Electric Light Department
Town of South Hadley

85 Main Street
South Hadley, MA 01075-2797

Telephone 413-536-1050
Fax 413-536-0741

NOTICE UNDER MASSACHUSETTS GENERAL LAWS CHAPTER 30A, SECTION 20

BOARD OF COMMISSIONERS' MEETING

A meeting of the Board of Commissioners of the Town of South Hadley Electric Light Department will be held at **6:00 P.M. on Thursday, November 19, 2015**, at the Selectboard Meeting Room at 116 Main Street, South Hadley, Massachusetts.

AT THE ORDER OF ANNE S. AWAD,
CHAIR OF THE BOARD

Anne S. Awad, Chair

MEETING AGENDA

Public comment

Business / financial report

Solar and alternative energy discussion

Correspondence

Executive Session to discuss strategy with respect to litigation and to discuss the deployment of security personnel or devices. *

* - Will not reconvene in open session.

TOWN OF SOUTH HADLEY, MASSACHUSETTS

ELECTRIC LIGHT DEPARTMENT

MANAGEMENT REPORT

SEPTEMBER 2015

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT

INDEX

TOWN OF SOUTH HADLEY MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT

FINANCIAL STATEMENT OVERVIEW

The 2015 year-to-date revenues from sale of electricity decreased by about $534,000 compared with the same period in 2014. Actual kWh sold increased by about 583,000 on a year-to-date basis. The average $/kWh revenue decreased by $.007155 in 2015. This revenue decrease, however, was offset by a decrease in cost of power of about $597,000. The average $/kWh cost decreased by $.010326 in 2015. The 2015 net revenue after cost of electricity purchased showed an increase of about $105,000 from 2014, or about 0.86% of 2014 revenues.

Distribution expenses increased by about $46,000 compared to 2014. Customer account expenses and general and administrative expenses, on a combined basis, increased by about $96,000 compared to 2014.

On a year-to-year comparative basis, the September 2015 results were not as good as the September 2014 results. For the period ended September 2015, SHELD shows a year-to-date profit of about $100,000.

At September 30, 2015, SHELD shows a very healthy financial position. When compared to other companies in the electric power distribution industry, SHELD's 2015 liquidity and leverage ratios equal or exceed those of its peers.

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
STATEMENT OF NET POSITION
SEPTEMBER 30, 2015 AND 2014

Assets

	2015	2014
Capital Assets		
Distribution Plant	$ 29,451,198	$ 30,202,192
General Plant	5,719,524	6,343,855
Construction-in-Progress	628,221	13,927
Total	35,798,943	36,559,974
Less Accumulated Depreciation	29,964,250	30,678,619
Total Capital Assets	5,834,693	5,881,355
Restricted Assets		
Cash - Depreciation Fund	4,935,906	5,016,102
Cash - Customer Deposits	229,874	181,450
Investment - OPEB Liability Trust	596,025	608,461
Deferred Charges	1,080,111	1,080,412
Total Restricted Assets	6,841,916	6,886,425
Current Assets		
Cash - Operating Fund	3,491,167	2,506,409
Investment - MLDM Reserve Trust	11,767,244	11,654,953
Accounts Receivable - Net of Allowance	383,199	880,275
Inventory	438,976	466,616
Prepaid Expense	48,928	45,857
Other Assets	24,516	24,516
Total Current Assets	16,154,030	15,578,626
TOTAL ASSETS	$ 28,830,639	$ 28,346,406

Liabilities and Net Position

	2015	2014
Long Term Liabilities		
Accrued Compensated Absences	$ 1,014,970	$ 1,175,629
Other Post-Employment Benefit	590,006	484,404
Total	1,604,976	1,660,033
Less Current Portion	257,096	244,265
Total Long Term Liabilities	1,347,880	1,415,768
Current Liabilities		
CP of Accrued Compensated Absences	208,304	199,146
CP of Post-Employment Benefits	48,792	45,119
Accounts Payable	682,839	571,182
Customer Deposits	229,874	181,450
Accrued Expenses	12,020	13,160
Total Current Liabilities	1,181,829	1,010,057
Net Position		
Net Investment in Capital Assets	5,834,693	5,881,355
Restricted	6,022,036	6,220,571
Unrestricted	14,444,201	13,818,655
Total Net Position	26,300,930	25,920,581
TOTAL LIABILITIES AND NET POSITION	$ 28,830,639	$ 28,346,406

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
STATEMENT OF REVENUE AND EXPENSE
NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Operating Revenues			
Residential	$ 6,468,457	$ 6,773,200	$ (304,743)
Commercial	2,060,327	2,109,982	(49,655)
Industrial	2,458,094	2,607,433	(149,339)
Municipal	632,242	658,571	(26,329)
Other	48,994	52,716	(3,722)
Total Operating Revenues	11,668,114	12,201,902	(533,788)
Operating Expense			
Cost of Power Sold			
Purchased Power	7,064,744	7,703,234	(638,490)
Transmission Expense	1,589,344	1,543,076	46,268
Supplies and Expenses	123,115	127,913	(4,798)
Total Cost of Power Sold	8,777,203	9,374,223	(597,020)
Distribution Expense			
Salaries and Wages	463,144	423,320	39,824
Supplies and Expenses	215,116	209,045	6,071
Total Distribution Expenses	678,260	632,365	45,895
Customer Accounts Expense			
Salaries and Wages	154,672	134,693	19,979
Supplies and Expenses	100,469	62,105	38,364
Uncollectible Accounts	36,688	100,000	(63,312)
Total Customer Accounts Expenses	291,829	296,798	(4,969)
General and Administrative Expense			
Salaries and Wages	368,488	239,273	129,215
Insurance	67,878	57,256	10,622
Pension and Benefits	352,297	371,194	(18,897)
General	55,204	51,241	3,963
Supplies and Expenses	108,258	143,265	(35,007)
Legal Expense	64,074	53,286	10,788
Total General and Administrative Expenses	1,016,199	915,515	100,684
Depreciation Expense	794,454	800,812	(6,358)
Total Operating Expenses	11,557,945	12,019,713	(461,768)
Operating Income (Loss)	110,169	182,189	(72,020)
Nonoperating Revenues	(9,595)	172,817	(182,412)
Income (Loss) Before Capital Contributions and Transfer Out	$ 100,574	$ 355,006	$ (254,432)

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
STATEMENT OF CASH FLOWS
NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Cash Flows from Operating Activities			
Receipts from Customers	$ 12,117,394	$ 12,463,448	$ (346,054)
Payments to Power Suppliers	(8,646,056)	(9,228,273)	582,217
Payments to Employees	(1,007,899)	(797,069)	(210,830)
Payments for Other Operations	(1,083,461)	(1,212,058)	128,597
Net Cash Provided by (Used in) Operating Activities	1,379,978	1,226,048	153,930
Cash Flows from Financing Activities*			
Acquisition of Capital Assets	(798,408)	(631,538)	(166,870)
Proceeds from Disposition of Capital Assets	3,003		3,003
Capital Contribution	42,463	122,174	(79,711)
Transfers Out	(102,355)	(114,679)	12,324
Net Cash Provided by (Used in) Financing Activities	(855,297)	(624,043)	(231,254)
Cash Flows from Investing Activities			
Nonoperating Revenues	120,761	172,817	(182,412)
Acquisition of Investment - OPEB Liability Trust	26,870	(20,903)	47,773
Acquisition of Investment - MLDM Reserve Trust	(80,069)	(55,752)	(24,317)
Net Cash Provided by (Used in) Investing Activities	67,562	96,162	(158,956)
Net Increase (Decrease) in Cash	592,243	698,167	(236,280)
Cash - Beginning	8,064,705	7,005,794	1,058,911
Cash - Ending	$ 8,656,948	$ 7,703,961	$ 822,631

	2015	2014	Variance
Reconciliation of Operating Income (Loss) to Net Cash Provided (Used) by Operating Activities			
Operating Income (Loss)	$ 110,169	$ 182,189	(72,020)
Adjustment to Reconcile Operating Income (Loss) to Net Cash Provided by (Used in) Operating Activities:			
Depreciation	794,454	800,812	(6,358)
Changes in Assets and Liabilities:			
Deferred Charges	504	(27,789)	28,293
Accounts Receivable	449,280	261,546	187,734
Inventory	-	-	-
Prepaid Expense	(22,853)	(29,646)	6,793
Other Current Assets	-	-	-
Accounts Payable	10,665	(195,132)	205,797
Customer Deposits	50,024	27,150	22,874
Accrued Liabilities	(12,717)	18	(12,735)
Accrued Compensated Absences	(26,548)	179,900	(206,448)
Other Post-Employment Benefits	27,000	27,000	-
Net Cash Provided by (Used in) Operating Activities	$ 1,379,978	$ 1,226,048	$ 153,930

* Non-capital and Capital Financing Activities Combined

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
SCHEDULE OF ELECTRIC REVENUES, COST OF POWER, AND KILOWATT HOURS
NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014

	2015		2014		Variance	
	$ Amount	**KWH**	**$ Amount**	**KWH**	**$ Amount**	**KWH**
Sale of Electricity						
Residential	$ 6,468,457	46,730,209	$ 6,773,200	46,566,628	$ (304,743)	163,581
Commercial	2,060,327	14,094,926	2,109,982	13,709,832	(49,655)	385,094
Industrial	2,458,094	20,258,663	2,607,433	20,194,744	(149,339)	63,919
Municipal	632,242	4,880,437	658,571	4,894,306	(26,329)	(13,869)
Other	48,994	245,371	52,716	261,116	(3,722)	(15,745)
Total Sale of Electricity	$ 11,668,114	86,209,606	$ 12,201,902	85,626,626	$ (533,788)	582,980
$ / KWH	$ 0.135346		$ 0.142501		$ (0.007155)	
Cost of Power						
Purchased Power	7,064,744	90,189,192	7,703,234	87,083,792	(638,490)	3,105,400
Transmission Expense	1,589,344		1,543,076		46,268	
Supplies and Expenses	123,115		127,913		(4,798)	
Total Cost of Power	$ 8,777,203	90,189,192	$ 9,374,223	87,083,792	$ (597,020)	3,105,400
$ / KWH	$ 0.097320		$ 0.107646		$ (0.010326)	
Gross Profit	$ 2,890,911		$ 2,827,679		$ 104,702	

