costs that do not vary with usage. These costs may include, for examples, costs of meters, service lines, meter reading, and customer billing.[6] In most major U.S. cities, the fixed charge ranges from $5 per month to $10 per month, as shown in the chart below.[7]

Figure 2. Fixed charges in major U.S. cities



Source: Utility tariff sheets for residential service as of August 19, 2015.

Although fixed charges have historically been a small part of customers' bills, more and more utilities across the country—from Hawaii to Maine—are seeking to increase the portion of the bill that is paid through a flat, monthly fixed charge, while decreasing the portion that varies according to usage.

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[6] Frederick Weston, "Charging for Distribution Utility Services: Issues in Rate Design," Prepared for the National Association of Regulatory Utility Commissioners (Montpelier, VT: Regulatory Assistance Project, December 2000).

[7] Based on utility tariff sheets for residential service as of August 2015.

Connecticut Light & Power's proposed increase in the fixed charge to $25.50 per month was significantly higher than average,[8] but hardly unique.

Other recent examples include:

- The Hawaiian Electric Companies' proposal to increase the customer charge from $9.00 to $55.00 per month (an increase of $552 per year) for full-service residential customers, and $71.00 per month for new distributed generation customers (an increase of $744 per year);[9]
- Kansas City Power and Light's proposal to increase residential customer charges 178 percent in Missouri, from $9.00 to $25.00 per month (an increase of $192 per year);[10] and
- Pennsylvania Power and Light's March 2015 proposal to increase the residential customer charge from approximately $14.00 to approximately $20.00 per month (an increase of more than $70 per year).[11]

Figure 3 below displays those fixed charge proposals that are currently pending, while Figure 4 displays the proposals that have been ruled upon in 2014-2015.

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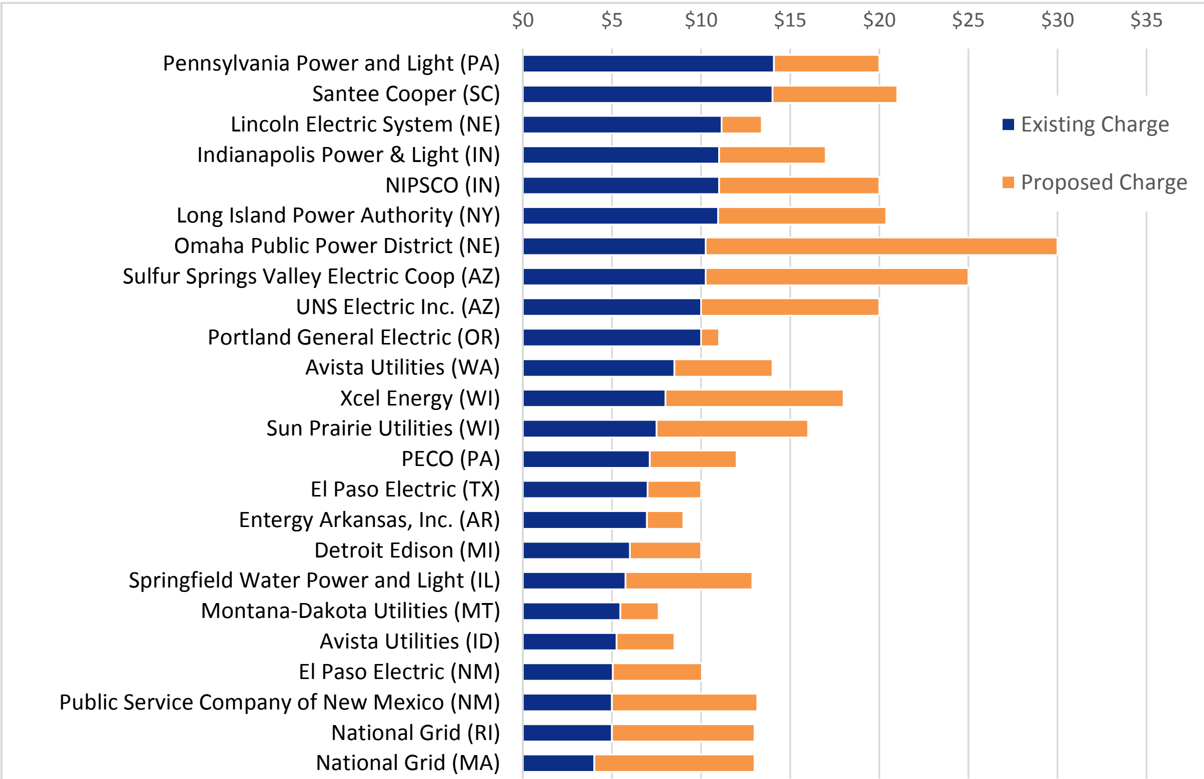
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[9] Hawaiian Electric Companies' Distributed Generation Interconnection Plan, Docket 2011-0206, submitted August 26, 2014, at http://files.hawaii.gov/puc/3_Dkt 2011-0206 2014-08-26 HECO PSIP Report.pdf.

[10] Kansas City Power and Light, Case No.: ER-2014-0370.

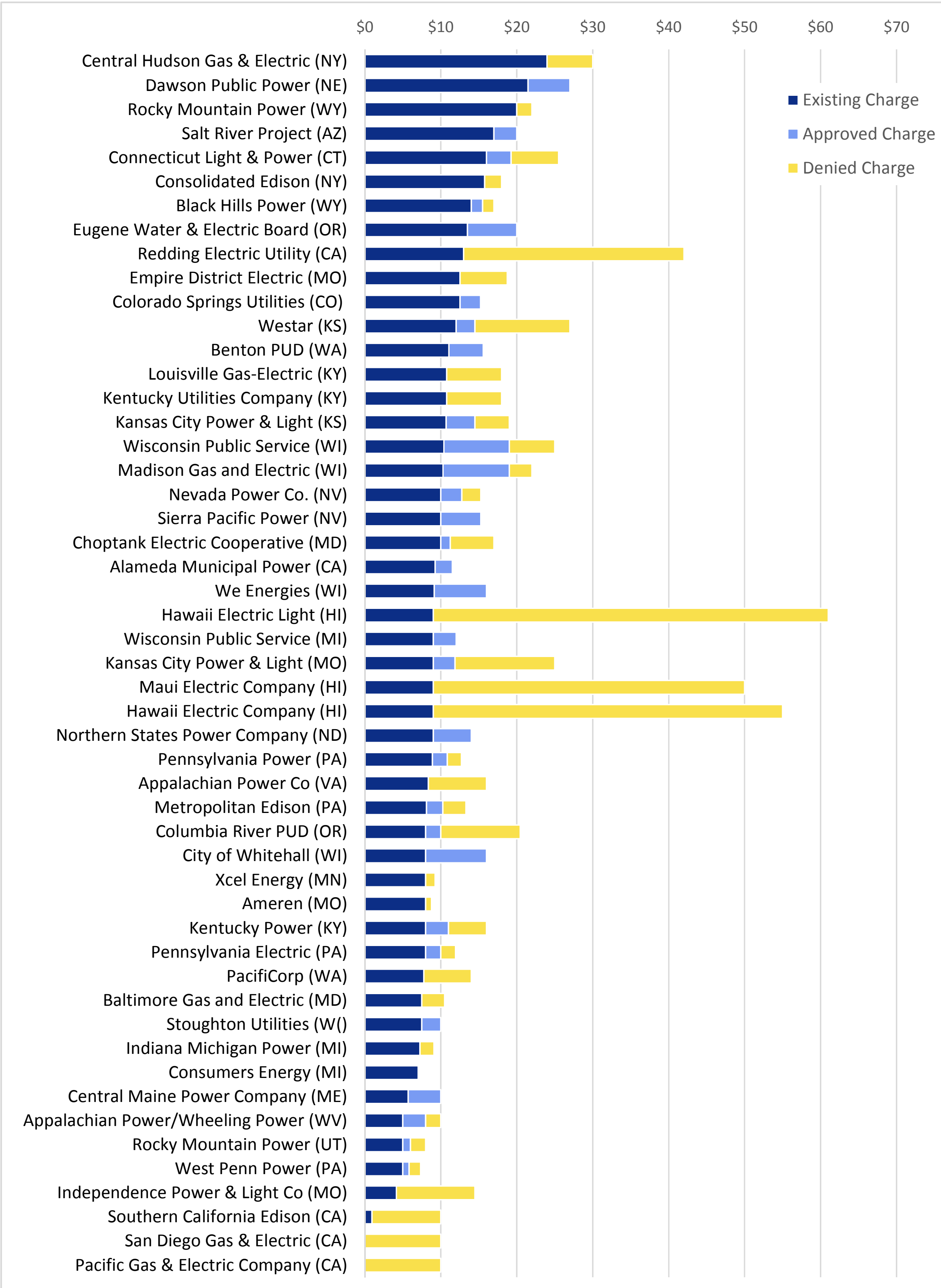
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



Source: See Appendix B

Figure 4. Recent decisions regarding fixed charge proposals



Notes: "Denied" includes settlements that did not increase the fixed charge. Source: See Appendix B

What is Behind the Trend Toward Higher Fixed Charges?

It is important to note that the question of whether to increase the fixed charge is a rate design decision. Rate design is not about how *much* total revenue a utility can collect; rather, rate design decisions determine *how* the utility can collect a set amount of revenue from customers. That is, once the amount of revenues that a utility can collect is determined by a commission, rate design determines the method for collecting that amount. However, if electricity sales deviate from the predicted level, a utility may actually collect more or less revenue than was intended.

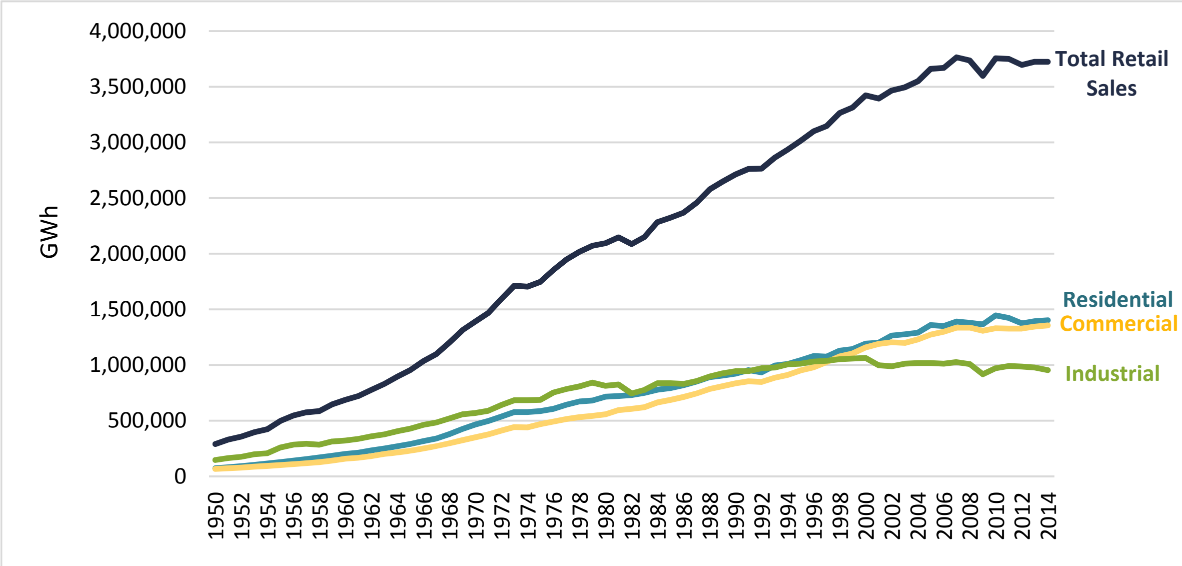
Rates are typically composed of some combination of the following three types of charges:

- Fixed charge: dollars per customer
- Energy charge: cents per kilowatt-hour (kWh) used
- Demand charge: dollars per kilowatt (kW) of maximum power used[12]

Utilities have a clear motivation for proposing higher fixed charges, as the more revenue that a utility can collect through a fixed monthly charge, the lower the risk of revenue under-recovery. Revenue certainty is an increasing concern for utilities across the country as sales stagnate or decline. According to the U.S. Energy Information Administration, electricity sales have essentially remained flat since 2005, as shown in Figure 5 below. This trend is the result of many factors, including greater numbers of customers adopting energy efficiency and distributed generation—such as rooftop solar—as well as larger economic trends. This trend toward flat sales is in striking contrast to the growth in sales that utilities have experienced since 1950, and has significant implications for utility cost recovery and ratemaking.

[12] Demand charges are typically applied only to medium to large commercial and industrial customers. However, some utilities are seeking to start applying demand charges to residential customers who install distributed generation.

Figure 5. Retail electricity sales by sector



Source: U.S. Energy Information Administration, September 2015 Monthly Energy Review, Table 7.6 Electricity End Use.

Reduced electricity consumption—whether due to customer conservation efforts, rooftop solar, or other factors—strikes at the very heart of the traditional utility business model, since much of a utility's revenue is tied directly to sales. As Kansas City Power and Light recently testified:

> From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery.[13]

At the same time that sales, and thus revenue growth, have slowed, utility costs have increased, as much utility infrastructure nears retirement age and needs replacement. The American Society of Civil Engineers estimates that $57 billion must be invested in electric distribution systems by 2020, and another $37 billion in transmission infrastructure.[14]

[13] Direct Testimony of Tim Rush, Kansas City Power & Light, Docket ER-2014-0370, October 2014, page 63.

[14] American Society of Civil Engineers, "2013 Report Card for America's Infrastructure: Energy," 2013, http://www.infrastructurereportcard.org.

3. How Fixed Charges Harm Customers

Reduced Customer Control

As technology advances, so too have the opportunities for customers to monitor and manage their electricity consumption. Many utilities are investing in smart meters, online information portals, and other programs and technologies in the name of customer empowerment. "We think customer empowerment and engagement are critical to the future of energy at Connecticut Light & Power and across the nation," noted the utility's director of customer relations and strategy.[15]

The fixed charge reduces customer control, as the only way to avoid the charge is to stop being a utility customer.

Despite these proclamations of support for customer empowerment and ratepayer-funded investments in demand-management tools, utilities' proposals for raising the fixed charge actually serve to disempower customers. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charge reduces the ability of customers to lower their bills by consuming less energy. Overall, the fixed charge reduces customer control, as the only way to avoid the fixed charge is to stop being a utility customer, an impossibility for most customers

Low-Usage Customers Hit Hardest

Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage customers may have invested in energy-efficient appliances or installed solar panels, or they may have lower incomes and live in dense housing.

Figure 6 illustrates the impact of increasing the fixed charge for residential customers from $9.00 per month to $25.00 per month, with a corresponding decrease in the per-kilowatt-hour charge. Customers who consume 1,250 kilowatt-hours per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kilowatt-hours per month would see their bill rise by nearly 40 percent. High usage customers (who tend to have higher incomes) would see a bill decrease. The data presented in the figure approximates the impact of Kansas City Power & Light's recently proposed rate design.[16]

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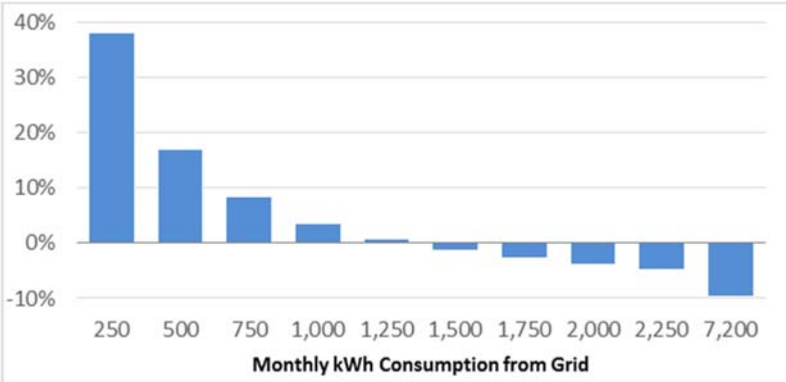
[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

[16] Missouri Public Service Commission Docket ER-2014-0370.

Figure 6. Increase in average monthly bill

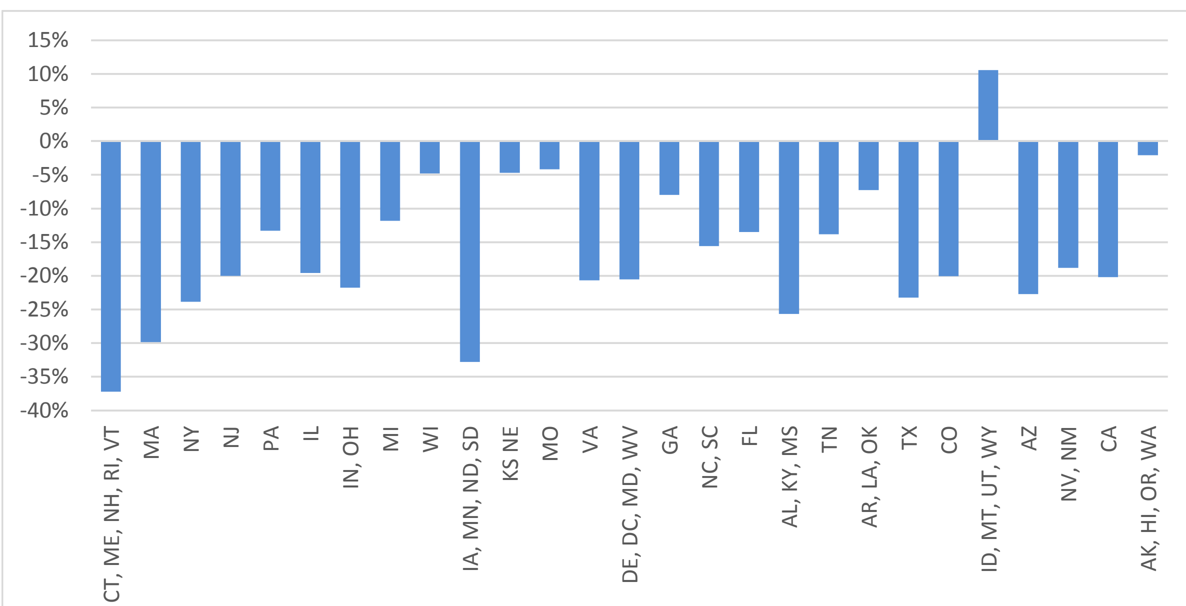


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

Low-income customers are disproportionately affected by increased fixed charges, as they tend to be low-usage customers. Figure 7 compares median electricity consumption for customers at or below 150 percent of the federal poverty line to electricity consumption for customers above that income level, based on geographic region. Using the median value provides an indication of the number of customers above or below each usage threshold—by definition, 50 percent of customers will have usage below the median value. As the graph shows, in nearly every region, most low-income customers consume less energy than the typical residential customer.

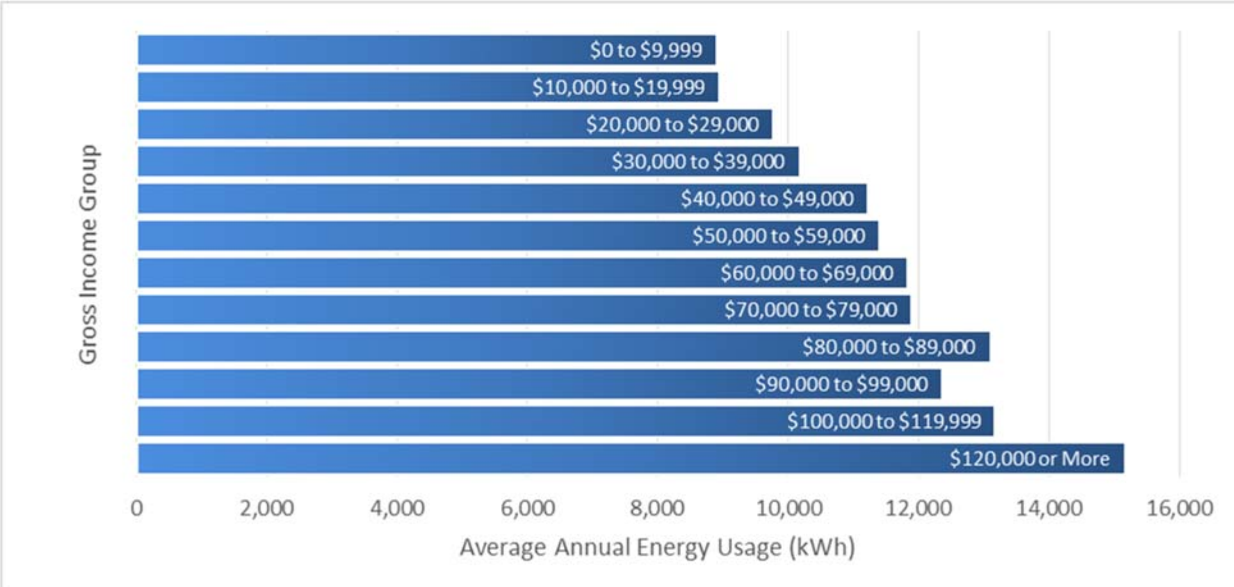
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



Source: Energy Information Administration Residential Energy Consumption Survey, 2009. http://www.eia.gov/consumption/residential/data/2009. Developed with assistance from John Howat, Senior Policy Analyst, NCLC.

The same relationship generally holds true for average usage. Nationwide, as gross income rises, so does average electricity consumption, generally speaking.

Figure 8. Nationwide average annual energy usage by income group



Source: Energy Information Administration Residential Energy Consumption Survey, 2009 http://www.eia.gov/consumption/residential/data/2009.

Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, higher fixed charges tend to raise bills most for those who can least afford the increase. This shows that rate design has important equity implications, and must be considered carefully to avoid regressive impacts.

Reduced Incentives for Energy Efficiency and Distributed Generation

Energy efficiency and clean distributed generation are widely viewed as important tools for helping reduce energy costs, decrease greenhouse gas emissions, create jobs, and improve economic competitiveness. Currently, ratepayer-funded energy efficiency programs are operating in all 50 states and the District of Columbia.[17] These efficiency programs exist alongside numerous other government policies, including building codes and appliance standards, federal weatherization assistance, and tax incentives. Distributed generation (such as rooftop solar) is commonly supported through tax incentives and net energy metering programs that compensate customers who generate a portion of their own electricity.

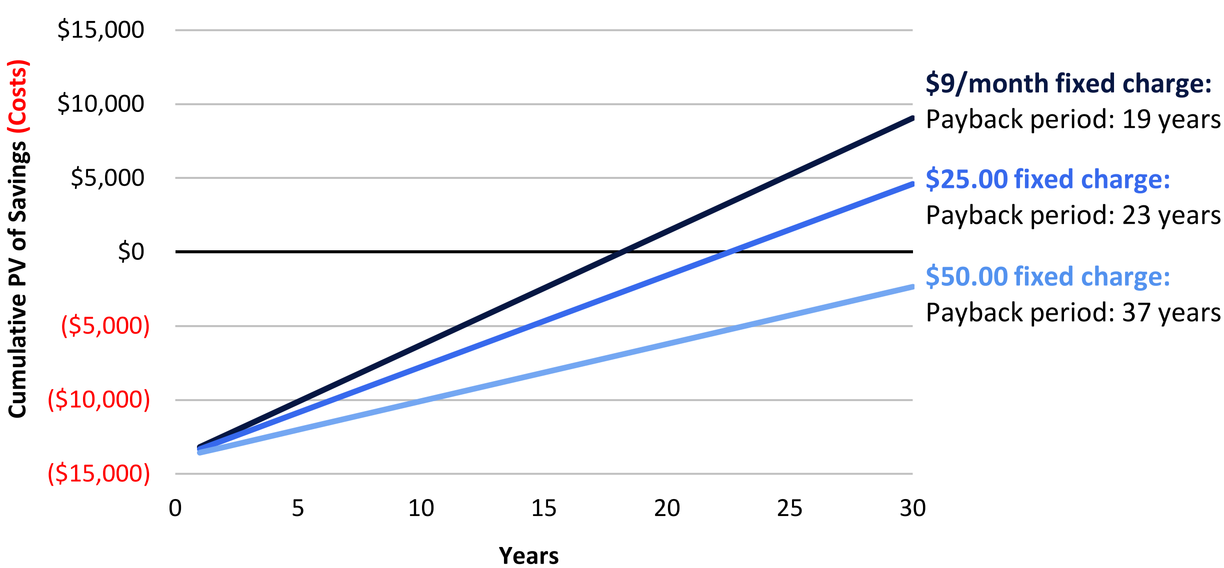
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

Increasing fixed charges can significantly reduce incentives for customers to reduce consumption through energy efficiency, distributed generation, or other means. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to lower their bills by reducing consumption. Customers who are considering making investments in energy efficiency measures or distributed generation will have longer payback periods over which to recoup their initial investment. In some cases, a customer might never break even financially when the fixed charge is increased. Increasing the fixed charge also penalizes customers who have already taken steps to reduce their energy consumption by implementing energy efficiency measures or installing distributed generation.

"When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?"

Figure 9 illustrates how the payback period for rooftop solar can change under a net metering mechanism with different fixed charges. Under net metering arrangements, a customer can offset his or her monthly electricity usage by generating solar electricity—essentially being compensated for each kilowatt-hour produced. However, solar customers typically cannot avoid the fixed charge. For a fairly typical residential customer, raising the fixed charge from $9.00 per month to $25.00 per month could change the payback period for a 5 kW rooftop solar system from 19 years to 23 years – longer than the expected lifetime of the equipment. Increasing the fixed charge to $50.00 per month further exacerbates the situation, causing the project to not break even until 37 years in the future, and virtually guaranteeing that customers with distributed generation will face a significant financial loss.

Figure 9. Rooftop solar payback period under various customer charges



All three scenarios assume monthly consumption of 850 kWh. The $9.00 per month fixed charge assumes a corresponding energy charge of 10.36 cents per kWh, while the $25 fixed charge assumes an energy charge of 8.48 cents per kWh, and the $50 fixed charge assumes an energy charge of 5.54 cents per kWh.

In Connecticut, customers decried the proposed fixed charge as profoundly unfair: "When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?" noted one frustrated customer. "Where is the incentive to spend hard-earned money to improve your appliances, or better insulate your home or more efficiently set your thermostats or air conditioning not to be wasteful, trying to conserve energy for the next generation - when you will allow the utility company to just turn around and now charge an additional fee to offset your savings?"[18]

Increased Electricity System Costs

High fixed charges may actually encourage customers to leave the system, leaving fewer and fewer customers to shoulder the costs of the electric system.

Because higher fixed charges reduce customer incentives to reduce consumption, they will undermine regulatory policies and programs that promote energy efficiency and clean distributed generation, leading to higher program costs, diminished results, or both. Rate design influences the effectiveness of these regulatory policies by changing the price signals that customers see. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer.

The flip side of this is that customers may actually increase their energy consumption since they perceive the electricity to be cheaper. Under such a scenario, states will have to spend more funds on incentives to achieve the same level of energy efficiency savings and to encourage the same amount of distributed generation as achieved previously at a lower cost. Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

In extreme cases, high fixed charges may actually encourage customers to leave the system. As rooftop solar and storage costs continue to fall, some customers may find it less expensive to generate all of their own electricity without relying on the utility at all. Once a customer departs the system, the total system costs must be redistributed among the remaining customers, raising electricity rates. These higher rates may then lead to more customers defecting, leaving fewer and fewer customers to shoulder the costs.

Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

The end result of having rate design compete with public policy incentives is that customers will pay more—either due to higher energy efficiency and distributed generation program costs, or through more investments needed to meet higher electricity demand. Meanwhile, customers who have already invested in energy efficiency or distributed generation will get burned by the reduced value of their investments and may choose to

[18] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

leave the grid, while low-income customers will experience higher bills, and all customers will have fewer options for reducing their electricity bills.

4. RATE DESIGN FUNDAMENTALS

To understand utilities' desire to increase the fixed charge—and some of the arguments used to support or oppose these proposals—it is first necessary to review how rates are set.

Guiding Principles

Rates are designed to satisfy numerous objectives, some of which may be in competition with others. In his seminal work, *Principles of Public Utility Rates,* Professor James Bonbright enumerated ten guiding principles for rate design. These principles are reproduced in the appendix, and can be summarized as follows:

1. Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.

2. Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.

3. Efficiency: Rates should provide efficient price signals and discourage wasteful usage.

4. Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

Different parts of the rate design process address different principles. First, to determine sufficient revenues, the utility's revenue requirement is determined based on a test year (either future or historical). Second, a cost-of-service study divides the revenue requirement among all of the utility's customers according to the relative cost of serving each class of customers based on key factors such as the number of customers, class peak demand, and annual energy consumption. Third, marginal costs may be used to inform efficient pricing levels. Finally, rates are designed to ensure that they send efficient price signals, and are relatively stable, understandable, and simple.

Cost-of-Service Studies

Cost-of-service study results are often used when designing rates to determine how the revenue requirement should be allocated among customer classes. An *embedded* cost-of-service study generally begins with the revenue requirement and allocates these costs among customers. An embedded cost-of-service study is performed in three steps:

- First, costs are functionalized, meaning that they are defined based upon their function (e.g., production, distribution, transmission).

- Second, costs are classified as energy-related (which vary by the amount of energy a customer consumes), demand-related (which vary according to customers' maximum energy demand), or customer-related (which vary by the number of customers).

- Finally, these costs are allocated to the appropriate customer classes. Costs are allocated on the principle of "cost causation," where customers that cause costs to be incurred should be responsible for paying them. Unit costs (dollars per kilowatt-hour, per kilowatt of demand, or per customer-month) from the cost-of-service study can be used as a point of reference for rate design.

A *marginal* cost study differs from an embedded cost study in that it is forward-looking and analyzes how the costs of the electric system would change if demand increased. A marginal cost study is particularly useful for informing rate design, since according to economic theory, prices should be set equal to marginal cost to provide efficient price signals.

One of the challenges of rate design comes from the need to reconcile the differences between embedded and marginal cost-of-service studies. Rates need to meet the two goals of allowing utilities to recover their historical costs (as indicated in embedded cost studies), and providing customers with efficient price signals (as indicated in marginal cost studies).

It is worth noting that there are numerous different approaches to conducting cost-of-service studies, and thus different analysts can reach different results.[19] Some jurisdictions consider the results of multiple methodologies when setting rates.

Rate Design Basics

Most electricity customers are charged for electricity using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed charge (e.g., $9 per month) plus an energy charge based on usage (e.g., $0.10 per kilowatt-hour).[20] The fixed charge (or "customer charge") is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, while the energy charge reflects the cost to generate and deliver energy.

Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, an energy charge, and a demand charge, because they are large users and have meters capable of measuring demand as well as energy use. The demand charge is designed to reflect the maximum amount of energy a customer withdraws at any one time, often measured as the maximum demand (in kilowatts) during the billing month. While the fixed charge is still designed to recover customer costs that are largely independent of usage, the cost to deliver energy through the transmission and distribution system is recovered largely through the demand charge, while the energy charge primarily reflects fuel costs for electricity generation.

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[19] Commonly used cost-of-service study methods are described in the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Utility Commissioners.

[20] There are many variations of energy charge; the charge may change as consumption increases ("inclining block rates"), or based on the time of day ("time-of-use rates").

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

Utilities commonly argue that most of their costs are fixed, and that that the fixed charge is appropriate for recovering such "fixed" costs. For example, in its 2015 rate case, National Grid stated, "as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible."[21]

Response

This argument conflates the accounting definition with the economic definition of fixed and variable costs.

- In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. In this sense of the term, fixed costs can include poles, wires, and power plants.[22] This definition contrasts with variable costs, which are the costs that are directly related to the amount of energy the customer uses and that rise or fall as the customer uses more or less energy.
- Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the planning horizon—perhaps a term of 10 or more years for an electric utility. Over this timeframe, most costs are variable.

Because utilities must recover the costs of the investments they have already made in electric infrastructure, they frequently employ the accounting definition of fixed costs and seek to ensure that revenues match costs. This focus is understandable. However, this approach fails to provide efficient price signals to customers. As noted above, it is widely accepted in economics that resource allocation is most efficient when all goods and services are priced at marginal cost. For efficient electricity investments to be made, the marginal cost must be based on the appropriate timeframe. In *Principles of Public Utility Rates*, James Bonbright writes:

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant

[21] National Grid Pricing Panel testimony, Book 7 of 9, Docket No. D.P.U. 15-155, November 6, 2015, page 36.

[22] Many of these costs are also "sunk" in the sense that the utility cannot easily recover these investments once they have been made.

> marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[23]

A fixed charge that includes long-run marginal costs provides no price signal relevant to resource allocation, since customers cannot reduce their consumption enough to avoid the charge. In contrast, an energy charge that reflects long-run marginal costs will encourage customers to consume electricity efficiently, thereby avoiding inefficient future utility investments.

"Fixed Costs Are Unavoidable"

Argument

By classifying some utility costs as "fixed," utilities are implying that these costs remain constant over time, regardless of customer energy consumption.

Response

Past utility capital investments are depreciated over time, and revenues collected through rates must be sufficient to eventually pay off these past investments. While these past capital investments are fixed in the sense that they cannot be avoided (that is, they are "sunk costs"), some future capital investments can be avoided if customers reduce their energy consumption and peak demands. Inevitably, the utility will have to make new capital investments; load growth may require new generating equipment to be constructed or distribution lines to be upgraded. Rate design has a role to play in sending appropriate price signals to guide customers' energy consumption and ensure that efficient future investments are made.

In short, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be analyzed to some degree on a forward-going basis to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The Fixed Charge Should Recover Distribution Costs"

Argument

The electric distribution system is sized to deliver enough energy to meet the maximum demand placed on the system. As such, the costs of the distribution system are largely based on customer peak demands, which are measured in kilowatts. For this reason, large customers typically face a demand charge that is based on the customer's peak demand. Residential customers, however, typically do not have the metering capabilities required for demand charges, nor do they generally have the means to

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[23] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). P. 336.

monitor and reduce their peak demands. Residential demand-related costs have thus historically been recovered through the energy charge.

Where demand charges are not used, utilities often argue that these demand-related costs are better recovered through the fixed charge, as opposed to the energy charge. Similar to the arguments above, utilities often claim that the costs of the distribution system—poles, wires, transformers, substations, etc.— are "fixed" costs.[24]

Response

While the energy charge does not perfectly reflect demand-related costs imposed on the system, it is far superior to allocating demand-related costs to all residential customers equally through the fixed charge. Recent research has demonstrated that there exists "a strong and significant correlation between monthly kWh consumption and monthly maximum kW demand," which suggests that "it is correct to collect most of the demand-related capacity costs through the kWh energy charge."[25]

Not all distribution system costs can be neatly classified as "demand-related" or "customer-related," and there is significant gray area when determining how these costs are classified. In general, however, the fixed charge is designed to recover customer-related costs, not any distribution-system cost that does not perfectly fall within the boundaries of "demand-related" costs. Bonbright himself warned against misuse of the fixed charge, stating that a cost analyst is sometimes "under compelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."[26]

Where it is used at all, the customer (fixed) charge should be limited to only recovering costs that vary directly with the number of customers, such as the cost of the meter, service drop, and customer billing, as has traditionally been done.[27]

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[24] For example, in UE-140762, PacifiCorp witness Steward testifies that "Distribution costs (along with retail and miscellaneous) are fixed costs associated with the local facilities necessary to connect and serve individual customers. Accordingly, these costs should be recovered through the monthly basic charges and load size charges (which are based on demand measurements)." JRS-1T, p. 17. Another example is provided in National Grid's 2015 rate case application. The utility's testimony states: "the distribution system is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand, and, once constructed, distribution system costs are fixed in nature. In other words, reducing energy consumption does not result in a corresponding reduction in distribution costs. Therefore, as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible." D.P.U. 15-155, Pricing Panel testimony, November 6, 2015, page 36.

[25] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," *Fortnightly* 27, no. 4 (May 2014).

[26] *Principles of Public Utility Rates*, Dr. James Bonbright, Columbia University Press, 1961, p. 349.

[27] Weston, 2000: "there is a broad agreement in the literature that distribution investment is causally related to peak demand" and not the number of customers; and "[t]raditionally, customer costs are those that are seen to vary with the number of customers on the system: service drops (the line from the distribution radial to the home or business), meters, and billing and collection." Pp. 28-29.

"Cost-of-Service Studies Should Dictate Rate Design"

Argument

Utilities sometimes argue that adherence to the principle of "cost-based rates" means that the unit costs identified in the cost-of-service study (i.e., dollars per kilowatt-hour, dollars per kilowatt, and dollars per customer) should be replicated in the rate design.

Response

The cost-of-service study can be used as a guide or benchmark when setting rates, but by itself it does not fully capture all of the considerations that should be taken into account when setting rates. This is particularly true if only an embedded cost-of-service study is conducted, rather than a marginal cost study. As noted above, embedded cost studies reflect only historical costs, rather than marginal costs. Under economic theory, prices should be set equal to marginal cost in order to provide an efficient price signal. Reliance on marginal cost studies does not fully resolve the issue, however, as marginal costs will seldom be sufficient to recover a utility's historical costs.

"I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."

Further, cost-of-service studies do not account for benefits that customers may be providing to the grid. In the past, customers primarily imposed costs on the grid by consuming energy. As distributed generation and storage become more common, however, customers are increasingly becoming "prosumers"—providing services to the grid as well as consuming energy. By focusing only on the cost side of the equation, cost-of-service studies generally fail to account for such services.

Cost-of-service study results are most useful when determining *how much* revenue to collect from different types of customers, rather than *how* to collect such revenue. Clearly, rates can be set to exactly mirror the unit costs revealed by the embedded cost-of-service study (dollars per customer, per kilowatt, or per kilowatt-hour), but other rate designs may yield approximately the same revenue while also accomplishing other policy objectives, particularly that of sending efficient price signals. Indeed, most products in the competitive marketplace—whether groceries, gasoline, or restaurant meals—are priced based solely on usage, rather than also charging a customer access fee and another fee based on maximum consumption.

This point was echoed recently by Karl Rabago, a former Texas utility commissioner: "I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."[28]

[28] Rabago direct testimony, NY Orange & Rockland Case 14-E-0493, p. 13.

As a final note, utility class cost of service studies are just that. They are performed by the utility and rely on numerous assumptions on how to allocate costs. Depending on the method and cost allocation chosen, results can vary dramatically, and represent one party's view of costs and allocation. Different studies can and do result in widely varying results. Policymakers should view with skepticism a utility claim that residential customers are not paying their fair share of costs based on such studies.

"Low-Usage Customers Are Not Paying Their Fair Share"

Argument

It is often claimed that a low fixed charge results in high-usage customers subsidizing low-usage customers.

Response

The reality is much more complicated. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Thus, many low-usage customers impose lower demands on the system, and should therefore be responsible for a smaller portion of the distribution system costs. Furthermore, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed Charges Are Necessary to Mitigate Cost-Shifting Caused by Distributed Generation"

Argument

Several utilities have recently proposed that fixed customer charges should be increased to address the growth in distributed generation resources, particularly customer-sited photovoltaic (PV) resources. Utilities argue that customers who install distributed generation will not pay their "fair share" of costs, because they will provide much less revenue to the utility as a result of their decreased need to consume energy from the grid. This "lost revenue" must eventually be paid by other customers who do not install distributed generation, which will increase their electricity rates, causing costs to be shifted to them.

The utilities' proposed solution is to increase fixed charges—at least for the customers who install distributed generation, and often for all customers. The higher fixed charges are proposed to ensure that customers with distributed generation continue to pay sufficient revenues to the utility, despite their reduced need for external generation.

While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power.

Response

Concerns about potential cost-shifting from distributed generation resources are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. The power from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will dramatically reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

This is a critical element of distributed generation resources that often is not recognized or fully addressed in discussions about alternative ratemaking options such as higher fixed charges. Unlike all other electricity resources, distributed generation typically provides the electric utility system with generation that is nearly free of cost to the utility and to other customers. This is because, in most instances, host customers pay for the installation and operation of the distributed generation system, with little or no payment required from the utility or other customers.[29]

One of the most important and meaningful indicators of the cost-effectiveness of an electricity resource is the impact that it will have on utility revenue requirements. The present value of revenue requirements (PVRR) is used in integrated resource planning practices throughout the United States as the primary criterion for determining whether an electricity resource is cost-effective and should be included in future resource plans.

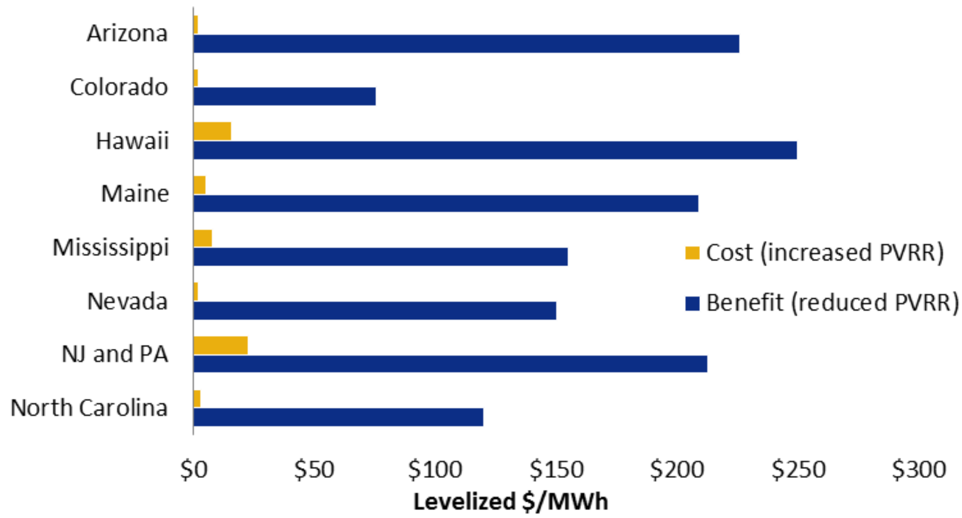
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

Several recent studies have shown that distributed generation resources are very cost-effective because they can significantly reduce revenue requirements by avoiding generation, transmission, and distribution costs, and only require a small increase in other utility expenditures. Figure 10 presents the benefits and costs of distributed generation according to six studies, where the benefits include all of the ways that distributed generation might reduce revenue requirements through avoided costs, and the costs include all of the ways that distributed generation might increase revenue requirements.[30] These costs typically include (a) the utility administrative costs of operating net energy metering programs, (b) the utility costs of interconnecting distributed generation technologies to the distribution grid, and (c) the utility costs of integrating intermittent distributed generation into the distribution grid.

[29] If a utility offers some form of an incentive to the host customer, such as a renewable energy credit, then this will represent an incremental cost imposed upon other customers. On the other hand, distributed generation customers provided with net energy metering practices do not require the utility or other customers to incur any new, incremental cost.

[30] Appendix C includes citations for these studies, along with notes on how the numbers in Figure 10 were derived.

Figure 10. Recent studies indicate the extent to which distributed generation benefits exceed costs



As indicated in the figure, all of these studies make the same general point: Distributed generation resources are very cost-effective in terms of reducing utility revenue requirements. In fact, they are generally more cost-effective than almost all other electricity resource options. The results presented in Figure 10 above indicate that distributed generation resources have benefit-cost ratios that range from 9:1 (New Jersey and Pennsylvania) to roughly 40:1 (Colorado, Maine, North Carolina) to as high as 113:1 (Arizona). These benefit-cost ratios are far higher than other electricity resource options, because the host customers typically pay for the cost of installing and operating the distributed generation resource.

Rate designs should be structured to encourage the development of very cost-effective resources, not to discourage them.

This point about distributed generation cost-effectiveness is absolutely essential for regulators and others to understand and acknowledge when making rate design decisions regarding distributed generation, for several reasons:

- The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may possibly even eliminate, any cost-shifting that might occur between distributed generation host customers and other customers.[31]
- When arguments about cost-shifting from distributed generation resources are used to justify increased fixed charges, it is important to assess and consider the likely magnitude of cost-shifting in light of the benefits offered by distributed generation. It is quite possible that any cost-shifting is *de minimis*, or non-existent.
- The net benefits of distributed generation should be considered as an important factor in making rate design decisions. Rate designs should be structured to encourage the

[31] This may not hold at very high levels of penetration, as integration costs increase once distributed generation levels hit a certain threshold. However, the vast majority of utilities in the United States have not yet reached such levels.

development of very cost-effective resources; they should not be designed to discourage them.

Again, policy makers should proceed with caution on claims regarding cost shifting. Where cost shifting is analyzed properly and found to be a legitimate concern, it can be addressed through alternative mechanisms that apply to DG customers, rather than upending the entire residential rate design in ways that can negatively affect all customers.

6. RECENT COMMISSION DECISIONS ON FIXED CHARGES

Commission Decisions Rejecting Fixed Charges

Commissions in many states have largely rejected utility proposals to increase the fixed charge, citing a variety of reasons, including rate shock to customers and the potential to undermine state policy goals. Below are several reasons that commissions have given for rejecting such proposals.

Customer Control

In 2015, the Missouri Public Service Commission rejected Ameren's request to increase the residential customer charge, stating:

> The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control.[32]

Energy Efficiency, Affordability, and Other Policy Goals

The Minnesota Public Utilities Commission recently ruled against a relatively small increase in the fixed charge (from $8.00 to $9.25), citing affordability and energy conservation goals, as well as revenue regulation (decoupling) as a protection against utility under-recovery of revenues:

> In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation. The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory" and the utility's need for revenue sufficient to enable it to provide service.
>
> The Commission concludes that raising the Residential and Small General Service customer charges… would give too much weight to the fixed customer cost calculated in Xcel's class-cost-of-service study and not enough weight to affordability and energy conservation. … The Commission concurs with the OAG that this circumstance highlights the need for caution in making any decision that would further burden low-income, low-usage customers, who are unable to absorb or avoid the increased cost.

[32] Missouri Public Service Commission Report and Order, File No. ER-2014-0258, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service, April 29, 2015, pages 76-77.

> The Commission also concludes that a customer-charge increase for these classes would place too little emphasis on the need to set rates to encourage conservation. This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability.[33]

Similarly, in March of 2015, the Washington Utilities and Transportation Commission rejected an increase in the fixed charge based on concerns regarding affordability and conservation signals. The commission also reaffirmed that the fixed charge should only reflect costs directly related to the number of customers:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.[34]

In 2012, the Missouri Public Service Commission rejected Ameren Missouri's proposed increase in the customer charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[35]

In 2013, the Maryland Public Service Commission rejected a small increase in the customer charge, noting that such an increase would reduce customers' control of their bills and would be inconsistent with the state's policy goals.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the

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[33] Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota; Findings of Fact, Conclusions, and Order; Docket No. E-002/GR-13-868, May 8, 2015, p. 88.

[34] Washington Utilities and Transportation Commission, Final Order Rejecting Tariff Sheets, Resolving Contested Issues, Authorizing And Requiring Compliance Filings; Docket UE-140762, March 25, 2015, p. 91.

[35] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

> reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[36]

Commission Decisions Approving Higher Fixed Charges

Higher fixed charges have been rejected in numerous cases, but not all. In many cases, a small increase in the fixed charge has been approved through multi-party settlements, rather than addressed by the commission. Where commissions have specifically approved fixed charge increases, they often cite some of the flawed arguments that are addressed in Chapter 5 above. Below we provide some examples and briefly describe the commission's rationale.

Fixed Charges and Recovery of Distribution System Costs

Over the past few years, Wisconsin has approved some of the highest fixed charges in the country, based on the rationale that doing so will "prevent intra-class subsidies… provide appropriate price signals to ratepayers, and encourage efficient utility scale planning…."[37] This rationale is largely based on two misconceptions: (1) that short-run marginal costs provide an efficient price signal to ratepayers and will encourage efficient electric resource planning, and (2) that recovering certain distribution system costs through the fixed charge is more appropriate than recovering them through the energy charge.[38]

As discussed above, a rate design that fails to reflect long-run marginal costs will result in inefficient price signals to customers and ultimately result in the need to make more electric system investments to support growing demand than would otherwise be the case. Not only will growing demand result in the need for additional generation capacity, it may cause distribution system components to wear out faster, or to be replaced with larger components. Wrapping such costs up in the fixed charge sends the signal to customers that these costs are unavoidable, when in fact future investment decisions are in part determined by the level of system use.

Further, using the fixed charge to recover distribution system costs that cannot be readily classified as "demand-related" or "customer-related" exemplifies the danger that Bonbright warned of regarding using the category of customer costs as a "dumping ground" for costs that do not fit in the other

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36 In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

37 Docket 3270-UR-120, Order at 48.

38 For example, Wisconsin Public Service Corporation argued that the fixed charge should include a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors, rather than only the customer-related costs.

categories. Use of the fixed charge for recovery of such costs tends to harm low-income customers, as well as distort efficient price signals.

Despite generally approving significantly higher fixed charges in recent years, in a December 2015 order the Wisconsin Public Service Commission approved only a slight increase in the fixed charge and signaled its interest in evaluating the impacts of higher fixed charges to ensure that the Commission's policy goals are being met. Specifically, the Commission directed one of its utilities to work with commission staff to conduct a study to assess the impacts of the higher fixed charges on customer energy use and other behavior.[39] This order indicates that perhaps the policy may be in need of further study.

Demand Costs Not Appropriate for Energy Charge

In approving Sierra Pacific Power's request for a higher fixed charge, the Nevada Public Service Commission wrote:

> If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable.[40]

Despite declaring that demand-related costs are inappropriately recovered in the energy charge, the commission makes no argument for why the fixed charge is a more appropriate mechanism for recovering such costs. Nor does the commission recognize that customer demand (kW) and energy usage (kWh) are likely correlated, or that recovering demand-related costs in the fixed charge may introduce even greater cross-subsidies among customers.

Settlements

Many of the recent proceedings regarding fixed charges have ended in a settlement agreement. Several of these settlements have resulted in the intervening parties, including the utility, agreeing to make no change to the customer charge or fixed charge. For example, Kentucky Utilities and Louisville Gas & Electric requested a 67 percent increase in the fixed charge, from $10.75 to $18.00 per month. The case ultimately settled, with neither utility receiving an increase in the monthly fixed charge.[41] While

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[39] Wisconsin Public Service Commission, Docket 6690-UR-124, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, December 17, 2015.

[40] Nevada Public Service Commission, Docket 13-06002, *Application of Sierra Pacific Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto*, Modified Final Order, January 29, 2014, Page 176.

[41] Kentucky Public Service Commission Order, Case No. 2014-00372, *In the Matter of Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, page 4; Kentucky Public Service Commission Order, Case No. 2014-00371, *In the Matter of Application of Kentucky Utility Company for an Adjustment of Its Electric and Gas Rates*, page 4.

settlements seldom explicitly state the rationale behind such decisions, it is safe to expect that many of the settling parties echo the concerns stated by the Commissions above.

In conclusion, the push to significantly increase the fixed charge has largely been rejected by regulators across the country as unnecessary and poor public policy. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason. In addition, in late 2015, it appeared that some utilities were beginning to propose new demand charges for residential customers instead of increased fixed charges.

7. Alternatives to Fixed Charges

Utilities are turning to higher fixed charges in an effort to slow the decline of revenues between rate cases, since revenue collected through the fixed charge is not affected by reduced sales. In the past, costs were relatively stable and sales between rate cases typically provided utilities with adequate revenue, but this is not necessarily the case anymore. The current environment of flat or declining sales growth, coupled with the need for additional infrastructure investments, can pose financial challenges for a utility and cause it to apply for rate cases more frequently.

Higher fixed charges are an understandable reaction to these trends, but they are an ill-advised remedy, due to the adverse impacts described above. Alternative rate designs exist that can help to address utility revenue sufficiency and volatility concerns, as discussed below. Furthermore, in many cases, utilities are reacting to perceived or future threats, rather than to a pressing current revenue deficiency. Simply stated, there is no need to increase the fixed charge.

Rate Design Options

Numerous rate design alternatives to higher fixed charges are available under traditional cost-of-service ratemaking. Below we discuss several of these options, and describe some of the key advantages and disadvantages of each. No prioritization of the options is implied, as rate design decisions should be made to address the unique circumstances of a particular jurisdiction. For example, the rate design adopted in Hawaii, where approximately 15 percent of residential customers on Oahu have rooftop solar,[42] may not be appropriate for a utility in Michigan.

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[42] As of the third quarter of 2015, nearly 40,000 customers on Oahu were enrolled in the Hawaiian Electric Company's net metering program, as reported by HECO on its website: http://www.hawaiianelectric.com/heco/_hidden_Hidden/Community/Renewable-Energy?cpsextcurrchannel=1#05

Status Quo

One option is to simply maintain the current level of fixed charges and allow utilities to file frequent rate cases, if needed. This option is likely to be most appropriate where a utility is not yet facing any significant earnings shortfall, but is instead seeking to preempt what it views as a future threat to its earnings.

By maintaining the current rate structure rather than changing it prematurely, this option allows the extent of the problem to be more accurately assessed, and the remedy appropriately tailored to address the problem. Maintaining the current rate structure clearly also avoids the negative impacts on ratepayers and clean energy goals that higher fixed charges would have, as discussed in detail above.

However, maintaining the status quo may have detrimental impacts on both ratepayers and the utility if the utility is truly at risk of significant revenue under-recovery.[43] Where a utility cannot collect sufficient revenues, it may forego necessary investments in maintaining the electric grid or providing customer service, with potential long-term negative consequences.

In addition, the utility may file frequent rate cases in order to reset rates, which can be costly. Rate cases generally require numerous specialized consultants and lawyers to review the utility's expenditures and investments in great detail, and can drag on for months, resulting in millions of dollars in costs that could eventually be passed on to customers. Because of this cost, a utility is unlikely to file a rate case unless it believes that significantly higher revenues are likely to be approved.

Finally, chronic revenue under-recovery can worry investors, who might require a higher interest rate in order to lend funds to the utility. Since utilities must raise significant financial capital to fund their investments, a higher interest rate could ultimately lead to higher costs for customers. However, such chronic under-recovery is unlikely for most utilities, and this risk should be assessed alongside the risks of overcharging ratepayers and discouraging efficiency.

Minimum Bills

Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. For example, if the minimum bill were set at $40, and the only other charge was the energy charge of $0.10 per kWh, then the minimum bill would only apply to customers using less than 400 kWh, who would otherwise experience a bill less than $40. Given that the national average residential electricity usage is approximately 900 kWh per month, the minimum bill would have no effect on most residential customers.

[43] Of course, the claim that the utility is at risk of substantially under-recovering its revenue requirement should be thoroughly investigated before any action is taken.

A key advantage claimed by proponents to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, without significantly distorting price signals for the majority of customers. The threshold that triggers the minimum bill is typically set well below the average electricity usage level, and thus most customers will not be assessed a minimum bill but will instead only see the energy charge (cents per kilowatt-hour). Minimum bills also have the advantage of being relatively simple and easy to understand.

Minimum bills may be useful where there are many customers that have low usage, but actually impose substantial costs on the system. For example, this could include large vacation homes that have high usage during the peak summer hours that drive most demand-related costs, but sit vacant the remainder of the year. Unfortunately, minimum bills do not distinguish these types of customers from those who have reduced their peak demand (for example through investing in energy efficiency or distributed generation), and who thereby impose lower costs on the system.[44] Further, minimum bills may also have negative financial impacts on low-income customers whose usage falls below the threshold. For these reasons, minimum bills are superior to fixed charges, but they still operate as a relatively blunt instrument for balancing ratepayer and utility interests. Further, utilities will have an incentive to push for higher and higher minimum bill levels.

To illustrate the impacts of minimum bills, consider three rate options: (1) an "original" residential rate structure with a fixed charge of $9 per month; (2) a minimum bill option, which keeps the $9 fixed charge but adds a minimum bill of $40; and (3) an increase in the fixed charge to $25 per month. In all cases, the energy charge is adjusted to ensure that the three rate structures produce the same amount of total revenues. The figure below illustrates how moving from the "original" rate structure to either a minimum bill or increased fixed charge option would impact different customers.

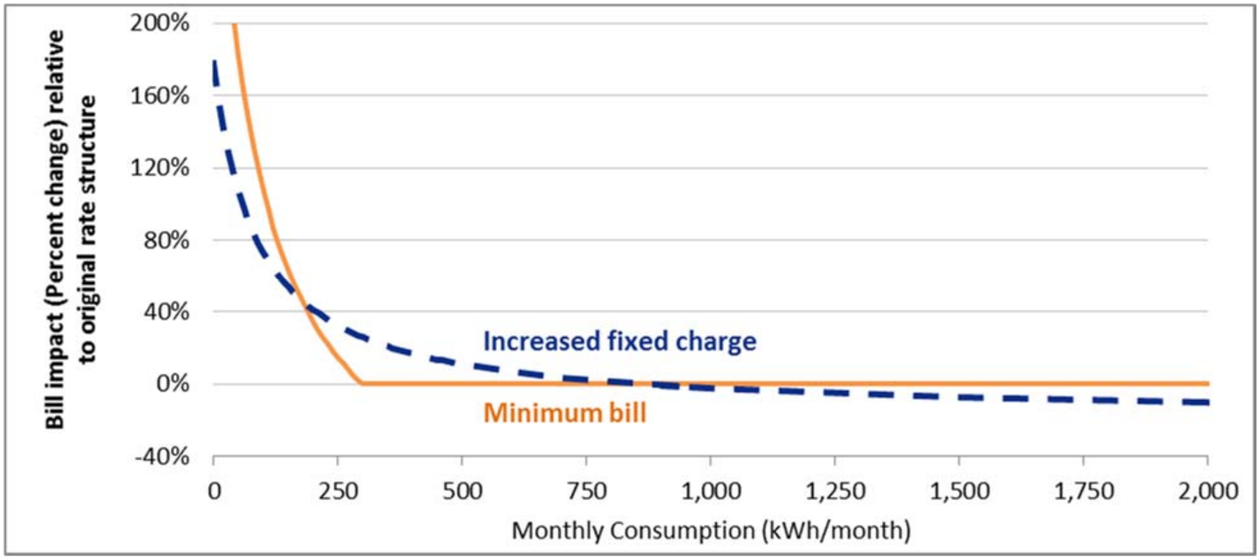
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

In contrast, under the $25 fixed charge, all customers using less than approximately 875 kWh per month (about half of residential customers) would see an increase in their electric bills, while customers using more than 875 kWh per month would see a *decrease* in their electric bills.

[44] In the short run, there is likely to be little difference in the infrastructure investments required to serve customers with high peak demands and those with low peak demands. However, in the long run, customers with higher peak demands will drive additional investments in generation, transmission, and distribution, thereby imposing greater costs on the system. A theoretically efficient price signal would reflect these different marginal costs in some manner in order to encourage customers to reduce the long-run costs they impose on the system.

Figure 11. Impact of minimum bill relative to an increased fixed charge

Rate Structure	Energy Charge	Fixed charge	Minimum bill
Typical rate structure	10.36 cents / kWh	$9 / Month	$0 / Month
Minimum bill	10.34 cents / kWh	$9 / Month	$40 / Month
Increased fixed charge	8.48 cents / kWh	$25 / Month	$0 / Month



Source: Author's calculations based on data from a representative Midwestern utility.

Time-of-Use Rates

Electricity costs can vary significantly over the course of the day as demand rises and falls, and more expensive power plants must come online to meet load.[45] Time-of-use (TOU) rates are a form of time-varying rate, under which electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have separate rates for peak and off-peak periods, but intermediate periods may also have their own rates.

Time-varying rate structures can benefit ratepayers and society in general by improving economic efficiency and equity. Properly designed TOU rates can improve economic efficiency by:

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;

2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

[45] Electricity costs also vary by season and weekday/weekend.

3. Providing appropriate price signals for customer investment in distributed energy resources that best match system needs.

Time-varying rates are also capable of improving equity by better allocating the costs of electricity production during peak periods to those causing the costs.

Despite their advantages, TOU rates are not a silver bullet and may be inappropriate in the residential rate class. They may not always be easily understood or accepted by residential customers. TOU rates also require specialized metering equipment, which not all customers have. In particular, the adoption of advanced metering infrastructure (AMI) may impose significant costs on the system.[46] Residential consumers often do not have the time, interest or knowledge to manage variable energy rates efficiently, so TOU blocks must be few and well-defined and still may not elicit desired results. Designing TOU rates correctly can be difficult, and could penalize vulnerable customers requiring electricity during extreme temperatures. Some consumer groups (such as AARP) urge any such rates be voluntary. Finally, even well-designed TOU rates may not fully resolve a utility's revenue sufficiency concerns.

Value of Solar Tariffs

Value of solar tariffs pay distributed solar generation based on the value that the solar generation provides to the utility system (based on avoided costs). Value of solar tariffs have been approved as an alternative to net metering in Minnesota and in Austin, Texas. In both places, a third-party consultant conducted an avoided cost study (value of solar study) to determine the value of the avoided costs of energy, capacity, line losses, transmission and distribution.

Value of solar tariffs are useful in that they more accurately reflect cost causation, thereby improving fairness among customers. They also maintain efficient price signals that discourage wasteful use of energy, and improve revenue recovery and stability.

However, value of solar tariffs are not easily designed, as there is a lack of consensus on the elements that should be incorporated, how to measure difficult-to-quantify values, and even how to structure the tariff. Value of solar rates are also not necessarily stable, since value-of-solar tariff rates are typically adjusted periodically. However, there is no reason that the tariff couldn't be affixed for a set time period, like many long-term power purchase agreements.

Alternatively, if the value of solar is determined to be less than the retail price of energy, a rider or other charge could be implemented to ensure that solar customers pay their fair share of costs. Regardless of the type of charge or compensation mechanism chosen, a full independent, third-party analysis of the costs and benefits of distributed generation should be conducted prior to making any changes to rates.

[46] AMI also allows remote disconnections and prepaid service options, both of which can disadvantage low-income customers. See, for example, Howat, J. *Rethinking Prepaid Utility Service: Customers at Risk.* National Consumer Law Center, June 2012.

Demand Charges

Generation, transmission, and distribution facilities are generally sized according to peak demands—either the local peak or the system peak. The peak demands are driven by the consumption levels of all electricity customers combined. Demand charges are designed to recover demand-related costs by charging electricity customers on the basis of maximum power demand (in terms of dollars per kilowatt), instead of energy (in terms of dollars per kilowatt-hour).

Designing rates to collect demand-related costs through demand charges may improve a utility's revenue recovery and stability. Proponents claim that such rates may also help send price signals that encourage customers to take steps to reduce their peak load. These charges have been in use for many years for commercial and industrial customers, but have rarely been implemented for residential customers.

Demand charges have several important shortcomings that limit how appropriate they might be for residential customers. First, demand charges remain relatively untested on the residential class. There is little evidence thus far that demand charges are well-understood by residential customers; instead, they would likely lead to customer confusion. This is particularly true for residential customers, who may be unaware of when their peak usage occurs and therefore have little ability or incentive to reduce their peak demand.

Second, depending on how they are set, demand charges may not accurately reflect cost causation. A large proportion of system costs are driven by system-wide peak demand, but the demand charge is often based on the customer's maximum demand (not the utility's). Thus demand charges do not provide an incentive for customers to reduce demand during the utility system peak in the way that time of use rates do. Theoretically, demand charges based on a customer's maximum demand could help reduce local peak demand, and therefore reduce some local distribution system costs. However, at the residential level, it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Since a customer's maximum demand is typically triggered by a short period of time in which that customer is using numerous household appliances, it is unlikely that this specific time period coincides exactly when other customers sharing the same transformer are experiencing their maximum demands. This averaging out over multiple customers means that a single residential customer's maximum demand is not likely to drive the sizing of a particular piece of distribution-system equipment. For this reason, demand charges for the residential class are not likely to accurately reflect either system or local distribution costs.

Third, few options currently exist for residential customers to automatically monitor and manage their maximum demands. Since customer maximum monthly demand is often measured over a short interval of time (e.g., 15 minutes), a single busy morning where the toaster, microwave, hairdryer, and clothes dryer all happen to be operating at the same time for a brief period could send a customer's bill skyrocketing. This puts customers at risk for significant bill volatility. Unless technologies are implemented to help customers manage their maximum demands, demand charges should not be used.

Fourth, demand charges are not appropriate for some types of distributed generation resources. Some utilities have proposed that demand charges be applied to customers who install PV systems under net energy metering policies. This proposal is based on the grounds that demand charges will provide PV customers with more accurate price signals regarding their peak demands, which might be significantly different with customer-sited PV. However, a demand charge is not appropriate in this circumstance, because PV resources do not provide the host customer with any more ability to control or moderate peak demands than any other customer. A PV resource might shift a customer's maximum demand to a different hour, but it might do little to reduce the maximum demand if it occurs at a time when the PV resource is not operating much (because the maximum demand occurs either outside of daylight hours, or on a cloudy day when PV output is low).

Fifth, demand charges may require that utilities invest in expensive metering infrastructure and in-home devices that communicate information to customers regarding their maximum demands. The benefits of implementing a customer demand charge may not outweigh the costs of such investments.

In sum, most residential customers are very unlikely to respond to demand charges in a way that actually reduces peak demand, either because they do not have sufficient information, they do not have the correct price signal, they do not have the technologies available to moderate demand, or the technologies that they do have (such as PV) are not controllable by the customer in a way that allows them to manage their demand. In those instances where customers cannot or do not respond to demand charges, these charges suffer from all of the same problems of fixed charges: they reduce incentives to install energy efficiency or distributed generation; they pose an unfair burden on low-usage customers; they provide an inefficient price signal regarding long-term electricity costs; and they can eventually result in higher costs for all customers. For these reasons, demand charges are rarely implemented for residential customers, and where they have been implemented, it has only been on a voluntary basis.

8. Conclusions

In this era of rapid advancement in energy technologies and broad-based efforts to empower customers, mandatory fixed charges represent a step backward. Whether a utility is proposing to increase the fixed charge due to a significant decline in electricity sales or as a preemptive measure, higher fixed charges are an inequitable and economically inefficient means of addressing utility revenue concerns. In some cases, regulators and other stakeholders have been persuaded by common myths that inaccurately portray an increased fixed charge as the necessary solution to current challenges facing the utility industry. While they may be desirable for utilities, higher fixed charges are far from optimal for society as a whole.

Fortunately, there are many rate design alternatives that address utility concerns about declining revenues from lower sales without causing the regressive results and inefficient price signals associated with fixed charges. Recent utility commission decisions rejecting proposals for increased fixed charges suggest that there is a growing understanding of the many problems associated with fixed charges, and that alternatives do exist. As this awareness spreads, it will help the electricity system continue its progression toward greater efficiency and equity.

Appendix A – Bonbright's Principles of Rate Design

In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   - (a) in the control of the total amounts of service supplied by the company;
   - (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[47]

[47] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

Appendix B – Recent Proceedings Addressing Fixed Charges

The tables below present data on recent utility proposals or finalized proceedings regarding fixed charges based on research conducted by Synapse Energy Economics. These cases were generally opened or decided between September 2014 and November 2015.

Table 1. List of finalized utility proceedings to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Alameda Municipal Power (CA)	AMP Board vote June 2015	$9.25	$11.50	$11.50	
Ameren (MO)	File No. ER - 2012-0166 Tariff No. YE-2014-0258	$8.00	$8.77	$8.00	Company initially proposed $12.00. Settling parties agreed to $8.77. Commission order rejected any increase, citing customer control
Appalachian Power Co (VA)	PUE-2014-00026	$8.35	$16.00	$8.35	
Appalachian Power/Wheeling Power (WV)	14-1152-E-42T	$5.00	$10.00	$8.00	
Baltimore Gas and Electric (MD)	9355, Order No. 86757	$7.50	$10.50	$7.50	Settlement based on Utility Law Judge
Benton PUD (WA)	Board approved in June 2015	$11.05	$15.60	$15.60	
Black Hills Power (WY)	20002-91-ER-14 (Record No. 13788)	$14.00	$17.00	$15.50	
Central Hudson Gas & Electric (NY)	14-E-0318	$24.00	$29.00	$24.00	
Central Maine Power Company (ME)	2013-00168	$5.71	$10.00	$10.00	Decoupling implemented as well
City of Whitehall (WI)	6490-ER-106	$8.00	$16.00	$16.00	
Columbia River PUD (OR)	CRPUD Board vote September 2015	$8.00	$20.45	$10.00	
Colorado Springs Utilities (CO)	City Council Volume No. 5	$12.52	$15.24	$15.24	
Connecticut Light & Power (CT)	14-05-06	$16.00	$25.50	$19.25	Active docket
Consolidated Edison (NY)	15-00270/15-E-0050	$15.76	$18.00	$15.76	Settlement
Consumers Energy (MI)	U-17735	$7.00	$7.50	$7.00	PSC Order
Choptank Electric Cooperative (MD)	9368, Order No. 86994,	$10.00	$17.00	$11.25	PSC approved smaller increase
Dawson Public Power (NE)	Announced June 2015	$21.50	$27.00	$27.00	Based on news articles
Empire District Electric (MO)	ER-2014-0351	$12.52	$18.75	$12.52	Settlement
Eugene Water & Electric Board (OR)	Board vote December 2014	$13.50	$20.00	$20.00	
Hawaii Electric Light (HI)	2014-0183	$9.00	$61.00	$9.00	Part of "DG 2.0"
Maui Electric Company (HI)	2014-0183	$9.00	$50.00	$9.00	Part of "DG 2.0"
Hawaii Electric Company (HI)	2014-0183	$9.00	$55.00	$9.00	Part of "DG 2.0"
Independence Power & Light Co (MO)	City Council vote September 2015	$4.14	$14.50	$4.14	Postponed indefinitely
Indiana Michigan Power (MI)	U-17698	$7.25	$9.10	$7.25	Settlement
Kansas City Power & Light (KS)	15-KCPE-116-RTS	$10.71	$19.00	$14.50	Settlement
Kansas City Power & Light (MO)	File No. ER-2014-0370	$9.00	$25.00	$11.88	
Kentucky Power (KY)	2014-00396	$8.00	$16.00	$11.00	Settlement was $14/month; PSC reduced to $11
Kentucky Utilities Company (KY)	2014-00371	$10.75	$18.00	$10.75	Settlement for KU LGE
Louisville Gas-Electric (KY)	2014-00372	$10.75	$18.00	$10.75	Settlement for KU LGE

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Madison Gas and Electric (WI)	3270-UR-120	$10.29	$22.00	$19.00	
Metropolitan Edison (PA)	R-2014-2428745	$8.11	$13.29	$10.25	Settlement
Nevada Power Co. (NV)	14-05004	$10.00	$15.25	12.75	Settlement
Northern States Power Company (ND)	PU-12-813	$9.00	$14.00	$14.00	Under previous rates, customers with underground lines paid $11/month
Pacific Gas & Electric Company (CA)	R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
PacifiCorp (WA)	UE-140762	$7.75	$14.00	$7.75	Commission order emphasized customer control
Pennsylvania Electric (PA)	R-2014-2428743	$7.98	$11.92	$9.99	Settlement
Pennsylvania Power (PA)	R-2014-2428744	$8.86	$12.71	$10.85	Settlement
Redding Electric Utility (CA)	City Council Meeting June 2015	$13.00	$42.00	$13.00	Postponed consideration until 2/2017
Rocky Mountain Power (UT)	13-035-184	$5.00	$8.00	$6.00	Settlement
Rocky Mountain Power (WY)	20000-446-ER-14 (Record No. 13816)	$20.00	$22.00	$20.00	
Salt River Project (AZ)	SRP Board vote February 2015	$17.00	$20.00	$20.00	Elected board of SRP voted Feb. 26 2015
San Diego Gas & Electric (CA)	A.14-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
Sierra Pacific Power (NV)	13-06002, 13-06003, 13-06004	$9.25	$15.25	$15.25	
Southern California Edison (CA)	A.13-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.94	$10.00	$0.94	$10 minimum bill adopted instead
Stoughton Utilities (W()	5740-ER-108	$7.50	$10.00	$10.00	
We Energies (WI)	5-UR-107	$9.13	$16.00	$16.00	
West Penn Power (PA)	R-2014-2428742	$5.00	$7.35	$5.81	Settlement
Westar (KS)	15-WSEE-115-RTS	$12.00	$27.00	$14.50	Settlement
Wisconsin Public Service (MI)	U-17669	$9.00	$12.00	$12.00	Settlement
Wisconsin Public Service (WI)	6690-UR-123	$10.40	$25.00	$19.00	
Xcel Energy (MN)	E002 / GR-13-868	$8.00	$9.25	$8.00	Commission order emphasized customer control

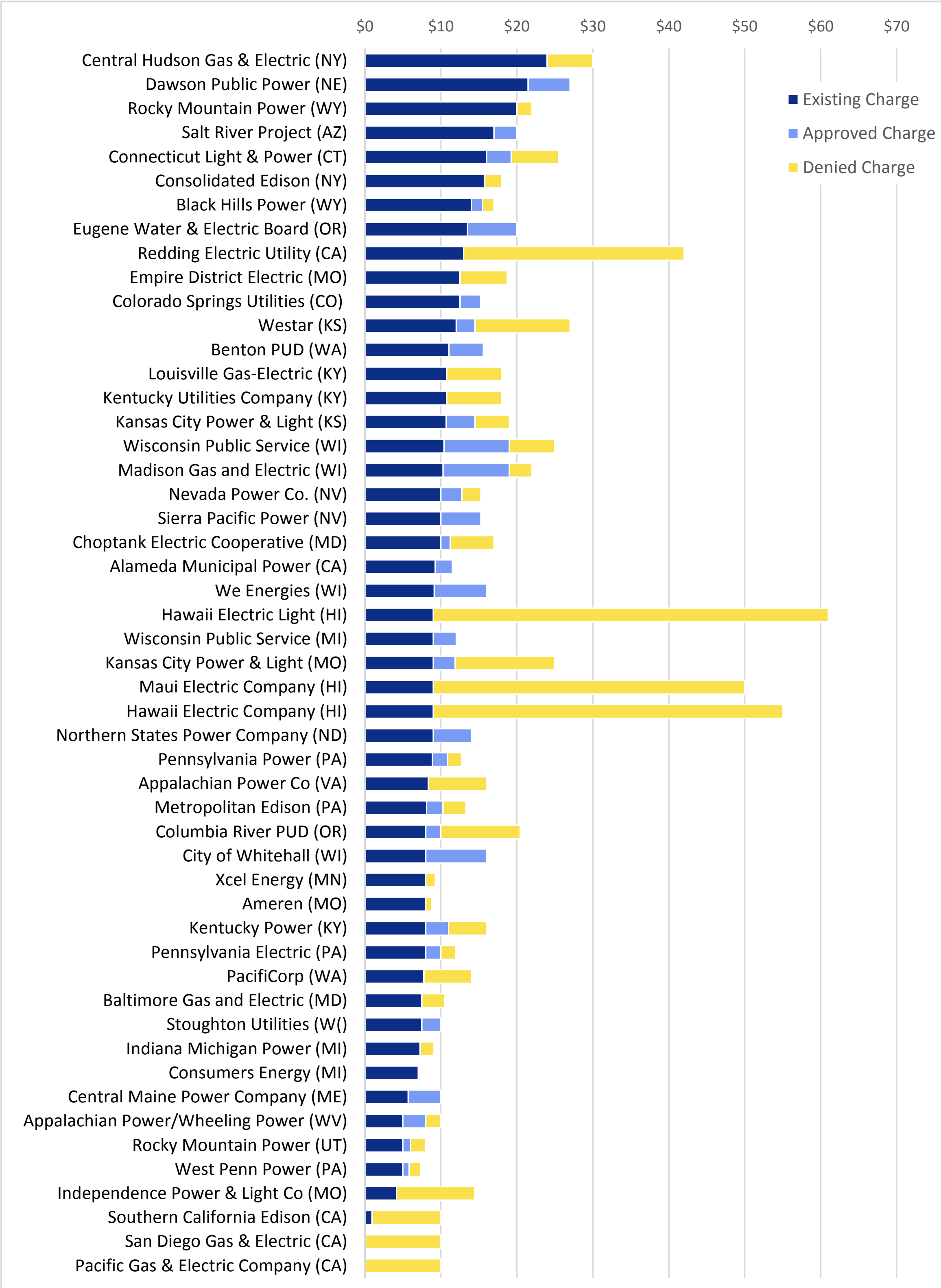
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Avista Utilities (ID)	AVU-E-15-05	$5.25	$8.50		Active docket
Avista Utilities (WA)	UE-150204	$8.50	$14.00		
Detroit Edison (MI)	U-17767	$6.00	$10.00		Proposed order has rejected residential increase
El Paso Electric (TX)	44941	$7.00	$10.00		Public hearings ongoing
El Paso Electric (NM)	15-00127-UT	$5.04	$10.04		Public hearings ongoing
Entergy Arkansas, Inc. (AR)	15-015-U	$6.96	$9.00		Active docket
Indianapolis Power & Light (IN)	44576/44602	$11.00	$17.00		Active docket, values reflect proposal for customers that use more than 325 kWh
Lincoln Electric System (NE)	City council proceeding	$11.15	$13.40		City council decision is pending
Long Island Power Authority (NY)	15-00262	$10.95	$20.38		Rejected by PSC, LIPA Board has ultimate decision
Montana-Dakota Utilities (MT)	D2015.6.51	$5.48	$7.60		BSC based on per day not per month, values converted to monthly
National Grid (MA)	D.P.U. 15-120	$4.00	$13.00		Proposed as part of Grid Mod plan, presented as "Tier 3" customer, for use between 601 to 1,200 kWh per month
National Grid (RI)	RIPUC DOCKET NO. 4568	$5.00	$13.00		Presented as "Tier 3" customer, for use between 751 to 1,200 kWh per month
NIPSCO (IN)	44688	$11.00	$20.00		Active Docket
Omaha Public Power District (NE)	Public power	$10.25	$30.00		Based on news coverage of stakeholder meetings. No specific number submitted, $20, $30, $35 where floated past stakeholders
PECO (PA)	R-2015-2468981	$7.12	$12.00	$8.45	Settlement not yet ratified
Public Service Company of New Mexico (NM)	15-00261-UT	$5.00	$13.14		Public hearings ongoing
Portland General Electric (OR)	UE 294	$10.00	$11.00		Proposed
Pennsylvania Power and Light (PA)	R-2015-2469275	$14.09	$20.00	$14.09	Settlement not yet ratified
Santee Cooper (SC)	State utility	$14.00	$21.00		Pending, expected decision in December 2015
Springfield Water Power and Light (IL)	Municipal board	$5.76	$12.87		Pending as of Oct 1 2015
Sulfur Springs Valley Electric Coop (AZ)	E-01575A-15-0312	$10.25	$25.00		Active docket
Sun Prairie Utilities (WI)	5810-ER-106	$7.00	$16.00		
UNS Electric Inc. (AZ)	E-04204A-15-0142	$10.00	$20.00		Active docket, hearings in March 2016
Xcel Energy (WI)	4220-UR-121	$8.00	$18.00		

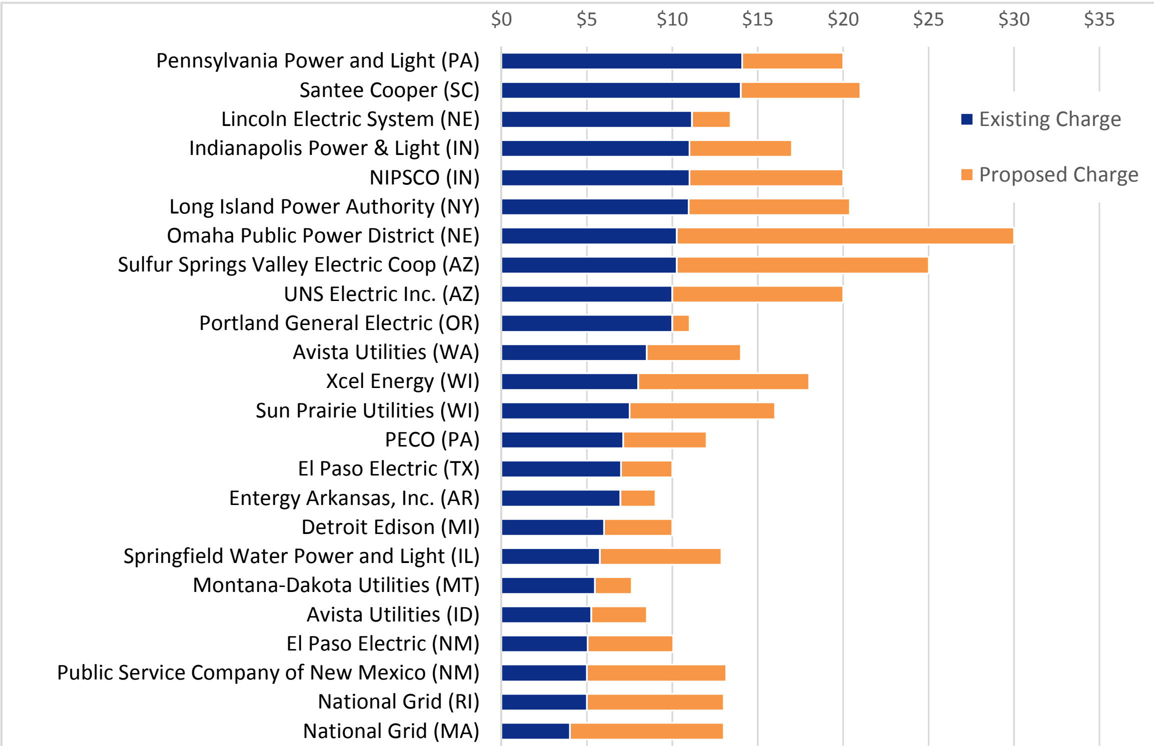
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Figure 13. Existing and proposed fixed charges of utilities with pending proceedings to increase fixed charges

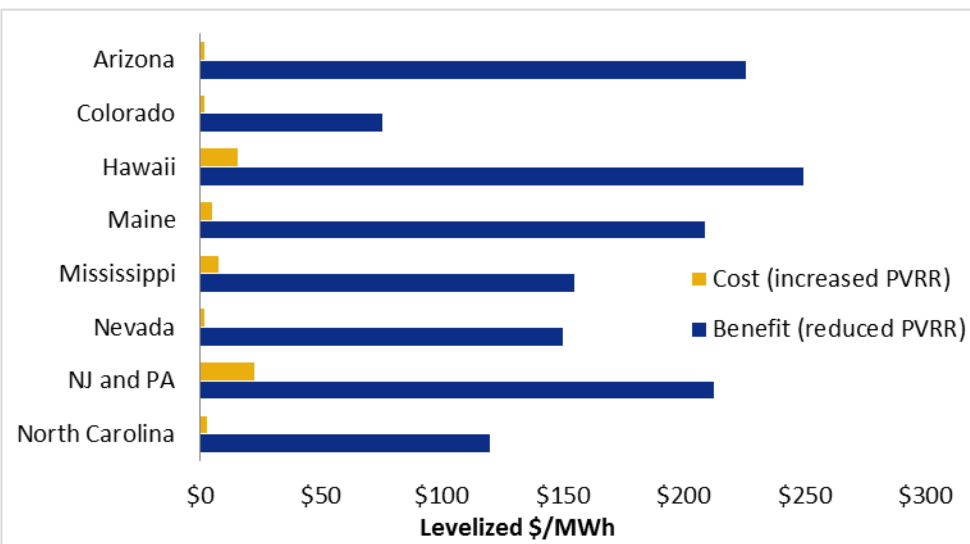


APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS

A utility's revenue requirement represents the amount of revenue that it must recover from customers to cover the costs of serving customers (plus a return on its investments). Customers who invest in distributed PV may increase certain costs while reducing others. Costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost. At the same time, a NEM system will avoid other costs for the utility, such as energy, capacity, line losses, etc. These avoided costs will reduce revenue requirements, and thus are a benefit. These costs and benefits over the PV's lifetime can be converted into present value to determine the impact on the utility's present value of revenue requirements (PVRR).