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
PERCENT OF REVENUE ANALYSIS
NINE MONTHS ENDED SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Operating Revenues			
Residential	55.44	55.51	(0.07)
Commercial	17.66	17.29	0.37
Industrial	21.07	21.37	(0.30)
Municipal	5.42	5.40	0.02
Other	0.41	0.43	(0.02)
Total Operating Revenues	100.00	100.00	(0.00)
Operating Expense			
Cost of Power Sold			
Purchased Power	60.55	63.13	(2.58)
Transmission Expense	13.62	12.65	0.97
Supplies and Expenses	1.06	1.05	0.01
Total Cost of Electricity Sold	75.23	76.83	(1.60)
Distribution Expense			
Salaries and Wages	3.97	3.47	0.50
Supplies and Expenses	1.84	1.71	0.13
Total Distribution Expenses	5.81	5.18	0.63
Customer Accounts Expense			
Salaries and Wages	1.33	1.10	0.23
Supplies and Expenses	0.86	0.51	0.35
Uncollectible Accounts	0.31	0.82	(0.51)
Total Customer Accounts Expenses	2.50	2.43	0.07
General and Administrative Expense			
Salaries and Wages	3.16	1.96	1.20
Insurance	0.58	0.47	0.11
Pension and Benefits	3.02	3.04	(0.02)
General	0.47	0.42	0.05
Supplies and Expenses	0.93	1.17	(0.24)
Legal Expense	0.55	0.44	0.11
Total General and Administrative Expenses	8.71	7.50	1.21
Depreciation Expense	6.81	6.56	0.25
Total Operating Expenses	99.06	98.50	0.56
Operating Income (Loss)	0.94	1.50	(0.56)
Nonoperating Revenues	(0.08)	1.42	(1.50)
Income (Loss) Before Capital Contributions and Transfer Out	0.86	2.92	(2.06)

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
STATEMENT OF REVENUE AND EXPENSE
SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Operating Revenues			
Residential	$ 784,679	$ 749,901	$ 34,778
Commercial	273,495	246,541	26,954
Industrial	303,338	319,077	(15,739)
Municipal	62,593	60,891	1,702
Other	5,526	5,982	(456)
Total Operating Revenues	1,429,631	1,382,392	47,239
Operating Expense			
Cost of Power Sold			
Purchased Power	792,764	759,845	32,919
Transmission Expense	211,951	207,782	4,169
Supplies and Expenses	11,346	17,019	(5,673)
Total Cost of Power Sold	1,016,061	984,646	31,415
Distribution Expense			
Salaries and Wages	44,353	46,002	(1,649)
Supplies and Expenses	13,770	32,690	(18,920)
Total Distribution Expenses	58,123	78,692	(20,569)
Customer Accounts Expense			
Salaries and Wages	14,829	15,343	(514)
Supplies and Expenses	48,701	11,931	36,770
Uncollectible Accounts	-	-	-
Total Customer Accounts Expenses	63,530	27,274	36,256
General and Administrative Expense			
Salaries and Wages	38,254	32,036	6,218
Insurance	6,997	10,289	(3,292)
Pension and Benefits	47,524	39,982	7,542
General	215	2,079	(1,864)
Supplies and Expenses	15,087	16,904	(1,817)
Legal Expense	1,815	10,436	(8,621)
Total General and Administrative Expenses	109,892	111,726	(1,834)
Depreciation Expense	89,317	88,979	338
Total Operating Expenses	1,336,923	1,291,317	45,606
Operating Income (Loss)	92,708	91,075	1,633
Nonoperating Revenues	15,401	4,151	11,250
Income (Loss) Before Capital Contributions and Transfer Out	108,109	95,226	$ 12,883

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
STATEMENT OF CASH FLOWS
SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Cash Flows from Operating Activities			
Receipts from Customers	$ 1,437,913	$ 1,414,456	$ 23,457
Payments to Power Suppliers	(380,700)	(712,216)	331,516
Payments to Employees	(97,435)	(93,381)	(4,054)
Payments for Other Operations	(255,410)	(326,023)	70,613
Net Cash Provided by (Used in) Operating Activities	704,368	282,836	421,532
Cash Flows from Financing Activities*			
Acquisition of Capital Assets	(130,290)	(27,463)	(102,827)
Proceeds from Disposition of Capital Assets			-
Capital Contribution	-	5,000	(5,000)
Transfers Out	(11,373)	(12,742)	1,369
Net Cash Provided by (Used in) Financing Activities	(141,663)	(35,205)	(106,458)
Cash Flows from Investing Activities			
Nonoperating Revenues	15,401	4,151	(182,412)
Acquisition of Investment - OPEB Liability Trust	8,877	9,285	(408)
Acquisition of Investment - MLDM Reserve Trust	(19,033)	(6,128)	(12,905)
Net Cash Provided by (Used in) Investing Activities	5,245	7,308	(195,725)
Net Increase (Decrease) in Cash	567,950	254,939	119,349
Cash - Beginning	8,088,997	7,449,022	639,975
Cash - Ending	$ 8,656,947	$ 7,703,961	$ 759,324
Reconciliation of Operating Income (Loss) to Net Cash Provided (Used) by Operating Activities			
Operating Income (Loss)	$ 92,708	$ 91,075	$ 1,633
Adjustment to Reconcile Operating Income (Loss) to Net Cash Provided by (Used in) Operating Activities:			
Depreciation	89,317	88,979	338
Changes in Assets and Liabilities:			
Deferred Charges	(1,200)	1,371	(2,571)
Accounts Receivable	8,282	32,064	(23,782)
Inventory	-	-	-
Prepaid Expense	7,102	10,266	(3,164)
Other Current Assets	-	-	-
Accounts Payable	444,656	4,471	440,185
Customer Deposits	11,580	2,750	8,830
Accrued Liabilities	(377)	(440)	63
Accrued Compensated Absences	49,300	49,300	-
Other Post-Employment Benefits	3,000	3,000	-
Net Cash Provided by (Used in) Operating Activities	$ 704,368	$ 282,836	$ 421,532

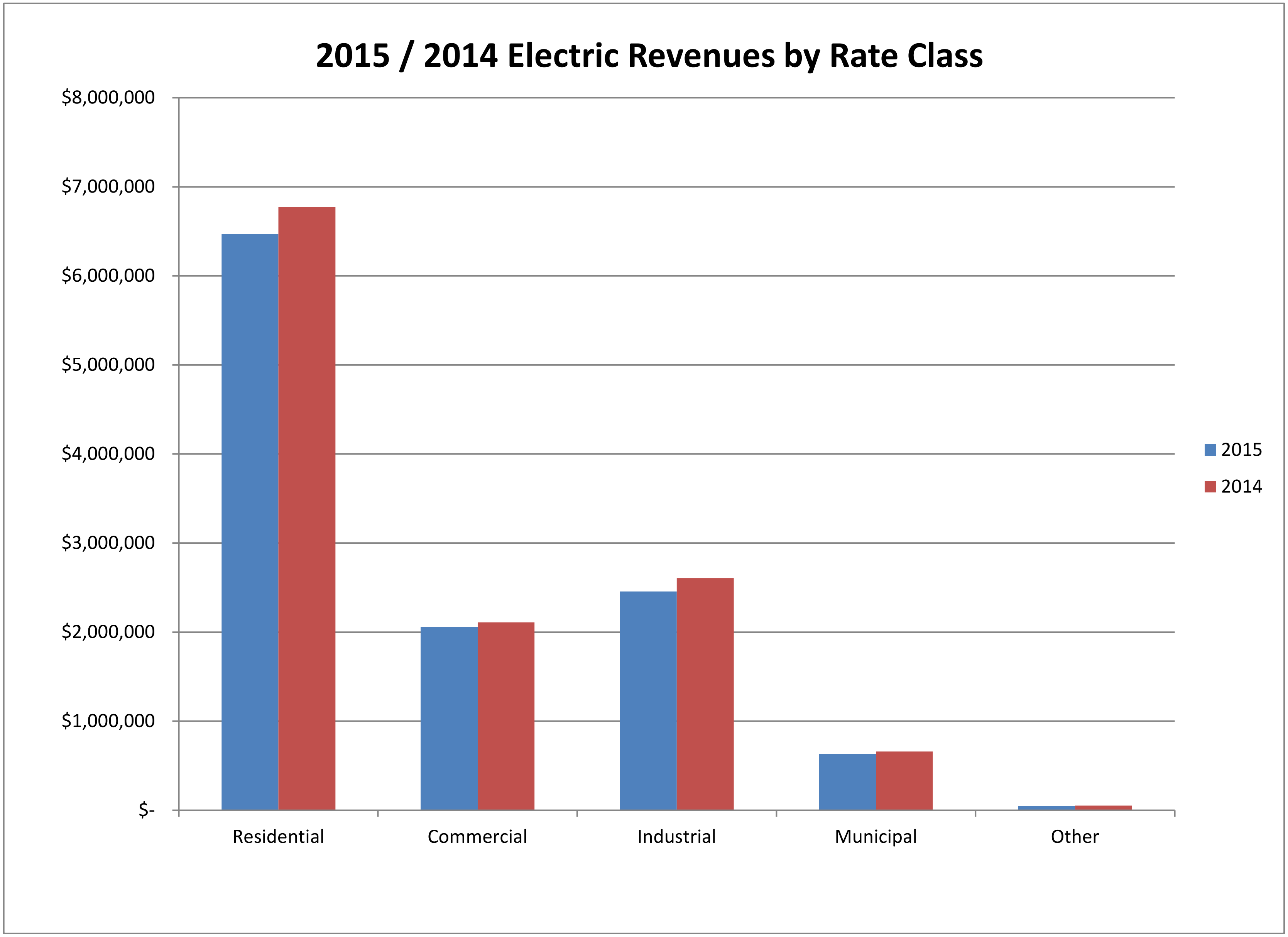
* Non-capital and Capital Financing Activities Combined