Over the past few years, at least eight net metering studies have quantified the impact of NEM on a utility's revenue requirement. Key results from these studies are summarized in the table and figure below. Note that only those costs and benefits that affect revenue requirements are included as costs or benefits. If a study included benefits that do not affect revenue requirements (such as environmental externality costs, reduced risk, fuel hedging value, economic development, and job impacts), then they were subtracted from the study results. Similarly, the costs presented below include only NEM system integration, interconnection, and administration costs.[48] Other costs that are sometimes included in the studies but do not affect revenue requirements, such as lost revenues, are not included.

Figure 14. Recent studies indicate extent to which NEM benefits exceed costs



[48] Historically, some utilities have offered incentives to customers that install solar panels (or other NEM installations). While these incentive payments do put upward pressure on revenue requirements, the incentives themselves are removed from Figure 14 and Table 3 to help compare costs and benefits when utility-specific incentives are taken out of the equation.

Table 3. Net metering studies that report PVRR benefits and costs

Year	State	Funded / Commissioned by	Prepared by	Benefit ($/MWh)	Cost ($/MWh)	Benefit-Cost Ratio
2013	Arizona	---------	Crossborder Energy	226*	2	113
2013	Colorado	Xcel Energy	Xcel Energy	75.6	1.8	42
2014	Hawaii	HI PUC	E3	250*	16	16
2015	Maine	Maine Public Utilities Commission	Clean Power Research, et. al.	209	5	42
2014	Mississippi	Mississippi Public Service Commission	Synapse Energy Economics	155	8	19
2014	Nevada	State of Nevada Public Utilities Commission	E3	150	2	75
2012	NJ and PA	Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association	Clean Power Research	213*	23*	9
2013	North Carolina	NC Sustainable Energy Association	Crossborder Energy	120*	3	40

**Indicates that the value displayed in the table is the midpoint of the high and low values reported in the study.*

Source: Synapse Energy Economics, 2015.

Arizona

The Arizona study, performed by Crossborder Energy, presents 20-year levelized values in 2014 dollars.[49] Benefits include avoided energy, generation capacity, ancillary services, transmission, distribution, environmental compliance, and costs of complying with renewable portfolio standards. The avoided environmental benefits account for non-CO_2 market costs of NO_X, SO_X, and water treatment costs, and thus are included as revenue requirement benefits. The benefits range from $215 per MWh to $237 per MWh. Figure 14 and Table 3 present the midpoint value of this range: $226 per MWh. The report estimates integration costs to be $2 per MWh.

Colorado

The Colorado study, performed by the utility Xcel Energy, presents 20-year levelized net avoided costs under three cases in the report's Table 1.[50] The benefits include avoided energy, emissions, capacity, distribution, transmission and line losses. The benefits also include an avoided hedge value, which does not affect revenue requirements. Removing the hedge value from the benefits yields a revenue

[49] Crossborder Energy. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Page 2. Table 1.

[50] Xcel Energy. 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. Executive Summary, page V.

requirement benefit of $75.6 per MWh. The study estimates solar integration costs to be $1.80 per MWh.

Hawaii

The Hawaii study, performed by E3, presents the 20-year levelized costs and benefits of NEM on the various Hawaii utilities (HECO, MECO, HELCO, and KIUC). The base case NEM benefits are $213 per MWh for KIUC,[51] $234 per MWh for MECO,[52] $242 per MWh for HELCO,[53] and $287 for HECO.[54] Figure 14 and Table 3 present the midpoint of these values: $250 per MWh. The NEM revenue requirement costs are estimated to be $16 per MWh, which includes integration costs ($6 per MWh) and transmission and distribution interconnection costs ($10 per MWh).[55]

Maine

The Maine study, prepared by several co-authors, presents the 25-year levelized market and societal benefits for Central Maine Power Company.[56] The revenue requirement benefits, including avoided costs and market price response benefits, are $209 per MWh. The study estimates the NEM revenue requirement costs to be $5 per MWh, reflecting NEM system integration costs.

Mississippi

The Mississippi study, prepared by Synapse Energy Economics, presents base case 25-year levelized benefits associated with avoided energy, capacity, transmission and distribution, system losses, environmental compliance costs, and risk.[57] The total revenue requirements benefit is $155 per MWh, which excludes the $15 per MWh risk benefit. The NEM administrative costs are estimated to be $8 per MWh.

Nevada

The Nevada study, conducted by E3, presents costs and benefits on a 25-year levelized basis in 2014 dollars. The study estimates the costs and benefits for several "vintages" of rooftop solar. Figure 14 and Table 3 present the vintage referred to as "2016 installations," because this is most representative of

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[51] E3, Evaluation of Hawaii's Renewable Energy Policy and Procurement, January 2014, page 53, Figure 26.

[52] Ibid. Page 50, Figure 23.

[53] Ibid. Page 47, Figure 20.

[54] Ibid. Page 43, Figure 17.

[55] Ibid. Pages 55 and 56.

[56] Clean Power Research, Sustainable Energy Advantage, & Pace Law School Energy and Climate Center for Maine PUC. 2015. *Maine Distributed Solar Valuation Study*. Page 50. Figure 7.

[57] Synapse Energy Economics for Mississippi PSC. 2014. *Net Metering in Mississippi*. Pages 33 and 38.

costs and benefits in the future. The revenue requirement benefits, including avoided costs and renewable portfolio standard value, are estimated to be $150 per MWh. The E3 study also reports the "incentive, program, and integration costs" to be $6 per MWh.[58] This value includes the integration costs, which were assumed by E3 to be $2 per MWh.[59] Customer incentive costs are not included in any of the results presented in Figure 14 and Table 3, so the revenue requirement costs for Nevada include only the integration costs of $2 per MWh.

New Jersey and Pennsylvania

The New Jersey and Pennsylvania study, prepared by several co-authors, presents the 30-year levelized value of solar for seven locations.[60] The benefits include energy benefits (that would contribute to reduced revenue requirements), strategic benefits (that may not contribute to reduced revenue requirements), and other benefits (some of which would contribute to reduced revenue requirements). To determine the revenue requirement benefits, the benefits associated with "security enhancement value," "long term societal value," and "economic development value" are excluded. The highest reported benefit value was in Scranton ($243 per MWh) and the lowest value was reported in Atlantic City ($183 per MWh). Figure 14 and Table 3 present the midpoint of these two values: $213 per MWh. Similarly, they present the midpoint of the solar integration costs ($23 per MWh).

North Carolina

The North Carolina study, prepared by Crossborder Energy, presents 15-year levelized values in 2013 dollars per kWh. The benefits are presented for three utilities separately. A high/low range of benefits were presented for each benefit category (energy, line losses, generation capacity, transmission capacity, avoided emissions, and avoided renewables). The low avoided emissions estimate reflects the costs of compliance with environmental regulations, which will affect revenue requirements, but the high avoided emissions estimate reflects the social cost of carbon, which will not affect revenue requirements. Therefore, the low avoided emissions value ($4 per MWh) is included, but the incremental social cost of carbon value ($18 per MWh) is excluded. The lowest revenue requirement benefit presented in the study is $93 per MWh for DEP, and the highest one is $147 per MWh for DNCP (after removing the incremental social cost of carbon). Figure 14 and Table 3 present the midpoint between the high and low values, $120 per MWh, as the revenue requirement benefit. The study also identifies $3 per MWh in revenue requirement costs.

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[58] E3 for Nevada PUC. 2014. *Nevada Net Energy Metering Impacts Evaluation*. Page 96.

[59] Ibid. Page 61.

[60] Clean Power Research for Mid-Atlantic & Pennsylvania Solar Energy Industries Associations. 2012. *The Value of Distributed Solar Electric Generation to NJ and PA*. Page 18.

GLOSSARY

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. (See Marginal Cost Pricing, Value-Based Rates.)

Capacity: The maximum amount of power a generating unit or power line can provide safely.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility (see Value-Based Rates).

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or Critical Peak Pricing (CPP): Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer Charge: A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.

Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a certain period. The charge may be designed in many ways. For example, it may be based on a customer's maximum demand during a monthly billing cycle, during a seasonal period, or during an annual cycle. In addition, some demand charges only apply to a customer's maximum demand that coincides with the system peak, or certain peak hours. Typically assessed in cents per kilowatt.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. (See Marginal Cost.)

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed (i.e., cents per kilowatt-hour).

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

Flat Rate: A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Inverted Rates/Inclining Block Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Load Shape: The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Long-Run Marginal Costs: The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. (See Embedded Cost.)

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

Rate Case: A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs.

Straight Fixed Variable (SFV) Rate Design: A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Time-of-Use Rates: A form of time-varying rate. Typically the hours of the day are segmented to "off-peak" and "peak" periods. The peak period rate is higher than the off-peak period rate.

Time-Varying Rates: Rates that vary by time of day in order to more accurately reflect the fluctuation of costs. A common, and simple form of time-varying rate is time-of-use rates.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. (See Short Run Marginal Cost.)

Volumetric Rate: A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the customer (e.g., cents/kWh, or cents/kW). May also be referred to as the "variable rate." If referring to cents per kilowatt-hour, it is often referred to as the "energy charge."

Adapted from Lazar (2011) "Electricity Regulation in the US: A Guide." Regulatory Assistance Project.

Electricity and Natural Gas Consumption Analysis: NCLC Methodology and Results

National Consumer Law Center (NCLC) generated electricity usage tables and graphs using microdata from the U.S. Department of Energy, Energy Information Administration 2009 Residential Energy Consumption Survey (RECS). The 2009 RECS includes detailed residential energy consumption and expenditure information from 27 U.S. geographic areas referred to as "reportable domains." Some reportable domains reflect data from a single state while others are comprised of multiple, adjoining states.

The RECS survey instrument includes questions regarding a broad range of demographic factors and household characteristics. Using SPSS statistical software NCLC tabulated RECS consumption and demographic data by reportable domain to generate the tables and graphs of kilowatt-hour usage by poverty status, household income category, race, age, and Hispanic origin.

Results of these analyses clearly demonstrate that – on average and with remarkable consistency across the U.S. – lower-income, African American, Latino, and elder-headed households use less electricity than their counterparts. Therefore, utility proposals to increase mandatory fees and charges while de-emphasizing the volumetric portion of customers' bills penalize low-volume consumers and disproportionately harms these groups of ratepayers.

Contact: John Howat
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Customer Concerns with Implementing Demand Rates

NASUCA and NARUC Conferences
Austin, Texas
November 2015

David Springe
Consumer Counsel
Kansas Citizens' Utility Ratepayer Board

Don’t believe the Rhetoric

- *“It is widely agreed that existing tariffs do not reflect the cost structure of providing electricity service to customers”*

  = FALSE

- *“Consumer advocates refuse to discuss changes to rate design”*

  = FALSE

What is the Objective?

- Collect costs through fixed charges?
  - Raising customer charges is unpopular
  - Demand charges achieve same result if you can’t actually avoid them
- Achieve better efficiency through demand prices?
  - Must be based on coincident peak
  - Must remove other price suppression measures
  - Must ask-”is there a better way to do this?”

Legitimate Concerns

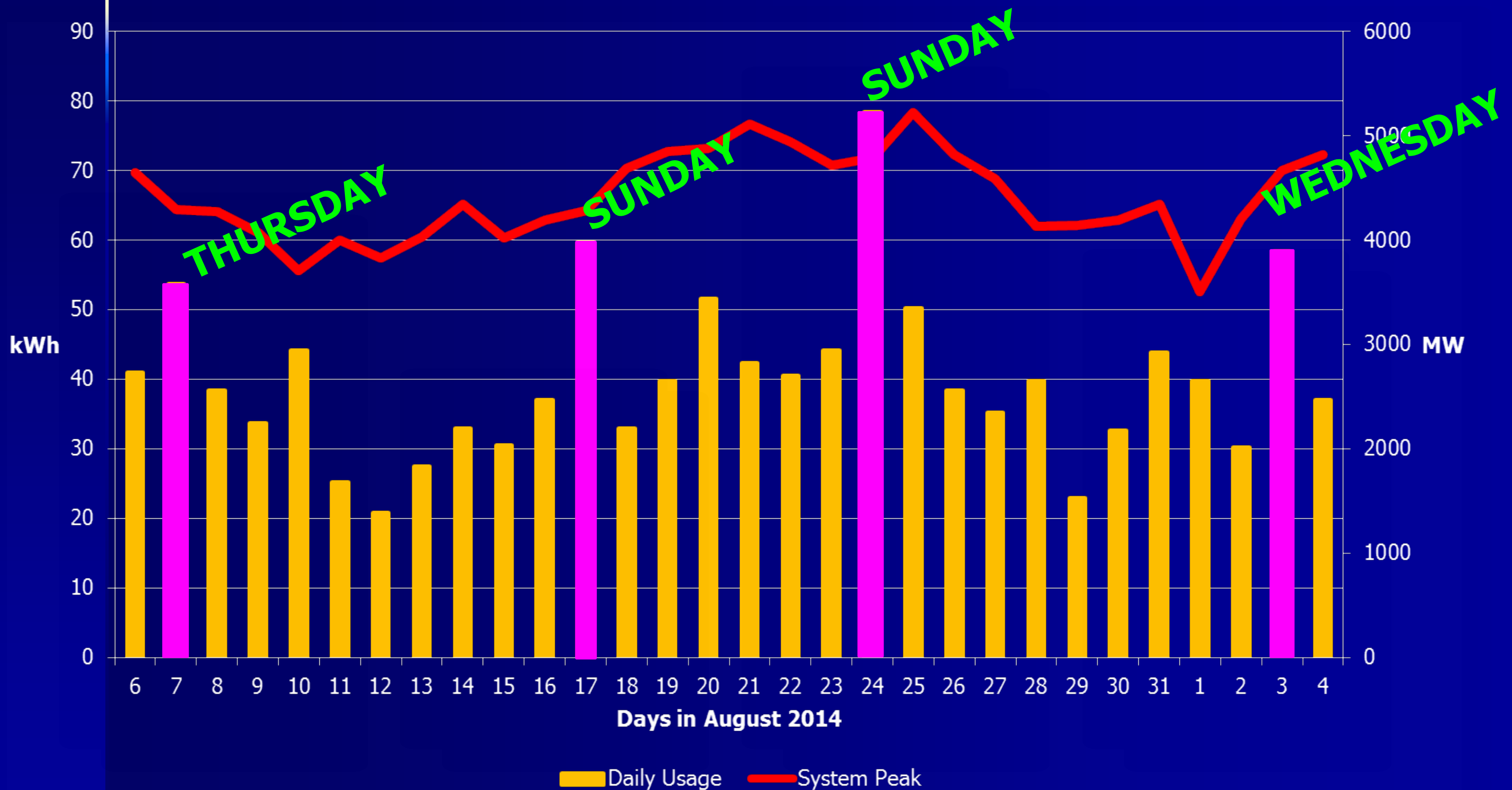
- Higher bills for low use customers
  - Low use customers may be low income
- Limited ability to change usage
  - Some things must run (AC, Refrig, Med)
- Difficult to understand
  - Difference between broad concept and actual understanding of KW use

Legitimate Concerns

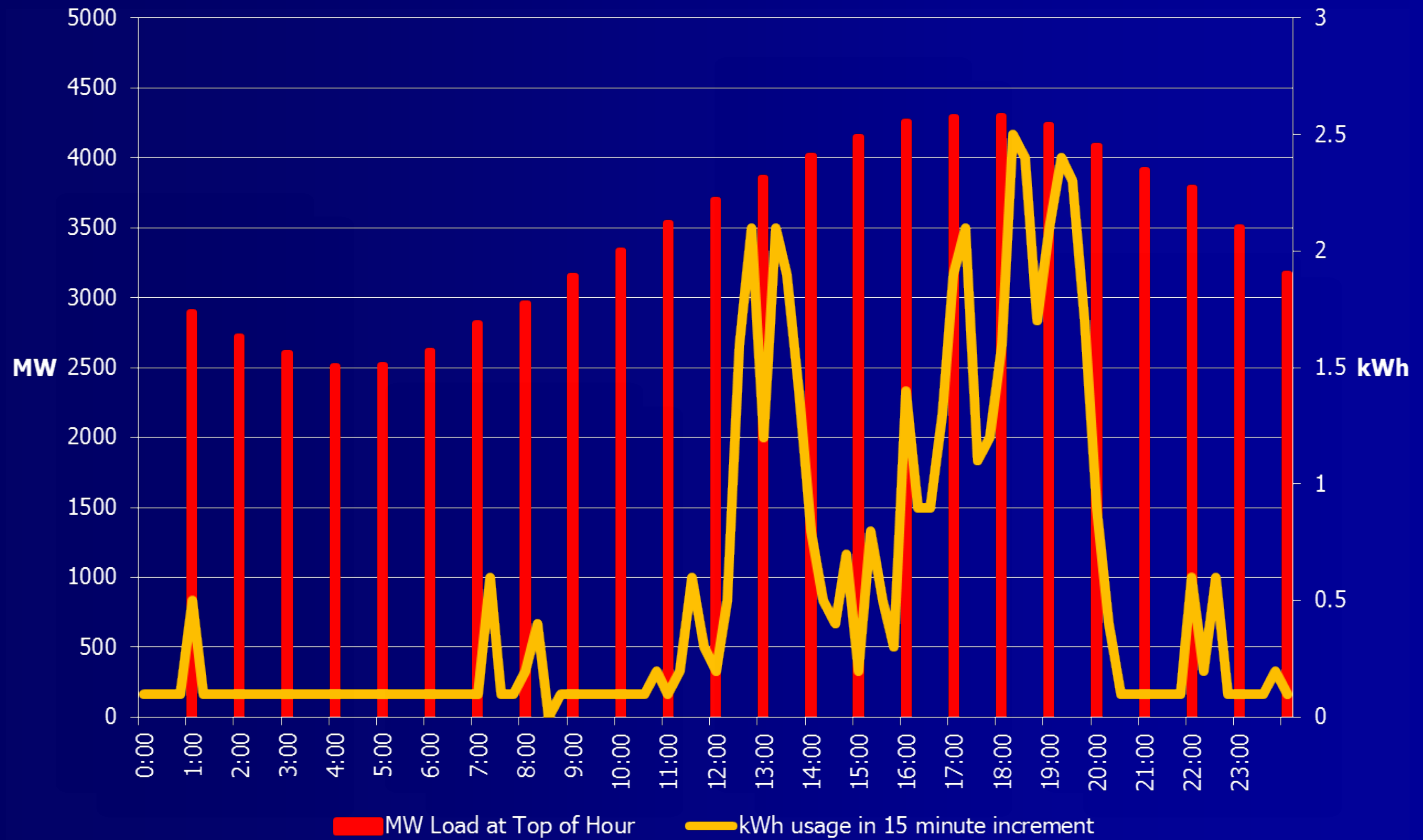
- Smart meters don’t read KW’s
- Residential has more diversity than large commercial or industrial
- Very difficult to calculate correct KW rate in ratemaking process

2014 Monthly kWh Usage vs System Peak (MW)

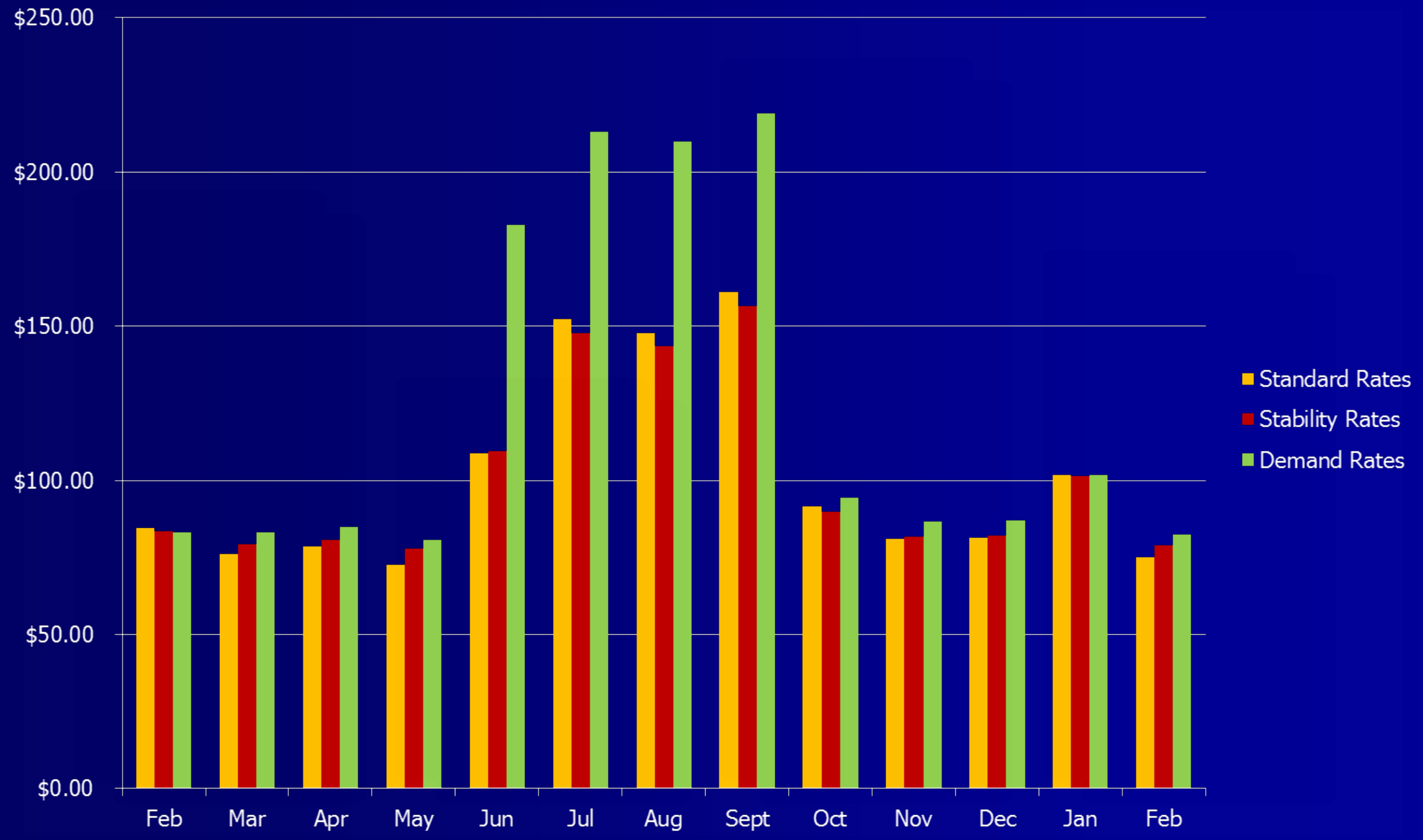
August Billing Cycle:
Daily kWh usage vs Daily System Peak (MW)



August 7, 2014
kWh usage (15 minute increments) vs Hourly System Load (MW)



Bill impacts: Standard Rates verse Demand Rates



Predictable Result

Bill impact of Demand Rates

				Westar Proposed Rate Design		
		kWh	Kw	Standard	Stability	**Demand**
2014	Feb	582	6	$84.53	$83.46	**$83.33**
	Mar	513	8	$76.29	$79.49	**$83.37**
	Apr	533	8	$78.68	$80.64	**$85.10**
	May	483	8	$72.71	$77.76	**$80.77**
	Jun	785	10	$108.79	$109.59	**$182.89**
	Jul	1134	10	$152.24	$147.85	**$213.07**
	Aug	1100	10	$147.92	$143.51	**$210.13**
	Sept	1203	10	$161.00	$156.64	**$219.04**
	Oct	640	8	$91.46	$89.92	**$94.35**
	Nov	553	8	$81.07	$81.79	**$86.83**
	Dec	557	8	$81.55	$82.02	**$87.17**
2015	Jan	726	8	$101.74	$101.59	**$101.79**
	Feb	504	8	$75.21	$78.97	**$82.59**

Volumetric rates

- Do allocate costs rather elegantly
- Customers do understand kWh’s
- Smart meters actually read kWh’s
- Can set discrete pricing times to send better price signals
- Can give same education as demand rates to achieve same goal

Conversation Checklist

- What is the objective?
- What is the specific plan?
- Does the plan support the objective?
- Does the data/evidence support the plan and objective?
- Is there a easier/better way?
- Protections for vulnerable customers?
- 2nd and 3rd order concerns

Contact Information

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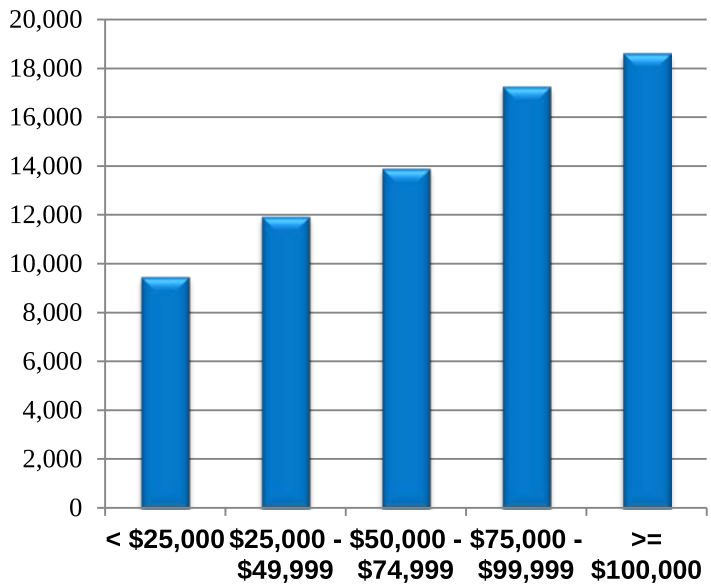
NCLC®

NATIONAL CONSUMER LAW CENTER®

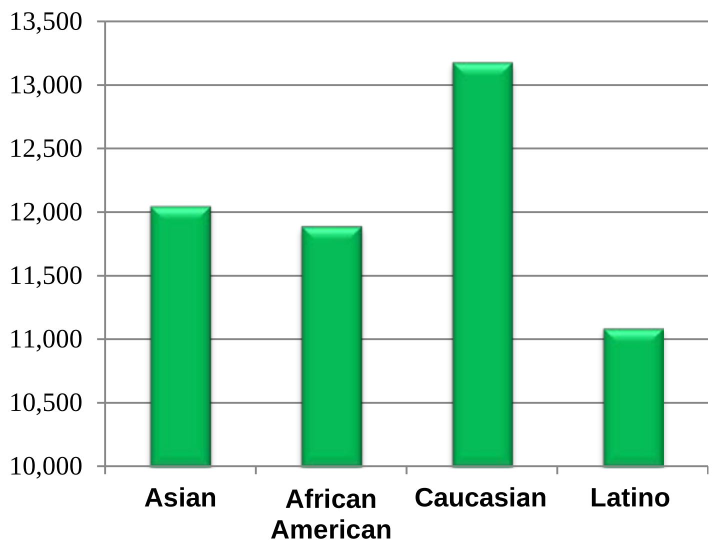
Utility Rate Design:
How Mandatory Monthly Customer Fees Cause Disproportionate Harm

U.S. Region: TX

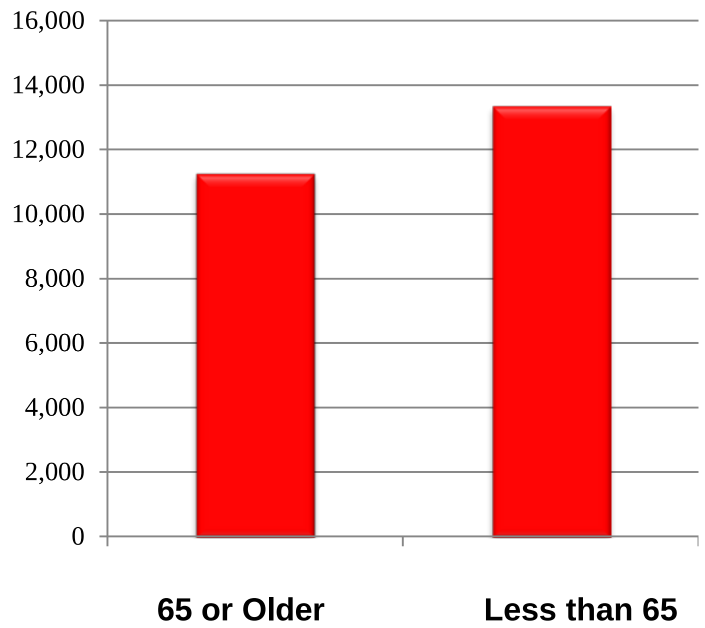
Median 2009 Residential Electricity Usage (KWH), by Income



Median 2009 Residential Electricity Usage (KWH), by Race/Ethnicity



Median 2009 Residential Electricity Usage (KWH), by Age



2009 Residential Energy Consumption by Income, Race/Ethnicity, & Age

HOUSEHOLD INCOME	MEDIAN ELECTRICITY USAGE (KWH)
< $25,000	9,484
$25,000 - $49,999	11,948
$50,000 - $74,999	13,920
$75,000 - $99,999	17,274
>=$100,000	18,631

HOUSEHOLD RACE	MEDIAN ELECTRICITY USAGE (KWH)
Asian	12,052
African American	11,894
Caucasian	13,183
Latino	11,094

HOUSEHOLD AGE	MEDIAN ELECTRICITY USAGE (KWH)
65 years or older	11,265
Less than 65 years	13,358

Source: U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available)

BEFORE THE ARIZONA CORPORATION C

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COMMISSIONERS

DOUG LITTLE, Chairman
BOB STUMP
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ANDY TOBIN

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AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142 **NOTICE OF FILING SURREBUTTAL TESTIMONY** **ARIZONA UTILITY RATEPAYER ALLIANCE**

The Arizona Utility Ratepayer Alliance ("AURA") hereby files surrebuttal testimony by its witnesses, Patrick J. Quinn, Thomas Alston, and Scott J. Rubin.

Respectfully submitted on February 23, 2016, by:

Craig A. Marks

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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY
OF
PATRICK J. QUINN
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
FEBRUARY 23, 2016

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Patrick J. Quinn. My business address is 5521 E. Cholla St., Scottsdale, AZ 85254, and my phone number is (602) 579-1934.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. ARE YOU THE SAME PATRICK J. QUINN WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. AURA proposes modifications to the rate design proposals from Unisource Electric, Inc. ("UNSE") and the Arizona Corporation Commission's Utility Division Staff's ("Staff").

Specifically, the Commission should approve UNSE's rebuttal two-part rate (termed the "transition" rate) as the permanent residential rate design, not UNSE's rebuttal three-part rate. However, the residential customer charge should be lowered from $15.00 to RUCO's proposed $12.26, with any reduction in revenues spread over the usage charges once a revenue requirement is approved. Additionally, as Staff suggests, there should be no changes to net metering until the generic docket on the cost and value of solar is completed.

Q. WHY DOES AURA SUPPORT THE UNSE REBUTTAL TWO-PART RATE?

The rebuttal two-part rate:

- Avoids the numerous problems associated with a mandatory demand charge;

- Is fairer to customers and consistent with best-practice rate design principles that include understandability, ease of administration, nondiscrimination, revenue stability, and gradualism; and
- Is superior to a three-part rate in aligning costs of service with cost recovery.

Q. WHY DOES AURA OPPOSE THE UNSE REBUTTAL THREE-PART RATE?

First, and most importantly, the testimony of nationally-recognized rate design expert Scott Rubin demonstrates that facts do not support UNSE's assertion that its proposed three-part rate design recovers costs more equitably, promotes fairness, and reduces intra-class subsidization. In fact, precisely the opposite is true. Compared to UNSE's rebuttal two-part rate design proposal, its proposed rebuttal three-part rate design is less equitable, unfair to lower-cost customers, and increases intra-class subsidization.

Q. ARE THERE OTHER REASONS WHY THE UNSE REBUTTAL THREE-PART RATE SHOULD NOT BE APPROVED?

Yes. A significant reason that UNSE's three-part rate design does not work is that over 80 percent of UNSE residential demand costs are based on summer peaks and the relationship between billing demand and summer peak demand is relatively weak. This is a common issue with residential demand charges. As a recent article by Jim Lazar published in *Natural Gas and Electricity* points out, "Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak."[1]

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[1] Lazar, Jim. "Use Great Caution in Design of Residential Demand Charges." *Natural Gas & Electrify, Regulatory Assistance Project* February, 2016 P.15.

Q. ARE THERE ANY OTHER REASONS WHY THE UNSE REBUTTAL THREE-PART RATE SHOULD NOT BE APPROVED?

Yes. Tom Alston discusses issues inherent to mandatory demand charges as they have currently been proposed. Other downsides of these charges are that they:

- May be overly confusing and limit residential customers' ability to control their bills;
- May negatively affect property values;
- May overly burden low and fixed income customers;
- Are untested in other service territories; and
- Are inconsistent with accepted best practices.

Q. DOES AURA OPPOSE VOLUNTARY DEMAND CHARGES?

A. No, AURA supports customer choice and would not oppose properly designed voluntary demand charges.

Q. WOULD ADOPTING UNSE'S AND STAFF'S RECOMMENDED RATE DESIGNS SUPPORT ECONOMIC DEVELOPMENT?

A. No. UNSE has expressed a desire to "play a bigger role in attracting and promoting the growth of businesses in its service territories," and has proposed an Economic Development Rate ("EDR") to help promote economic development. A proven and well-studied[2] way to support this development is to promote Distributed Generation ("DG"). Unfortunately, demand charges have the effect of greatly reducing the economic benefits

---

[2] Solar Jobs Census, *Energy Foundation Arizona* 2014
http://www.thesolarfoundation.org/wp-content/uploads/2015/02/Arizona-Solar-Jobs-Census-2014.pdf

Distributed Generation Standard Contracts and Renewable Energy Fund Jobs, Economic and Environmental Impact Study, *Brattle Group* April 30, 2014
http://www.energy.ri.gov/documents/DG/RI%20Brattle%20DG-REF%20Study.pdf

The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania *MSEIA* November, 2012
http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

of Distributed DG systems. Under the proposed three-part rate, a DG system, such as roof-top solar, would not typically be producing energy concurrently with the demand assessment time period (although it may coincide with the system peak) and thus reduce demand charges only slightly if at all. If economic development is truly a concern then DG should be supported through the adoption of the UNS rebuttal two-part rate.

The Alliance for Solar Choice has made a well-reasoned case for the value of DG. AURA supports a thorough investigation of DG costs and benefits, as part of a larger investigation into the costs and benefits of all customer subsidies.

Q. SHOULD ANY RATE DESIGN CHANGES THAT INCLUDE DEMAND CHARGES BE POSTPONED UNTIL THE NEXT RATE CASE?

A. Yes, Mr. Rubin demonstrates that UNSE's three-part rate design would actually further shift costs to low-usage customers, so for that reason alone this proposal should be rejected in this case. Further, because of the radical nature of the rate-designs proposed, the short time for full consideration, and the lack of full participation from the communities most affected (due to a short comment period), any significant rate-design changes should be postponed until UNSE's next rate case.

Q. IF THE COMMISSION APROVES A THREE PART RATE, SHOULD IMPLEMENTATION BE DELAYED FOR STUDY?

A. Should the Commission authorize a three-part rate instead of the rebuttal two-part rate, UNSE should only make the new rate available to customers on a voluntary basis to allow for education and data collection.

The included testimony of Scott Rubin conclusively demonstrates that the three-part rate, as currently proposed, is ineffective in recovering demand-related costs and any revision should be based on data from customers participating in a pilot study.

Q. WHAT IS AURA'S POSITION ON ENERGY EFFICIENCY?

AURA agrees with most of what the Southwest Energy Efficiency Project ("SWEEP") states in its testimony. We support Energy Efficiency as a low-cost energy resource and recognize a need for an increase in funding and a more streamlined method of approving the Integrated Resource Plan. To insure continued funding of EE programs a more stable cost recovery mechanism than is currently utilized must be approved. SWEEP's proposal to fund EE in base rates is a viable alternative.

Q. SHOULD ANY PROPOSED RATE BE BASED ON ACTUAL CUSTOMER DATA?

A. Yes. Actual customer data must be analyzed to evaluate the impact of different rate design options. Rate impacts have the potential to surprise in some analyses, for example, essentially no improvement in cost relationships were achieved after a move to rates based on billing demand. The goal is to Remember One Thing: Customers. UNS must obtain real data from customers and analyze the actual bill impacts (and relationship to cost) of different rates design options. Data and experience from other jurisdictions should also be evaluated.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY
OF
THOMAS ALSTON
ON BEHALF OF
ARIZONA UTILITY RATEPAYER ALLIANCE
FEBRUARY 23, 2016

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Thomas D. Alston My business address is 5521 E. Cholla St., Scottsdale, AZ 85254, and my phone number is 602-524-9978.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

Q. ARE YOU THE SAME THOMAS ALSTON WHO PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?

A. Yes.

Q. ARE DEMAND CHARGES OVERLY CONFUSING?

A. Yes. Demand charges are more difficult to understand than time-of-use charges. Large companies often hire sophisticated consultants to help them effectively manage demand charges. Residential customers do not have access to these resources. Residential demand charges have traditionally favored upper-income home owners with the time, resources, and education to understand complex rate designs and bills. As I discuss later in my testimony, low-income customers may have more difficulty adjusting to a demand-based rate design.

Below, is a typical APS residential bill that includes demand charges. To fully understand this bill, and accordingly how to adjust behavior to minimize charges, a customer would need to know the following:

1. On peak vs off peak per-kWh charges and when peak times occur;
2. What a per-kW demand charge actually is;

3. When the demand charge occurred and what was going on in the house to cause usage to spike;
4. Whether or not peak demand only occurs during on-peak hours;
5. What percentage of the bill can be attributed to per kWh charges vs demand charges (there are several demand charges on this bill that would have to be added together);
6. How to control demand by limiting total usage, for instance, it is intuitive to make sure that lights in a house are turned off when not in use but less intuitive to make sure an AC unit does not kick on while doing laundry; and
7. It is up to the Commission to decide if the answer to these questions can be reasonably derived from bills, such as the one below, by the average residential customer.

Your electricity bill [redacted]
August 12, 2015

Your account number [redacted]

Your service plan: Combined Advantage 7pm - Noon

Meter number: [redacted]
Meter reading cycle: 08

Charges for electricity services

Cost of electricity you used

Customer account charge	$6.90
Delivery service charge	$52.49
Demand charge on-peak - delivery	$50.40
Environmental benefits surcharge	$11.34
Federal environmental improvement surcharge	$0.41
System benefits charge	$11.13
Power supply adjustment*	$3.33
Metering*	$5.39
Meter reading*	$1.80
Billing*	$2.03
Generation of electricity on-peak*	$43.69
Generation of electricity off-peak*	$68.02
Demand charge on-peak - generation*	$100.80
Federal transmission and ancillary services*	$19.49
Federal transmission cost adjustment*	$24.61
Four-Corners adjustment*	$7.35
LFCR adjustor	$5.97
Cost of electricity you used	$415.15

Taxes and fees

Regulatory assessment	$0.97
State sales tax	$23.77
County sales tax	$2.97
City sales tax	$11.46
Franchise fee	$8.32
Cost of electricity with taxes and fees	$462.64

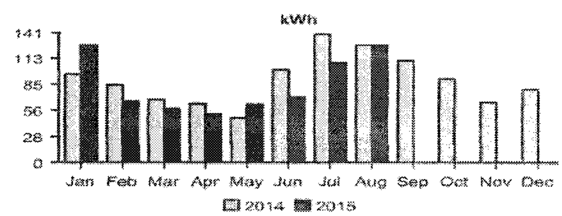
Total charges for electricity services **$462.64**

** These services are currently provided by APS but may be provided by a competitive supplier.*

Amount of electricity you used

Meter reading on Aug 12	43071
Meter reading on Jul 14	39322
Total electricity you used, in kWh	**3749**
On-peak meter reading on Aug 12	6875
On-peak meter reading on Jul 14	6218
On-peak electricity you used, in kWh (Noon to 7 pm Monday to Friday)	**657**
Off-peak electricity you used, in kWh (7 pm to noon weekdays, all day Saturday and Sunday and certain holidays)	**3092**
On-peak demand meter reading	11.2
Your billed on-peak demand in kW	**11.2**

Average daily electricity use per month



Comparing your monthly use

	This month	Last month	This month last year
Billing days	29	32	30
Average outdoor temperature	92°	93°	91°
Your total use in kWh	3749	3513	3884
Percentage of on-peak use	18%	14%	20%
Your billed demand in kW	11.2	7.8	11.7
Your average daily cost	$15.95	$12.15	$15.93

Q. ARE RESIDENTIAL DEMAND CHARGES CONSISTENT WITH BEST PRACTICES FOR HOW SYSTEM CAPACITY COSTS SHOULD BE REFLECTED IN RATES?

A. No, residential customers have a great deal of diversity in their usage, which seldom coincides with the system peak. Below, is a table that shows how three-part vs. two-part rates align with best practices for reflecting capacity costs in rates as outlined in a recent article by Jim Lazar.[1]

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

Q. COULD DEMAND CHARGES AFFECT PROPERTY VALUES?

A. Yes. Vacation homes in use one or two days a month could receive dramatically higher bills as a large portion of each bill would be based on the few days a month the property was in use. This could increase electricity costs for a property by hundreds or even

1 Lazar, Jim. "Use Great Caution in Design of Residential Demand Charges." Natural Gas & Electrify, Regulatory Assistance Project February, 2016 P.15 Exhibit 3

thousands of additional dollars per year, putting a damper on the purchase of vacation homes and the associated tourism that comes with it.

Q. WOULD DEMAND CHARGES DISPORPOTIONATELY AFFECT LOW-INCOME CUSTOMERS?

A. Yes, low-income customers are often time-deprived, and as a result do not have the luxury of spreading out usage load so as to avoid raising peak demand. In other words, if one is pressed for time, sometimes the laundry needs to get done at the same time the air conditioning is running. Low-income customers are also less likely to have access to load-limiters, monitoring devices, and energy efficiency improvements that can help wealthier customers limit their demand. AURA shares the concerns on this matter expressed in the testimony submitted on behalf of the Arizona Community Action Association.

Q. ARE MANDATORY RESIDENTIAL DEMAND CHARGES USED BY OTHER UTILITIES?

A. To AURA's knowledge no other utility in the country has implemented mandatory residential demand charges. There is no compelling reason for the Commission to lead the nation into uncharted rate-design testimony. If the Commission were to approve a three-part rate, it would be forcing all residential customers to adopt a rate design that has not been tested in a real-world setting.

AURA has offered compelling reasons why it would be premature to implement mandatory residential demand charges. And the law of unintended consequences ensures that there would likely be other negative consequences that no party can presently foresee.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

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

DOCKET NO. E-04204A-15-0142

SURREBUTTAL TESTIMONY
OF
SCOTT J. RUBIN
ON BEHALF OF
ARIZONA UTILITY RATEPAYER
ALLIANCE FEBRUARY 23, 2016

I INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND TELEPHONE NUMBER.

A. My name is Scott J. Rubin. My business address is 333 Oak Lane, Bloomsburg, PA 17815, and my phone number is 570-387-1893.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of the Arizona Utility Ratepayer Alliance ("AURA").

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

A. I am an independent consultant and an attorney. My practice is limited to matters affecting the public utility industry.

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

A. I have been asked by AURA to review the rebuttal testimony on rate design issues filed by UNS Electric Inc. ("UNSE").

Q. WHAT ARE YOUR QUALIFICATIONS TO PROVIDE THIS TESTIMONY IN THIS CASE?

A. I have testified as an expert witness before utility commissions or courts in the District of Columbia; the province of Nova Scotia; and the states of Alaska, Arizona, California, Connecticut, Delaware, Illinois, Kentucky, Maine, Maryland, Mississippi, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, and West Virginia. I also have testified as an expert witness before various legislative committees. I also have served as a consultant to the staffs of state utility commissions, as well as to national utility trade associations, and state and local governments throughout the country. Prior to establishing my own consulting and law practice, I was employed by the Pennsylvania

Office of Consumer Advocate from 1983 through January 1994 in increasingly responsible positions. From 1990 until I left state government, I was one of two senior attorneys in that Office. Among my other responsibilities in that position, I had a major role in setting its policy positions on water and electric matters. In addition, I was responsible for supervising the technical staff of that Office. I also testified as an expert witness for that Office on rate design and cost of service issues.

Throughout my career, I developed substantial expertise in matters relating to the economic regulation of public utilities. I have published articles, contributed to books, written speeches, and delivered numerous presentations, on both the national and state level, relating to regulatory issues. I have attended numerous continuing education courses involving the utility industry. I also have participated as a faculty member in utility-related educational programs for the Institute for Public Utilities at Michigan State University, the American Water Works Association, and the Pennsylvania Bar Institute.

Q. HAVE YOU CONTRIBUTED TO ANY BOOKS ON THE TOPIC OF UTILITY RATE DESIGN?

A. Yes. I served on the editorial committee for the fifth edition of *Water Rates, Fees, and Charges* (Manual M1) published by the American Water Works Association in 2000. That book is the primary rate-setting manual for the water utility industry, including cost-of-service studies and rate design.

Q. HAVE YOU PUBLISHED ANY PAPERS ON THE TOPIC OF UTILITY RATE DESIGN?

A. Yes. In November 2015, I published a paper on this topic in *The Electricity Journal.* The paper is entitled "Moving Toward Demand-Based Residential Rates." In that paper, I discussed and analyzed several options for designing cost-based residential rates. A copy of the paper is provided as Exhibit SJR-1 accompanying this testimony.

Q. DO YOU HAVE ANY EXPERIENCE THAT IS PARTICULARLY RELEVANT TO THE ISSUES IN THIS CASE?

A. Yes, I do. I have testified on numerous occasions as a rate design and cost of service expert. For example, during the past three years, I have testified as a cost-of-service study and/or rate design expert in electric utility rate cases in Alaska (Chugach Electric and Municipality of Anchorage), Connecticut (United Illuminating), District of Columbia (Potomac Electric), Illinois (Commonwealth Edison and Ameren), Mississippi (Entergy), Ohio (Duke Energy, Dayton Power & Light, and the FirstEnergy companies), and Pennsylvania (Pike County Light & Power). My complete curriculum vitae is attached to this testimony as Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I testified as a rate design and cost-of-service study expert witness before this Commission in a rate case involving the former Citizens Utilities' water operations in 1996 (Docket Nos. E-1032-95-417, et al.).

II PURPOSE OF TESTIMONY

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

A. In its rebuttal testimony and exhibits, UNSE presents a new rate design for residential customers. UNSE claims that its new rate design, which includes demand charges for residential customers, more equitably recovers the cost of service than the rate design it proposed in its direct case. My testimony will evaluate UNSE's claim using data provided by UNSE as part of its rebuttal filing and workpapers.

III RATE DESIGN TESTIMONY

Q. WHAT DOES UNSE SPECIFICALLY CLAIM REGARDING ITS REVISED RATE DESIGN.

A. Four UNSE rebuttal witnesses claim that its new rate design would be fairer to all residential customers. Specifically, Mr. Hutchens states that UNSE "is attempting to modify its rates to (i) recover costs more equitably … [and] (iv) promote the efficient use of the Company's electric system." Hutchens rebuttal, p. 4, lines 14-17. Similarly, Mr. Dukes testifies in his rebuttal that "UNS Electric is trying to address *all* ratepayer subsidization in this case, by moving rates closer to cost-of-service." Dukes rebuttal, p. 19, lines 23-24 (emphasis in original). Mr. Jones's rebuttal testimony contains a similar claim, where he states: UNSE "is attempting to modify its rates to (i) reduce intra-class subsidization where possible, [and] (ii) promote fairness between like situated customers and recover costs from cost causers." Jones rebuttal, p. 1, lines 24-26. Finally, Dr. Overcast states that "a multi-part rate reflects cost causation more accurately [than an energy-only rate] and when unbundled will be consistent with the principles of cost causation and matching costs and revenues with a proper design." Overcast rebuttal, p. 8, lines 15-17.

Q. DID UNSE PROVIDE ANY ANALYSES TO SUPPORT ITS CONTENTION THAT THE CURRENT TWO-PART RATE DESIGN (CUSTOMER CHARGE AND ENERGY CHARGE) IS NOT CONSISTENT WITH THE COST OF SERVING RESIDENTIAL CUSTOMERS?

A. No.

Q. DID UNSE PROVIDE ANY ANALYSES TO SUPPORT ITS CONTENTION THAT ITS PROPOSED THREE-PART RATE DESIGN (CUSTOMER CHARGE, DEMAND CHARGE, AND ENERGY CHARGE) IS CONSISTENT WITH THE COST OF SERVING RESIDENTIAL CUSTOMERS?

A. No.

Q. HAS UNSE PROVIDED DATA THAT ALLOW SUCH ANALYSES TO BE PERFORMED?

A. Yes, at least in part. UNSE has provided a cost-of-service study ("COSS") from which the essential elements of the cost to serve each customer can be calculated. In addition, UNSE has provided hourly meter reading data for an entire 12-month period for a sample of 100 residential customers. While it would be ideal to have such data for all of UNSE's residential customers, I recognize that most residential customers did not have automated metering equipment installed for the entire test year.

Q. HAVE YOU PERFORMED AN ANALYSIS OF THE COST TO SERVE EACH OF THE 100 CUSTOMERS IN UNSE'S SAMPLE?

A. Yes.

Q. HAVE YOU ALSO COMPARED THE REVENUES THAT EACH OF THOSE 100 CUSTOMERS WOULD PROVIDE UNDER UNSE'S DIFFERENT RATE-DESIGN PROPOSALS?

A. Yes.

Q. BEFORE DISCUSSING THE RESULTS OF YOUR ANALYSES, PLEASE EXPLAIN HOW YOU ESTIMATED THE COST TO SERVE EACH CUSTOMER.

A. The best estimate we have of the cost to serve a customer is a COSS. I recognize that different COSS have been presented in this case, and I do not take a position on the various studies that have been presented. For purposes of consistency, I have used UNSE's most recent COSS provided in the file: *2015 UNSE Schedule G-COSS-R.xlsx*. I say that this is for consistency because I am evaluating UNSE's rate design proposals. So it is reasonable to compare those proposals to UNSE's COSS to test UNSE's claim that its rate design was developed to more closely track the results of its own analysis of the cost to serve customers.

UNSE's COSS includes four types of demand-related functions (production, transmission, distribution primary, and distribution secondary); one energy-related function (essentially fuel and purchased power); and four categories of customer-related functions (delivery, meter, billing and collections, and meter reading). UNSE's study develops a specific cost (a dollar amount) to provide each of these functions to the residential class of customers, each of which is based on a particular allocation methodology, as shown in the following table.

Function	Cost of Service	Allocation to Residential
Production demand	$20,709,455	Coincident peak (A&E/4CP)
Transmission demand	8,775,515	A&E/4CP
Distribution primary demand	10,625,712	Class Non-Coincident Peak (NCP)
Distribution secondary demand	1,173,823	NCP
Total demand-related costs	**$41,284,505**	
Energy	**$44,744,078**	Energy Usage (kWh)
Customer delivery	$ 7,991,033	Number of Customers
Customer meter	646,494	Number of Customers
Customer billing & collections	4,113,357	Number of Customers
Customer meter reading	942,211	Number of Customers
Total customer-related costs	**$13,693,095**	
Total residential cost of service	**$ 99,721,678**	

Source: File: *2015 UNSE Schedule G-COSS-R.xlsx*, Tab: *Functionalization_RES.*

Q. HOW IS THIS INFORMATION USED TO ESTIMATE THE COST TO SERVE A SPECIFIC CUSTOMER?

A. In utility rate cases, rate design and COSS experts (including me) are always talking about "cost causation." It is important to understand what that means. With the possible exception of very large customers under special rates, we do not attempt to determine the actual cost to serve each customer. Indeed, such an analysis would be impossible because each customer is slightly different. Some customers are closer to substations meaning that the distribution circuit serving them is shorter (usually meaning less expensive) than the circuit serving customers who are further from the substation. Some customers have underground service which usually is more expensive than overhead service. Some neighborhoods might have transformers that serve five or ten buildings, while others might have transformers that serve just one or two buildings. Some customers are located further from the street than others meaning that the cost of the service line connecting the distribution line to the premises would be different. I could go on and on. The point is that a cost-of-service study, and ratemaking in general, is designed to estimate the cost to serve the typical customer within a customer class or subclass. The principle of cost causation is not specific to each individual customer, but to customer classes that have certain characteristics in common.

For this reason, when we attempt to determine the cost to serve a particular customer, we are actually determining how a customer's use of the electric system affects the costs that are allocated to the customer's class. For example, secondary distribution costs are allocated among the customer classes based on the class's non-coincident peak ("NCP") demand. During the test year, the residential class's NCP demand occurred on July 24, 2014, in the hour from 4:00 pm to 5:00 pm (appearing in UNSE's data as the hour ending 17).[1] Thus, if we are trying to determine the secondary distribution cost to serve Jane Doe at 123 Any Street, we evaluate how much electricity she used on July 24, 2014, between 4:00 pm and 5:00 pm; that is, how much she contributed to the residential class's demand at the time of the class NCP.

Q. HOW DO YOU USE THIS UNDERSTANDING OF COST CAUSATION TO CONTINUE YOUR ANALYSIS?

A. The next step is to determine the unitized cost of each cost element. For example, as shown in the table above, the residential class has been allocated $13,693,095 of costs based on the number of customers in the class. The class has 82,607 customers.[2] So, each residential customer has "caused" UNSE to incur $165.76 per year in customer-related costs. The following table shows the unitized costs per year for each cost element. A more detailed calculation of these amounts is shown in my Exhibit SJR-2.

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[1] File: *UNSE RES LR Data.xlsx*, Tab: *Res Adj.*
[2] File: *2015 UNSE Schedule G-COSS-R.xlsx* Tab: *G-7 Allocations* Cell: J38

Function	Unitized Cost of Service
Production & transmission	$108.17 per kW based on 4CP
Production & transmission	$70.53 per kW based on average[3]
Distribution demand	$44.13 per kW based on NCP
Energy	$0.054304 per kWh
Customer costs	$165.76 per customer

Q. WHAT DID YOU DO WITH THESE UNITIZED COSTS OF SERVICE?

A. I applied these unitized costs of service to the specific characteristics of each of the 100 customers in the sample provided by UNSE.[4] These specific characteristics are sometimes referred to as a customer's "units of service." That is, for each of the 100 customers in the sample, I determined the customer's demand (in kW) at the time of the system peak (based on the highest coincident peak in each of the four summer months (4CP)),[5] the customer's demand at the time of the class NCP, and the customer's annual energy consumption. In addition, each customer is equal to one customer for the purposes of determining customer-related costs. Each customer's units of service are then multiplied by the corresponding element of the unitized cost of service. When the results for a customer are summed, we have an estimate of the cost to serve each customer.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. The following table shows these calculations for one customer in UNSE's sample.[6]

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[3] Average demand is equal to annual kilowatt-hour consumption divided by the number of hours in the year (8760 in the test year).

[4] The sample of 100 customers was provided as part of Mr. Dukes's rebuttal workpapers in the file: *UNSE Res Hrly 0713-0615.xlsx.*

[5] According to the file: *UNSE RES LR Data.xlsx*, Tab: *Res Adj* the system coincident peaks occurred on July 15, 2014 hour end 18, July 23, 2014 hour end 16, August 6, 2014 hour end 17, and September 2, 2014 hour end 17.

[6] The data are for the customer with the identifier 52657. Note that the figures in the table are rounded for ease of presentation. The more precise estimate of the cost to serve this customer, without rounding, is $672.64.

Function	Unitized Cost of Service	Units of Service	Cost of Service
Production & transmission	$108.17 per kW 4CP	1.45 kW	$ 156.85
Production & transmission	$70.53 per kW avg.	0.46 kW	32.44
Distribution demand	$44.13 per kW NCP	2.25 kW	99.29
Energy	$0.054304 per kWh	4021.2 kWh	218.37
Customer costs	$165.76 per customer	1	165.76
Total cost of service			$ 672.71

Q. WHY IS THIS ESTIMATE OF THE COST TO SERVE EACH CUSTOMER IMPORTANT?

A. This estimate of the cost to serve each customer can be used to compare the revenues that would be collected from each customer under different rate design options. As I explain below, the difference between the costs and revenues under different options can then be compared to determine how well each rate design tracks the cost to serve customers.

Q. DO YOU USE ALL OF THE DATA IN THE ABOVE TABLE TO COMPARE RATE DESIGN OPTIONS?

A. I considered all of these data, but I found that including Energy costs in the analysis tends to mask important differences in rate design options. Approximately 45% of the residential class's cost of service is for energy costs. Those costs are allocated to the customer class based solely on energy consumption, and all of the rate designs (except one) collect these costs from customers using exactly the same factor (energy consumption in kWh). That is, there is essentially no difference among the rate design options in how they recover fuel, purchased power, and related costs. Because energy-related costs are such a large part of customers' bills and the cost of service, it was difficult to see the differences among different rate design options. The results that I discuss below, therefore, compare the distribution portion of customers' bills (all charges except the Base Power Supply Charge (BPSC) and the Purchased Power and Fuel

Adjustment Charge (PPFAC)) with distribution costs (unitized Demand costs and Customer costs from the COSS).

Q. WHAT RATE DESIGNS DID YOU EVALUATE?

A. I evaluated existing rates and five rate design options under proposed rates. The rate design options are UNSE's originally proposed two-part rate, UNSE's originally proposed three-part rate, UNSE's rebuttal two-part rate (termed the "transition" rate design), UNSE's rebuttal three-part rate with no adjustment for load factor, and UNSE's rebuttal three-part rate based on a minimum load factor of 15% in each month.

Q. PLEASE DESCRIBE YOUR FIRST ANALYSIS AND WHAT CONCLUSIONS YOU REACHED FROM IT.

A. My first analysis is provided in Exhibit SJR-3. The solid black line on the graph represents equality between revenues (shown on the left or y axis) and the distribution cost of service (shown on the bottom or x axis). For ease of reference, I will call this the Equality Line. Points that lie above the Equality Line represent customers who are providing revenues in excess of their cost of service; points below the Equality Line are customers whose revenues are less than their cost of service.

The other line on the graph (the dashed line) is the trend (or regression) line. This line represents the best statistical relationship among the 100 points plotted on the graph. The closer this line is to the Equality Line, the better job the rate design does in tracking the customer-specific cost of service.

Three other factors are important to note here. First, the R-square of the trend line (shown below the graph) provides a numeric representation of how closely the trend line represents the individual customers. The closer the R-square is to 1.0, the better the trend line represents the customer data. The second important factor is the slope of the trend line (also shown below the graph). The slope is the change in the annual bill for each $1.00 increase in the cost of serving the customer. The closer the slope is to 1, the better the rate design does in increasing revenues by an amount equal to an increase in costs. Third, I calculate the average percentage difference between each customer's cost of service and revenues (using the absolute value). The smaller the average percentage difference, the closer the rate design comes to tracking each customer's cost of service.

Exhibit SJR-3 shows a comparison of the customer-specific distribution cost-of-service with annual distribution revenues under existing rates. UNSE has asked for a significant increase in distribution revenues, so it is not surprising that existing rates produce substantially less revenues than UNSE claims under proposed rates (that is, almost all points lie below the Equality Line). Thus, the average difference between revenues and costs is 36%. The existing slope is 0.607. This indicates that as costs increase, the existing rate design does not do a very good job of collecting the cost of service from higher-cost customers. Stated differently, higher-cost customers (those with larger demands) are paying a lower percentage of the cost to serve them than are lower-cost customers.

My analysis of existing rates shows that there certainly is room for improvement in the rate design. Not only do rates need to be increased (assuming for the sake of illustration, as I do throughout, that UNSE's revenue requirement claims are justified), but the rate design could be modified to do a better job of collecting revenues from higher-cost customers (that is, move the slope of the trend line closer to 1.0).

Q. PLEASE TURN NOW TO YOUR ANALYSIS OF UNSE'S RATE DESIGN PROPOSALS. WHAT IS SHOWN ON EXHIBIT SJR-4?

A. Exhibit SJR-4 shows UNSE's originally proposed rate design. This is a two-part rate consisting of a customer charge of $20.00 per month and a two-block consumption charge: 3.0810¢ per kWh for the first 400 kWh per month, and 5.0810¢ per kWh for all consumption in excess of 400 kWh per month.[7] My exhibit shows that this rate design constitutes an improvement over existing rates. The slope of the trend line is 0.846. This means that for every $100 by which the cost to serve a customer increases, this rate design collects $84.60 in additional revenues from the customer. This is an improvement over the existing rate design, but it still results in some higher-cost customers paying less than their cost of service.

The average difference between revenues and costs is 22% under this rate design. Once again, this is an improvement over the existing rates where customers' revenues differed from costs by 36%.

One troubling factor with this rate design is that the trend line starts above the Equality Line then crosses the Equality Line at about $800 in costs. In other words, lower-cost customers are paying more than the cost to serve them, while higher-cost customers are paying less than cost. It appears that this inequity is primarily due to the customer charge of $20 per month ($240 per year) which is substantially higher than the unitized customer cost of $165.76 per year. Simply, this rate design has a customer charge that is too high resulting in consumption charges that are too low. This leads to some lower-cost customers (those with lower demands) subsidizing some higher-cost customers (those with higher demands) under this rate design.

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[7] UNSE Schedule H-3 (Revised 6/3/2015), page 1.

Finally, the graph at the bottom of Exhibit SJR-4 (known as a histogram) shows the number of customers whose bills would increase by certain percentages compared to existing rates. Under this rate design, annual distribution bill increases range from 47% to 95%. The bill impacts are quite spread out, with most customers seeing increases in the range of 50% to 85%.

Q. PLEASE DESCRIBE EXHIBIT SJR-5.

A. Exhibit SJR-5 provides the same type of presentation as Exhibit SJR-4, but for UNSE's originally proposed residential three-part (demand) rate. I understand that UNSE originally presented this rate as an optional rate.

This original three-part rate consisted of a customer charge of $20 per month, a charge of $6.00 per kW for the first 7 kW of demand (measured as the maximum one hour during the month, regardless of day of week or time of day)[8] in a month, $9.95 per kW for demand in excess of 7 kW, and a consumption charge of 1.0¢ per kWh for all energy consumed.[9]

UNSE's original three-part rate is notably worse in reflecting the cost of service than UNSE's originally proposed two-part rate. The slope of the trend line is only 0.717 meaning that higher-cost customers would pay much less than the cost to serve them. Further, the average difference between revenues and costs is 35% compared to 22% under the original two-part rate. It also appears that this rate structure was not designed to be applicable to all customers because the total revenues that would be collected from these 100 customers would exceed the cost of serving the customers by more than $9,500 per year (15% more than the cost of service). Finally, this rate structure would have

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[8] Dukes direct testimony, p. 24, lines 8-9.
[9] UNSE Schedule H-3 (Revised 6/3/2015), p. 1.

enormous customer impacts, with more than 45% of customers seeing their annual distribution bills increase by more than 100%. In contrast, a few customers would have annual increases of less than 35%.

Simply stated, UNSE's original three-part rate design did a much worse job of tracking the cost of service than did UNSE's original two-part rate design. Based on the data in UNSE's sample of 100 customers, a two-block consumption charge came much closer to tracking the cost of serving customers than did a rate based on a customer's single monthly peak demand.

Q. WHAT IS SHOWN IN EXHIBIT SJR-6?

A. Exhibit SJR-6 provides a similar analysis of UNSE's rebuttal two-part rate, which UNSE called a "transition" rate. This rate design consists of a customer charge of $15 per month and it retains the existing three-block consumption charge: 3.2258¢ per kWh for the first 400 kWh per month, 4.2258¢ per kWh for the next 600 kWh per month, and 6.0258¢ per kWh for all consumption in excess of 1,000 kWh per month.[10]

UNSE's rebuttal transition rate does a very good job of having a customer's revenues track the cost of serving the customer. The slope of the trend line is 0.881 meaning that the rate design makes substantial progress toward having higher-cost customers provide higher-revenues. This rate design also has a lower average difference between revenues and costs, at 19%. It also can be seen that with a customer charge that is much closer to the customer-related cost of service ($180 per year in revenues compared to $165.76 in costs), lower-cost customers are not providing significant subsidies to higher-use customers. Finally, because this rate design is similar in structure to existing rates, the range of customer bill impacts is much tighter than in UNSE's originally proposed rates:

[10] UNSE Exhibit CAJ-R-4, Schedule H-3, p. 4.

annual increases in distribution bills range from 42% to 56% for all customers in the sample group.

Q. DID YOU ALSO ANALYZE THE THREE-PART RESIDENTIAL RATE STRUCTURE UNSE PROPOSED IN ITS REBUTTAL?

A. Yes. In its rebuttal testimony, UNSE proposed a three-part rate that differs from its originally proposed demand rate structure in several respects. The new proposal contains a lower customer charge than the original proposal, and has only a single block demand rate instead of the two-block rate proposed initially. In addition, UNSE changed the measure of demand that would be used to bill customers. Its original demand charge was based on a customer's highest single-hour demand at any time during the month. UNSE's rebuttal proposal measures demand only during on-peak hours.[11]

Apparently because of concerns with bill impacts during the transition to a new rate structure, UNSE also proposed limiting the demand for billing purposes to no more than what the customer's demand would be if the customer had a 15% load factor during the month.[12]

For completeness, I analyzed UNSE's rebuttal three-part rate structure both with and without the 15% load factor limiter.

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[11] In the summer months of May through October, on-peak hours are Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day) between 2 pm and 8 pm. In the other six months, on-peak hours are Monday through Friday (excluding Thanksgiving, Christmas Day, and New Year's Day) between 5 am and 9 am and 5 pm and 9 pm. See Dukes rebuttal testimony, p. 7, line 26 and Tariff RES-TOU (Sheet 102-1).

[12] Monthly load factor is the ratio of the customer's average demand to its maximum demand during the month. For example, if a customer uses 720 kWh in a month with 30 days (720 hours), the customer's average demand is 1.0 kW. If the customer's peak demand during the month is 3.0 kW, the customer's load factor would be 0.333.

Q. WHAT DID YOUR ANALYSIS SHOW CONCERNING UNSE'S REBUTTAL THREE-PART RESIDENTIAL RATE WITHOUT THE 15% LOAD FACTOR LIMITER?

A. Exhibit SJR-7 shows my analysis of the rebuttal demand rate without a limiter. The rate consists of a customer charge of $15.00 per month, a demand charge of $5.15 per kW (using on-peak demand as described above), and an energy charge of 1.6760¢ per kWh.[13]

UNSE's rebuttal three-part rate is notably worse in reflecting the cost of service than UNSE's rebuttal two-part rate (the "transition" rate). The slope of the trend line is only 0.636 meaning that higher-cost customers would pay much less than the cost to serve them. This is the worst result of any of UNSE's proposed rate designs, and dramatically worse than the transition rate which had a slope of 0.881. Further, the average difference between revenues and costs is 23% compared to 19% under the rebuttal two-part rate. Finally, this rate structure would have significant customer impacts, with more than 10% of customers seeing their annual distribution bills increase by more than 100% while another 10% of customers would see increases of 25% or less. Overall annual increases would range from 9% to 182%.

I would emphasize that these dramatic bill changes do not bring rates closer to tracking the cost of service. Indeed quite the opposite is true -- rates are further removed from cost, and the subsidies to higher-cost customers are greater, under the rebuttal three-part rate than they are under the rebuttal two-part rate. That is, contrary to the claims of several UNSE witnesses, the three-part rate proposed in rebuttal does not collect the cost of service from residential customers in a more equitable manner.

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[13] UNSE Exh. CAJ-R-4, Schedule H-3, p. 4.

Q. DOES USING THE LOAD FACTOR LIMITER IMPROVE THE FAIRNESS OF UNSE'S REBUTTAL THREE-PART RATE?

A. Yes, but the improvement is very slight. Exhibit SJR-8 uses the same rates as I used in Exhibit SJR-7, but the billing units for demand are different because of the limitation that demand will not be higher than that which the customer would have with a 15% load factor. For example, if a customer used 720 kWh during a 30-day month, its average demand during the month would be 1.0 kW, as I discussed above. If the customer's highest demand during the month were 8.0 kW, its load factor would be 12.5%. UNSE's demand limiter would restate the maximum demand to 6.67 kW (1 / 6.67 = 15%) and use that lower amount for billing purposes in that month.

Exhibit SJR-8 shows that using the demand limiter reduces some of the highest bill impacts, but does little to improve the overall fairness of the rate design. Specifically, the highest bill increase has been reduced from 182% without the limiter to 113% with the limiter. That is still more than 10 times the percentage increase of the customer with the lowest bill impact.

Moreover, the limit does little to improve the overall fairness of this rate design. The slope of the trend line improves just slightly, from 0.636 to 0.657, meaning that higher-cost customers would provide revenues substantially less than the cost to serve them. Further, the average difference between a customer's revenues and the cost to serve the customer also improves just slightly, from 23% without the limiter to 21% with the limiter. Both of these results are worse than UNSE's two-part rebuttal rate, with a slope of 0.881 (enhanced recovery of costs from higher-cost customers) and an average cost-revenue differential of 19%.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that the facts do not support the assertions of UNSE rebuttal witnesses that its proposed three-part rate design recovers costs more equitably, promotes fairness, and reduces intra-class subsidization. In fact, precisely the opposite is true. Compared to UNSE's rebuttal two-part rate design, its proposed rebuttal three-part rate design is less equitable, is unfair to lower-cost customers, and increases intra-class subsidization.

Q. IF SO MUCH OF THE COST OF SERVING RESIDENTIAL CUSTOMERS IS RELATED TO DEMAND, DOES IT MAKE SENSE TO YOU THAT A DEMAND-BASED RATE WOULD DO A WORSE JOB OF RECOVERING COSTS THAN A RATE WITHOUT A DEMAND COMPONENT?

A. Yes, it makes sense given the way these rates have been designed. UNSE's COSS allocates demand-related costs among the customer classes based on various measures of demand, nearly all of which are driven primarily by summer demand. Most demand-related costs are based on either the class non-coincident peak (which occurred on July 24 during the test year) or a demand allocator that uses a combination of non-coincident peak, average demand, and the four system coincident peaks during the months of June through September.

There is a relatively small average-demand component (average demand measures year-round energy consumption). On Exhibit SJR-2, line 25, I showed that the average demand component is \$6.6 million out of total demand-related costs of \$41.3 million (line 5 of Exhibit SJR-2), or about 16% of demand costs. In other words, approximately 84% of demand costs for the residential class are based on summer peak demands.

The logical question, then, is what type of rate design provides a better proxy for summer demands. Is it better to use each customer's monthly demand throughout the year or to use a customer's energy consumption throughout the year, weighted using inclining block rates?

Q. HAVE YOU PERFORMED ANY ANALYSIS TO TRY TO ANSWER THIS QUESTION?

A. Yes. In order to try to understand this relationship, I prepared a few simple regression analyses. First, on Exhibit SJR-9, I compared each customer's contribution to peak demands to the customer's average monthly billing demand (using the measure of billing demand in UNSE's rebuttal, including the demand limiter). This exhibit contains two graphs. The top graph shows the relationship between summer coincident peak demand and billing demand; the bottom graph shows class non-coincident peak demand and billing demand. These graphs show that there is some relationship between billing demand and summer coincident peak demand, but the R-square of 0.687 indicates that there is considerable variability in the relationship. The bottom graph shows a much weaker relationship between the customer's demand during the single non-coincident peak hour and the customer's annual billing demand. The R-square is 0.551, but simply looking at the data shows that customers with essentially the same contribution to NCP demand have vastly different monthly billing demands.

Exhibit SJR-10 provides similar comparisons, but instead of using monthly billing demand, I used weighted annual energy consumption. Specifically, I weighted energy usage by using the relative prices in the three rate blocks proposed by UNSE in its rebuttal transition rate design. In that rate design, the block 2 rate is 1.31 times the block 1 rate (4.2258¢ compared to 3.2258¢) and the block 3 rates is 1.87 times the block 1 rate (6.0258¢ compared to 3.2258¢). By weighting energy consumption in this manner, I developed an equivalent level of energy consumption that is used for billing purposes. The exhibit shows that for both summer coincident peaks and non-coincident peak, the weighted energy consumption used in UNSE's rebuttal two-part rate design bears a stronger relationship to peak demand allocators than does the monthly demand used in UNSE's three-part rebuttal demand rate. Specifically, the R-square is higher for each comparison using weighted energy than it is using billing demand (0.747 compared to 0.687 for CP demand and 0.588 compared to 0.551 for NCP demand).

These relationships show why UNSE's two-part rate design does a better job of reflecting the cost of service and reducing intra-class subsidies than does UNSE's three-part (demand) rate design. Just because a rate uses something called "demand" does not mean that it bears a better relationship to the types of demand measures used in allocating costs in a cost-of-service study.

The essential task of rate design is to try to find understandable, and readily measurable, proxies for each component of the cost of service so that bills can be rendered that fairly reflect each customer's contribution to the cost of service. No method will be perfect, but based on the available data UNSE's rate structure using three consumption blocks (with inclining rates in each block) is a reasonable proxy for class non-coincident demand and system coincident demand. My cost analyses and my demand analyses show that UNSE's rate design with three consumption blocks with inclining block rates is superior to its rate designs that use monthly billing demand.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Commission reject UNSE's unsupported assertion that its proposed three-part residential demand rates are superior to a rate structure based on a two-part rate with inclining consumption block rates. My analyses of the available data show that precisely the opposite is true. I further recommend, therefore, that the Commission adopt UNSE's so-called rebuttal "transition" rate design for residential customers who do not elect time-of-use rates. (Of course, the actual rates need to be adjusted based on the final revenue requirement determined by the Commission.) This rate design is structured in the same manner as existing rates which should minimize any issues with customer understanding, ease of administration, or metering technology. The rate design also is superior to UNSE's other proposed rate designs in its ability to fairly collect the cost of service from each customer and minimize the level of intra-class subsidies. Finally, of all of the rate designs put forth by UNSE, this rate design also has the fairest impact on customers, with all customers in the sample having annual bills for distribution service increase by a fairly consistent percentage.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Appendix A

Scott J. Rubin

Attorney + Consultant

333 Oak Lane • Bloomsburg, PA 17815

Current Position

Public Utility Attorney and Consultant. 1994 to present. I provide legal, consulting, and expert witness services to various organizations interested in the regulation of public utilities.

Previous Positions

Lecturer in Computer Science, Susquehanna University, Selinsgrove, PA. 1993 to 2000.

Senior Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1990 to 1994. I supervised the administrative and technical staff and shared with one other senior attorney the supervision of a legal staff of 14 attorneys.

Assistant Consumer Advocate, Office of Consumer Advocate, Harrisburg, PA. 1983 to 1990.

Associate, Laws and Staruch, Harrisburg, PA. 1981 to 1983.

Law Clerk, U.S. Environmental Protection Agency, Washington, DC. 1980 to 1981.

Research Assistant, Rockville Consulting Group, Washington, DC. 1979.

Current Professional Activities

Member, American Bar Association, Public Utility Law Section.

Member, American Water Works Association.

Admitted to practice law before the Supreme Court of Pennsylvania, the New York State Court of Appeals, the United States District Court for the Middle District of Pennsylvania, the United States Court of Appeals for the Third Circuit, and the Supreme Court of the United States.

Previous Professional Activities

Member, American Water Works Association, Rates and Charges Subcommittee, 1998-2001.

Member, Federal Advisory Committee on Disinfectants and Disinfection By-Products in Drinking Water, U.S. Environmental Protection Agency, Washington, DC. 1992 to 1994.

Chair, Water Committee, National Association of State Utility Consumer Advocates, Washington, DC. 1990 to 1994; member of committee from 1988 to 1990.

Member, Board of Directors, Pennsylvania Energy Development Authority, Harrisburg, PA. 1990 to 1994.

Member, Small Water Systems Advisory Committee, Pennsylvania Department of Environmental Resources, Harrisburg, PA. 1990 to 1992.

Member, Ad Hoc Committee on Emissions Control and Acid Rain Compliance, National Association of State Utility Consumer Advocates, 1991.

Member, Nitrogen Oxides Subcommittee of the Acid Rain Advisory Committee, U.S. Environmental Protection Agency, Washington DC. 1991.

Education

J.D. with Honors, George Washington University, Washington, DC. 1981.

B.A. with Distinction in Political Science, Pennsylvania State University, University Park, PA. 1978.

Publications and Presentations (* denotes peer-reviewed publications)

1. "Quality of Service Issues," a speech to the Pennsylvania Public Utility Commission Consumer Conference, State College, PA. 1988.

2. K.L. Pape and S.J. Rubin, "Current Developments in Water Utility Law," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 1990.

3. Presentation on Water Utility Holding Companies to the Annual Meeting of the National Association of State Utility Consumer Advocates, Orlando, FL. 1990.

4. "How the OCA Approaches Quality of Service Issues," a speech to the Pennsylvania Chapter of the National Association of Water Companies. 1991.

5. Presentation on the Safe Drinking Water Act to the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Seattle, WA. 1991.

6. "A Consumer Advocate's View of Federal Pre-emption in Electric Utility Cases," a speech to the Pennsylvania Public Utility Commission Electricity Conference. 1991.

7. Workshop on Safe Drinking Water Act Compliance Issues at the Mid-Year Meeting of the National Association of State Utility Consumer Advocates, Washington, DC. 1992.

8. Formal Discussant, Regional Acid Rain Workshop, U.S. Environmental Protection Agency and National Regulatory Research Institute, Charlotte, NC. 1992.

9. S.J. Rubin and S.P. O'Neal, "A Quantitative Assessment of the Viability of Small Water Systems in Pennsylvania," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute (Columbus, OH 1992), IV:79-97.

10. "The OCA's Concerns About Drinking Water," a speech to the Pennsylvania Public Utility Commission Water Conference. 1992.

11. Member, Technical Horizons Panel, Annual Meeting of the National Association of Water Companies, Hilton Head, SC. 1992.

12. M.D. Klein and S.J. Rubin, "Water and Sewer -- Update on Clean Streams, Safe Drinking Water, Waste Disposal and Pennvest," *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 1992.

13. Presentation on Small Water System Viability to the Technical Assistance Center for Small Water Companies, Pa. Department of Environmental Resources, Harrisburg, PA. 1993

14. "The Results Through a Public Service Commission Lens," speaker and participant in panel discussion at Symposium: "Impact of EPA's Allowance Auction," Washington, DC, sponsored by AER*X. 1993.

15. "The Hottest Legislative Issue of Today -- Reauthorization of the Safe Drinking Water Act," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, San Antonio, TX. 1993.