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
SCHEDULE OF ELECTRIC REVENUES, COST OF POWER, AND KILOWATT HOURS
SEPTEMBER 30, 2015 AND 2014

	2015		2014		Variance	
	$ Amount	KWH	$ Amount	KWH	$ Amount	KWH
Sale of Electricity						
Residential	$ 784,679	5,497,912	$ 749,901	5,009,678	$ 34,778	488,234
Commercial	273,495	1,889,904	246,541	1,613,098	26,954	276,806
Industrial	303,338	2,535,368	319,077	2,487,152	(15,739)	48,216
Municipal	62,593	465,206	60,891	445,748	1,702	19,458
Other	5,526	27,840	5,982	29,039	(456)	(1,199)
Total Sale of Electricity	$ 1,429,631	10,416,230	$ 1,382,392	9,584,715	$ 47,239	831,515
$ / KWH	$ 0.137250		$ 0.144229		$ (0.006979)	
Cost of Power						
Purchased Power	792,764	9,699,932	759,845	8,963,706	32,919	736,226
Transmission Expense	211,951		207,782		4,169	
Supplies and Expenses	11,346		17,019		(5,673)	
Total Cost of Power	$ 1,016,061	9,699,932	$ 984,646	8,963,706	$ 31,415	736,226
$ / KWH	$ 0.104749		$ 0.109848		$ (0.005099)	
Gross Profit	$ 413,570		$ 397,746		$ 14,320	

TOWN OF SOUTH HADLEY, MASSACHUSETTS
ELECTRIC LIGHT DEPARTMENT
PERCENT OF REVENUE ANALYSIS
SEPTEMBER 30, 2015 AND 2014

	2015	2014	Variance
Operating Revenues			
Residential	54.89	54.25	0.64
Commercial	19.13	17.83	1.30
Industrial	21.22	23.08	(1.86)
Municipal	4.38	4.40	(0.02)
Other	0.38	0.44	(0.06)
Total Operating Revenues	100.00	100.00	0.00
Operating Expense			
Cost of Power Sold			
Purchased Power	55.45	54.97	0.48
Transmission Expense	14.83	15.03	(0.20)
Supplies and Expenses	0.79	1.23	(0.44)
Total Cost of Power Sold	71.07	71.23	(0.16)
Distribution Expense			
Salaries and Wages	3.10	3.33	(0.23)
Supplies and Expenses	0.96	2.36	(1.40)
Total Distribution Expenses	4.06	5.69	(1.63)
Customer Accounts Expense			
Salaries and Wages	1.04	1.11	(0.07)
Supplies and Expenses	3.41	0.86	2.55
Uncollectible Accounts	0.00	0.00	0.00
Total Customer Accounts Expenses	4.45	1.97	2.48
General and Administrative Expense			
Salaries and Wages	2.68	2.32	0.36
Insurance	0.49	0.74	(0.25)
Pension and Benefits	3.32	2.89	0.43
General	0.02	0.15	(0.13)
Supplies and Expenses	1.06	1.22	(0.16)
Legal Expense	0.13	0.75	(0.62)
Total General and Administrative Expenses	7.70	8.07	(0.37)
Depreciation Expense	6.25	6.44	(0.19)
Total Operating Expenses	93.53	93.40	0.13
Operating Income (Loss)	6.47	6.60	(0.13)
Nonoperating Revenues	1.08	0.30	0.78
Income (Loss) Before Capital Contributions and Transfer Out	7.55	6.90	0.65


2015 / 2014 Electric Revenues by Rate Class
$8,000,000
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
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Residential
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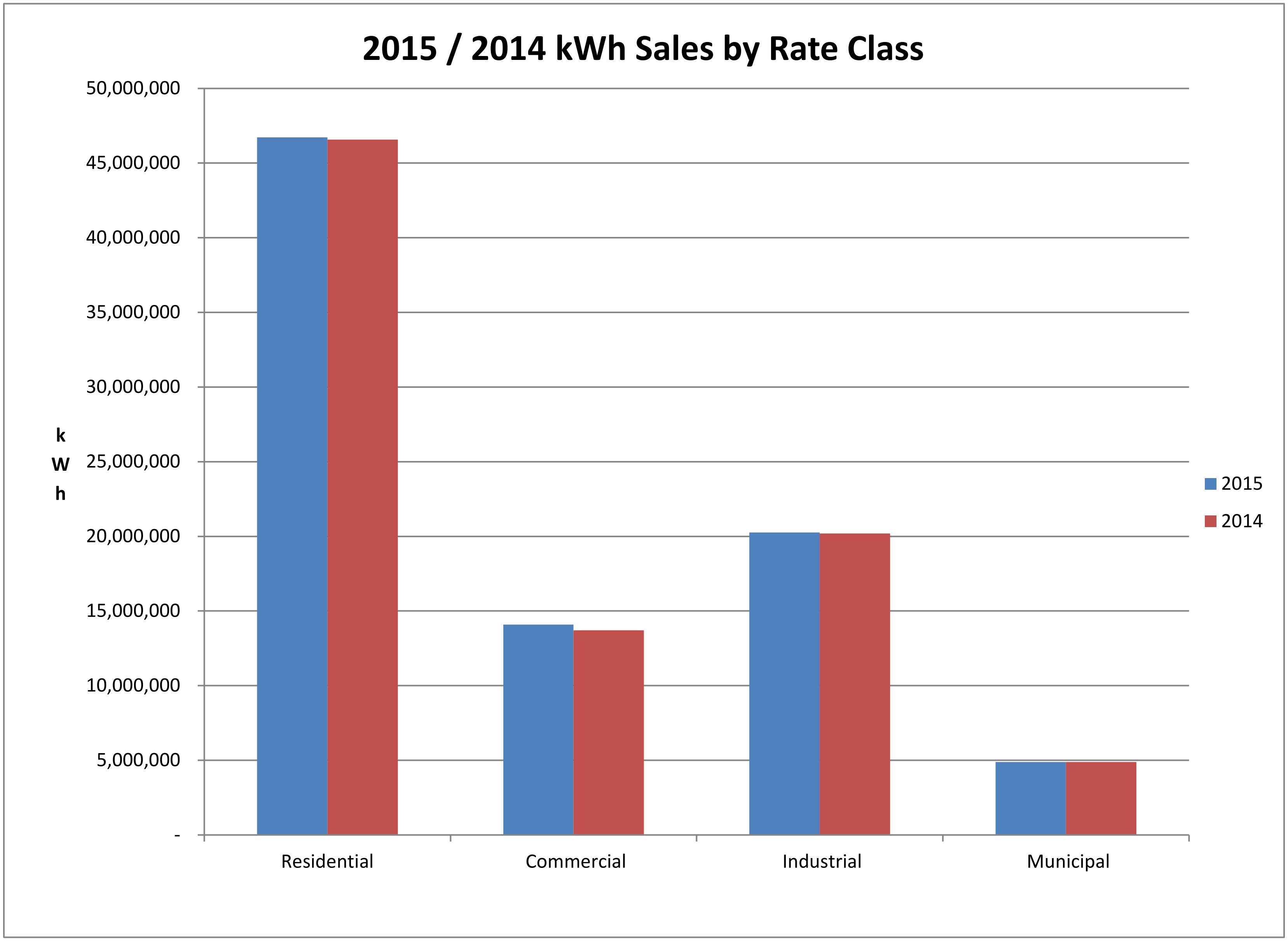
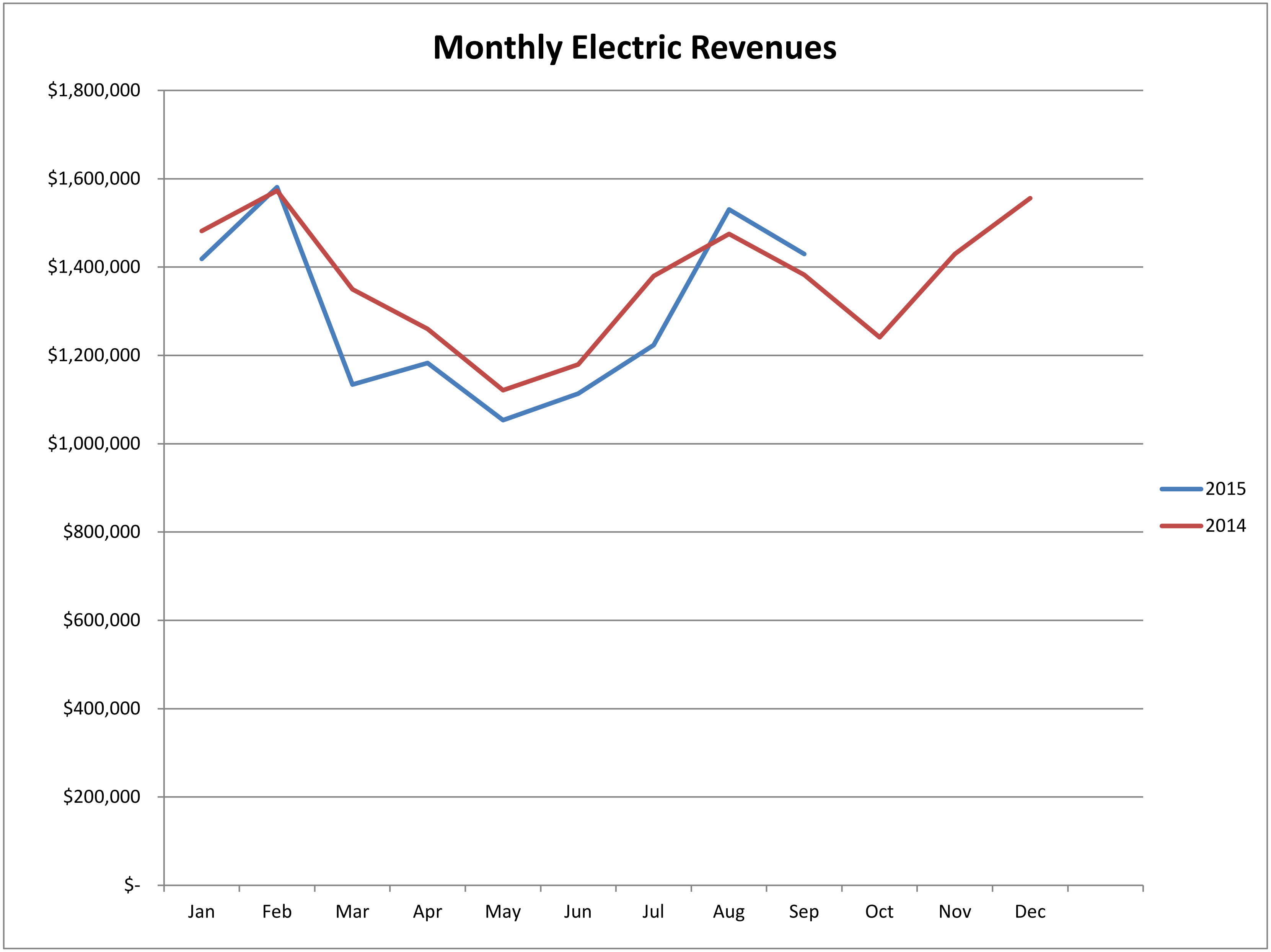
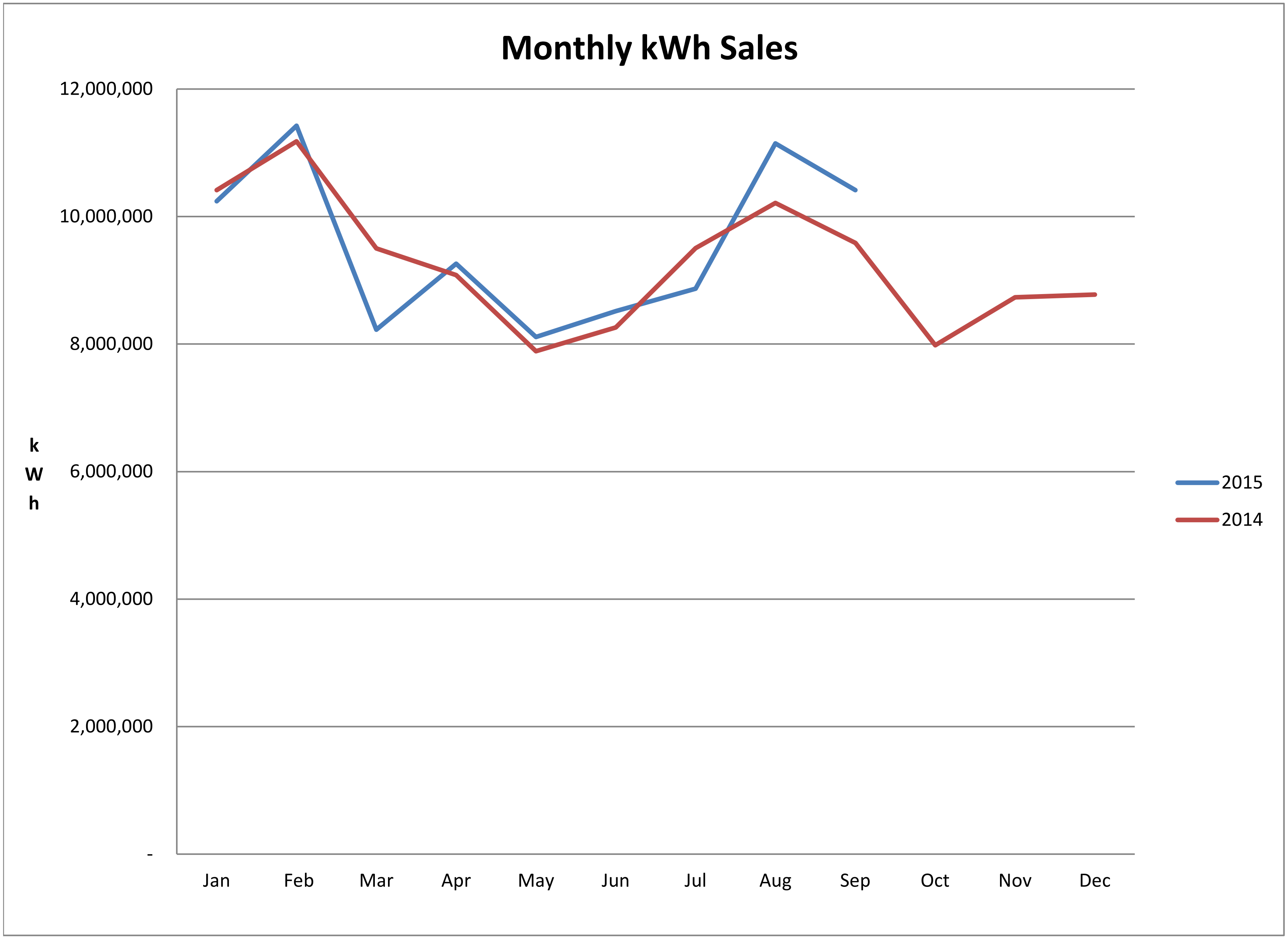
Industrial
Municipal
Other
2015
2014