16. "Water Service in the Year 2000," a speech to the Conference: "Utilities and Public Policy III: The Challenges of Change," sponsored by the Pennsylvania Public Utility Commission and the Pennsylvania State University, University Park, PA. 1993.

17. "Government Regulation of the Drinking Water Supply: Is it Properly Focused?," speaker and participant in panel discussion at the National Consumers League's Forum on Drinking Water Safety and Quality, Washington, DC. 1993. Reprinted in *Rural Water*, Vol. 15 No. 1 (Spring 1994), pages 13-16.

18. "Telephone Penetration Rates for Renters in Pennsylvania," a study prepared for the Pennsylvania Office of Consumer Advocate. 1993.

19. "Zealous Advocacy, Ethical Limitations and Considerations," participant in panel discussion at "Continuing Legal Education in Ethics for Pennsylvania Lawyers," sponsored by the Office of General Counsel, Commonwealth of Pennsylvania, State College, PA. 1993.

20. "Serving the Customer," participant in panel discussion at the Annual Conference of the National Association of Water Companies, Williamsburg, VA. 1993.

21. "A Simple, Inexpensive, Quantitative Method to Assess the Viability of Small Water Systems," a speech to the Water Supply Symposium, New York Section of the American Water Works Association, Syracuse, NY. 1993.

22. * S.J. Rubin, "Are Water Rates Becoming Unaffordable?," *Journal American Water Works Association*, Vol. 86, No. 2 (February 1994), pages 79-86.

23. "Why Water Rates Will Double (If We're Lucky): Federal Drinking Water Policy and Its Effect on New England," a briefing for the New England Conference of Public Utilities Commissioners, Andover, MA. 1994.

24. "Are Water Rates Becoming Unaffordable?," a speech to the Legislative and Regulatory Conference, Association of Metropolitan Water Agencies, Washington, DC. 1994.

25. "Relationships: Drinking Water, Health, Risk and Affordability," speaker and participant in panel discussion at the Annual Meeting of the Southeastern Association of Regulatory Commissioners, Charleston, SC. 1994.

26. "Small System Viability: Assessment Methods and Implementation Issues," speaker and participant in panel discussion at the Annual Conference of the American Water Works Association, New York, NY. 1994.

27. S.J. Rubin, "How much should we spend to save a life?," *Seattle Journal of Commerce*, August 18, 1994 (Protecting the Environment Supplement), pages B-4 to B-5.

28. S. Rubin, S. Bernow, M. Fulmer, J. Goldstein, and I. Peters, *An Evaluation of Kentucky-American Water Company's Long-Range Planning*, prepared for the Utility and Rate Intervention Division, Kentucky Office of the Attorney General (Tellus Institute 1994).

29. S.J. Rubin, "Small System Monitoring: What Does It Mean?," *Impacts of Monitoring for Phase II/V Drinking Water Regulations on Rural and Small Communities* (National Rural Water Association 1994), pages 6-12.

30. "Surviving the Safe Drinking Water Act," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Reno, NV. 1994.

31. "Safe Drinking Water Act Compliance -- Ratemaking Implications," speaker at the National Conference of Regulatory Attorneys, Scottsdale, AZ. 1995. Reprinted in *Water*, Vol. 36, No. 2 (Summer 1995), pages 28-29.

32. S.J. Rubin, "Water: Why Isn't it Free? The Case of Small Utilities in Pennsylvania," *Utilities, Consumers & Public Policy: Issues of Quality, Affordability, and Competition, Proceedings of the Fourth Utilities, Consumers and Public Policy Conference* (Pennsylvania State University 1995), pages 177-183.

33. S.J. Rubin, "Water Rates: An Affordable Housing Issue?," *Home Energy*, Vol. 12 No. 4 (July/August 1995), page 37.

34. Speaker and participant in the Water Policy Forum, sponsored by the National Association of Water Companies, Naples, FL. 1995.

35. Participant in panel discussion on "The Efficient and Effective Maintenance and Delivery of Potable Water at Affordable Rates to the People of New Jersey," at The New Advocacy: Protecting Consumers in the Emerging Era of Utility Competition, a conference sponsored by the New Jersey Division of the Ratepayer Advocate, Newark, NJ. 1995.

36. J.E. Cromwell III, and S.J. Rubin, *Development of Benchmark Measures for Viability Assessment* (Pa. Department of Environmental Protection 1995).

37. S. Rubin, "A Nationwide Practice from a Small Town in Pa.," *Lawyers & the Internet – a Supplement to the Legal Intelligencer and Pa. Law Weekly* (February 12, 1996), page S6.

38. "Changing Customers' Expectations in the Water Industry," speaker at the Mid-America Regulatory Commissioners Conference, Chicago, IL. 1996, reprinted in *Water* Vol. 37 No. 3 (Winter 1997), pages 12-14.

39. "Recent Federal Legislation Affecting Drinking Water Utilities," speaker at Pennsylvania Public Utility Law Conference, Pennsylvania Bar Institute, Hershey, PA. 1996.

40. "Clean Water at Affordable Rates: A Ratepayers Conference," moderator at symposium sponsored by the New Jersey Division of Ratepayer Advocate, Trenton, NJ. 1996.

41. "Water Workshop: How New Laws Will Affect the Economic Regulation of the Water Industry," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, San Francisco, CA. 1996.

42. * E.T. Castillo, S.J. Rubin, S.K. Keefe, and R.S. Raucher, "Restructuring Small Systems," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 65-74.

43. * J.E. Cromwell III, S.J. Rubin, F.C. Marrocco, and M.E. Leevan, "Business Planning for Small System Capacity Development," *Journal American Water Works Association*, Vol. 89, No. 1 (January 1997), pages 47-57.

44. "Capacity Development – More than Viability Under a New Name," speaker at National Association of Regulatory Utility Commissioners Winter Meetings, Washington, DC. 1997.

45. * E. Castillo, S.K. Keefe, R.S. Raucher, and S.J. Rubin, *Small System Restructuring to Facilitate SDWA Compliance: An Analysis of Potential Feasibility* (AWWA Research Foundation, 1997).

46. H. Himmelberger, *et al.*, *Capacity Development Strategy Report for the Texas Natural Resource Conservation Commission* (Aug. 1997).

47. Briefing on Issues Affecting the Water Utility Industry, Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

48. "Capacity Development in the Water Industry," speaker at the Annual Meeting of the National Association of Regulatory Utility Commissioners, Boston, MA. 1997.

49. "The Ticking Bomb: Competitive Electric Metering, Billing, and Collection," speaker at the Annual Meeting of the National Association of State Utility Consumer Advocates, Boston, MA. 1997.

50. Scott J. Rubin, "A Nationwide Look at the Affordability of Water Service," *Proceedings of the 1998 Annual Conference of the American Water Works Association*, Water Research, Vol. C, No. 3, pages 113-129 (American Water Works Association, 1998).

51. Scott J. Rubin, "30 Technology Tips in 30 Minutes," *Pennsylvania Public Utility Law Conference*, Vol. I, pages 101-110 (Pa. Bar Institute, 1998).

52. Scott J. Rubin, "Effects of Electric and Gas Deregulation on the Water Industry," *Pennsylvania Public Utility Law Conference*, Vol. I, pages 139-146 (Pa. Bar Institute, 1998).

53. Scott J. Rubin, *The Challenges and Changing Mission of Utility Consumer Advocates* (American Association of Retired Persons, 1999).

54. "Consumer Advocacy for the Future," speaker at the Age of Awareness Conference, Changes and Choices: Utilities in the New Millennium, Carlisle, PA. 1999.

55. Keynote Address, $1 Energy Fund, Inc., Annual Membership Meeting, Monroeville, PA. 1999.

56. Scott J. Rubin, "Assessing the Effect of the Proposed Radon Rule on the Affordability of Water Service," prepared for the American Water Works Association. 1999.

57. Scott J. Rubin and Janice A. Beecher, The Impacts of Electric Restructuring on the Water and Wastewater Industry, *Proceedings of the Small Drinking Water and Wastewater Systems International Symposium and Technology Expo* (Phoenix, AZ 2000), pp. 66-75.

58. American Water Works Association, *Principles of Water Rates, Fees, and Charges, Manual M1 – Fifth Edition* (AWWA 2000), Member, Editorial Committee.

59. Janice A. Beecher and Scott J. Rubin, presentation on "Special Topics in Rate Design: Affordability" at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

60. Scott J. Rubin, "The Future of Drinking Water Regulation," a speech at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

61. Janice A. Beecher and Scott J. Rubin, "Deregulation Impacts and Opportunities," a presentation at the Annual Conference and Exhibition of the American Water Works Association, Denver, CO. 2000.

62. Scott J. Rubin, "Estimating the Effect of Different Arsenic Maximum Contaminant Levels on the Affordability of Water Service," prepared for the American Water Works Association. 2000.

63. * Janice A. Beecher and Scott J. Rubin, *Deregulation! Impacts on the Water Industry,* American Water Works Association Research Foundation, Denver, CO. 2000.

64. Scott J. Rubin, Methods for Assessing, Evaluating, and Assisting Small Water Systems, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

65. Scott J. Rubin, Consumer Issues in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2000.

66. "Be Utility Wise in a Restructured Utility Industry," Keynote Address at Be UtilityWise Conference, Pittsburgh, PA. 2000.

67. Scott J. Rubin, Jason D. Sharp, and Todd S. Stewart, "The Wired Administrative Lawyer," *5th Annual Administrative Law Symposium*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

68. Scott J. Rubin, "Current Developments in the Water Industry," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2000.

69. Scott J. Rubin, "Viewpoint: Change Sickening Attitudes," *Engineering News-Record*, Dec. 18, 2000.

70. Janice A. Beecher and Scott J. Rubin, "Ten Practices of Highly Effective Water Utilities," *Opflow*, April 2001, pp. 1, 6-7, 16; reprinted in *Water and Wastes Digest*, December 2004, pp. 22-25.

71. Scott J. Rubin, "Pennsylvania Utilities: How Are Consumers, Workers, and Corporations Faring in the Deregulated Electricity, Gas, and Telephone Industries?" Keystone Research Center. 2001.

72. Scott J. Rubin, "Guest Perspective: A First Look at the Impact of Electric Deregulation on Pennsylvania," *LEAP Letter*, May-June 2001, pp. 2-3.

73. Scott J. Rubin, Consumer Protection in the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2001.

74. Scott J. Rubin, Impacts of Deregulation on the Water Industry, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2001.

75. Scott J. Rubin, "Economic Characteristics of Small Systems," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 7-22.

76. Scott J. Rubin, "Affordability of Water Service," *Critical Issues in Setting Regulatory Standards*, National Rural Water Association, 2001, pp. 23-42.

77. Scott J. Rubin, "Criteria to Assess the Affordability of Water Service," White Paper, National Rural Water Association, 2001.

78. Scott J. Rubin, Providing Affordable Water Service to Low-Income Families, presentation to Portland Water Bureau, Portland, OR. 2001.

79. Scott J. Rubin, Issues Relating to the Affordability and Sustainability of Rates for Water Service, presentation to the Water Utility Council of the American Water Works Association, New Orleans, LA. 2002.

80. Scott J. Rubin, The Utility Industries Compared – Water, NARUC Annual Regulatory Studies Program, East Lansing, MI. 2002.

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83. Scott J. Rubin, Overview of Small Water System Consolidation, presentation to National Drinking Water Advisory Council Small Systems Affordability Working Group, Washington, DC. 2002.

84. Scott J. Rubin, Defining Affordability and Low-Income Household Tradeoffs, presentation to National Drinking Water Advisory Council Small Systems Affordability Working Group, Washington, DC. 2002.

85. Scott J. Rubin, "Thinking Outside the Hearing Room," *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2002.

86. Scott J. Rubin, "Update of Affordability Database," White Paper, National Rural Water Association. 2003.

87. Scott J. Rubin, *Understanding Telephone Penetration in Pennsylvania*, Council on Utility Choice, Harrisburg, PA. 2003.

88. Scott J. Rubin, *The Cost of Water and Wastewater Service in the United States*, National Rural Water Association, 2003.

89. Scott J. Rubin, What Price Safer Water? Presentation at Annual Conference of National Association of Regulatory Utility Commissioners, Atlanta, GA. 2003.

90. George M. Aman, III, Jeffrey P. Garton, Eric Petersen, and Scott J. Rubin, Challenges and Opportunities for Improving Water Supply Institutional Arrangements, *Water Law Conference*, Pennsylvania Bar Institute, Mechanicsburg, PA. 2004.

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93. Scott J. Rubin, Buying and Selling a Water System – Ratemaking Implications, *Pennsylvania Public Utility Law Conference*, Pennsylvania Bar Institute, Harrisburg, PA. 2005.

94. *Thinking Outside the Bill: A Utility Manager's Guide to Assisting Low-Income Water Customers*, American Water Works Association. 2005; Second Edition published in 2014

95. * Scott J. Rubin, "Census Data Shed Light on US Water and Wastewater Costs," *Journal American Water Works Association*, Vol. 97, No. 4 (April 2005), pages 99-110, reprinted in Maxwell, *The Business of Water: A Concise Overview of Challenges and Opportunities in the Water Market.*, American Water Works Association, Denver, CO. 2008.

96. Scott J. Rubin, Review of U.S. Environmental Protection Agency Notice Concerning Revision of National-Level Affordability Methodology, National Rural Water Association. 2006.

97. * Robert S. Raucher, et al., *Regional Solutions to Water Supply Provision*, American Water Works Association Research Foundation, Denver, CO. 2007.

98. Scott J. Rubin, Robert Raucher, and Megan Harrod, The Relationship Between Household Financial Distress and Health: Implications for Drinking Water Regulation, National Rural Water Association. 2007.

99. * John Cromwell and Scott Rubin, *Estimating Benefits of Regional Solutions for Water and Wastewater Service*, American Water Works Association Research Foundation, Denver, CO. 2008.

100. Scott J. Rubin, "Current State of the Water Industry and Stimulus Bill Overview," in *Pennsylvania Public Utility Law* (Pennsylvania Bar Institute). 2009.

101. Scott J. Rubin, Best Practice in Customer Payment Assistance Programs, webcast presentation sponsored by Water Research Foundation. 2009.

102. * Scott J. Rubin, How Should We Regulate Small Water Utilities?, National Regulatory Research Institute. 2009.

103. * John Cromwell III, et al., *Best Practices in Customer Payment Assistance Programs*, Water Research Foundation, Denver, CO. 2010.

104.* Scott J. Rubin, What Does Water Really Cost? Rate Design Principles for an Era of Supply Shortages, Infrastructure Upgrades, and Enhanced Water Conservation, , National Regulatory Research Institute. 2010.

105. Scott J. Rubin and Christopher P.N. Woodcock, Teleseminar: Water Rate Design, National Regulatory Research Institute. 2010.

106. David Monie and Scott J. Rubin, Cost of Service Studies and Water Rate Design: A Debate on the Utility and Regulatory Perspectives, Meeting of New England Chapter of National Association of Water Companies, Newport, RI. 2010.

107. * Scott J. Rubin, A Call for Water Utility Reliability Standards: Regulating Water Utilities' Infrastructure Programs to Achieve a Balance of Safety, Risk, and Cost, National Regulatory Research Institute. 2010.

108.* Raucher, Robert S.; Rubin, Scott J.; Crawford-Brown, Douglas; and Lawson, Megan M. "Benefit-Cost Analysis for Drinking Water Standards: Efficiency, Equity, and Affordability Considerations in Small Communities," *Journal of Benefit-Cost Analysis*: Vol. 2: Issue 1, Article 4. 2011.

109. Scott J. Rubin, A Call for Reliability Standards, *Journal American Water Works Association*, Vol. 103, No. 1 (Jan. 2011), pp. 22-24.

110. Scott J. Rubin, Current Topics in Water: Rate Design and Reliability. Presentation to the Water Committee of the National Association of Regulatory Utility Commissioners, Washington, DC. 2011.

111. Scott J. Rubin, Water Reliability and Resilience Standards, *Pennsylvania Public Utility Law Conference* (Pennsylvania Bar Institute). 2011.

112. Member of Expert Panel, Leadership Forum: Business Management for the Future, Annual Conference and Exposition of the American Water Works Association, Washington, DC. 2011.

113. Scott J. Rubin, Evaluating Community Affordability in Storm Water Control Plans, *Flowing into the Future: Evolving Water Issues* (Pennsylvania Bar Institute). 2011.

114. Invited Participant, Summit on Declining Water Demand and Revenues, sponsored by The Alliance for Water Efficiency, Racine, WI. 2012.

115. *Scott J. Rubin, Evaluating Violations of Drinking Water Regulations, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 51-52 (Expanded Summary) and E137-E147. Winner of the AWWA Small Systems Division Best Paper Award.

116. *Scott J. Rubin, Structural Changes in the Water Utility Industry During the 2000s, *Journal American Water Works Association*, Vol. 105, No. 3 (Mar. 2013), pp. 53-54 (Expanded Summary) and E148-E156.

117. * Scott J. Rubin, Moving Toward Demand-Based Residential Rates, *The Electricity Journal*, Vol. 28, No. 9 (Nov. 2015), pp. 63-71, http://dx.doi.org/10.1016/j.tej.2015.09.021.

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Testimony as an Expert Witness

1. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922404. 1992. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate.

2. *Pa. Public Utility Commission v. Shenango Valley Water Co.*, Pa. Public Utility Commission, Docket R-00922420. 1992. Concerning cost allocation, on behalf of the Pa. Office of Consumer Advocate

3. *Pa. Public Utility Commission v. Pennsylvania Gas and Water Co. - Water Division*, Pa. Public Utility Commission, Docket R-00922482. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

4. *Pa. Public Utility Commission v. Colony Water Co.*, Pa. Public Utility Commission, Docket R-00922375. 1993. Concerning rate design, on behalf of the Pa. Office of Consumer Advocate

5. *Pa. Public Utility Commission v. Dauphin Consolidated Water Supply Co. and General Waterworks of Pennsylvania, Inc.*, Pa. Public Utility Commission, Docket R-00932604. 1993. Concerning rate design and cost of service, on behalf of the Pa. Office of Consumer Advocate

6. *West Penn Power Co. v. State Tax Department of West Virginia*, Circuit Court of Kanawha County, West Virginia, Civil Action No. 89-C-3056. 1993. Concerning regulatory policy and the effects of a taxation statute on out-of-state utility ratepayers, on behalf of the Pa. Office of Consumer Advocate

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9. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company*, Ky. Public Service Commission, Case No. 93-434. 1994. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Utility and Rate Intervention Division.

10. *The Petition on Behalf of Gordon's Corner Water Company for an Increase in Rates*, New Jersey Board of Public Utilities, Docket No. WR94020037. 1994. Concerning revenue requirements and rate design, on behalf of the New Jersey Division of Ratepayer Advocate.

11. *Re Consumers Maine Water Company Request for Approval of Contracts with Consumers Water Company and with Ohio Water Service Company*, Me. Public Utilities Commission, Docket No. 94-352. 1994. Concerning affiliated interest agreements, on behalf of the Maine Public Advocate.

12. *In the Matter of the Application of Potomac Electric Power Company for Approval of its Third Least-Cost Plan*, D.C. Public Service Commission, Formal Case No. 917, Phase II. 1995. Concerning Clean Air Act implementation and environmental externalities, on behalf of the District of Columbia Office of the People's Counsel.

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105-EL-EFC. 1995. Concerning Clean Air Act implementation (case settled before testimony was filed), on behalf of the Office of the Ohio Consumers' Counsel.

14. *Kennebec Water District Proposed Increase in Rates*, Maine Public Utilities Commission, Docket No. 95-091. 1995. Concerning the reasonableness of planning decisions and the relationship between a publicly owned water district and a very large industrial customer, on behalf of the Maine Public Advocate.

15. *Winter Harbor Water Company, Proposed Schedule Revisions to Introduce a Readiness-to-Serve Charge*, Maine Public Utilities Commission, Docket No. 95-271. 1995 and 1996. Concerning standards for, and the reasonableness of, imposing a readiness to serve charge and/or exit fee on the customers of a small investor-owned water utility, on behalf of the Maine Public Advocate.

16. *In the Matter of the 1995 Long-Term Electric Forecast Report of the Cincinnati Gas & Electric Company*, Public Utilities Commission of Ohio, Case No. 95-203-EL-FOR, and *In the Matter of the Two-Year Review of the Cincinnati Gas & Electric Company's Environmental Compliance Plan Pursuant to Section 4913.05, Revised Cost*, Case No. 95-747-EL-ECP. 1996. Concerning the reasonableness of the utility's long-range supply and demand-management plans, the reasonableness of its plan for complying with the Clean Air Act Amendments of 1990, and discussing methods to ensure the provision of utility service to low-income customers, on behalf of the Office of the Ohio Consumers' Counsel..

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18. *In the Matter of the Application of Citizens Utilities Company for a Hearing to Determine the Fair Value of its Properties for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, and to Approve Rate Schedules Designed to Provide such Rate of Return*, Arizona Corporation Commission, Docket Nos. E-1032-95-417, *et al.* 1996. Concerning rate design, cost of service, and the price elasticity of water demand, on behalf of the Arizona Residential Utility Consumer Office.

19. *Cochrane v. Bangor Hydro-Electric Company*, Maine Public Utilities Commission, Docket No. 96-053. 1996. Concerning regulatory requirements for an electric utility to engage in unregulated business enterprises, on behalf of the Maine Public Advocate.

20. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-106-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

21. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-107-EL-EFC and 96-108-EL-EFC. 1996. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

22. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 96-101-EL-EFC and 96-102-EL-EFC. 1997. Concerning the costs and

procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

23. *An Investigation of the Sources of Supply and Future Demand of Kentucky-American Water Company (Phase II)*, Kentucky Public Service Commission, Docket No. 93-434. 1997. Concerning supply and demand planning, on behalf of the Kentucky Office of Attorney General, Public Service Litigation Branch.

24. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 96-103-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

25. *Bangor Hydro-Electric Company Petition for Temporary Rate Increase*, Maine Public Utilities Commission, Docket No. 97-201. 1997. Concerning the reasonableness of granting an electric utility's request for emergency rate relief, and related issues, on behalf of the Maine Public Advocate.

26. *Testimony concerning H.B. 1068 Relating to Restructuring of the Natural Gas Utility Industry*, Consumer Affairs Committee, Pennsylvania House of Representatives. 1997. Concerning the provisions of proposed legislation to restructure the natural gas utility industry in Pennsylvania, on behalf of the Pennsylvania AFL-CIO Gas Utility Caucus.

27. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cleveland Electric Illuminating Company and Toledo Edison Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 97-107-EL-EFC and 97-108-EL-EFC. 1997. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

28. *In the Matter of the Petition of Valley Road Sewerage Company for a Revision in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR92080846J. 1997. Concerning the revenue requirements and rate design for a wastewater treatment utility, on behalf of the New Jersey Division of Ratepayer Advocate.

29. *Bangor Gas Company, L.L.C., Petition for Approval to Furnish Gas Service in the State of Maine*, Maine Public Utilities Commission, Docket No. 97-795. 1998. Concerning the standards and public policy concerns involved in issuing a certificate of public convenience and necessity for a new natural gas utility, and related ratemaking issues, on behalf of the Maine Public Advocate.

30. *In the Matter of the Investigation on Motion of the Commission into the Adequacy of the Public Utility Water Service Provided by Tidewater Utilities, Inc., in Areas in Southern New Castle County, Delaware*, Delaware Public Service Commission, Docket No. 309-97. 1998. Concerning the standards for the provision of efficient, sufficient, and adequate water service, and the application of those standards to a water utility, on behalf of the Delaware Division of the Public Advocate.

31. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Cincinnati Gas and Electric Co. and Related Matters*, Public Utilities Commission of Ohio, Case No. 97-103-EL-EFC. 1998. Concerning fuel-related transactions with affiliated companies and the appropriate ratemaking treatment and regulatory safeguards involving such transactions, on behalf of the Ohio Consumers' Counsel.

32. *Olde Port Mariner Fleet, Inc. Complaint Regarding Casco Bay Island Transit District's Tour and Charter Service*, Maine Public Utilities Commission, Docket No. 98-161. 1998. Concerning the standards and requirements for allocating costs and separating operations between regulated and unregulated operations of a transportation utility, on behalf of the Maine Public Advocate and Olde Port Mariner Fleet, Inc.

33. *Central Maine Power Company Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Maine Public Utilities Commission, Docket No. 97-580. 1998. Concerning the treatment of existing rate discounts when designing rates for a transmission and distribution electric utility, on behalf of the Maine Public Advocate.

34. *Pa. Public Utility Commission v. Manufacturers Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00984275. 1998. Concerning rate design on behalf of the Manufacturers Water Industrial Users.

35. *In the Matter of Petition of Pennsgrove Water Supply Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98030147. 1998. Concerning the revenue requirements, level of affiliated charges, and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

36. *In the Matter of Petition of Seaview Water Company for an Increase in Rates for Water Service*, New Jersey Board of Public Utilities, Docket No. WR98040193. 1999. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

37. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Ohio Power Company and Columbus Southern Power Company and Related Matters*, Public Utilities Commission of Ohio, Case Nos. 98-101-EL-EFC and 98-102-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

38. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Dayton Power and Light Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 98-105-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

39. *In the Matter of the Regulation of the Electric Fuel Component Contained within the Rate Schedules of Monongahela Power Company and Related Matters*, Public Utilities Commission of Ohio, Case No. 99-106-EL-EFC. 1999. Concerning the costs and procedures associated with the implementation of the Clean Air Act Amendments of 1990, on behalf of the Ohio Consumers' Counsel.

40. *County of Suffolk, et al. v. Long Island Lighting Company, et al.*, U.S. District Court for the Eastern District of New York, Case No. 87-CV-0646. 2000. Submitted two affidavits concerning the calculation and collection of court-ordered refunds to utility customers, on behalf of counsel for the plaintiffs.

41. *Northern Utilities, Inc., Petition for Waivers from Chapter 820*, Maine Public Utilities Commission, Docket No. 99-254. 2000. Concerning the standards and requirements for defining and separating a natural gas utility's core and non-core business functions, on behalf of the Maine Public Advocate.

42. *Notice of Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2000-120. 2000. Concerning the appropriate methods for allocating costs and designing rates, on behalf of the Kentucky Office of Attorney General.

43. *In the Matter of the Petition of Gordon's Corner Water Company for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR00050304. 2000. Concerning the revenue requirements and rate design for a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

44. *Testimony concerning Arsenic in Drinking Water: An Update on the Science, Benefits, and Costs*, Committee on Science, United States House of Representatives. 2001. Concerning the effects on low-income households and small communities from a more stringent regulation of arsenic in drinking water.

45. *In the Matter of the Application of The Cincinnati Gas & Electric Company for an Increase in Gas Rates in its Service Territory*, Public Utilities Commission of Ohio, Case No. 01-1228-GA-AIR, *et al.* 2002. Concerning the need for and structure of a special rider and alternative form of regulation for an accelerated main replacement program, on behalf of the Ohio Consumers' Counsel.

46. *Pennsylvania State Treasurer's Hearing on Enron and Corporate Governance Issues*. 2002. Concerning Enron's role in Pennsylvania's electricity market and related issues, on behalf of the Pennsylvania AFL-CIO.

47. *An Investigation into the Feasibility and Advisability of Kentucky-American Water Company's Proposed Solution to its Water Supply Deficit*, Kentucky Public Service Commission, Case No. 2001-00117. 2002. Concerning water supply planning, regulatory oversight, and related issue, on behalf of the Kentucky Office of Attorney General.

48. *Joint Application of Pennsylvania-American Water Company and Thames Water Aqua Holdings GmbH*, Pennsylvania Public Utility Commission, Docket Nos. A-212285F0096 and A-230073F0004. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

49. *Application for Approval of the Transfer of Control of Kentucky-American Water Company to RWE AG and Thames Water Aqua Holdings GmbH*, Kentucky Public Service Commission, Case No. 2002-00018. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Kentucky Office of Attorney General.

50. *Joint Petition for the Consent and Approval of the Acquisition of the Outstanding Common Stock of American Water Works Company, Inc., the Parent Company and Controlling Shareholder of West Virginia-American Water Company*, West Virginia Public Service Commission, Case No. 01-1691-W-PC. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the Consumer Advocate Division of the West Virginia Public Service Commission.

51. *Joint Petition of New Jersey-American Water Company, Inc. and Thames Water Aqua Holdings GmbH for Approval of Change in Control of New Jersey-American Water Company, Inc.*, New Jersey Board of Public Utilities, Docket No. WM01120833. 2002. Concerning the risks and benefits associated with the proposed acquisition of a water utility, on behalf of the New Jersey Division of Ratepayer Advocate.

52. *Illinois-American Water Company, Proposed General Increase in Water Rates*, Illinois Commerce Commission, Docket No. 02-0690. 2003. Concerning rate design and cost of service issues, on behalf of the Illinois Office of the Attorney General.

53. *Pennsylvania Public Utility Commission v. Pennsylvania-American Water Company,* Pennsylvania Public Utility Commission, Docket No. R-00038304. 2003. Concerning rate design and cost of service issues, on behalf of the Pennsylvania Office of Consumer Advocate.

54. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 03-0353-W-42T. 2003. Concerning affordability, rate design, and cost of service issues, on behalf of the West Virginia Consumer Advocate Division.

55. *Petition of Seabrook Water Corp. for an Increase in Rates and Charges for Water Service*, New Jersey Board of Public Utilities, Docket No. WR3010054. 2003. Concerning revenue requirements, rate design, prudence, and regulatory policy, on behalf of the New Jersey Division of Ratepayer Advocate.

56. *Chesapeake Ranch Water Co. v. Board of Commissioners of Calvert County*, U.S. District Court for Southern District of Maryland, Civil Action No. 8:03-cv-02527-AW. 2004. Submitted expert report concerning the expected level of rates under various options for serving new commercial development, on behalf of the plaintiff.

57. *Testimony concerning Lead in Drinking Water*, Committee on Government Reform, United States House of Representatives. 2004. Concerning the trade-offs faced by low-income households when drinking water costs increase, including an analysis of H.R. 4268.

58. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0373-W-42T. 2004. Concerning affordability and rate comparisons, on behalf of the West Virginia Consumer Advocate Division.

59. *West Virginia-American Water Company,* West Virginia Public Service Commission, Case No. 04-0358-W-PC. 2004. Concerning costs, benefits, and risks associated with a wholesale water sales contract, on behalf of the West Virginia Consumer Advocate Division.

60. *Kentucky-American Water Company,* Kentucky Public Service Commission, Case No. 2004-00103. 2004. Concerning rate design and tariff issues, on behalf of the Kentucky Office of Attorney General.

61. *New Landing Utility, Inc.,* Illinois Commerce Commission, Docket No. 04-0610. 2005. Concerning the adequacy of service provided by, and standards of performance for, a water and wastewater utility, on behalf of the Illinois Office of Attorney General.

62. *People of the State of Illinois v. New Landing Utility, Inc.,* Circuit Court of the 15th Judicial District, Ogle County, Illinois, No. 00-CH-97. 2005. Concerning the standards of performance for a water and wastewater utility, including whether a receiver should be appointed to manage the utility's operations, on behalf of the Illinois Office of Attorney General.

63. *Hope Gas, Inc. d/b/a Dominion Hope*, West Virginia Public Service Commission, Case No. 05-0304-G-42T. 2005. Concerning the utility's relationships with affiliated companies, including an appropriate level of revenues and expenses associated with services provided to and received from affiliates, on behalf of the West Virginia Consumer Advocate Division.

64. *Monongahela Power Co. and The Potomac Edison Co.*, West Virginia Public Service Commission, Case Nos. 05-0402-E-CN and 05-0750-E-PC. 2005. Concerning review of a plan to finance the construction of pollution control facilities and related issues, on behalf of the West Virginia Consumer Advocate Division.

65. *Joint Application of Duke Energy Corp., et al., for Approval of a Transfer and Acquisition of Control*, Case Kentucky Public Service Commission, No. 2005-00228. 2005. Concerning the risks and benefits associated with the proposed acquisition of an energy utility, on behalf of the Kentucky Office of the Attorney General.

66. *Commonwealth Edison Company proposed general revision of rates, restructuring and price unbundling of bundled service rates, and revision of other terms and conditions of service,* Illinois Commerce Commission, Docket No. 05-0597. 2005. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

67. *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, Pennsylvania Public Utility Commission, Docket No. R-00051030. 2006. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

68. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, proposed general increases in rates for delivery service*, Illinois Commerce Commission, Docket Nos. 06-0070, et al. 2006. Concerning rate design and cost of service, on behalf of the Illinois Office of Attorney General.

69. *Grens, et al., v. Illinois-American Water Co.*, Illinois Commerce Commission, Docket Nos. 5-0681, et al. 2006. Concerning utility billing, metering, meter reading, and customer service practices, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

70. *Commonwealth Edison Company Petition for Approval of Tariffs Implementing ComEd's Proposed Residential Rate Stabilization Program*, Illinois Commerce Commission, Docket No. 06-0411. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

71. *Illinois-American Water Company, Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges Pursuant to 83 Ill. Adm. Code 655*, Illinois Commerce Commission, Docket No. 06-0196. 2006. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General and the Village of Homer Glen, Illinois.

72. *Illinois-American Water Company, et al.*, Illinois Commerce Commission, Docket No. 06-0336. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Illinois Office of Attorney General.

73. *Joint Petition of Kentucky-American Water Company, et al.*, Kentucky Public Service Commission, Docket No. 2006-00197. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Kentucky Office of Attorney General.

74. *Aqua Illinois, Inc. Proposed Increase in Water Rates for the Kankakee Division*, Illinois Commerce Commission, Docket No. 06-0285. 2006. Concerning various revenue requirement, rate design, and tariff issues, on behalf of the County of Kankakee.

75. *Housing Authority for the City of Pottsville v. Schuylkill County Municipal Authority*, Court of Common Pleas of Schuylkill County, Pennsylvania, No. S-789-2000. 2006. Concerning the reasonableness and uniformity of rates charged by a municipal water authority, on behalf of the Pottsville Housing Authority.

76. *Application of Pennsylvania-American Water Company for Approval of a Change in Control*, Pennsylvania Public Utility Commission, Docket No. A-212285F0136. 2006. Concerning the risks and benefits associated with the proposed divestiture of a water utility, on behalf of the Pennsylvania Office of Consumer Advocate.

77. *Application of Artesian Water Company, Inc., for an Increase in Water Rates*, Delaware Public Service Commission, Docket No. 06-158. 2006. Concerning rate design and cost of service, on behalf of the Staff of the Delaware Public Service Commission.

78. *Central Illinois Light Company, Central Illinois Public Service Company, and Illinois Power Company: Petition Requesting Approval of Deferral and Securitization of Power Costs*, Illinois Commerce Commission, Docket No. 06-0448. 2006. Concerning a utility's proposed purchased power phase-in proposal, in behalf of the Illinois Office of Attorney General.

79. *Petition of Pennsylvania-American Water Company for Approval to Implement a Tariff Supplement Revising the Distribution System Improvement Charge*, Pennsylvania Public Utility Commission, Docket No. P-00062241. 2007. Concerning the reasonableness of a water utility's proposal to increase the cap on a statutorily authorized distribution system surcharge, on behalf of the Pennsylvania Office of Consumer Advocate.

80. *Adjustment of the Rates of Kentucky-American Water Company*, Kentucky Public Service Commission, Case No. 2007-00143. 2007. Concerning rate design and cost of service, on behalf of the Kentucky Office of Attorney General.

81. *Application of Kentucky-American Water Company for a Certificate of Convenience and Necessity Authorizing the Construction of Kentucky River Station II, Associated Facilities and Transmission Main*, Kentucky Public Service Commission, Case No. 2007-00134. 2007. Concerning the life-cycle costs of a planned water supply source and the imposition of conditions on the construction of that project, on behalf of the Kentucky Office of Attorney General.

82. *Pa. Public Utility Commission v. Pennsylvania-American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-00072229. 2007. Concerning rate design and cost of service, on behalf of the Pennsylvania Office of Consumer Advocate.

83. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 07-0195. 2007. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

84. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates for Water Service Provided In the Lake Erie Division*, Public Utilities Commission of Ohio, Case No.07-0564-WW-AIR. 2007. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

85. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.,* Pennsylvania Public Utility Commission, Docket No. R-00072711. 2008. Concerning rate design, on behalf of the Masthope Property Owners Council.

86. *Illinois-American Water Company Proposed increase in water and sewer rates*, Illinois Commerce Commission, Docket No. 07-0507. 2008. Concerning rate design and demand studies, on behalf of the Illinois Office of Attorney General.

87. *Central Illinois Light Company, d/b/a AmerenCILCO; Central Illinois Public Service Company, d/b/a AmerenCIPS; Illinois Power Company, d/b/a AmerenIP: Proposed general increase in rates for electric delivery service*, Illinois Commerce Commission Docket Nos. 07-0585, 07-0586, 07-0587. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

88. *Commonwealth Edison Company: Proposed general increase in electric rates*, Illinois Commerce Commission Docket No. 07-0566. 2008. Concerning rate design and cost of service studies, on behalf of the Illinois Office of Attorney General.

89. *In the Matter of Application of Ohio American Water Co. to Increase Its Rates*, Public Utilities Commission of Ohio, Case No. 07-1112-WS-AIR. 2008. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

90. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Authority to Increase Rates for its Gas Service*, Public Utilities Commission of Ohio, Case Nos. 07-829-GA-AIR, et al. 2008. Concerning the need for, and structure of, an accelerated infrastructure replacement program and rate surcharge, on behalf of the Office of the Ohio Consumers' Counsel.

91. *Pa. Public Utility Commission v. Pennsylvania American Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2032689. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

92. *Pa. Public Utility Commission v. York Water Company*, Pennsylvania Public Utility Commission, Docket No. R-2008-2023067. 2008. Concerning rate design, cost of service study, and other tariff issues, on behalf of the Pennsylvania Office of Consumer Advocate.

93. *Northern Illinois Gas Company d/b/a Nicor Gas Company,* Illinois Commerce Commission, Docket No. 08-0363. 2008. Concerning rate design, cost of service, and automatic rate adjustments, on behalf of the Illinois Office of Attorney General.

94. *West Virginia American Water Company,* West Virginia Public Service Commission, Case No. 08-0900-W-42T. 2008. Concerning affiliated interest charges and relationships, on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia.

95. *Illinois-American Water Company Application for Approval of its Annual Reconciliation of Purchased Water and Purchased Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 08-0218. 2008. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

96. *In the Matter of Application of Duke Energy Ohio, Inc. for an Increase in Electric Rates*, Public Utilities Commission of Ohio, Case No. 08-0709-EL-AIR. 2009. Concerning rate design and cost of service, on behalf of the Office of the Ohio Consumers' Counsel.

97. *The Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 09-0166 and 09-0167. 2009. Concerning rate design and automatic rate adjustments on behalf of the Illinois Office of Attorney General, Citizens Utility Board, and City of Chicago.

98. *Illinois-American Water Company Proposed Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 09-0319. 2009. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General and Citizens Utility Board.

99. *Pa. Public Utility Commission v. Aqua Pennsylvania Inc.*, Pennsylvania Public Utility Commission, Docket No. R-2009-2132019. 2010. Concerning rate design, cost of service, and automatic adjustment tariffs, on behalf of the Pennsylvania Office of Consumer Advocate.

100. *Apple Canyon Utility Company and Lake Wildwood Utilities Corporation Proposed General Increases in Water Rates*, Illinois Commerce Commission, Docket Nos. 09-0548 and 09-0549. 2010. Concerning parent-company charges, quality of service, and other matters, on behalf of Apple Canyon Lake Property Owners' Association and Lake Wildwood Association, Inc.

101. *Application of Aquarion Water Company of Connecticut to Amend its Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-02-13. 2010. Concerning rate design, proof of revenues, and other tariff issues, on behalf of the Connecticut Office of Consumer Counsel.

102. *Illinois-American Water Company Annual Reconciliation Of Purchased Water and Sewage Treatment Surcharges*, Illinois Commerce Commission, Docket No. 09-0151. 2010. Concerning the reconciliation of purchased water and sewer charges, on behalf of the Illinois Office of Attorney General.

103. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket Nos. R-2010-2166212, et al. 2010. Concerning rate design and cost of service study for four wastewater utility districts, on behalf of the Pennsylvania Office of Consumer Advocate.

104. *Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, Illinois Power Company d/b/a AmerenIP Petition for accounting order*, Illinois Commerce Commission, Docket No. 10-0517. 2010. Concerning ratemaking procedures for a multi-district electric and natural gas utility, on behalf of the Illinois Office of Attorney General.

105. *Commonwealth Edison Company Petition for General Increase in Delivery Service Rates*, Illinois Commerce Commission Docket No. 10-0467. 2010. Concerning rate design and cost of service study, on behalf of the Illinois Office of Attorney General.

106. *Pa. Public Utility Commission v. City of Lancaster Bureau of Water*, Pennsylvania Public Utility Commission, Docket No. R-2010-2179103. 2010. Concerning rate design, cost of service, and cost allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

107. *Application of Yankee Gas Services Company for Amended Rate Schedules*, Connecticut Department of Public Utility Control, Docket No. 10-12-02. 2011. Concerning rate design and cost of service for a natural

gas utility, on behalf of the Connecticut Office of Consumers' Counsel.

108. *California-American Water Company*, California Public Utilities Commission, Application 10-07-007. 2011. Concerning rate design and cost of service for multiple water-utility service areas, on behalf of The Utility Reform Network.

109. *Little Washington Wastewater Company, Inc., Masthope Wastewater Division*, Pennsylvania Public Utility Commission Docket No. R-2010-2207833. 2011. Concerning rate design and various revenue requirements issues, on behalf of the Masthope Property Owners Council.

110. *In the matter of Pittsfield Aqueduct Company, Inc.*, New Hampshire Public Utilities Commission Case No. DW 10-090. 2011. Concerning rate design and cost of service on behalf of the New Hampshire Office of the Consumer Advocate.

111. *In the matters of Pennichuck Water Works, Inc. Permanent Rate Case and Petition for Approval of Special Contract with Anheuser-Busch, Inc.*, New Hampshire Public Utilities Commission Case Nos. DW 10-091 and DW 11-014. 2011. Concerning rate design, cost of service, and contract interpretation on behalf of the New Hampshire Office of the Consumer Advocate.

112. *Artesian Water Co., Inc. v. Chester Water Authority*, U.S. District Court for the Eastern District of Pennsylvania Case No. 10-CV-07453-JP. 2011. Concerning cost of service, ratemaking methods, and contract interpretation on behalf of Chester Water Authority.

113. *North Shore Gas Company and The Peoples Gas Light and Coke Company Proposed General Increases in Rates for Gas Service*, Illinois Commerce Commission, Docket Nos. 11-0280 and 11-0281. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General, the Citizens Utility Board, and the City of Chicago.

114. *Ameren Illinois Company: Proposed general increase in electric delivery service rates and gas delivery service rates*, Illinois Commerce Commission, Docket Nos. 11-0279 and 11-0282. 2011. Concerning rate design and cost of service for natural gas and electric distribution service, on behalf of the Illinois Office of Attorney General and the Citizens Utility Board.

115. *Pa. Public Utility Commission v. Pennsylvania-American Water Co.*, Pennsylvania Public Utility Commission, Docket No. R-2011-2232243. 2011. Concerning rate design, cost of service, sales forecast, and automatic rate adjustments on behalf of the Pennsylvania Office of Consumer Advocate.

116. *Aqua Illinois, Inc. Proposed General Increase in Water and Sewer Rates*, Illinois Commerce Commission, Docket No. 11-0436. 2011. Concerning rate design and cost of service on behalf of the Illinois Office of Attorney General.

117. *City of Nashua Acquisition of Pennichuck Corporation*, New Hampshire Public Utilities Commission, Docket No. DW 11-026. 2011. Concerning the proposed acquisition of an investor-owned utility holding company by a municipality, including appropriate ratemaking methodologies, on behalf of the New Hampshire Office of Consumer Advocate.

118. *An Application by Heritage Gas Limited for the Approval of a Schedule of Rates, Tolls and Charges*, Nova Scotia Utility and Review Board, Case NSUARB-NG-HG-R-11. 2011. Concerning rate design and

cost of service, on behalf of the Nova Scotia Consumer Advocate.

119. *An Application of Halifax Regional Water Commission for Approval of a Cost of Service and Rate Design Methodology,* Nova Scotia Utility and Review Board , Case NSUARB-W-HRWC-R-11. 2011. Concerning rate design and cost of service, on behalf of the Nova Scotia Consumer Advocate.

120. *National Grid USA and Liberty Energy Utilities Corp.*, New Hampshire Public Utilities Commission, Docket No. DG 11-040. 2011. Concerning the costs and benefits of a proposed merger and related conditions, on behalf of the New Hampshire Office of Consumer Advocate.

121. *Great Northern Utilities, Inc., et al.*, Illinois Commerce Commission, Docket Nos. 11-0059, et al. 2012. Concerning options for mitigating rate impacts and consolidating small water and wastewater utilities for ratemaking purposes, on behalf of the Illinois Office of Attorney General.

122. *Pa. Public Utility Commission v. Aqua Pennsylvania, Inc.,* Pennsylvania Public Utility Commission, Docket No. R-2011-2267958. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Pennsylvania Office of Consumer Advocate.

123. *Golden State Water Company*, California Public Utilities Commission, Application 11-07-017. 2012. Concerning rate design and quality of service, on behalf of The Utility Reform Network.

124. *Golden Heart Utilities, Inc. and College Utilities Corporation*, Regulatory Commission of Alaska, Case Nos. U-11-77 and U-11-78. 2012. Concerning rate design and cost of service, on behalf of the Alaska Office of the Attorney General.

125. *Illinois-American Water Company*, Illinois Commerce Commission, Docket No. 11-0767. 2012. Concerning rate design, cost of service, and automatic rate adjustment mechanisms, on behalf of the Illinois Office of Attorney General.

126. *Application of Tidewater Utilities, Inc., for a General Rate Increase in Water Base Rates and Tariff Revisions*, Delaware Public Service Commission, Docket No. 11-397. 2012. Concerning rate design and cost of service study, on behalf of the Staff of the Delaware Public Service Commission.

127. *In the Matter of the Philadelphia Water Department's Proposed Increase in Rates for Water and Wastewater Utility Services*, Philadelphia Water Commissioner, FY 2013-2016. 2012. Concerning rate design and related issues for storm water service, on behalf of Citizens for Pennsylvania's Future.

128. *Corix Utilities (Illinois) LLC, Hydro Star LLC, and Utilities Inc. Joint Application for Approval of a Proposed Reorganization*, Illinois Commerce Commission, Docket No. 12-0279. 2012. Concerning merger-related synergy savings and appropriate ratemaking treatment of the same, on behalf of the Illinois Office of Attorney General.

129. *North Shore Gas Company and The Peoples Gas Light and Coke Company*, Illinois Commerce Commission, Docket Nos. 12-0511 and 12-0512. 2012. Concerning rate design, cost of service study, and automatic rate adjustment tariff on behalf of the Illinois Office of Attorney General.

130. *Pa. Public Utility Commission v. City of Lancaster Sewer Fund*, Pennsylvania Public Utility Commission, Docket No. R-2012-2310366. 2012. Concerning rate design, cost of service, and cost

allocation, on behalf of the Pennsylvania Office of Consumer Advocate.

131. *Aquarion Water Company of New Hampshire*, New Hampshire Public Utilities Commission, Docket No. DW 12-085. 2013. Concerning tariff issues, including an automatic adjustment clause for infrastructure improvement, on behalf of the New Hampshire Office of Consumer Advocate.

132. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1682-EL-AIR, et al. 2013. Concerning rate design and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

133. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Natural Gas Distribution Rates*, Public Utilities Commission of Ohio, Case No. 12-1685-GA-AIR, et al. 2013. Concerning cost-of-service study, rate design, and tariff issues, on behalf of the Office of the Ohio Consumers' Counsel.

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CrossMark

Moving Toward Demand-Based Residential Rates

The widespread use of automated metering infrastructure in the electricity distribution industry is generating increasing discussion of residential demand charges. An analysis of six types of residential rate designs shows that designing residential rates with seasonal consumption charges might make significant progress toward a more efficient rate design. Seasonal usage rates are understandable to customers, avoid many of the problems with demand-based rates, do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

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I. Background

The widespread use of automated metering infrastructure (AMI) in the electricity distribution industry is generating increasing discussion of residential demand charges. Conferences are being held where pro-demand-charge consultants (Ryan Hledik, 2015) square off against anti-demand-charge consultants (Barbara Alexander, 2015); interest groups are posting blogs about the desirability of residential demand charges (Rocky Mt. Institute, 2015); and articles are being published in this *Journal* to try to elucidate points on both sides of the issue (Blank and Gegax, 2014; Hledik, 2014).

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Both sides make valid points. On the one hand, every electricity distribution cost-of-service study (COSS) recognizes that a substantial portion of distribution costs are demand-related. Most utilities, however, have residential rates that contain a customer charge and one or more rates based on energy consumption (rates per kilowatt-hour). Residential demand charges are rare. Where they exist, they are nearly always optional. This means that most residential customers continue to pay demand-related costs through a combination of a flat-rate customer charge and per-kWh charges, rates that may not precisely mirror a customer's demand.

On the other side are those who suggest that residential demand charges are fraught with problems, not the least of which are the need for substantial consumer education and difficulties with tariff administration (including reprogramming utility billing systems and training customer service personnel). Those on the "anti" side of the debate also note that there are important rate design concerns other than strict adherence to the results of a COSS. These include understandability, efficiency, gradualism, revenue stability, and affordability.

With AMI the industry has an unprecedented opportunity to better understand the relationship between peak demand and energy consumption on a very granular level – that is, that of the individual customer. The challenge will be to use this information to move toward a residential rate design that is more efficient (that is, improves the collection of demand-related costs from residential customers who cause the demand), yet remains understandable, affordable, and easy to administer.

Any potential rate design must represent a compromise involving a series of trade-offs.

II. Advantages and Disadvantages of Different Rate Designs

Before discussing any specific analyses, it is worth remembering that there is no "perfect" rate design. The rate design process involves developing averages and groupings for thousands, or even millions, of customers. No rate design will exactly capture the actual cost to serve an individual residential customer, but the goal is to have a rate design that treats all customers fairly within the confines of the averaging and grouping process.

Thus, any potential rate design must represent a compromise involving a series of trade-offs. Prof. Bonbright taught that among the factors to be evaluated in a rate design are fairness (including relationship of the rates to cost), encouraging the wise use of the service, understandability, ease of administration, non-discrimination, revenue stability, and gradualism (Bonbright, 1961).

Billing based on annual demand has a certain theoretical appeal, but the annual demand is not known until the end of the peak season. A summer-peaking utility might experience its peak in July or August, or even in September during an unusual weather event. Similarly, a winter-peaking utility could reach its peak in December, January, or February. Moreover, a utility whose peak fluctuates (winter peaking some years, summer peaking in others) might not know its annual peak until an entire year passes. In any event, billing based on the annual peak always will be based on some event in the past, often many months before, that the customer can no longer control. When a customer moves during the year or a new home is added to the service territory, there also could be a serious question about the fairness of the billing determinant that will be used for the new account.

Further, the customer's ability to control its peak-period usage might be limited, or simply the

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result of luck (good or bad). For instance, if a customer happens to be on vacation during the peak day, her contribution to the annual peak might be unusually low compared to her normal seasonal consumption. Similarly, if a customer happens to have the bad luck of having visitors on the peak day, her contribution to the peak might be unusually high compared to her normal seasonal usage.

Other events also could hamper a customer's ability to control consumption during the precise peak hour, especially because the time of the peak is not knowable when energy is being consumed. These might include appliance cycling during the day (how the refrigerator was cycling during the peak hour), whether the customer has a medical device (such as an oxygen concentrator) that was required to work during the peak hour, whether the peak hour occurred during the work day or after the customer returned home from work, and so on.

Rates based on billing (that is, monthly) demand would eliminate some of the temporal shift involved when annual demand is used, but there is a question about the relationship between a customer's monthly peak demands and his contribution to the annual system peak. This is particularly the case for customers who peak off-season, such as space-heating customers in a summer-peaking utility.

Similarly, billing based on annual energy consumption has some advantages (it is easy to understand and administer, and it spreads the utility's revenues throughout the year), but it may not be fair to consumers who use electricity efficiently (that is, high-load-factor customers who control their peak usage). Such a rate also can send the incorrect price signal that the cost of electricity distribution is the same throughout the year, regardless of the time of day or season of consumption.

From a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability.

Collecting demand costs partially through customer charges also can be problematic. Implicitly, this type of rate design assumes that all customers contribute equally to peak demand, which is rarely the case. It also assumes that there are no differences in distribution facilities based on a customer's peak demand. This ignores the fact that transformers and other facilities might be sized differently depending on the expected demands from connected customers. For example, why should a customer in an apartment without air conditioning pay the same amount for demand-related costs as a customer in a large, air-conditioned home where the thermostat is set to 70 °F? Per-customer billing of demand-related costs also fails to send any price signal to a customer about the longer-term costs the customer's energy usage patterns cause to the system.

Seasonal billing also can create problems, both for the utility and for customers. For example, high summer charges essentially give space-heating customers a "free ride" on the distribution network. While heating customers may not "cause" the system peak, heating customers certainly use wires, poles, transformers, and other distribution facilities that were sized to meet summer peak demands. Setting a non-summer distribution charge very low, therefore, could be unfair to customers.

Finally, from a utility's perspective, having most distribution costs collected in the peak season could create concerns with revenue stability, particularly if weather happens to be unusual (a summer that is much cooler than normal, for example). Such seasonal pricing certainly would change the cash flows of electric distribution utilities, making the cash-flow patterns similar to those experienced by natural gas distribution utilities (very high

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peak-season revenues) that may require a utility to have a significant line of credit to provide adequate off-season cash flows.

III. Previous Research

In 2014, Blank and Gegax (Blank and Gegax, 2014), working with a small data set (43 households), used linear regression analysis to show that annual energy consumption (kWh) was positively but somewhat weakly correlated with a customer's contribution to peak demand (expressed in kilowatts). Their regression analysis showed that while the result was statistically significant ($\rho < 0.001$) annual kWh explained only 38 percent of the variability in peak demand (kW).

That study also posited that a regression through the origin (that is, an intercept equal to zero) might do a better job of explaining the relationship between kWh and kW. Given the different measurements involved in linear regression analyses with and without an intercept term, Eisenhauer explains that the *R*-squared cannot be used to compare results; rather, results using the two approaches must be evaluated by comparing the standard errors of the analyses (the lower the standard error, the closer the correlation between the variables) (Eisenhauer, 2003). On this basis, the analyses of Blank and Gegax show that the regression with an intercept term is superior (a standard error of 1.96 compared to the regression without an intercept's standard error of 3.06).

Blank and Gegax also suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness. They did not develop any analyses, however, that would evaluate this hypothesis.

Blank and Gegax suggested that a rate that divided demand charge recovery between the customer charge and the kWh charge might enhance fairness.

IV. Methods

This article expands on the Blank and Gegax approach to evaluate the ability of different residential rate designs. Rate designs are compared for their ability to collect demand-related costs in a manner that might be fairer to customers and consistent with other important rate design principles and goals.

In particular, linear regression analysis is used on a data set containing monthly energy consumption and annual contribution to the system peak demand for 77,675 residential accounts. The data set contains data for a portion of the service area of an electric distribution utility in U.S. Department of Energy climate zone 5 (U.S. Department of Energy, 2013). Some customers in the data set use electricity for space heating in the winter, but most do not. Many (but not all) non-heating customers have summer peak usage evidencing energy usage for air conditioning or other seasonal space cooling. Prior to developing the final data set, some outliers were eliminated (such as accounts with highly atypical usage or demand profiles, those with missing data, etc.).

Hledik (2014) notes that some residential demand charges are developed using billing demand (that is, each customer's maximum demand in each billing period), rather than contribution to annual peak demand. In order to evaluate a rate design using billing demand, it is necessary to have the monthly peak demand for each customer. The data set does not contain those monthly demands, so monthly demands were estimated for each customer using the base, low, and high usage load profiles developed by the U.S. Department of Energy (DOE) for a city within the utility's service area.

Specifically, the ''low'' load profile was used for accounts with annual usage less than 7,500 kWh; the ''base'' profile was used for accounts using between 7,500 and 12,500 kWh during the year; and

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the "high" profile was used for accounts using more than 12,500 kWh in the year. From each load profile, the peak demand was determined for each month. From that monthly peak demand, a monthly load factor (ratio of average demand to peak demand) was calculated for each month. The July load factor from the applicable load profile was then compared to the actual July load factor (July was the month when the peak occurred in the data set) for each customer to calibrate the results. For example, if a customer had a load factor in July of 0.50 but the applicable DOE load profile had a July load factor of 0.45, the actual load factor for the month was 11 percent higher than the profile. It was assumed, therefore, that the load factor would be 11 percent higher than the applicable DOE profile in all other months. The monthly load factor was then used to calculate the monthly billing demand. The following equation shows the calculation of May billing demand for a customer in the "base" group (using between 7,500 and 12,500 kWh in the year).

$$kW_{May} = \frac{kWh_{May}/744}{BLF_{May} \times [(kWh_{Jul}/744)/(kW_{Annual}/BLF_{Jul})]}$$

where kW = Peak kW demand in a period (month or Annual); kWh = kWh consumption in a period; BLF = Load factor calculated from DOE Base profile in a period; 744 = Number of hours in a 31-day month.

Illustrative rates were then calculated for six different rate design options, as described in Table 1. The rates are based on the customer cost ($13.25 per month per customer) and demand charge ($4.93 per kW per month based on annual peak demand) used by Blank and Gegax. Applying those rates to the customers in the data set produces revenues of approximately $27.7 million. All other rate design options were designed to collect the same amount of revenues.

For purposes of these analyses, it is assumed that the existing rate design is the All kWh design. Thus, the existing rate has a customer charge that collects customer-related costs of $13.25 per month. All other costs (to simplify, it is assumed that all other distribution costs are demand-related) are collected through a flat charge of 1.52¢ per kWh throughout the year.

The second assumption is that the Annual Demand rate represents the cost to serve each customer. That is, this rate collects all customer-related costs in an equal amount per customer and all demand-related costs based solely on each customer's contribution to the annual peak demand. This also makes the

Table 1: Rate Design Options.

Option	Description	Customer Charge (per month)	Demand Charge (per kW per month)	Summer Energy (per kWh)	Non-Summer Energy (per kWh)
Annual Demand	Per kW charge based on annual peak	$13.25	$4.93	– 0 –	– 0 –
Billing Demand	Per kW charge based on monthly peak	$13.25	$5.55	– 0 –	– 0 –
All kWh	All demand costs per kWh	$13.25	– 0 –	1.52¢	1.52¢
Split	Demand costs 60% per kWh; 40% in customer charge	$19.84	– 0 –	0.91¢	0.91¢
All Summer	All demand costs per summer (Jun–Sep) kWh	$13.25	– 0 –	4.79¢	– 0 –
Seasonal	Summer kWh charge is 2 times non-summer charge	$13.25	– 0 –	2.31¢	1.15¢

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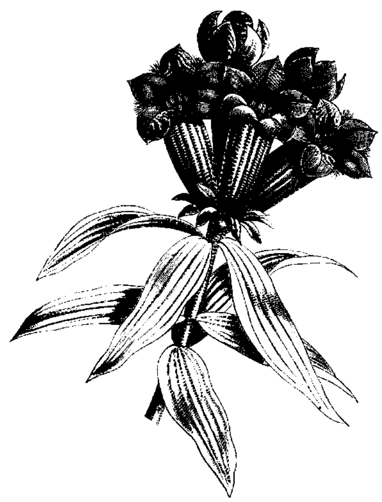
simplifying assumption that all demand-related costs are allocated to customer classes based solely on a single coincident peak (that is, each class's contribution to the single hour of the year with the highest system demand).

Thus, the assumed cost to serve each customer (the Annual Demand rate) can be compared to the charges under other rate designs to assess the relationship between the cost of service and revenues for each customer. Rather than comparing demand (measured in kW) against charges (measured in dollars per year), the analyses compare the customer-specific cost of service (in dollars per year) against charges under other rate design options (also in dollars per year for each customer). Because of the existence of a fixed customer charge, bills will never approach zero, which avoids one of the analytical issues raised by Blank and Gegax in their analyses that compared demand (kW) to energy (kWh).

V. Results

Initially, the characteristics of the cost of service are examined. The data show that the cost to serve customers varies from a low of $159.35 per year (a customer with almost no contribution to peak demand) to $750.48 per year (the highest-demand customer), with an average of $356.79 per year (standard deviation of 103.78).

Next, the existing rate (All kWh) is compared to the cost of service. While the cost of service indicated a maximum cost of $750.48, the existing rates result in a maximum annual bill that is substantially higher: $919.00. While the average annual bill is essentially the same as the cost of service ($356.75 versus $356.79), the existing rates' standard deviation is higher (127.77 versus 103.78), providing an initial



indication that there is a meaningful difference between revenues and costs for many customers.

A linear regression analysis provides further evidence that the existing rate does not ideally track the cost of service for many customers. The analysis shows that the existing rate is positively but modestly correlated with the cost of service, and the relationship is statistically significant ($\rho < 0.001$). Specifically, both the intercept (169.200) and slope (0.526) are positive, indicating that the relationship is logical (customers with higher costs pay higher rates). The R-squared, however, is 0.419, which indicates that there is a substantial unexplained variance between the cost of service and customers' annual bills.

The next stage in the analysis is to evaluate each rate design option in two ways. First, the option is compared to the cost of service with a linear regression analysis. Second, the magnitude of rate change (compared to the existing All kWh rate) is described to indicate whether this type of rate design change might create unacceptable customer impacts. The results of these analyses are shown in Tables 2 and 3.

Several points are noteworthy in these results. First, to move immediately to rates based on annual demand (even if other obstacles could be overcome) would result in dramatic rate changes, ranging from a 76 percent decrease to a 162 percent increase. Ten percent of customers would experience annual bill decreases of 29 percent or less, while another 10 percent of customers would face annual bill increases of 32 percent or more, as shown in Fig. 1. It is unlikely that a revenue-neutral rate design change having changes of this magnitude would be consistent with the rate design criteria of public acceptability and gradualism. The difference from existing (kWh-based) rates is simply too severe.

Interestingly, adopting a rate design based on billing demand

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Table 2: Results of Linear Regression Analyses Compared to Cost (All Demand).

Option	Intercept	Slope	*R*-squared	Significance
All kWh	169.200	0.526	0.419	$\rho < 0.001$
Billing Demand	178.876	0.499	0.426	$\rho < 0.001$
Split	43.695	0.878	0.419	$\rho < 0.001$
All Summer	60.580	0.830	0.846	$\rho < 0.001$
Seasonal	125.856	0.648	0.550	$\rho < 0.001$

Table 3: Bill Changes from Rate Design Options Compared to Existing Bills (All kWh).

Option	Average % Change	Min/Max % Change	10th/90th Percentile	% Bills Increased
Annual Demand	4.4%	−76%/+162%	−29%/+32%	62%
Billing Demand	0.6%	−40%/+183%	−14%/+16%	43%
Split	4.6%	−25%/+49%	−14%/+24%	60%
All Summer	3.0%	−76%/+74%	−26%/+26%	63%
Seasonal	0.7%	−19%/+18%	−6%/+6%	61%

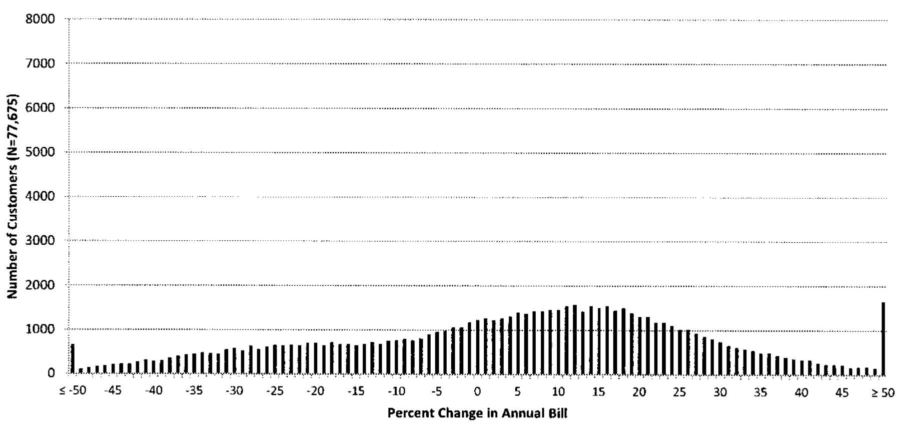

Fig. 1: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Annual Demand

(that is, the customer's peak demand in each billing month) would make almost no progress toward aligning rates with the cost of service. Specifically, this option (Billing Demand) has an *R*-squared of just 0.426 (compared to existing rates' *R*-squared of 0.419) when compared to the cost of service. While this option would have a less severe rate impact than moving to the Annual Demand option, there are still sizeable rate dislocations, with some customers experiencing increases even higher than those experienced under the Annual Demand option (as high as 183 percent). Most customers, however, would experience increases in the range of ±15% (Fig. 2), which is somewhat more acceptable than the ±30% range under the Annual Demand option. Further, this is the only rate design option evaluated that has more customers receiving annual bill decreases than increases (43 percent receive increases, compared to the other options where more than 60 percent of customers receive increases).

It also is interesting to note that the Split option that collects 60 percent of demand-related costs through a kWh charge and 40 percent through the customer charge, does nothing to better align costs and revenues. The *R*-squared under this option is identical to the *R*-squared of existing rates at 0.419. In this

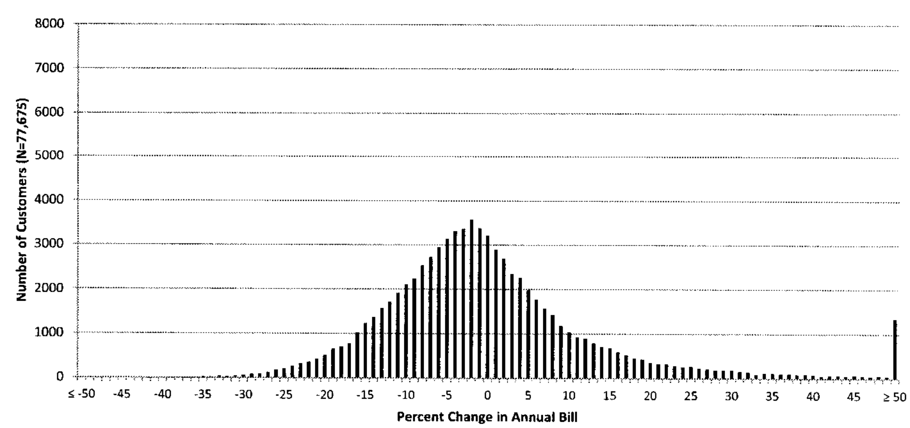

Fig. 2: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Billing Demand

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example, this option represents a classic case of a rate design that creates winners and losers but does nothing to improve the overall efficiency of the rate design (that is, the rate design's ability to more closely track the cost of service).

The last two options evaluated represent cases that may achieve some of the benefits of demand-based rates without using a kW billing determinant. The rate design that collects all demand-related costs through peak-season (summer) kWh charges comes much closer to tracking the cost of service, with an R-squared of 0.846. This type of rate could avoid the educational and implementation problems of a demand-based rate while better aligning rates with costs. This type of rate design, however, does have theoretical problems, as discussed above (particularly the problems of revenue stability and off-season customers getting the free use of the distribution network). Moving to this type of rate design also would create significant annual bill changes for customers. Most customers would experience increases in the range of ±26%, with the highest and lowest increases of approximately ±75% (Fig. 3).

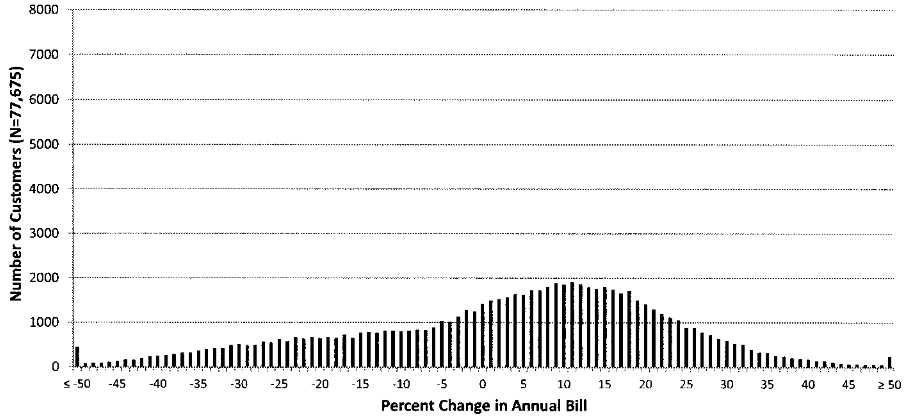

Fig. 3: Distribution of Rate Increases Required to Move from All kWh Rates to Rates Based on Summer kWh

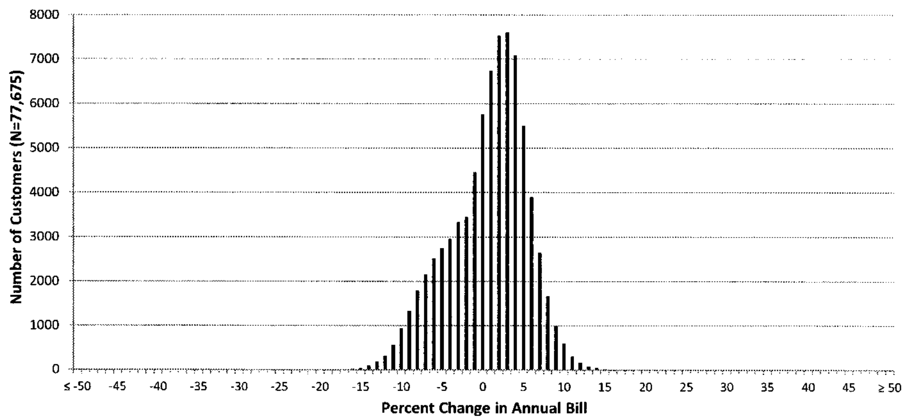

Fig. 4: Distribution of Rate Increases Required to Move from All kWh Rates to Seasonal kWh Rates

The final option evaluated has a summer kWh charge that is double the non-summer kWh charge. This might represent an incremental change in the rate design that does not involve the issues associated with demand-based billing, but moves closer toward cost-based rates in a gradual manner that considers customer impacts. This type of rate design makes meaningful movement toward tracking the cost of service (R-squared of 0.550 compared to the existing rate design's 0.419), but without the drastic changes in annual bills that the other rate design options would engender. Under this option, most customers would see bills change within the range of ±6%, with no customer experiencing a change outside the range of ±19%, as shown in Fig. 4.

VI. Conclusion

The illustrative rate design options evaluated in this article contain some important results. For example, shifting costs between consumption and customer charges may do nothing to improve the efficiency of the

  http://dx.doi.org/10.1016/j.tej.2015.09.021

rate design, even though customers experience dramatic changes in their annual bills. Similarly, while one might expect monthly billing demands to be closely correlated with annual peak demand, that is not the case in this data set. In fact, using monthly billing demands does very little to improve the efficiency of the rate design compared to a simple kWh-based rate design. Once again, while winners and losers are created, the overall rate design is no better at tracking the cost of serving customers than a consumption-based design.

From these examples, it appears that designing residential electric distribution rates with seasonal consumption charges (higher peak-season charges) might make significant progress toward a more efficient rate design. Seasonal kWh rates are understandable to customers, avoid many of the problems with demand-based rates (such as the "lucky" customer who happens to be away from home on the day of the annual peak), do not require significant implementation expenditures, and may avoid the extreme bill impacts of some demand-based rate options.

There are a limitless number of rate design options available to utilities and regulators. With the wide-scale deployment of AMI, data will be available that will allow analysts to develop rate design options that improve the efficiency of the rate design (that is, its ability to have a customer's revenues collect the cost of serving the customer) while also evaluating the impacts of the rate design change on customers. This article has highlighted some of the statistical and comparative techniques that should be helpful in the development of such rates. It is hoped that analysts and researchers will further explore these topics with more extensive data sets, other rate design options, and different statistical techniques for evaluating the ability to improve rate design efficiency while remaining sensitive to other longstanding rate design principles and goals.■

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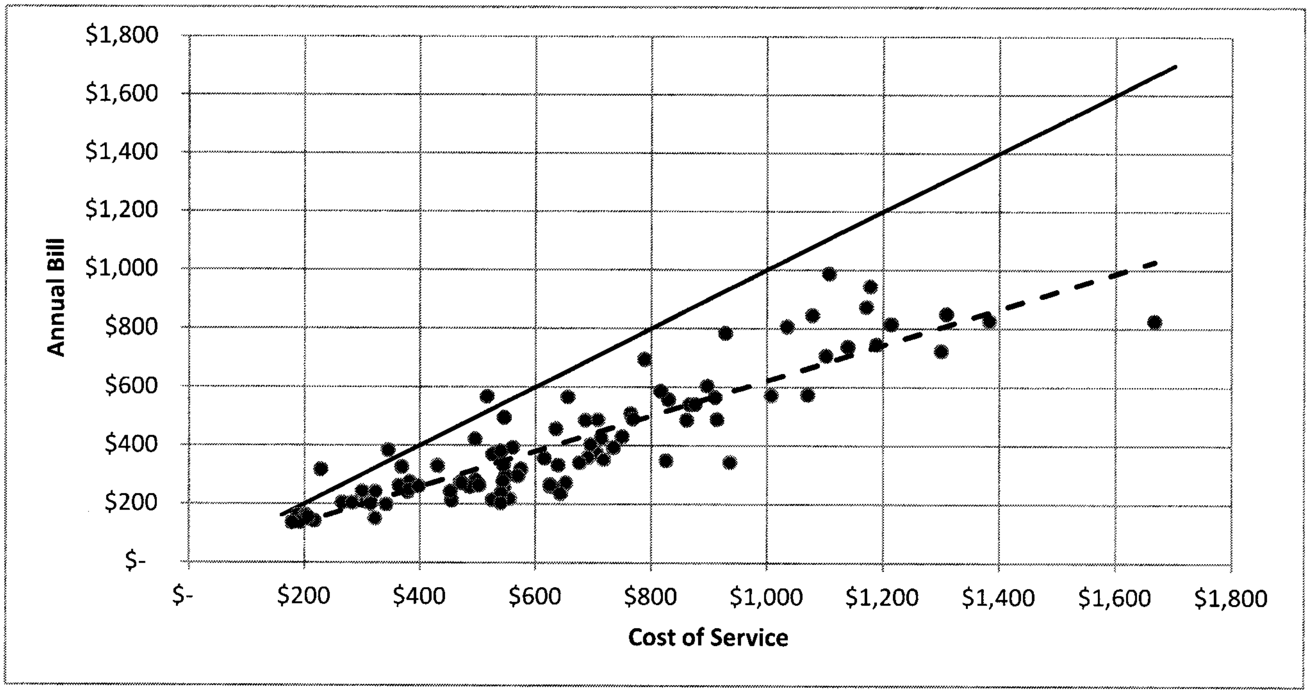
 http://dx.doi.org/10.1016/j.tej.2015.09.021

UNS Electric Inc. Exhibit SJR-2
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Residential Cost of Service, Units of Service, and Unit Cost
(All data from: 2015 UNSE Schedule G-COSS-R.xlsx)

	Cost of Service				
1	Production demand	$	20,709,455	A&E/4CP	Data from the Functionalization_RES tab
2	Transmission demand		8,775,515	A&E/4CP	
3	Distribution primary demand		10,625,712	NCP	
4	Distribution secondary demand		1,173,823	NCP	
5	Total demand	$	41,284,505		
6	Energy	$	44,744,078	KWH	
7	Customer delivery	$	7,991,033	Customers	
8	Customer meter		646,494	Customers	
9	Customer billing & collections		4,113,357	Customers	
10	Customer meter reading		942,211	Customers	
11	Total customer	$	13,693,095		
	Units of Service				
12	Residential customers		82,607		G-7 Allocations tab, J38
13	Residential sales		823,953,185	kWh	G-7 Allocations tab, I32
14	Residential NCP		267,360	kW	NCP tab, C65
15	Residential CP		211,252	kW	NCP tab, C60
	For calculation purposes, simplify the A&E/4CP allocator to				
16	Average demand		22.50%		Calculated in Work copy of COSS
17	4 CP		77.50%		
18	Equals		184,883.48	kW	(line 13 / 8760 x line 16) + (line 15 x line 17)
	Annual Unit Costs				
19	Production demand	$	112.01	per kW (A&E/4CP)	line 1 / line 18
20	Transmission demand	$	47.47	per kW (A&E/4CP)	line 2 / line 18
21	Distribution primary demand	$	39.74	per kW (NCP)	line 3 / line 14
22	Distribution secondary demand	$	4.39	per kW (NCP)	line 4 / line 14
23	Energy	$	0.054304	per kWh	line 6 / line 13
24	Customer-related costs	$	165.76	per customer	line 11 / line 12
	Restated Annual Unit Costs				
	Average demand:				
25	22.50% of A&E/4CP costs	$	6,634,118		(line 1 + line 2) x line 16
26	Average demand		94,059	kW	line 13 / 8760
27	Average demand-related	$	70.53	per kW @ avg.	line 25 / line 26
28	Convert to cost per kWh	$	0.008052	per kWh	line 27 / 8760
29	Energy costs	$	44,744,078		line 6
30	Energy costs per kWh	$	0.054304	per kWh	line 29 / line 13
31	**Energy-related unit cost**	**$**	**0.062356**	**per kWh**	line 28 + line 30
	4 CP related:				
32	77.50% of A&E/4CP costs	$	22,850,852		line 1 + line 2 - line 25
33	**4 CP related unit cost**	**$**	**108.17**	**per kW @ 4 CP**	line 32 / line 15
34	**NCP related unit cost**	**$**	**44.13**	**per kW @ NCP**	line 21 + line 22
35					
32	**Customer related unit cost**	**$**	**165.76**	**per customer**	line 24

Sample of 100 Residential Customers
Comparison of Cost of Service and Present Distribution Bill

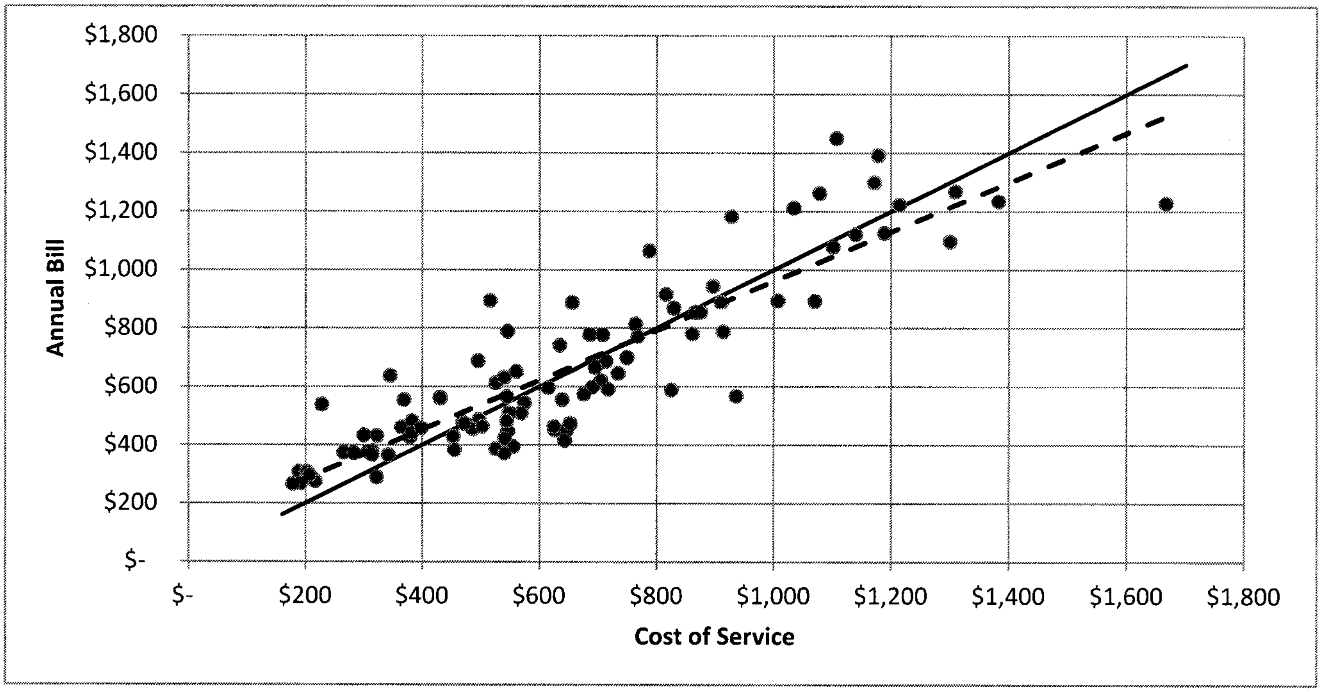


Slope	0.607	N	100			
Intercept	15.805	Avg. Diff.	36%	Tot. Rev.	$	39,934
R-square	0.797	% > Cost	3	Tot. Cost	$	63,175