2015 / 2014 kWh Sales by Rate Class
50,000,000
45,000,000
40,000,000
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
-
kWh
Residential
Commercial
Industrial
Municipal
2015
2014


Monthly Electric Revenues
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
2014


Monthly kWh Sales
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
-
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Jan
Feb
Mar
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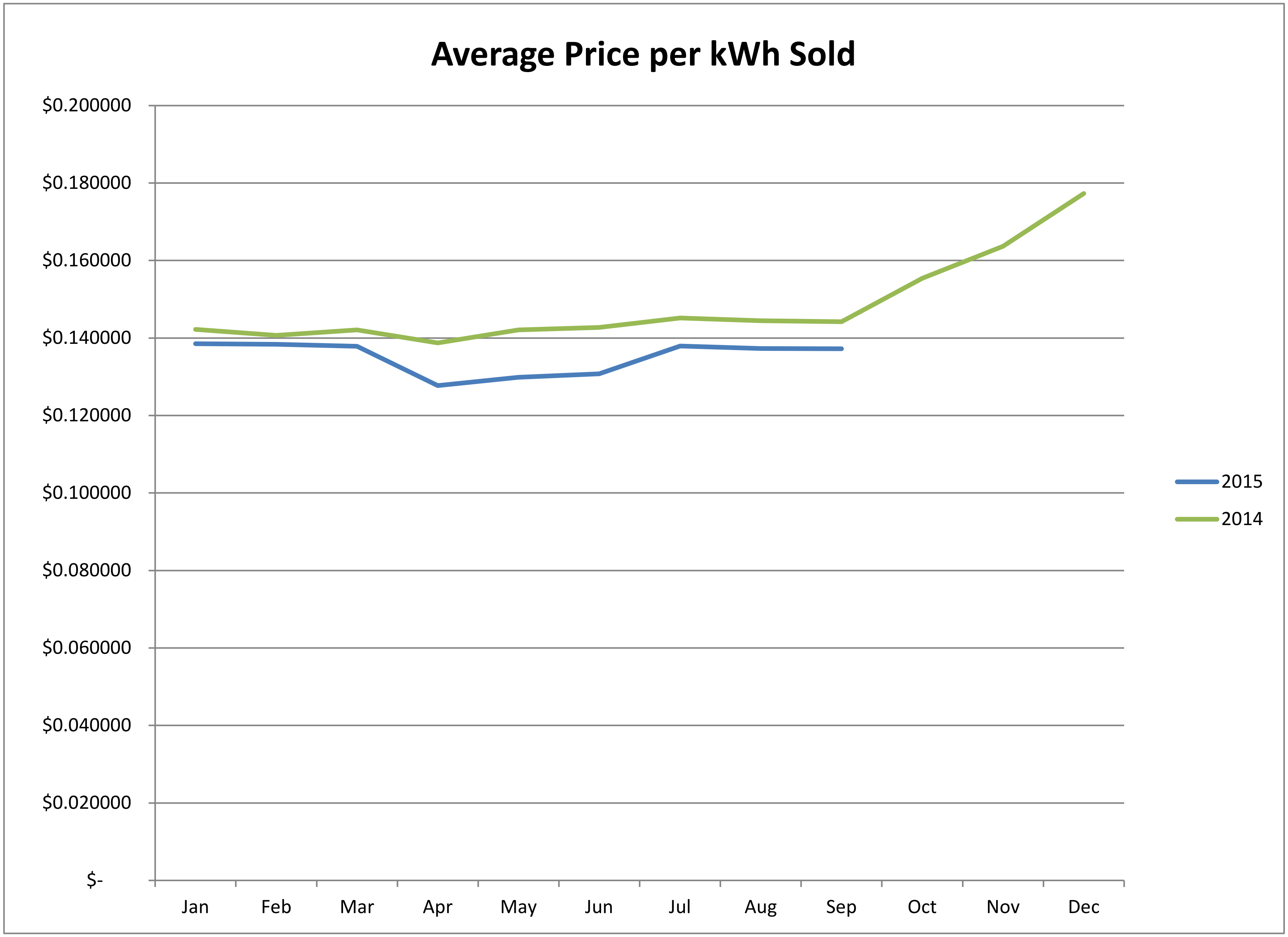
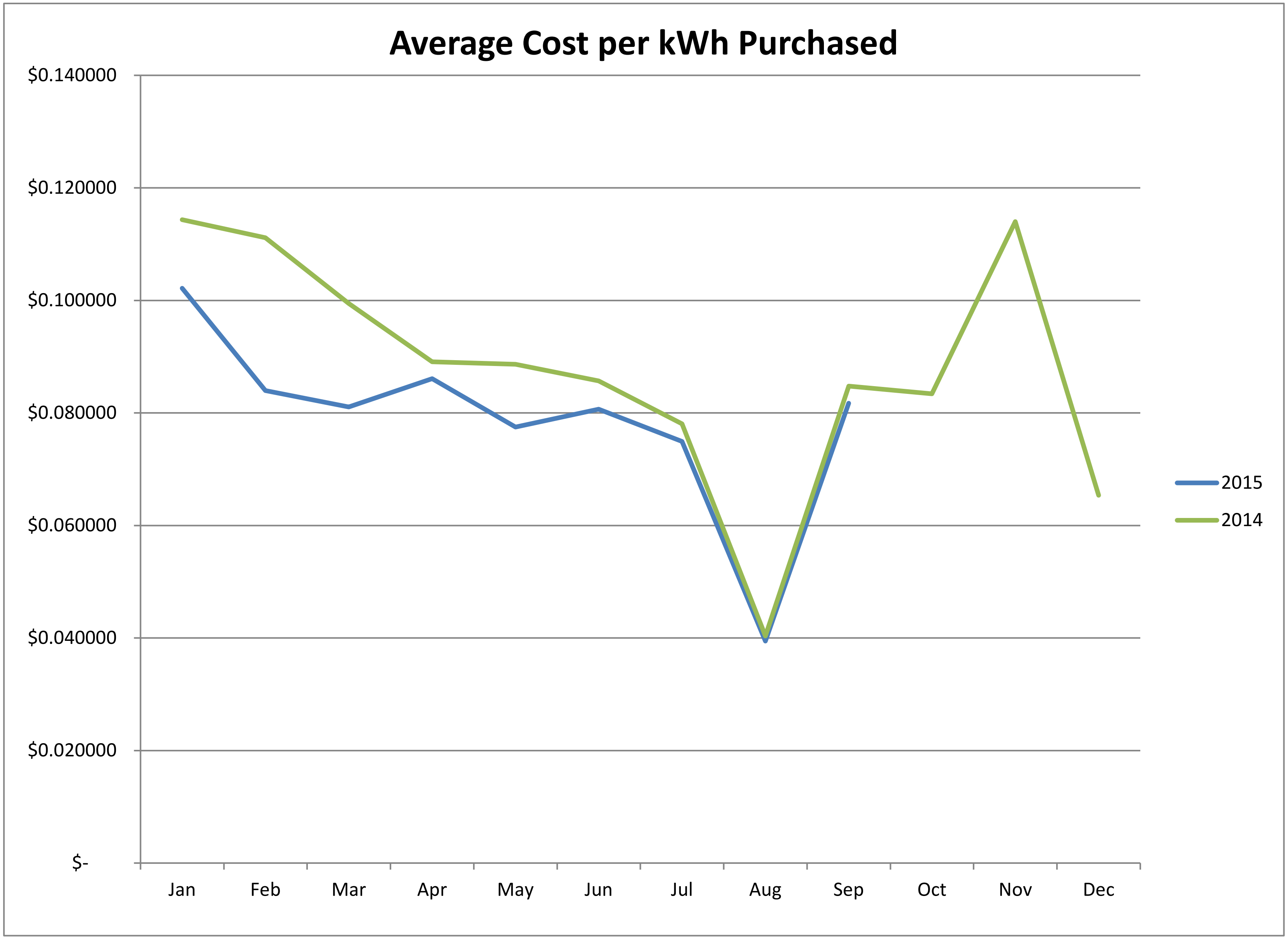
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
2014


Average Price per kWh Sold
$0.200000
$0.180000
$0.160000
$0.140000
$0.120000
$0.100000
$0.080000
$0.060000
$0.040000
$0.020000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2015
2014


Average Cost per kWh Purchased
$0.140000
$0.120000
$0.100000
$0.080000
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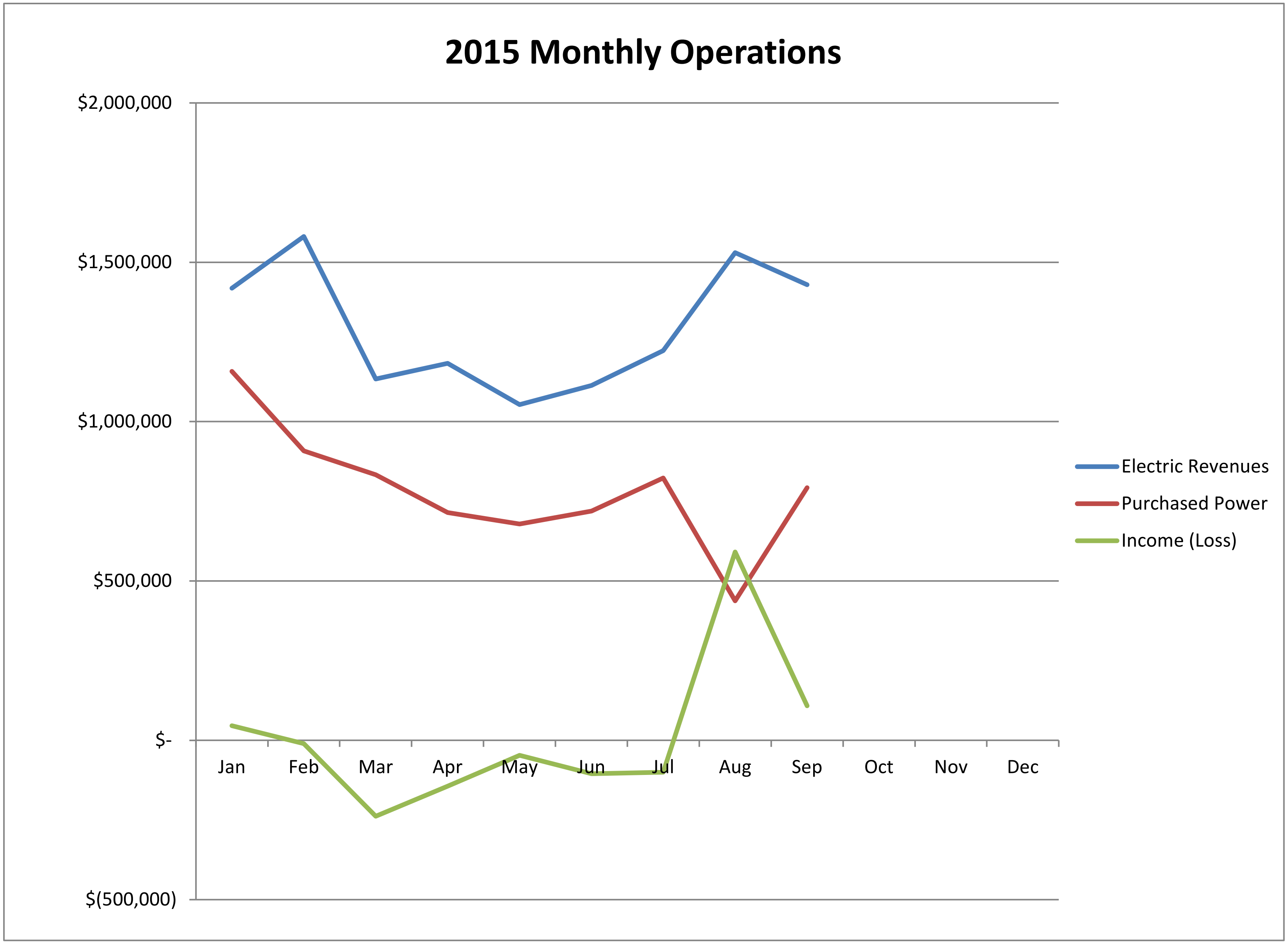
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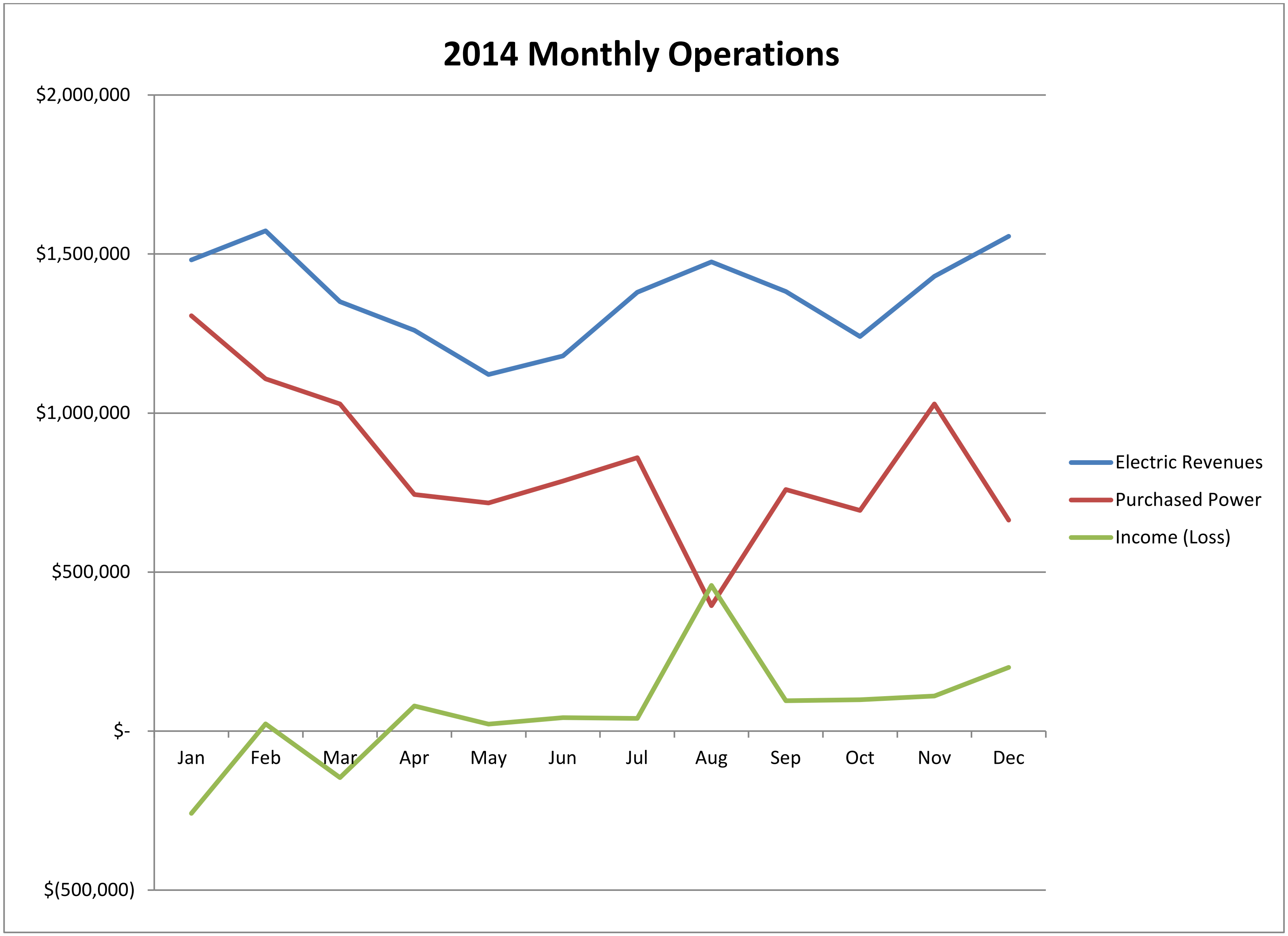
Electric Revenues
Purchased Power
Income (Loss)