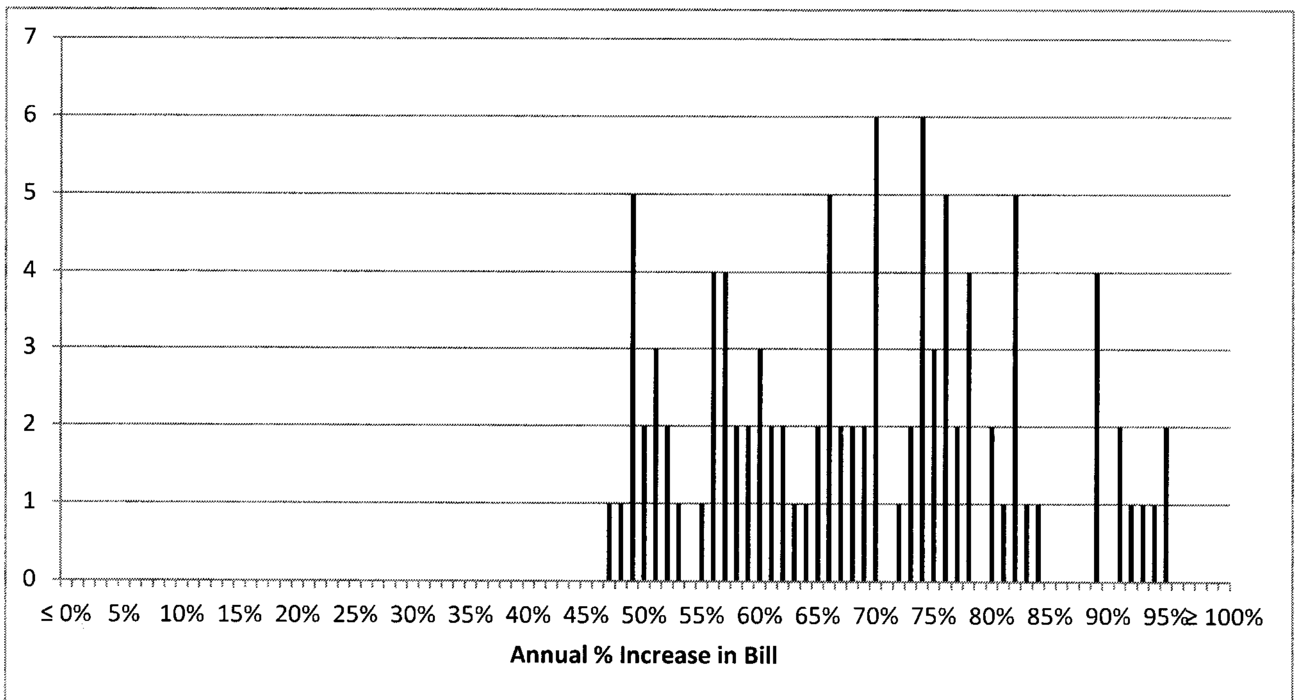
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-4

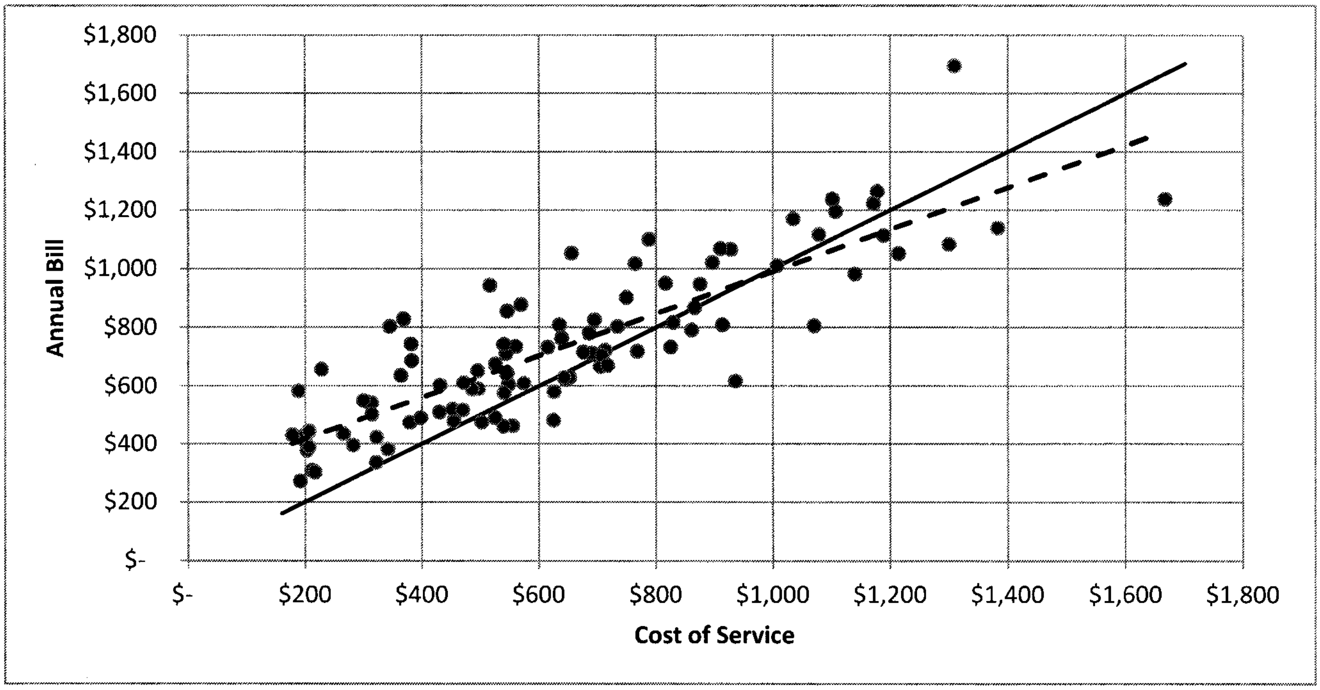
Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Originally Proposed Distribution Bill



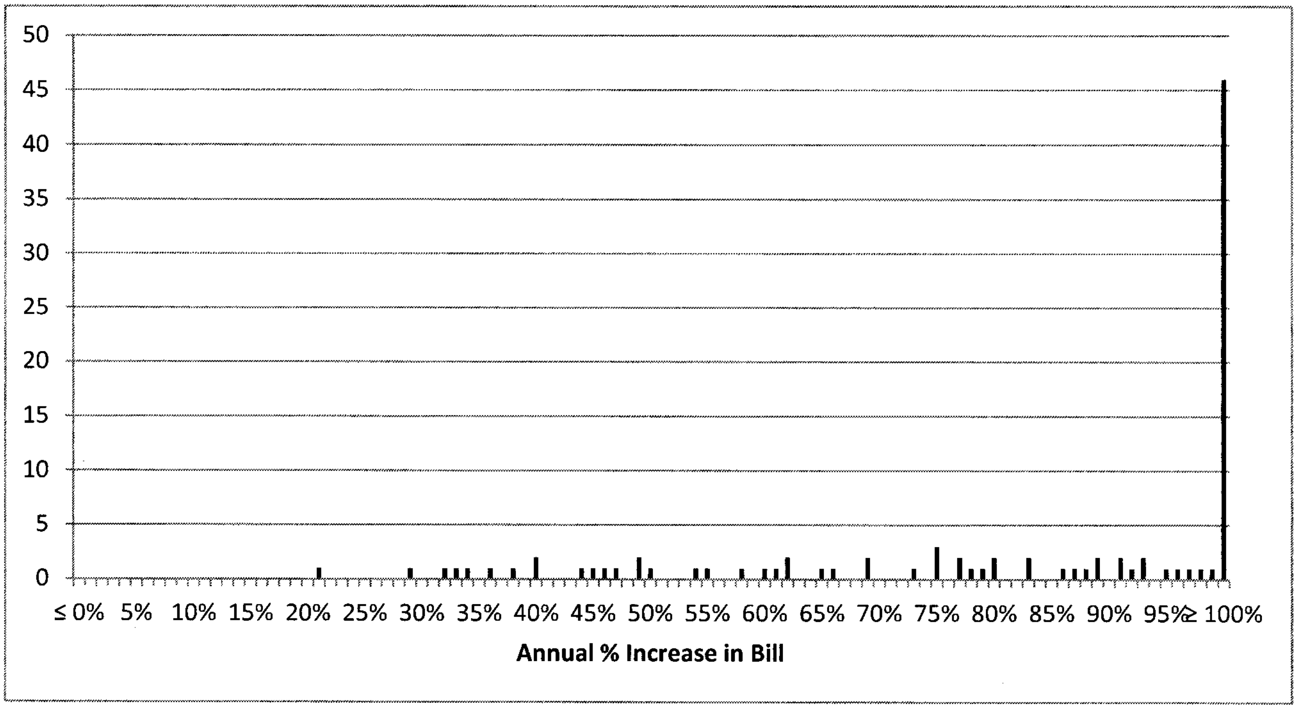
Slope	0.846	N	100	Range		47% to 95%
Intercept	114.490	Avg. Diff.	22%	Tot. Rev.	$	64,904
R-square	0.797	% > Cost	54	Tot. Cost	$	63,175



Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Originally Proposed Demand Distribution Bill



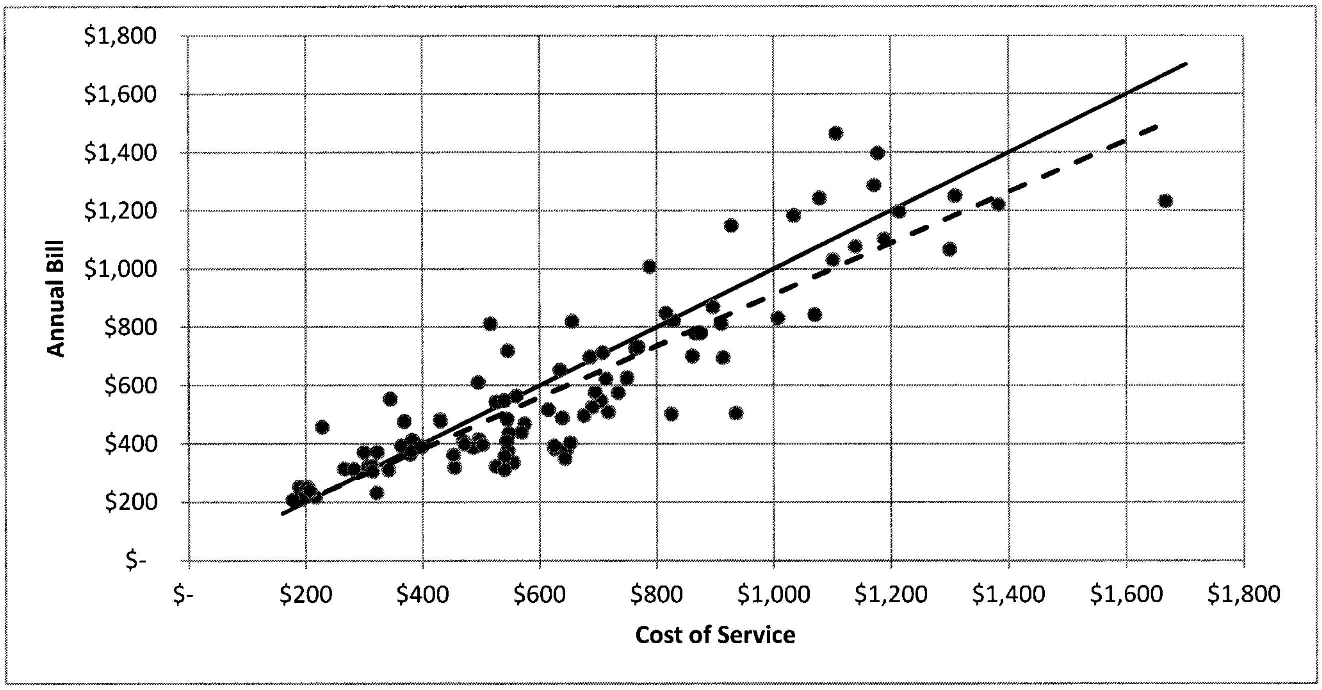
Slope	0.717	N	100	Range		21% to 257%
Intercept	273.979	Avg. Diff.	35%	Tot. Rev.	$	72,685
R-square	0.725	% > Cost	75	Tot. Cost	$	63,175



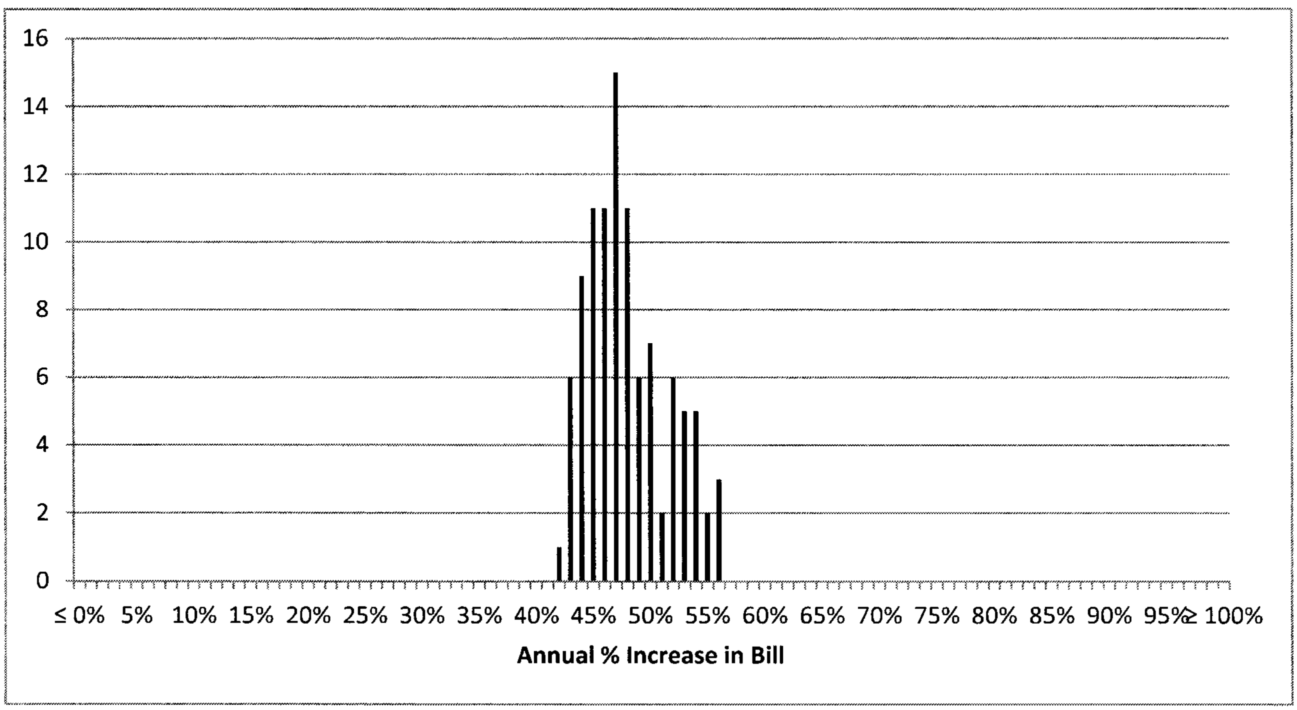
UNS Electric Inc. Exhibit SJR-6

Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Transition Distribution Bill

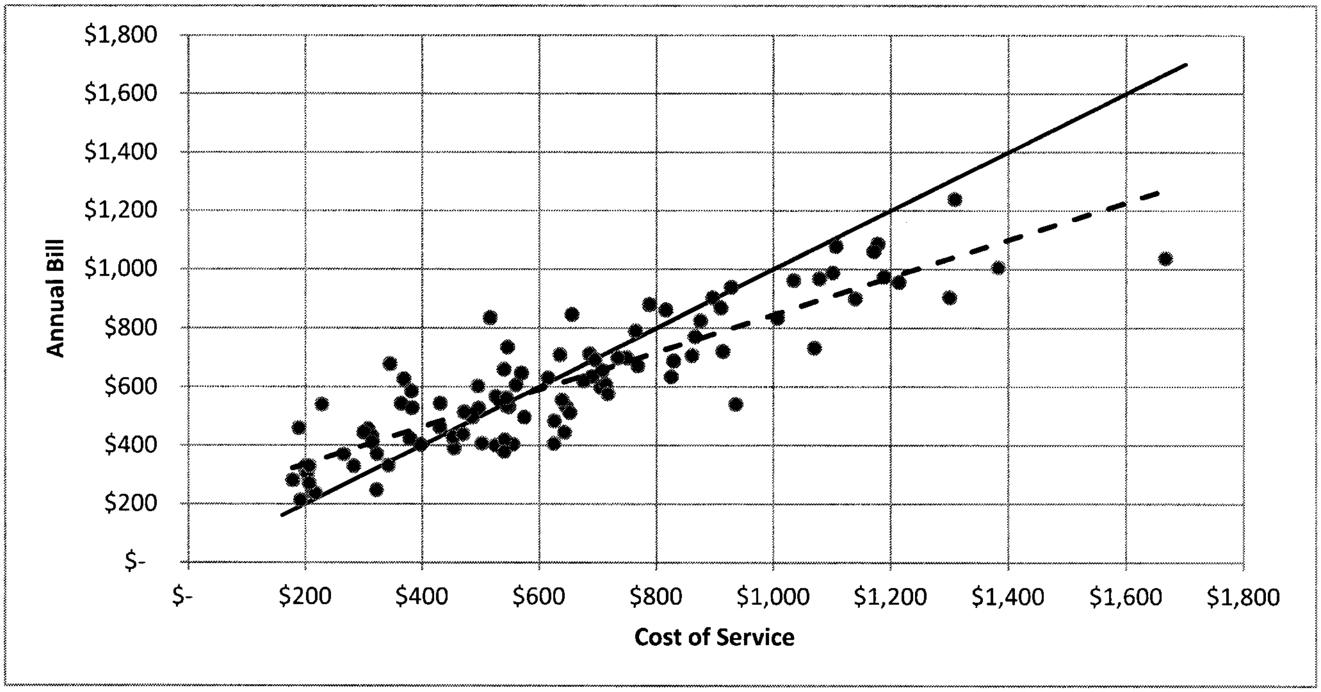


Slope	0.881	N	100	Range	42% to 56%		
Intercept	30.202	Avg. Diff.	19%	Tot. Rev.	$	58,692
R-square	0.797	% > Cost	41	Tot. Cost	$	63,175

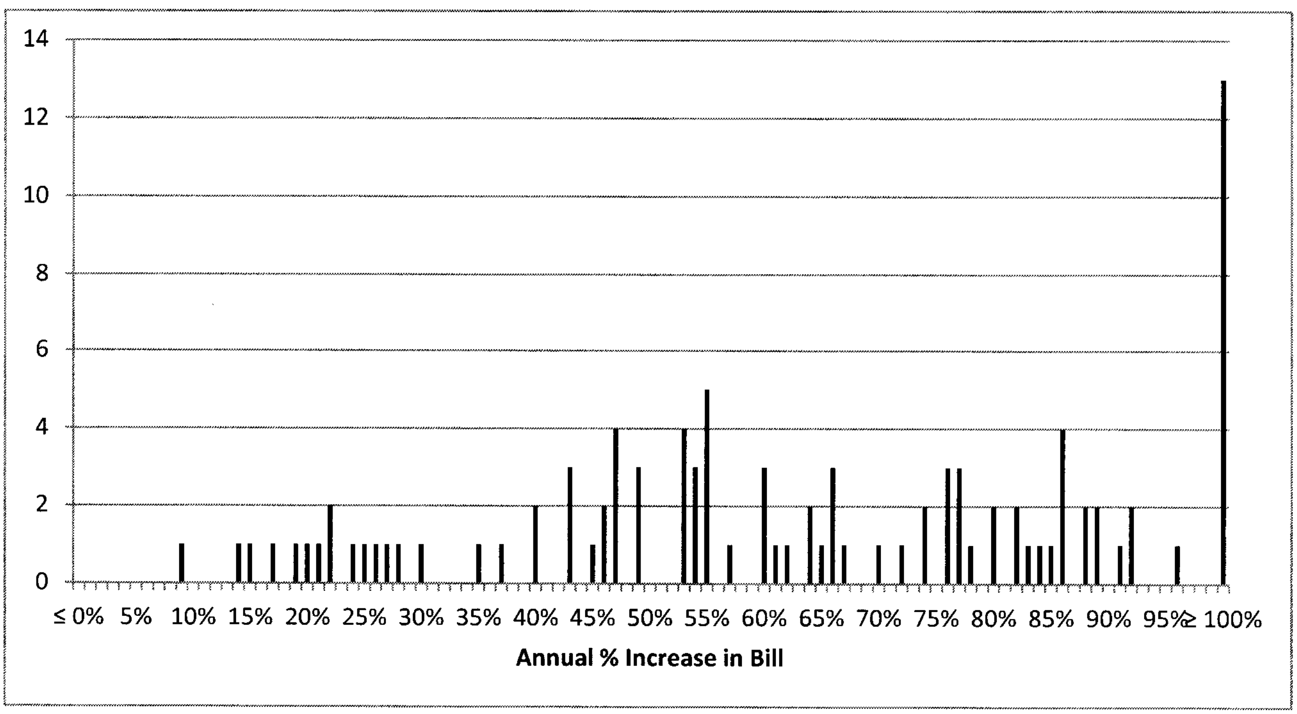


UNS Electric Inc. Exhibit SJR-7
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Demand Distribution Bill (No Limiter)



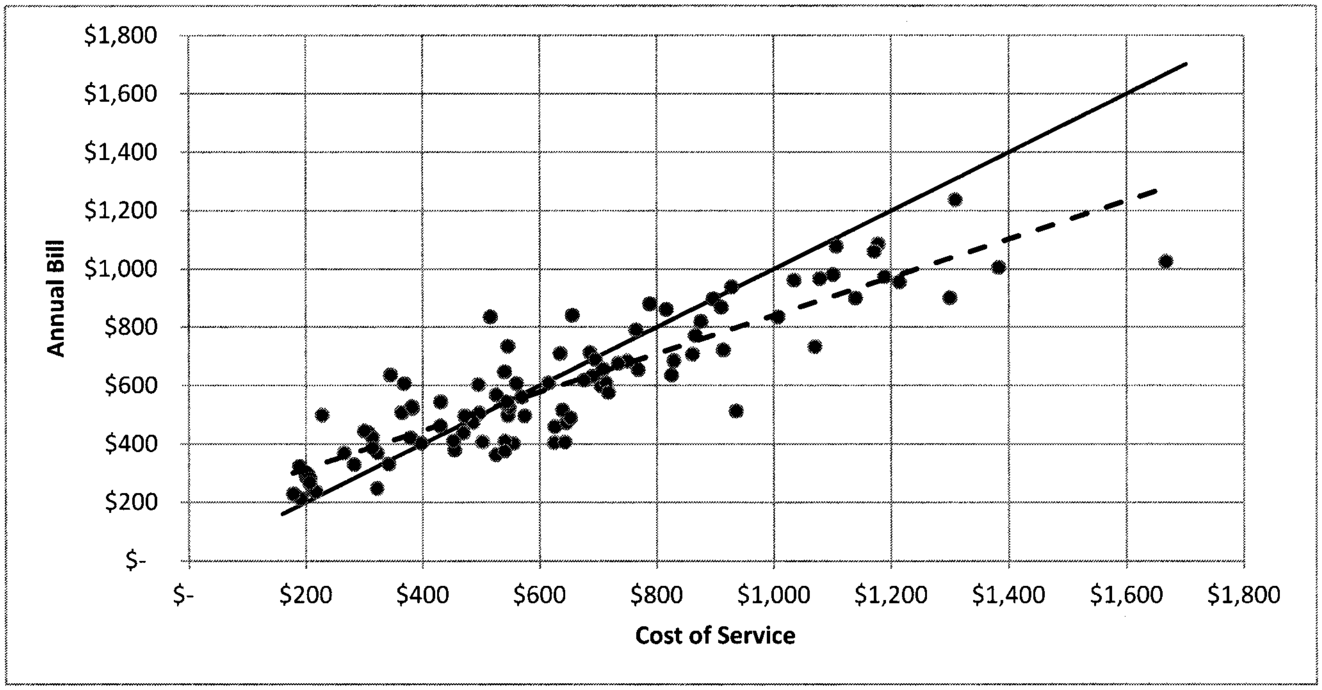
Slope	0.636	N	100	Range		9% to 182%
Intercept	208.738	Avg. Diff.	23%	Tot. Rev.	$	61,078
R-square	0.773	% > Cost	49	Tot. Cost	$	63,175



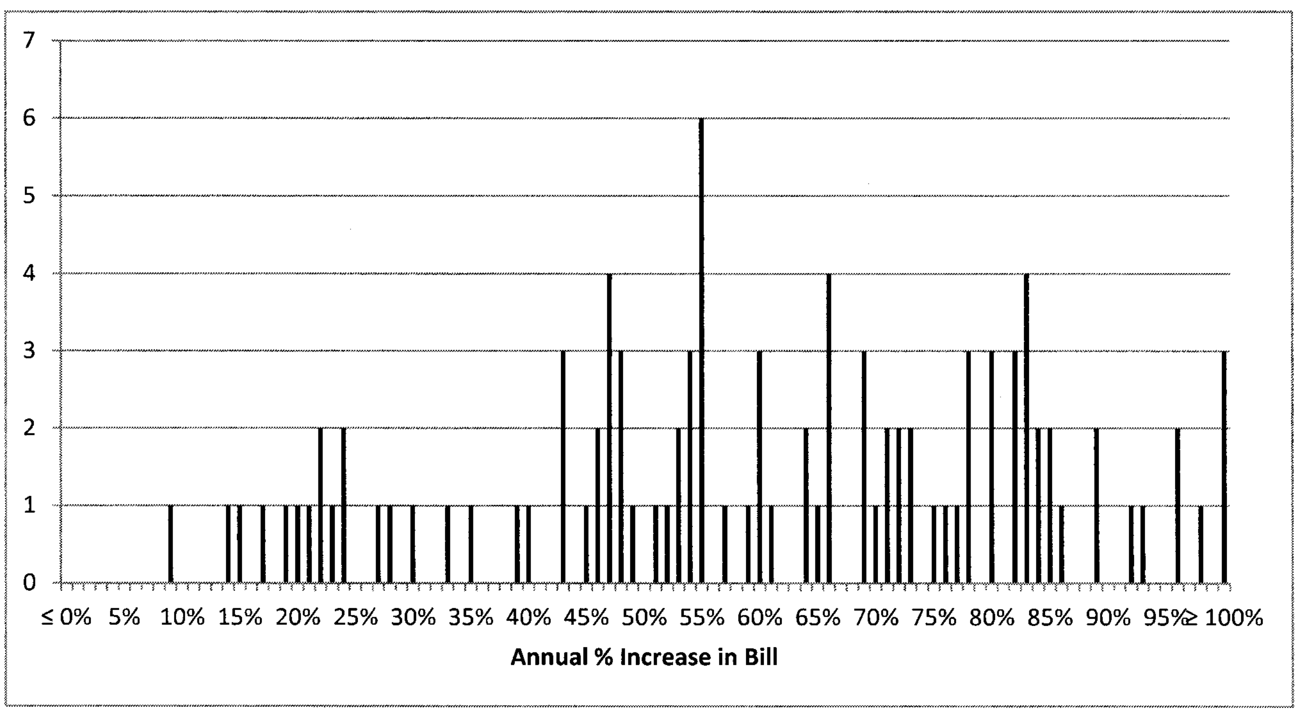
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-8

Sample of 100 Residential Customers
Comparison of Cost of Service and UNS Rebuttal Proposed Demand Distribution Bill (15% L.F. Limit)

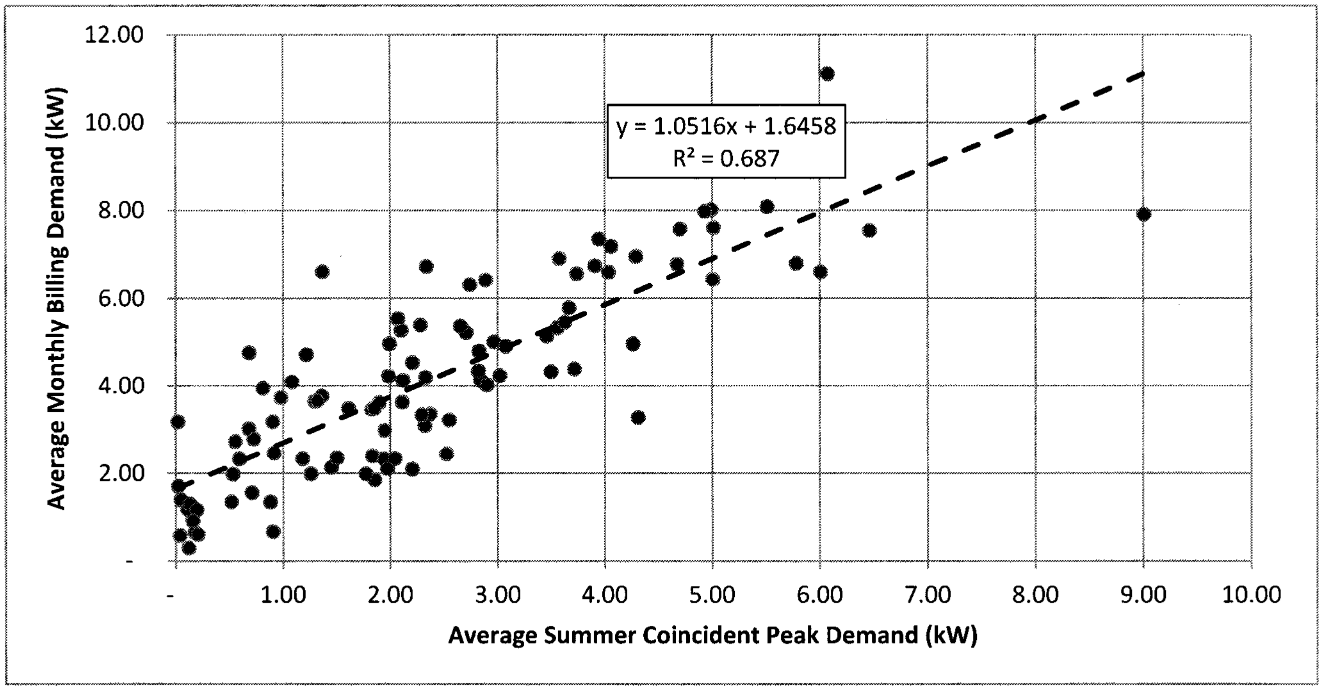


Slope	0.657	N	100	Range		9% to 113%
Intercept	183.234	Avg. Diff.	21%	Tot. Rev.	$	59,847
R-square	0.785	% > Cost	44	Tot. Cost	$	63,175

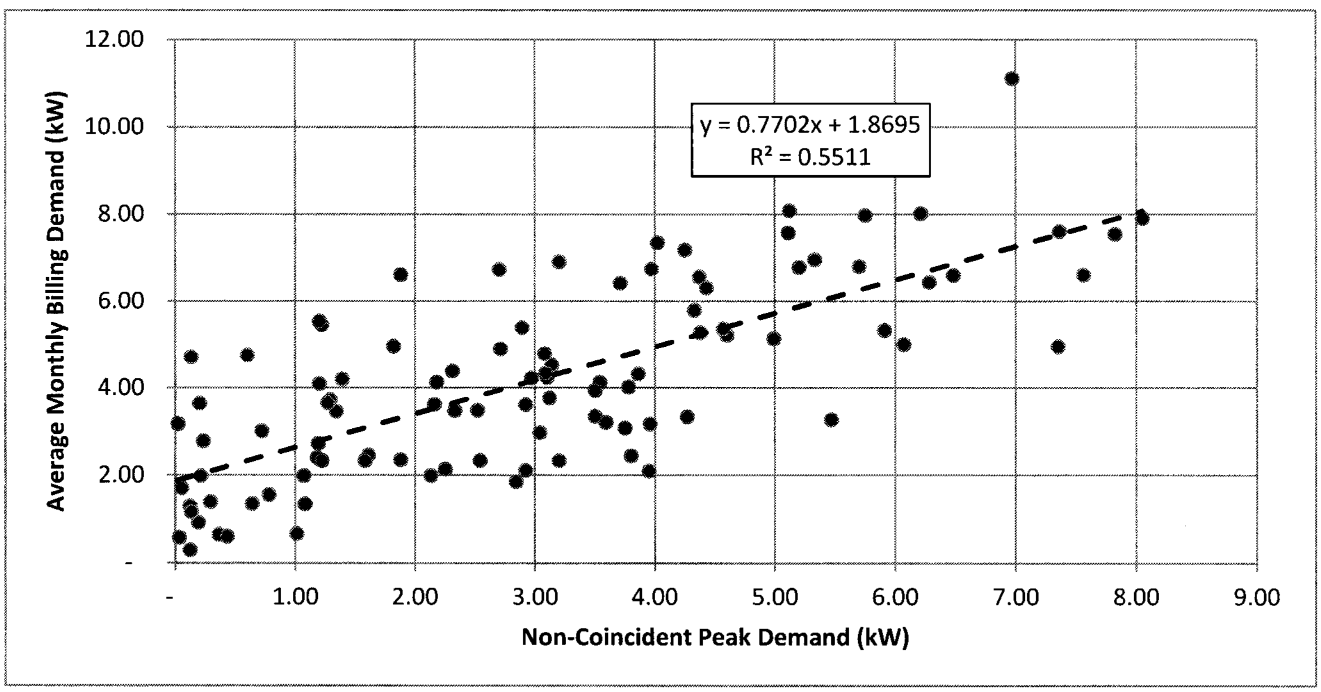


Sample of 100 Residential Customers

Comparison of Summer Coincident Peak Demand and Monthly Billing Demand (With 15% L.F. Limit)



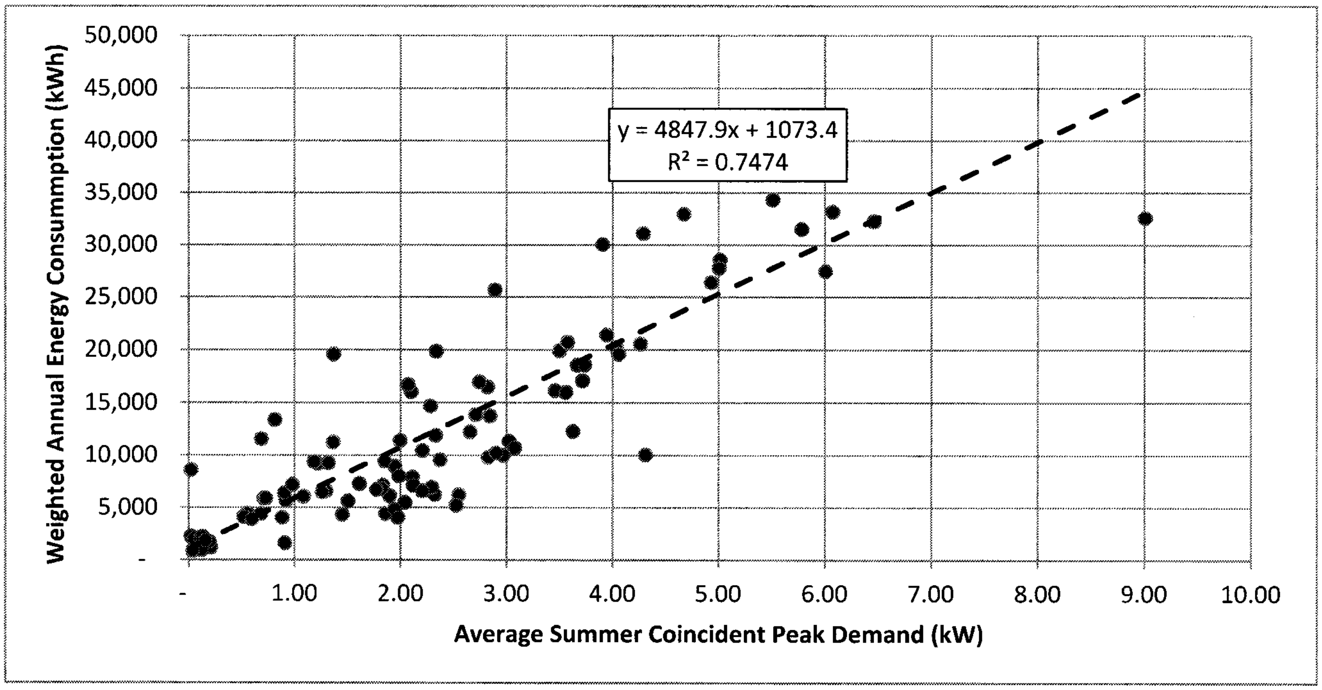
Comparison of Non-Coincident Peak Demand and Monthly Billing Demand (With 15% L.F. Limit)



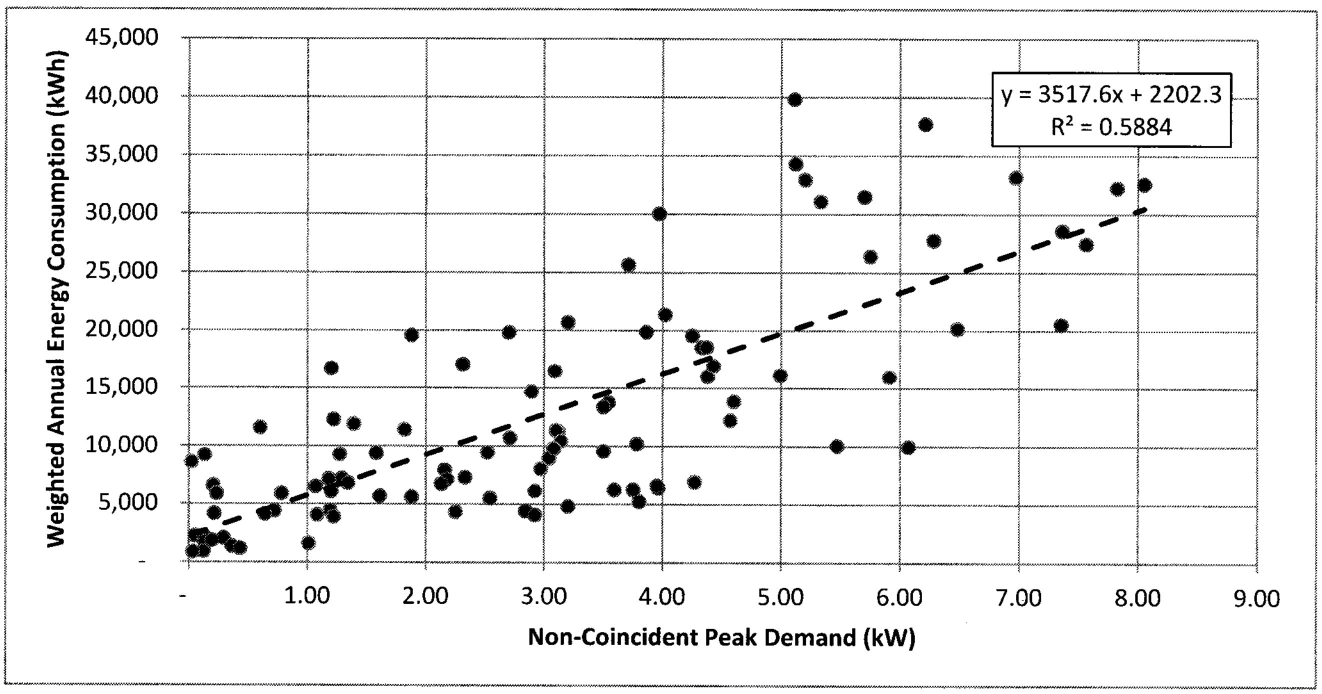
UNS Electric Inc.
Arizona Corp. Comm'n Docket No. E-04204A-15-0142

Exhibit SJR-10

Sample of 100 Residential Customers
Comparison of Summer Coincident Peak Demand and Annual Energy Consumption (Weighted)



Comparison of Non-Coincident Peak Demand and Annual Energy Consumption (Weighted)



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ATTACHMENTS

EXECUTIVE SUMMARY - SURREBUTTAL

The Residential Utility Consumer Office ("RUCO") has reviewed the rebuttal testimony of UNS Electric, Inc. ("Company, UNS, or UNSE"), and the various interveners' direct testimony on rate design.

RUCO continues to recommend a traditional rate design for 98 percent of UNS customers and recommends three options for the 2 percent of UNSE customers that are Distributed Generation (DG) customers. RUCO is opposed to both Staff's and the Company's proposed mandatory demand rates, neither of which are in the interest of ratepayers and should be rejected by the Commission.