2014 Monthly Operations
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Electric Revenues
Purchased Power
Income (Loss)

DISTRIBUTIVE GENERATION

As with most Massachusetts Municipal Light Departments, SHELD developed and implemented a distributive generation policy (net metering) to promote and encourage distributive generation installations (i.e. small scale solar and wind).

At the time SHELD recognized that its policy resulted in shifting costs from distributive generation customers to non-distributive generation customers. To minimize the impact of this cost-shifting, SHELD established caps on both the size and number of installations it would accept. The cap is composed of two tiers. Tier 1, which was established for residential and small commercial installations, has substantially been utilized. Tier 2, which was established for larger commercial installations, has never been utilized and at this point it does not seem likely it will be. As a result, Tier 1 installations have been allowed to utilize the capacity available under the Tier 2. (Exhibit 1)

Distributive generation policies can be structured in a variety of different ways. One only need look at our local MLPs (CELD, HG&E, SHELD, WG&E) to understand that. Each MLP has a different policy (Exhibit 2).

The main differences are:

1. Is there a cap?
2. Is billing done gross or net?
3. What is the basis for billing credits?

Under SHELD current distributive generation policy:

1. SHELD purchases excess generation at full retail (which is about 3x our normally cost of power)
2. SHELD purchases excess generation when produced, whether or not it is needed. If it is excess to our need, we have to sell it at a loss in the market.
3. Distributive generation does not reduce our capacity commitments to ISO. Our cost remain the same and have to be allocated over a smaller kWh base.
4. For customers that are either net producers or small consumers, SHELD recovers virtually no contribution for use of its distribution system. These customers actually use the distribution system more since they both buy and sell over it.

As you can see from the forgoing, SHELD policy is simply not sustainable. There is currently a movement within the industry to rethink distributive generation policies. The move is away from net metering and towards a model that will promote long-term growth.

SHELD needs to develop a policy that will promote the long-term growth of distributive generation. Such a policy will allow for the elimination of caps and encourage the development of distributive generation as a significant piece of SHELD’s future power portfolio. In order for this to happen, costs will need to be borne by the rate payers that receive the benefit.

SOUTH HADLEY ELECTRIC LIGHT DEPARTMENT
CAPACITY LIMITATIONS

Net Metering Policy	2010 kW Peak	CAP Rate	CAP kW
Tier 1 (Residential < 10kW) (Small Commercial < 100kW)	28,500	1.00%	285
Tier 2 (Large Customer < 500kW))	28,500	2.00%	570

Note: Tier 1 cap has been reached with existing solar installations - Appx 30 customers

Since it seems unlikely that any of our current customers will establish a Tier two solar installation, we have continued to allow Tier 1 installation to use this portion of the cap

SOUTH HADLEY ELECTRIC LIGHT DEARTMENT
COMPARISON OF DISTRIBUTED GENERATION POLICIES

Municipal Light Department	**CELD**	**HG&E**	**SHELD**	**WG&E**
Program Caps	Yes	No	Yes	No
Basisi for Billing	Net	Gross - Credit	Net	Net
Basis for Credit	Generation	LMP	Full Rate	LMP
Net Consumers				
Customer kWh use	500,000	500,000	500,000	500,000
Customer kWh generation	(375,000)	(375,000)	(375,000)	(375,000)
Amount Billed	18,750	60,000	18,750	18,750
Net Generators				
Customer kWh use	500,000	500,000	500,000	500,000
Customer kWh generation	(750,000)	(750,000)	(750,000)	(750,000)
Amount Billed	(15,000)	45,000	(37,500)	(10,000)

A net meterimg policy with full retail credit results in cost shifting to other customers. This type of policy is unsustainable and necesitates the overall program limits.

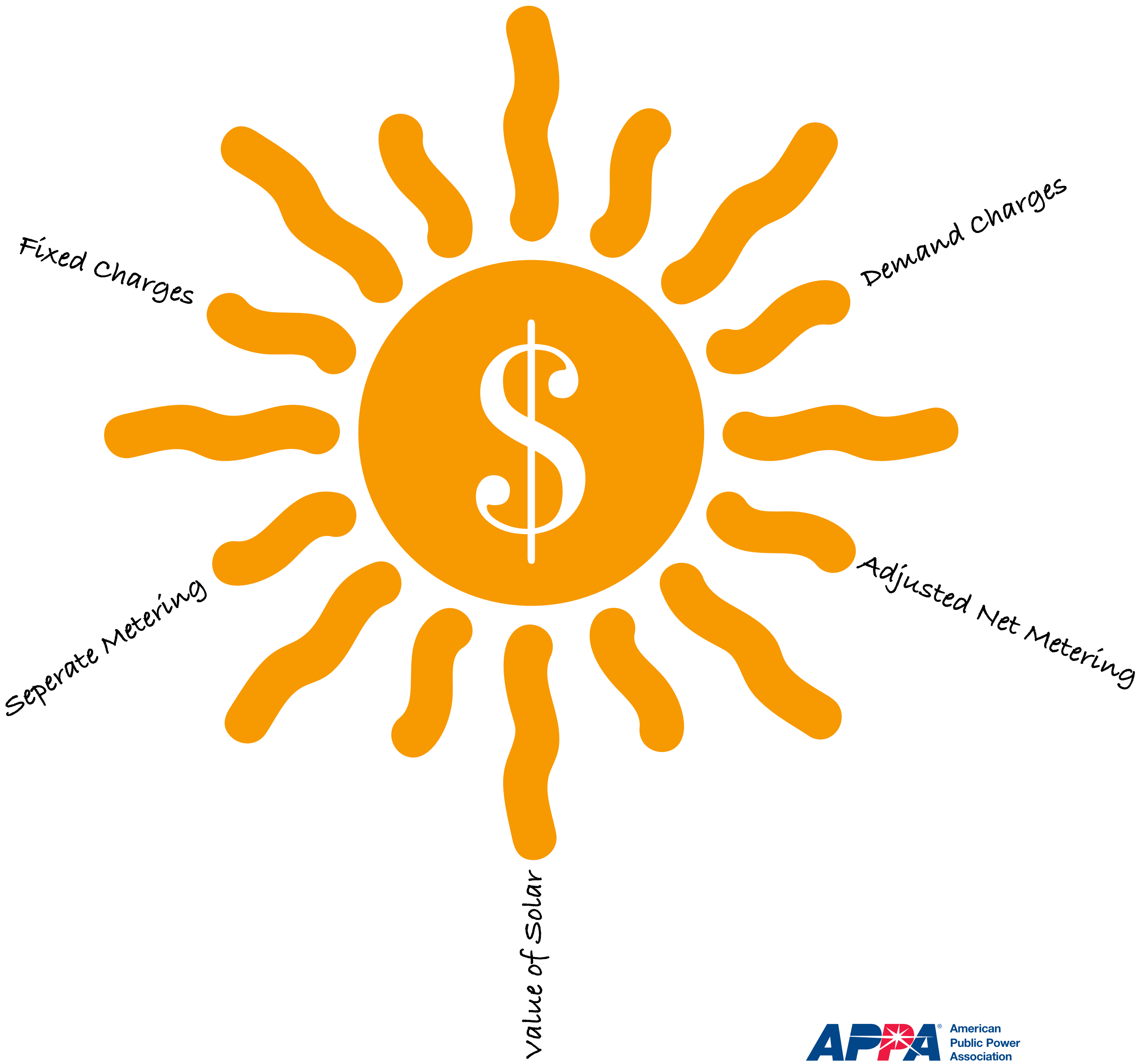
It is difficult for SHELD to determine the extent of cost shifting related to its current net metering policy due to type of metering utilized. SHELD uses bi-direction meters which only captures excess kWh activity.

For example - in the illustration above, a bi-direction meter might show customer kWh use as 200,000 and customer kWh generation as 75,000. The net kWh would still be 175,000. The 300,000 kWh would not be captured. The 300,000 kWh represents generation used internally.

Rate Design for Distributed Generation

NET METERING ALTERNATIVES

With Public Power Case Studies



American Public Power Association
SEVENTY-FIVE YEARS

Rate Design for Distributed Generation

NET METERING ALTERNATIVES

With Public Power Case Studies

Prepared by
Paul Zummo, Manager, Policy Research and Analysis
American Public Power Association

PUBLISHED JUNE 2015

American Public Power Association

The American Public Power Association represents not-for-profit, community-owned electric utilities that power homes, businesses and streets in nearly 2,000 towns and cities, serving 48 million Americans. More at www.PublicPower.org.