RUCO is perplexed as to why Staff, and now the Company, are pushing a mandatory demand rate onto residential ratepayers with such urgency. In fact, there is such a rush that customers will not even have a full year of data to understand the potential impacts of their demand charge. This is important as there are both summer and winter charges (which are illogically the same price). It seems like Staff is pursuing a policy for policy sake without considering the impact to ratepayers. In fact, it was the Company that originally held back from proposing a mandatory demand rate because they were not ready, and it was the Company that suggested safeguards for ratepayers in their rebuttal.

If Staff seeks to solve the rooftop solar issue with this mandatory demand rate, there is no need. Both the Company and RUCO agree that solar participants can be treated differently than the standard residential customer. Partial requirements customers and Full Requirements are not "similarly situated". Decades of partial requirements customers and other policies back this up. Moreover, RUCO offered a solution to the claim of discrimination by certain solar advocates should this issue become divisive. RUCO put forward a "no export" option if a solar customer seeks to be on a traditional rate. This option was approved in Hawaii and a solar customer can get the same payback, broadly speaking, if they have enough load and a properly sized system. Further, RUCO offered two other options for solar customers, a rate design for sophisticated DG adopters, and a simple fixed credit rate tied to REST compliance.

In sum, there is no justification as to why rates must change dramatically and all within a year. Instead of allowing customer choice, nearly every residential UNS ratepayer will have only a single rate plan in which they are exposed to a new charge, one they have never seen before. Add in the lack of actionable data due to old meter technology plus the lackluster education plan and one should conclude that this policy is frankly unacceptable and detrimental to residential ratepayers.

I. INTRODUCTION

Q. Please state your name for the record.

A. My name is Lon Huber.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct rate design testimony in this docket on December 9, 2015.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will primarily address the Company/Staff's position on mandatory demand rates with brief mention of other parties' positions on rate design.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony is presented in three sections as below:

i. Introduction

ii. Concerns with UNSE's proposed mandatory demand rate;

- a. Equity and fairness in UNSE's proposed mandatory demand rate
- b. Customer education plan and timeline
- c. Time of Use demand rate design

iii. Other concerns

- a. Concerns regarding UNSE's proposed increase in fixed charges
- b. Concerns regarding UNSE's rate design as a means to recover fixed costs.

iv. Solutions to problems with UNSE's proposed rate design

Q. Are there any corrections you would like to make at this time?

A. Yes. When formulating the demand charge for the Advanced DG rate, RUCO asked the Company to provide a breakdown of fixed costs, customer costs, and variable costs. In the response, customer costs were inadvertently placed in the fixed cost category as well as the appropriate customer category. This led to a double counting of customer costs when calculating the demand charge for the Advanced DG rate. The correct figure should be $16 per kW per month for summer months. This figure also takes into account an estimate of the small impact a six-hour time-of-use (TOU) period and a three-hour averaging may have on the ultimate demand charge level.

II. CONCERNS WITH PROPOSED MANDATORY DEMAND RATE

a. Equity and fairness in UNSE's proposed mandatory demand rate

Q. How many Small General Service and Residential customers does the Company propose to move to the new three-part rate?

The Company now proposes to move all Small General Service ("SGS") and residential customers to a demand rate.

Q. What is the Company's stated motivation for moving all customers to this mandatory demand rate instead of only some customers?

A. The Company cites equity[1] and fairness[2] as motivation for moving all customers to the proposed demand rate.

[1] See Rebuttal Testimony of H. Edwin Overcast page 2, line 12
[2] Ibid. page 10, lines 5-6

Q. Does RUCO support moving all customers to a mandatory demand rate as an equitable and fair practice?

A. No. The Company argues that all SGS and residential customers should be treated similarly under the same mandatory demand rate because "using the same rate sends the same price signals"[3] to customers with like service characteristics. Utilities treat and categorize customers into different classes based on many factors. This is true for UNSE as well. Existing examples of customer classes include, CARES discount, agricultural, etc.

The utility ratemaking principle of fairness does not require all customers to be subject to the same rates, but rather be subject to rates that are fair. The proposal to require all customers to move to a mandatory demand rate is a misguided attempt at ensuring fair treatment.

Q. Do customers prefer rate options?

A. Yes. Utilities have increasingly been offering their customers more rate options. Using OpenEI US Utility Rate database data, the average number of residential rate options offered by utilities climbed from 1.87 residential rate options in 2013 to 3.2 residential rate options per utility in 2015[4]. This increase in rate offering also leads to an increase in customer satisfaction. J.D. Power senior director of energy, Andrew Heath stated recently, "the thing that really differentiates the top utilities, they provide the customer some form of choice." Heath goes on to state the utilities that offer greater choice, experience "a significant uplift in terms of overall customer

[3] See Rebuttal Testimony of H. Edwin Overcast page 48, lines 1-2
[4] http://en.openei.org/apps/USURDB/

satisfaction.[5]" Simply, customers prefer more options and do not appreciate a 'one size fits all' rate plan.

Q. Have UNS, TEP, and APS boasted about how they offer many different rate options to their customers?

A. Yes. In the deregulation debate in 2013, all the utilities mentioned their many rate options as a reason not pursue market restructuring. In the filings, it was clear that the companies were proud of their diverse offerings.

Tucson Electric Power Company and UNS Electric, Inc. stated the following:

> "Advocates also overlook the multitude of choices available to customers served by the Companies and other regulated Arizona utilities. Our customers can choose time-of-use rates, fixed price plans, "green" energy alternatives and incentives for energy efficiency and renewable power without forgoing the consumer protections offered in our regulated system."[6]

Arizona Public Service:

> "APS offers five varieties of residential time-of-use ("TOU") rates as well as TOU options for virtually all its commercial and industrial customers, including a TOU offering for schools specifically designed at their request. The Company offers demand response and energy efficiency programs, interruptible rates (as requested by some of the Company's larger customers), special contracts, combined metering

[5] http://www.utilitydive.com/news/for-top-utilities-customer-satisfaction-hinges-on-empowerment/402618/
[6] TEP and UNSE Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 10

and billing, and other rate or service offerings. One would be hard pressed to find any electric utility in this country that provides such a wide range of options to over one million customers."[7]

Q. Does the Company propose customer subsets for differential treatment?

A. Yes. In H. Edwin Overcast's Rebuttal testimony, he defines partial and full requirement customers and later suggests these two classes to be treated differently. Full requirement customers receive all their electricity from the utility, partial requirement customers receive some electricity for the utility, and the rest from DG. This creates two classes of customer.

In his definition of these two classes, Overcast also suggests that within the previously defined full and partial requirement classes, "Partial requirement customers differ from full requirement customers and from each other[8]". This suggests the partial requirement subset can be further refined. Thus differentiating DG and non-DG customers would not be a departure from normal ratemaking process.

Q. Could partial and full requirement customers be subject to different rate designs?

A. This is what RUCO is proposing. Two optional rates for new DG customers, as detailed later in this testimony, will allow UNSE to treat the two classes differently without being unduly discriminatory.

[7] APS Response Letter to Commissioners in Docket NO. E-00000 W-13-0135, page 2
[8] Rebuttal Testimony of H. Edwin Overcast page 10, lines 5-6

Q. Has the Company proposed applying a demand rate to a subset of their customers?

A. Yes. In fact, the Company proposed exactly this originally. In the Company's Direct Testimony mandatory three-part rates were proposed for the subset of DG customers that install distributed generation after June 1 2015, and optional for other non-DG SGS and residential customers[9].

Q. Has the Company changed its position since this initial proposal?

A. Yes. In its Rebuttal Testimony, the Company has expressed support for Staff's recommendation of a mandatory demand rate for all customers be adopted in this rate case.

Q. Why did UNSE not propose mandatory demand rates in its initial proposal?

A. In his Direct Testimony dated May 5, 2015, Dallas Dukes states "Presently, UNS Electric doesn't have the capability to measure demand for every customer and is not advocating a forced migration to such a structure at this time."[10]. Later, in his Rebuttal Testimony Dukes states, mandating all customers to move to a mandatory demand rate in the initial proposal would have been 'somewhat aggressive'[11]. It is unclear what changes occurred to reduce the demand rates to an acceptable level of aggressiveness between Dukes' two testimonies. Further demonstrating the Company's own doubt, Craig Jones states "three-part rates for all customers is a special

[9] Direct Testimony of Carmine Tilghman page 8, line 21
[10] See Direct Testimony of Dallas Dukes page 10 lines
[11] See Rebuttal Testimony of Dallas Dukes beginning on page 4, line 7

circumstance which may yield results that were unintended.[12]" Therefore, "UNS Electric could support keeping the rate design portion of this rate case open for a period of time in the event that significant unintended consequences arise that adversely affect the Company or its residential or SGS customers."[13]

Q. In RUCO's opinion, does the Company and Staff's position reflect the principle of rate gradualism?

A. No. The Company's original proposal represented a more gradual shift by moving some, but not all customers to a radically new rate design. However, the Company's present proposal is not gradual and subjects all UNS customers to this radical shift in a way that RUCO believes will be confusing and harmful.

b. Customer education plan and timeline

Q. Why will UNSE's proposed mandatory demand rate be confusing for customers?

A. Among other reasons, UNS does not have the right technology deployed to adequately inform ratepayers of their demand usage?

Q. Please explain.

A. There are two types of advanced meters generally used today, Advanced Metering Infrastructure (AMI) meters and Automatic Metering Reading

[12] See Rebuttal Testimony of Craig Jones page 6, lines 15-16
[13] See Rebuttal Testimony of Craig Jones page 6, lines 17-18

(AMR) meters. According to General Electric, a meter manufacturer with experience in both AMI and AMR meters, AMR meters are older technology that provides one-way communication from the meter to the utility, AMI meters provide two-way communication, from the utility company to the customer[14]. This means only AMI meters can interface directly with customers about their demand usage. Currently, UNSE has no AMI meters installed[15]. Therefore, UNSE does not have the optimal technology in place to support the proposed changes. While AMR meters can provide interval data, it is RUCO's understanding that the customer will not be able to receive data in a timely manner because it must first go through the Company.

Q. Have you reviewed the direct testimony of Staff witness Howard Solganick and Thomas M. Broderick?

A. Yes.

Q. Please summarize Staff's testimony as it relates to customers' ability understand and adapt to UNS' proposed new rate structure.

A. Mr. Broderick states on page 7 of his direct testimony:

> "Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before."

[14] General Electric's website; http://geappliance.esecurecare.net/app/answers/detail/a_id/22/~/what-is-the-difference-between-amr-and-ami-meters%3F
[15] RUCO data request 11.3

Mr. Broderick states on page 8 of his direct testimony:

> "Staff believes there will only be a temporary challenge for residential customers to understand, accept and adapt if the Company develops and implements a customer education program. Staff requests that UNSE define and develop the details for a rate migration transition process and share with the parties in its rebuttal testimony."

Further, Mr. Solganick states on page 8 of his direct testimony:

> "As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption." Later Solganick states, **"**My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future."

Q. Does UNS currently have this technology to support Mr. Broderick and Mr. Solganick's conclusions?

A. Not entirely. Based on RUCO data request 11.3. UNS does not have the current technology as 90.5% have AMR meters, and few customers have AMI meters.

Q. Is there currently an internet portal that UNS customers can log into to check their usage and demand profile?

A. No.

Q. Is Staff aware that UNS customers are unable to track their usage and demand in the way that Mr. Solganick described?

A. Yes. In response to data request 1.5 from RUCO, Staff stated that Mr. Solganick "was unable to find a UNSE portal with that capability."

Q. Does Staff recognize that there will be additional costs incurred by the Company (and ultimately ratepayers) to provide access to this data?

A. Yes. Staff recognizes that "the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP."

Q. Did Staff estimate what these costs will be?

A. No. However, the Company estimates a cost of $650,000 in response to RUCO data request 11.4.

Q. Does RUCO have further concerns regarding UNSE's proposed usage portal?

A. Yes. Only 76.2% of Arizonans have access to high speed internet, this is below the national average of 78.1%[16]. High speed internet is vital for users to access their electricity usage. Customers could also access their usage data using a smartphone. As of October 2014, only 64% of US adults own a smartphone[17]. This leaves a sizeable portion of UNSE customers without access to their usage even if it is made available through a portal.

[16] 2013 US Census Report https://www.census.gov/history/pdf/2013comp-internet.pdf
[17] Pew Research Center Mobile Technology Factsheet (October 2014) http://www.pewinternet.org/fact-sheets/mobile-technology-fact-sheet/

Q. What is RUCO's synopsis of Staff's recommendation?

A. RUCO finds it telling that Staff admitted that it will be challenging for customers to understand, at least at first. Staff places faith in a yet to be completed education plan and new technology that hasn't been developed yet and may not ever reach a large portion of UNS customers.

Q. What does this mean for ratepayers?

A. Higher costs in the form of added infrastructure in order to meet the requirements of Staff's mandatory demand rate. As well as confused customers lacking the connectivity and the hardware to understand the new charges.

Q. Does a Company witness also question the understandability of more advanced rate designs?

A. Yes. Dr. Overcast on page 33 of his testimony speaks to this and his answer was to undertake a 'gradual process done in steps'. To reduce confusion his first suggestion was to phase out the third tier of kWh rates followed by a move to seasonal and time differentiated energy charges.[18] Noticeably, he did not mention carrying out a rapid and complete switch to a three part rate design for all residential customers as Staff and the Company proposes.

Q. Does UNSE propose a timeline for their education plan and ultimate rollout of the proposed rates?

A. Yes. Summarized as:

[18] See Rebuttal Testimony of H. Edwin Overcast page 33 lines 15- 19

- May to June 2016. UNSE Implements transitional rates
- Present to December 2016. Analyze billing data
- May to October 2016. Customer education plan rolled out
- No later than November 2016. UNSE provides usage and demand data to customers.
- 1st quarter 2017. All residential and SGS customers moved to three-part rates and a redesigned bill introduced.[19]

Q. Does RUCO foresee issues with this timeline?

A. Yes. The proposed timeline is very tight to allow a full three months for customer demand data as proposed. All customers are expected to have AMR meters installed by the end of 2016[20]. Any setbacks will negatively impact this timeline.

Q. The timeline suggested provides some customers only three months of demand data before charging demand rates. Does RUCO feel this is adequate?

A. No. Three months of usage data will not provide enough information for customers to understand how their behavior will impact their electric bills. RUCO suggests greatly increasing this timeline before issuing bills using the new rates. The seasonal temperature variability in UNSE territory generally leads to higher usage and demand in summer, particularly due to air conditioning use. During shoulder seasons, air conditioning use is reduced, therefore demand during this time is unlikely to represent demand

[19] See Rebuttal Testimony of Dallas Dukes page 13 lines 1 - 12
[20] See Rebuttal Testimony of David Hutchens page 7, lines 10 -11.

during summer. For these reasons, RUCO takes issue with the lack of summer data available to customers. As proposed, the impact of three-part rates will not provide customers with accurate bill impacts before bills are issued.

Q. Does Staff believe it will be a challenge for residential customers to understand and accept a three-part tariff?

A. Yes. However, Staff says this challenge will be temporary if the Company implements a customer education program.

Q. Have you reviewed UNSE's Education Campaign, Exhibit DJD-R-1?

A. Yes, I have.

Q. Does RUCO have any comments about UNSE's proposed Education Campaign?

A. Yes. The listed campaign components are minimally specific and do little to ensure a customer will properly understand the changes. There is also little mention of education about demand management. RUCO feels that a complicated change such as a mandatory demand charge cannot be adequately explained using a bill insert and brochure. These are likely the only materials most customers will actually view.

Q. Does Staff explain how this education program will help customers understand and act upon their demand if they have no access to data about their demand?

A. No.

Q. Does RUCO have evidence suggesting UNSE's bill design is difficult for customers to understand?

A. Not directly, but generally it is found that customers have difficulty understanding traditional bills even without complicated demand charges. According to one study, only 39% of survey respondents were able to correctly respond to a question about the expected savings by reducing one's kWh usage[21]. The same study also found no single question in the bill interpretation section was answered correctly by more than 70% of respondents.

Q. Are there existing tools for customers to better understand energy usage and demand?

A. There are many tools to help customers understand kWh usage but few tools consider demand. Existing government programs serve as further evidence that customers cannot understand demand charges. The US government's online calculator tool for estimating appliance and home energy use only allows users to input an appliance wattage and cost per kWh[22]. Similarly, the Federal Trade Commission has adopted the recognizable yellow Energyguide label for new appliances. Both the calculator and label only consider yearly kWh performance and estimated yearly operating cost, they make no consideration for kW demand[23]. Using these tools, a reasonable customer could expect a new appliance to have a predictable impact to their estimated yearly operating cost. If the new appliance increased their peak demand, the customer would receive a

[21] Southwell, Brian G., et al (2012) Americans' Perceived and Actual Understanding of Energy
[22] http://energy.gov/energysaver/estimating-appliance-and-home-electronic-energy-use
[23] http://www.consumer.ftc.gov/articles/0072-shopping-home-appliances-use-energyguide-label

larger and unexpected bill. This represents a greater lack of customer understanding and a lack of adequate education tools.

Q. Who does RUCO believe should be responsible for demonstrating that UNSE customers will adequately comprehend the three-part tariff and understand how to manage their electricity bills?

A. RUCO believes the burden of proof is on Staff and the Company to demonstrate this.

Q. Are there other reasons why you have concerns about UNS' ability to develop and implement a customer education plan about mandatory demand charges? Please explain.

A. Yes, I have other reasons to be concerned. UNS' Residential Time-of-Use and Time-of Use-Super Peak tariffs (RES-01 TOU and RES-01 TOU SP) have very low subscription rates. During the test year, UNS reported an average of 230 customers on its Residential Time-of-Use tariff and only one customer on its Time-of-Use Super Peak tariff. This equates to less than 0.5% of residential customers. In comparison, 52% of APS customers are on time-of-use rates.[24] This raises concerns about UNS' ability to communicate to its customers about their rate offerings - especially non-standard ones - and to communicate specifically about energy usage as it relates to system peak.

[24] Ryan Randazzo (2015), Arizona leads California on time-of-use electricity plans. http://www.usatoday.com/story/money/2015/05/26/arizona-california-time-of-use-electricity/27985581/

Furthermore, given that these charges would be mandatory for all residential customers, UNS would need to execute a communication and education plan that touched all residential customers and educated them about their energy usage. Notably, UNS has faced complaints in the past when it has tried to educate a broad number of customers about their energy usage. When UNS implemented its Home Energy Reports program, it "received a number of complaints from enrollees… generally concerning the report being delivered 'unsolicited,' on an opt-out basis, rather than an opt-in."[25] These complaints were an influencing factor in UNS' decision to cancel the program.

c. Time of use demand rate design

Q. Please summarize your comments regarding the Company's proposed Time of Use rates.

A. RUCO supports a time of use rate design, however as proposed, the Time of Use demand rate does not accurately collect costs from customers as they are incurred to the utility. RUCO is also in disagreement with the company over the duration of the proposed demand peak.

[25] UNS Electric, Inc.'s Annual Demand-Side Management Progress Report, Docket No. E-00000U-14-0049

Q. Do you have comments regarding the inability of the proposed Time of Use demand rate to accurately collect costs from customers as they are incurred to UNSE?

A. Yes. The proposed rate does not differentiate demand as it contributes to seasonal peak demand. This means summer and winter peak costs are recovered as if they cost UNSE equally. Since the Company's plan is to 'recover generation costs through the demand charge' this contradicts the Company witness Dr. Overcast.[26] In his article attached to his Rebuttal Testimony, Overcast states "It will be important to develop seasonal and diurnal periods based on underlying marginal costs" [27].

Q. Please describe how UNSE's proposed demand rate peak is too long in duration.

A. UNSE's proposed peak demand times are from 2 pm to 8 pm. This is a 6-hour timeframe which customers are expected to minimize demand. This is an unreasonable expectation that regular customers can realistically monitor and reduce their usage over this timeframe, at least initially and without technology assistance. A shorter timeframe, such as 4 pm to 7 pm, is easier for customers to respond to and more accurately represents the peak demand times.

[26] See Rebuttal Testimony of Dallas Dukes beginning on page 8, line 24
[27] Overcast, Edwin H. Smart Rates for Smart Utilities page 15

Q. Are there other effects of the peak demand rate that are not in customer's best interest?

A. Yes. UNSE cites Bonbright's principles of rate design in several instances throughout various testimony including Overcast[28]**.** RUCO feels this wide peak time does not represent the principle of practicality. It is simply, impractical to discourage behavior that contributes to a standard customer's peak demand for nearly all evening hours. A demand peak that is narrower would be more practical.

Q. Have you conducted in depth analysis of the customer impacts from the three part rate?

A. No, the tight timeline and limited data available, prevented me from conducting an in-depth review. Since Staff did not provide a rate schedule with details around their vision of a three part rate, I had only the time from the Company's rebuttal.

Q. In that time did you conduct any analysis?

A. Yes, but at a very high level. I found that compared to the current two part rate, the proposed three part rate provides a significant increase to the bill of lower than average users and a discount to higher than average users. Using 795 kWh per month, the monthly average as seen in UNS's 2,309 smart meter customer sample, the results are stark. Any customer between that average and 250 kWh per month in usage will be paying 21% more than under current rates. I purposely excluded very low users or else that figure would be even larger. Conversely, if a household uses over 1,500

[28] See Rebuttal Testimony of Edwin H. Overcast page 44, beginning on line 5

kWh a month they will receive a 3% discount compared to the current rate structure.

III. OTHER CONCERNS

a. Concerns with proposed increase in fixed customer charge

Q. What is the National Association of State Utility Consumer Advocates ("NASUCA")?

A. NASUCA is an association comprised of many consumer advocates from numerous states and the District of Columbia. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. RUCO is a member of NASUCA.

Q. **Has NASUCA taken a position on increased fixed charges?**

A. Yes. NASUCA recently adopted resolution 2015-1

Q. What does NASUCA state in resolution 2015-1, "OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES"?

A. NASUCA opposes increasing the basic service charge. I have included a copy of this resolution (see Attachment B).

Q. Does UNSE's proposed rate design include increased fixed charges?

A. Yes

Q. Does UNSE believe fixed costs should be recovered primarily through fixed charges?

A. Yes. Craig Jones argues that the proposed rates "still leave a significant percentage of the Company's fixed costs subject to recovery through volumetric rates." but the proposed rates "are a good start in addressing appropriate fixed cost recovery."[29] This indicates that UNSE believes fixed costs should be recovered as fixed charges, with some combination of demand charges from their customers.

Q. Does RUCO agree with UNSE's method of fixed cost recovery?

A. No. There is no fundamental reason that fixed costs must be recovered through fixed prices or unavoidable demand charges. In fact, many industries in the global economy incur fixed costs that are ultimately recovered through prices that are not fixed. For example, gasoline is priced on a volumetric basis ($ per gallon), despite the fact that there are many fixed costs associated with its production (e.g. refineries, pipelines, etc.). This is further argued by Bonbright; "“regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions”[30].

[29] See Rebuttal Testimony of Craig Jones page 5, lines 12 - 14
[30] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 382

Q. Other than increased fixed charges, are there other ways utilities such as UNSE could recover unrecovered fixed costs?

A. Yes, there are several. These options range from implementing new time-of-use demand rates (which is RUCO's proposal) to simply increasing UNSE's current volumetric rates.

Q. Does RUCO support increased fixed charges as a way to increase fixed cost recovery?

A. No. For reasons explained previously in our testimony, we don't support increased fixed charges. RUCO finds additional support for its argument from Bonbright: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."[31] We believe there are many options, such as RUCO's proposal, that are better for customers while still ensuring greater fixed cost recovery for UNSE.

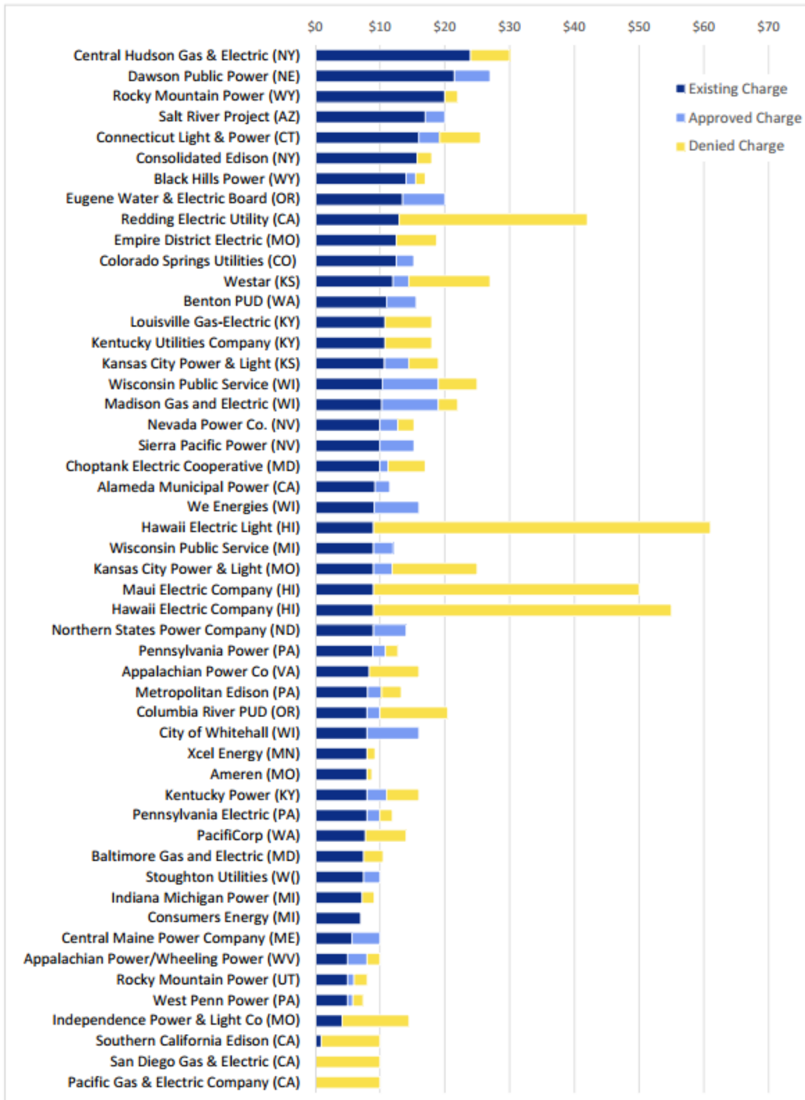
Q. Have there been other recent commission decisions regarding increased mandatory fixed charges?

A. Yes. Recent decisions by commissions in several states have either denied entirely or scaled back proposals to increase mandatory fixed charges proposed by utilities. Synapse recently analyzed 51 proposals decided between September 2014 and November 2015 and found that 41% of these proposals were rejected, and 33% were scaled back. The average

[31] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 141

approved fixed charge for these decisions is $11.87[32]. These decisions are summarized below.[33]

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

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[32] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity.

[33] Whited, M., Woolf, T., & Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p 46

Q. What are some of the reasons that these proposals were denied or scaled back?

A. There are many reasons why these proposals were denied or scaled back. Some include: concerns about reduced customer control; concerns about rate shock; concerns about inequitable impacts to low usage customers; concerns about inequitable impacts to low income customers; concerns about reduced incentives to invest in energy efficiency; and concerns about inefficient price signals.

Q. Can you provide a few example of Commission decisions?

A. Yes. When the Missouri Public Service Commission denied Ameren Missouri's request to increase its fixed charge it stated, "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy."[34] Similarly, when the State of Illinois Commerce Commission rejected Peoples Gas and North Shore Gas' proposals, it stated, "It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller portion of

[34] Missouri Public Service Commission (2015). Report and Order in the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service. See discussion on page 76-77.

the bill is subject to variable usage charges and customer efforts to reduce usage."[35]

Q. Have you reviewed the direct testimony of the other parties in this proceeding?

A. Yes.

Q. In particular have you reviewed the direct testimony of Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP")?

A. Yes.

Q. Please comment, on SWEEP's position that the basic service charge should not be increased.

A. RUCO agrees with SWEEP that increasing the basic service charge would have the following repercussions on ratepayers:

1. It would reduce the amount of control that ratepayers have on their energy consumption and bills. Customers have no ability to decrease mandatory fixed charges on their energy bills. However, they can control and mitigate the bill impact of charges collected through volumetric rates by reducing their energy use.

2. Low use customers, many of which are elderly or on fixed incomes, will be disproportionately affected by higher fixed charges and may have to make the choice between food, medicine, or paying their electric bill.

[35] State of Illinois Commerce Commission (2015). Order North Shore Gas Company, proposed general increase in gas rates; The Peoples Gas Light and Coke Company, Proposed general increase in gas rates. See discussion on page 176.

3. UNS would have one of the highest basic service charges in the western region.[36]

Q. Is Mr. Schlegel's testimony consistent with others that have filed testimony in this docket?

A. Yes. Cynthia Zwick on behalf of the Arizona Community Action stated the following:

> "Doubling the fixed charges in low-income households will not only disincentivize saving but it would lead to customers having less control over their energy bill and more wasteful electricity use."[37]

> "High fixed charges directly reduce incentives for customers to conserve energy by reducing the payback on investments in efficient appliances, insulation, or other residential or business improvements."[38]

b. Concerns with UNSE's rate design as a means to address unrecovered fixed costs

[36] See the Direct Testimony of SWEEP Jeffrey Schlegel starting on page 4.
[37] See page 15 of the direct testimony of Cynthia Zwick on behalf of the Arizona Community Action association regarding rate design.
[38] Ibid, page 19.

Q. Why is UNSE proposing rate design changes in this proceeding?

A. Among other reasons, UNSE is attempting to address issues associated with the recovery of its fixed costs in an era of declining energy sales and distributed generation.[39]

Q. Is UNSE's proposed rate design the only solution for addressing unrecovered fixed costs?

A. No. There are many possible rate designs that could help ensure fixed cost recovery for UNSE.

Q. Did other parties to this proceeding propose alternative rate designs intended to increase UNSE's fixed cost recovery?

A. Yes. Both Staff and RUCO proposed rate designs that are intended to increase UNSE's fixed cost recovery.

Q. As it relates to DG customers, is UNSE's rate design more closely aligned with RUCO's proposal or Staff's proposal?

A. UNSE claims Staff's proposed three-part TOU rate is "the superior rate for all customers, including DG customers[40]", however according to RUCO's data request 11.5, "the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs."[41].

[39] See Rebuttal testimony of Dallas Dukes ("Dukes"), page 2, line 22.
[40] See Rebuttal Testimony of Craig A Jones page 30, lines 19 - 20
[41] RUCO Data Request 11.5

IV. SOLUTIONS TO PROBLEMS WITH UNSE'S PROPOSED RATE DESIGN

Q. Does RUCO have constructive suggestions on how to improve the demand rates and other issues presented by parties?

A. Yes. Unlike some interveners, RUCO feels that it is valuable to put forward policy ideas that can create win-win outcomes for stakeholders.

Q. Does RUCO believe that standard rates need to evolve?

A. RUCO believes that rates need to continuingly, but gradually, evolve to reduce long-term system costs and to take advantage of new technologies. Volumetric TOU rates can accomplish most of this objective in conjunction with customer data and education. For residential customers, volumetric rates have been the norm and they are well understood. As long as one has a generally homogenized customer class they can work great.

Q. Is this rate case the best place to have this discussion?

A. No, it should be a statewide policy discussion culminating in a formal policy statement from the Commission. This will allow all stakeholders a voice into how the future of rates should be designed. For instance, this process would answer the question: should the state promote some customer choice or just one rate for nearly every customer within a customer class? This process will also prevent a gross mismatch of different policy and rate offerings by each utility in the state.

Q. Are there alternatives to high fixed charges that RUCO would like to propose?

A. Yes. RUCO believes that a minimum bill concept should be explored as a way to better address the Company's concern with fixed cost recovery of low energy users. A minimum bill can accomplish this and maintain conservation price signals that are important to RUCO and other stakeholders.

Q. Would RUCO be open to default residential TOU rate?

A. Yes. RUCO proposes the following rate design based largely on the Company's transitional TOU rate. The only change is to the on-peak and off-peak rates and a reduction of the basic service charge.

RUCO's Proposed 2-Part default TOU Rate

Basic Service Charge	$12.20	
Energy Delivery		Tier Limit
0-400 kWh	$ 0.032258	400
401-1,000 kWh	$ 0.042258	1,000
Over 1,000 kWh	$ 0.060258	
Base Power	**Summer**	**Winter**
On-Peak	$ 0.120000	$ 0.060000
Off-Peak	$ 0.060000	$ 0.030000

Q. Is RUCO working on additional revised rate schedules?

A. Yes, those will be filed in the future.

Q. Any thoughts on a demand based rate?

A. Yes. RUCO is open to an optional demand based TOU rate that any customer can select.

Q. What if the demand rate was mandatory?

A. As stated previously, RUCO is vehemently opposed to this. However, if a mandatory rate were to be adopted, RUCO would strongly suggest the following:

- Only a three-hour time window for each customer that can be staggered randomly to ensure that full six hours of peak is covered.
- More actionable and timely data must be available to the customer. This should include but not be limited to: Smart phone apps, shadow bills, pre-programed thermostats, and online portal with at least a year of past data.
- The summer charge must be higher than the winter charge. This sends more accurate price signals and reflects actual system cost drivers.
- No LFCR charge should be collected from this type of rate.

Q. Is this three hour TOU staggering a new concept?

A. No, Salt River Project (SRP) employs this tactic for their EZ-3 Price Plan.[42]

Q. While on SRP policy, did SRP strike all their residential rate plans when dealing with DG?

A. No, they created a rate specifically for DG customers.

[42] http://www.srpnet.com/prices/home/ez3.aspx

Q. Any suggestions as it relates to options for DG customers?

A. Not at this moment. RUCO is open to some modification of the three options put forward; however, RUCO continues to believe that the options provide win-win outcomes for all parties involved. First, it offers an advanced TOU rate that recovers fixed costs for the company while sending strong on-peak price signals to technology adopters. Second, it offers a simple and easy to understand fixed credit payment option to less sophisticated DG customers. This option is tied to the REST goals to ensure UNS meets its DG targets. Finally, to address the need that solar advocates stress, RUCO's third options allows a solar customer to be on any rate and offset their consumption behind the meter just like today. The only difference is that exports would be restricted.

Q. Are these options complicated?

A. No, they are straightforward to understand from a customer and installer perspective. Nothing is more simple than a fixed credit rate for 20 years as outlined in the RPS credit option. This is in stark contrast to the Company's plan of having an ever changing differential export rate tied to a PPA proxy of solar PV system possibly in another utility's service territory. How would a customer know how much they export? The Company does not provide historical interval data. Even if they could get this data after waiting a full year, how could they reasonably predict savings if the rate can change in any given year?

Q. Does this conclude your rebuttal testimony?

A. Yes.

ATTACHMENT A

Selected Company response to RUCO's data request

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO RESIDENTIAL UTILITY CONSUMER OFFICE'S FIRST SET OF DATA REQUESTS DOCKET NO. E-04204A-15-0142 DECEMBER 29, 2015

1.05 Rate Design – On page 8 of Staff witness Howard Solganick's testimony he states that his utility provides him with a portal so that he can monitor his usage and his neighbor's usage. Based on this statement please answer the following questions:

a. Do UNS customers currently have access to a portal so they can monitor their usage along with their neighbors?

b. If no to a., what does Mr. Solganick estimate the cost would be to implement this technology to UNS customers? In the response please include the initial set-up costs and ongoing yearly costs to maintain this portal that ratepayers will ultimately pay.

RESPONSE: **Staff witness Solganick was unable to find a UNSE portal with that capability.**

a. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

b. Staff witness Solganick recognizes that the costs to develop a portal depends on the existing capabilities of the Company's infrastructure including website, customer information system, meter data management systems and whether the website would be extended to its affiliate TEP. Therefore Mr. Solganick made no estimates, however the Company may make that estimate in its transition plan that has been requested by Staff.

RESPONDENT: **Howard S. Solganick, Energy Tactics & Services, Inc., 810 Persimmons Lane, Langhorn, PA 19047**

RUCO 11.3

Automatic Meter Reading ("AMR") and Advanced Meter Infrastructure ("AMI") – Please answer the following questions as they relate to AMR and AMI in UNS's service territory: a. Can AMR meters supply 15 minute or 30 minute interval data to customers?

b. Please provide the total number of residential meters. In addition, please provide the number of residential AMR meters and the number of residential AMI meters.

c. If not all of the residential meters are AMR, please estimate the approximate cost to install AMI meters. Stated another way, what would the approximate costs be to replace any existing AMR meters with AMI meters.

d. Is it the Company's long-range plan to replace all AMR meters with AMI meters, if so, when would this migration be completed by?

RESPONSE:

a. UNS Electric's AMR meters can provide 15 minute or 30 minutes interval data, but UNS Electric is currently recording hourly interval data for residential customers. See UNS Electric's response to RUCO 11.4(a) for supplying the interval data to customers.

b. UNS Electric currently has 83,718 meters and 75,767 AMR meters have been installed for its residential customers. The remaining 7,951 meters are non-AMR/AMI meters.

c. UNS Electric is focused on the AMR technology and it would be overly burdensome and somewhat speculative to approximate the costs to replace any existing AMR meters with AMI.

d. It is not currently in the long-range plan to replace all AMR meters with AMI Meters.

RESPONDENT:

Chis Fleenor

WITNESS:

Craig Jones

RUCO 11.4

Customer web portal – Please answer the following questions about web portal capabilities:

a. Does the Company currently have real time capabilities for customers to log into the Company's website and check their usage for the last 24 hours or longer? If yes, please explain?

b. If no to a., how much does the Company estimate the costs to be to implement this technology?

c. If no to a., if the Commission ordered the Company to implement this technology, how long would it take.

d. Can the Company web portal work in conjunction with an AMR meter? Or would a customer have to use an AMI meter to monitor his/her usage through the web portal?

e. If yes to d., please estimate the additional costs that must be incurred to have the AMR meters reequipped in order to communicate to the Company's web portal?

RESPONSE:

a. No. The Company's initial plan is to implement web portal capabilities that will allow Customers to access historical energy and demand interval data in multiple formats; for example, by billing period, previous 12 months and by day. The single day or 24 hour interval data will initially be available to a customer after mid-day the following day.

b. Approximately $650,000.

c. Approximately 6 months.

d. Yes, it is expected that the web portal will work with AMR meters.

e. None.

RESPONDENT:

Denise Smith / Brandy Marshall / Arunesh Mohan **WITNESS:**

Denise Smith

UNS ELECTRIC INC.'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-15-0142
February 4, 2016

RUCO 11.5

Fixed Cost Recovery – Please answer the following questions about fixed cost recovery:

a. In rebuttal testimony, witness Craig Jones stated that "Staff's recommended three-part TOU rate is the superior rate for all customers, *including DG customers."* (Emphasis added). All things held equal with adjustors such as the LFCR, which rate option, according to Company calculations, recovers more fixed costs from a typical solar DG customer, Staff's three-part TOU based rate design or RUCO's DG TOU Rate?

RESPONSE:

The response to the question would vary by set of circumstances, therefore the Company cannot choose one proposal over the other as it relates to the recovery of fixed costs. Neither Commission Staff's rate, as modified by the Company, nor RUCO's proposed Option #2 rate actually reflect cost causation and neither proposal provides for adequate fixed cost recovery from customers, in general, nor from DG customers in particular. By focusing the demand charge on the peak period these rate designs fail to provide for the recovery of costs associated with the maximum demand of customers that drive distribution costs. It is likely that for solar DG customers the peak demand on the distribution system will not be at the time of the system peak hours. Rather, the demand will likely occur in off-peak hours. And in RUCO's proposal, there are also no demand costs being charged for a winter peak, which may be the maximum load period for electric heating customers and winter seasonal customers who would have free capacity above whatever small summer use they may place on the system. The net result could be a rate that overcharges for peak hours through both a demand charge and a flat energy charge if it is more than the energy cost for the utility. I believe the Company's original proposal more correctly reflected the need to capture maximum distribution demand whenever it occurs in each month. However, the proposal the Company indicated it would accept in its rebuttal position is satisfactory since the Company recognizes it is merely a start for us to move in the direction of a more sophisticated rate that requires a gradual transition and ultimately includes an on-peak demand charge, but certainly not of the magnitude suggested by RUCO.

RESPONDENT:

Craig Jones

WITNESS: Craig Jones

ATTACHMENT B

The National Association of State Utility Consumer Advocates Resolution 2015-1

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

***Whereas**,* gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved**,** that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers**;**

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved**,** that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates*, Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5]*Id.* at 7-8.

[6]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7]*See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8]U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.