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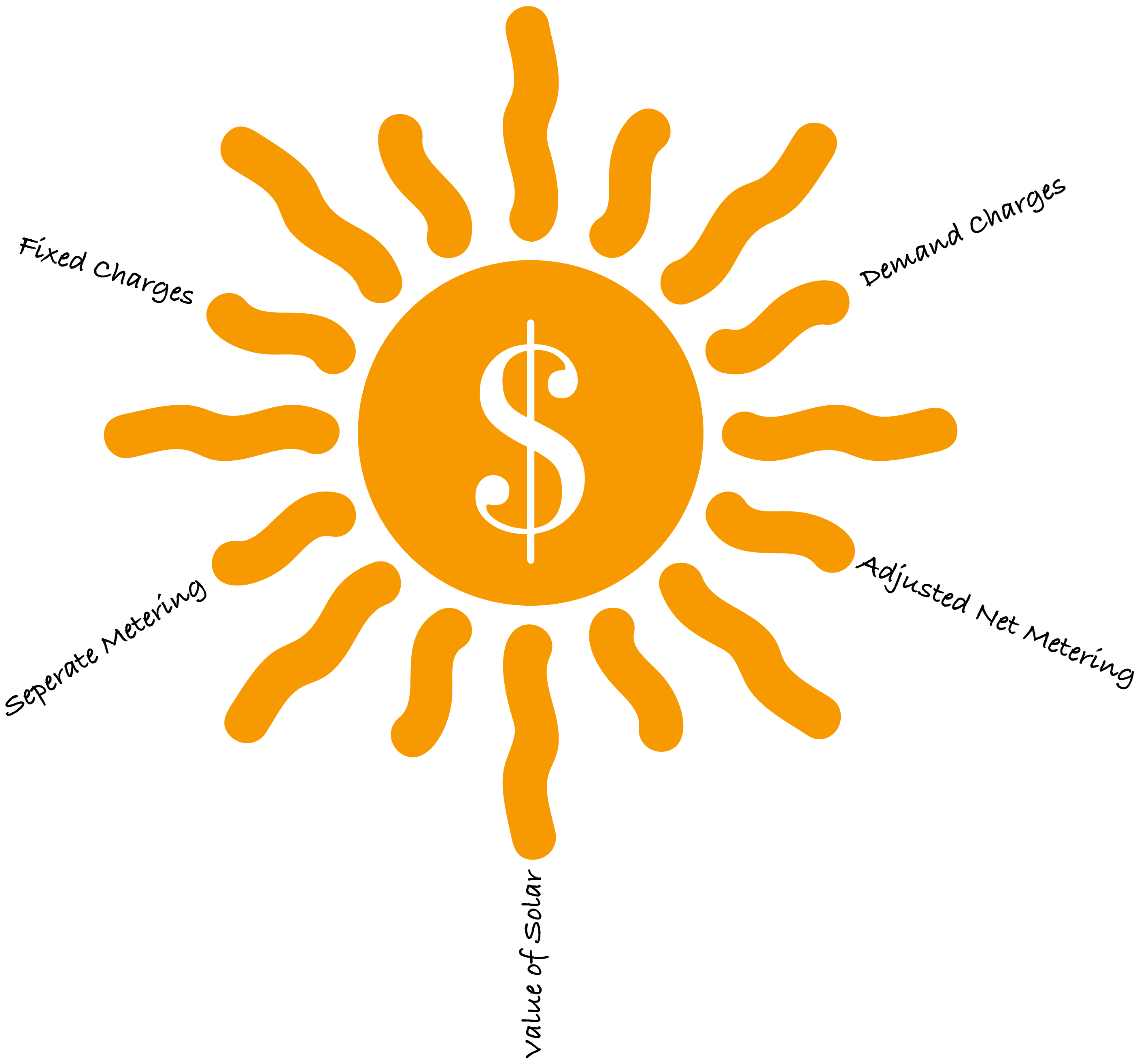
Contents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Fixed Charges
Demand Charges
Seperate Metering
Adjusted Net Metering
Value of Solar

Executive Summary

The American Public Power Association's "Rate Design for Distributed Generation" report examines rate design options for solar and other distributed generation (DG), using public power utility case studies. The report discusses how utilities have educated customers about new rates, and how DG and non-DG customers responded. While the rate design options have some drawbacks, and might not be technically feasible for all utilities, they offer the industry new models that account for the rate impacts of distributed generation.

The use of DG, particularly rooftop solar photovoltaic (PV), is growing fast. As of October 2014, just under 8,000 megawatts (MW) of solar capacity was installed on residential and business rooftops across the United States (U.S.).[1]

The growth of DG has been spurred by environmental concerns and economic considerations. Federal and state tax incentives are a driving force behind solar PV installations and can together cover up to 70 percent of the total cost of solar panels in some states.[2] Declining solar panel prices have also fueled growth in rooftop solar. Utility rate structures for distributed generation have provided a significant benefit to solar customers.

As DG becomes more widespread, rate analysts and researchers are developing new rate designs to help ensure that utilities recover their cost of service, encouraging while providing appropriate incentives for rooftop solar deployment.

Utilities can no longer afford to take a wait and see approach in rate design for DG, nor should they assume that old rate designs adopted before the escalation in DG installations will work in the future.

Most utilities in the U.S. use net metering to measure and compensate customers for the generation they produce. However net metering has several shortcomings and results in non-DG customers subsidizing DG customers.

Utilities have options other than traditional net metering. Many public power utilities have adopted new rate designs to serve DG customers. Some of these rate designs supplement net metering by recouping more of their fixed costs through fixed charges, while other designs provide comprehensive alternatives to net metering.

Utility rate setters must balance between simplicity and accuracy, align costs and prices, support environmental stewardship, and ensure that rate designs are well suited to customers. Customer communication and engagement are essential components of the rate-setting process.

This report does not examine every rate design option, nor does it suggest a single best option. It offers alternatives to traditional net metering, with case studies. Utilities can consider how they can adapt rate designs to suit their community's needs, factoring in market structure, state policies, and other considerations.

1 Mike Taylor, Joyce McLaren, Karlynn Cory, Ted Davidovich, John Sterling, and Miriam Makhyounl, Value of Solar: Program Design and Implementation Consideration (NREL/TP-6A20-62361. Golden, CO: National Renewable Energy Laboratory, 2015), 1.

2 American Public Power Association, Distributed Generation: An Overview of Recent Market and Policy Developments (Washington, DC: American Public Power Association, 2013), 6.

SECTION 1

Traditional Rate Design and Costs

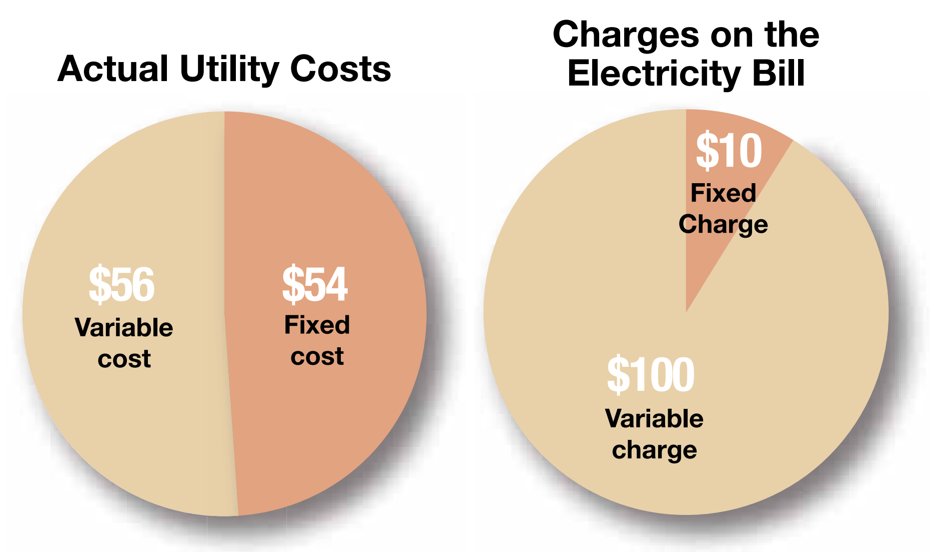
Most utilities follow a traditional cost-of-service model to set electricity rates. They have been guided by the principles established by James Bonbright[3] that rates should:

- Provide adequate and stable revenues to the utility.
- Be stable, predictable, and easy for customers to understand.
- Reflect fair cost allocation to rate classes.
- Reflect present and future private and social costs.
- Discourage wasteful use of service.
- Avoid undue discrimination in rate relationships (i.e. be subsidy free with no inter-customer burdens).
- Promote dynamic efficiency and innovation.

Utility rate analysts must forecast utility revenue requirements and allocate costs to each customer class. Traditional rate design has attempted to meet these allocated revenue requirements through a fairly simple method. Residential utility bills typically have two components — a fixed monthly customer charge and a variable energy charge based on kWh usage.[4] The variable energy charge typically makes up the lion's share of the bill.

The energy charge has traditionally been a flat $/kWh charge although a utility's cost to serve a customer varies greatly by time of day and season. Some utilities have introduced seasonal charges, with summer and winter rates set slightly higher than rates at other times of the year. Other utilities implement time-of-use rates— mostly a two-tiered rate, with charges for peak hours (e.g. 3 – 7 pm) set considerably higher. Some utilities use complicated formulas, such as critical peak pricing, with a very high charge for absolute peak hours, a slightly lower charge for less congested times, and a very low rate for off-peak hours such as the late evening.

Utilities recoup a large portion of their costs from residential customers through variable energy rates even though a high percentage of costs is fixed.



[3] James C. Bonbright, et al., Principles of Public Utility Rates, 2 nd ed. (Arlington, VA: Public Utilities Reports, Inc., 1988).

[4] Commercial and industrial customers usually have an additional demand charge based on peak usage, generally measured in dollars per kilowatt (kW) month. Utilities may have additional riders to their residential, commercial, and industrial tariffs, including fuel adjustment clauses.

A study by the Electric Power Research Institute (EPRI) shows that a typical residential customer uses 982 kWh of electricity per month, with a bill averaging $110. The bill is made up of three cost components — $70 can be allocated to generation, $30 to distribution, and $10 to transmission. Nearly all the distribution and transmission costs are fixed (or capacity-type) costs that do not vary based on hourly customer loads, while approximately 80 percent of generation costs are variable. This means that $54 of the typical bill is related to capacity or fixed costs, and $56 can be attributed to energy-related, or variable costs.[5] Yet a typical residential fixed charge is around $10 per month. So the utility recovers most of its fixed costs through variable rates.

Utilities have depended on variable charges to recover costs because:

- Analog meters can only record the customer's usage over a given time period, not the usage at a specific time of the day.
- Complex rate structures can overwhelm and confuse customers. A pilot study of time-of-use rates in California showed that while customers were able to grasp general concepts, such as prices being higher during peak periods on critical days, they did not understand basic rate structures.[6]

Time of use retail rates more accurately reflect the utility's actual cost to generate or purchase energy. Demand rates can be adjusted to align with the customer's contribution to the coincident system peak, and include a demand ratchet [7]. But such options add a layer of complexity to the rates.

No rate design will perfectly match costs and rates. Utility rate analysts have to determine how far they want to go to better align costs with rates. As Michael O'Boyle puts it:

> **Even if perfect cost causation was possible, it would overwhelm the consumer with information. Rates should approximate cost causation relative to other customers, with other public policy goals left to resolve the imperfections or justify certain cross subsidies over others.**[8]

Customer outreach and education are an essential aspect of any new rate design. Whatever the rate design, pilot programs have shown that customers will shave energy usage during peak periods if given a price signal to do so.

But even when customers have greater knowledge about rates, other tradeoffs exist. While higher fixed charges might provide adequate and stable revenues to the utility, they may not discourage wasteful use of service (some Bonbright principles are contradictory). Higher fixed monthly customer charges generally favor high-use customers, and might discourage conservation. Higher energy charges benefit low-use customers.[9]

Utilities have tried to balance these issues for a number of years. While perfect alignment between costs and rates has not been possible, cost of service analysis has helped utilities set rates that meet their revenue requirements.

DG has thrown a wrinkle in this equation. Net metering, the most common method of compensating distributed generators, has created severe problems.

[5] Electric Power Research Institute, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (Palo Alto, CA: EPRI, 2014), 21-22.

[6] Ahmed Faruqui and Ryan Hledik, Transitioning to Dynamic Pricing (Washington, DC: Brattle Group, 2009), 8.

[7] A demand ratchet is a mechanism incorporated into some commercial and industrial tariffs and is based upon historical demand. For example, if a customer records a peak usage of 100 kW during a billing cycle, if the demand ratchet was 50 percent, minimum billing demand would be 50 kW over the next year regardless of what the actual demand was during that period. The purpose of the demand ratchet is to protect against customers who have large demand swings.

[8] Michael O'Boyle, An Adaptive Approach to Promote System Optimization. Paper released through SEPA 51st State Project, 2015. Accessed at http://sepa51.org/submissions.php.

[9] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," Electricity Journal Volume 27, Issue 4 (2014), 32.

SECTION 2

Net Metering

Most utilities in the U.S. use net metering to measure the net monthly usage or surplus generation of customers with solar power.

Net metering is a basic mechanism. The meter runs forward when the customer takes electricity from the grid. It stops when the customer generates and consumes the same amount of electricity. The meter runs backwards when the customer puts any surplus electricity they generate from rooftop solar back into the grid.

If, at the end of the billing period, the customer has consumed more power than they've generated, the utility bills the customer the net usage amount in kilowatt-hours (kWh). If the consumer has produced more power than they've consumed, the utility credits the consumer for the excess kWh. Utilities have adopted a variety of policies regarding how long the credits roll over, if and when they expire, and whether or not the customer receives payment for excess generation at the end of the year.

While there are different methods for crediting excess generation,[10] under a net metering system, distributed generation is generally treated in effect as a retail transaction. A kWh exported to the grid is given the same value as a kWh consumed at a residence or place of business.

Net metering is simple, easy to understand, and available to utilities of all sizes and technological capabilities. However, paying the customer for solar generation at the retail energy charge implies that energy charges are only collecting the utility's variable generation costs. As utilities must also recover a combination of generation, transmission, and distribution capacity costs through their energy charges, net metering creates a revenue shortfall for the utility. The net shortfall is made up through higher energy charges for all DG and non-DG customers.[11]

As more customers install DG systems, the cost-revenue disparity grows wider, leading to even more cross-subsidization. This could cause a calamitous spiral — non-DG customers who pay higher rates may turn to self-generation, which further reduces utility revenue.

Ashley Brown explains that net metering did not develop "as part of a fully and deliberatively reasoned pricing policy."[12] Net metering became the de facto pricing mechanism out of convenience and lack of careful study.

Most meters lacked the ability to do anything more than go backwards and forwards, so utilities could only measure net consumption. With the slow penetration of DG initially, only a small number of utilities felt the revenue impacts of net metering. Most utilities have only a handful of net-metered customers, so they have not yet felt the need to consider alternative rate designs.

As Brown points out, these reasons are less applicable to present-day realities. Advanced meters can track usage on a more granular level, enabling more complicated rate mechanisms. With an increasing number of DG installations and customers, utilities are starting to see the revenue loss and non-DG customers are feeling the rate impacts.

An example provided by Southern California Public Power Authority (SCPPA) Rate Design Working Group helps explain why net metering creates a revenue shortfall.[13]

Even if the fixed cost percentage is less than in the above example, the problem remains. **As utilities typically recover such a high proportion of fixed costs through variable rates, reductions in energy usage by DG customers creates a revenue shortfall that other customers have to make up.**

[10] For a summary of net metering programs at the largest public power utilities, see American Public Power Association, Public Power Utilities: Net Metering Programs, 2014, accessed at: http://publicpower.org/files/PDFs/Public_Power_Net_Metering_Programs.pdf/.

[11] For a more detailed discussion of cross-subsidies, see American Public Power Association, Solar Photovoltaic Power: Assessing the Benefits & Costs, 2014, accessed at: http://publicpower.org/files/PDFs/74%20Solar-Photovotalic%20Power.pdf.

[12] Ashley Brown, "Net Metering: The Dark Cloud in a Sunny Sky," May 27, 2015 Accessed at http://blog.publicpower.org/sme/?p=576.

[13] Southern California Public Power Authority Rate Design Working Group. Updating Traditional Rate Design in the Electric Utility Industry, November 2014, 7.

Utility rate	=	12 cents/kWh (5 cents/kWh energy + 7 cents/kWh fixed)
Consumption reduced by 1 million kWh	=	Revenue reduced by $120,000
Avoided cost with reduced consumption	=	$50,000 (1 million kWh x 5 cents/kWh)
Fixed costs remaining with reduced consumption	=	$70,000 (1 million kWh x 7 cents/kWh)

The fixed costs are borne by the remaining, non-DG customers, thus creating a cross-subsidy.

Estimates of the total cross-class subsidy vary, but one study put the total subsidy for California ratepayers alone at $1.1 billion by 2020. As solar panels are typically more prevalent in more affluent neighborhoods, less affluent customers are subsidizing wealthier customers.[14]

When fixed costs are recovered through a variable charge, "the utility can be exposed to a revenue loss that exceeds the fuel and O&M expenses that were avoided — because customers reduced their energy consumption."[15] This leads to further rate increases, upsetting remaining customers. SCPPA states:

> **Without structural changes to traditional rates, utilities will be required to increase their rates more frequently in order to maintain existing reliability standards and meet financial responsibilities contained in their bond covenants.**[16]

Ashley Brown observes another form of subsidy. If in a day-ahead market, the distributor relies on solar DG to cover some proportion of total system load, and the solar energy becomes unavailable due to weather conditions, then the distributor will have to make high-cost spot purchases to make up for the lost solar production. These costs are then passed on to the remaining customers. If the distributor financially hedges this exposure to the spot market, these costs also are passed onto customers. Almost none of the costs are being passed on to the cost causer.[17]

Net metering causes revenue shortfalls for utilities, and creates a situation where one class of customers is subsidizing another. In the long run, this is untenable, especially as more customers install DG systems. Utilities should consider modified approaches to net metering, or completely new billing arrangements, some of which are described in section 3.

[14] Robert Borlick and Lisa Wood, Net Energy Metering: Subsidy Issues and Regulatory Solutions (Washington, DC: Edison Foundation: Institute for Electric Innovation, 2014), 3. The report further notes that when customers lease solar systems, the leasing company gets the lion's share of the subsidy rather than the customer.

[15] SCPPA, Updating Traditional Rate Design, 6.

[16] Ibid., 6.

[17] Brown, "Net Metering"

SECTION 3

Alternatives to Traditional Net Metering

Value of Solar

Austin Energy in Texas is the only utility in the U.S. to have implemented a value of solar (VOS) rate but the concept has generated much discussion. The state of Minnesota has mandated that its investor-owned utilities adopt a VOS rate, and has set a formula.[18] Other utilities have conducted VOS studies to measure the costs and benefits of distributed solar energy.[19]

What is value of solar? It is a measure of electric system attributes such as transmission costs, generation costs, environmental externalities, and other inputs, and of how distributed solar energy positively and negatively affects each. **VOS is an effort to associate a quantifiable benefit with each kWh of distributed solar exported to the grid.** Presumably, that number would become the kWh rate at which solar DG would be compensated.

VOS represents a departure from net metering. Austin Energy's VOS rate is based on a "buy-all, sell-all" approach where the DG customer buys all of the electricity it consumes from the distribution utility at one rate, and then separately sells all of its distributed generation output to the utility at the VOS rate.

CASE STUDY

Austin Energy's Buy-all, Sell-all Value of Solar Rate

Austin Energy worked with Clean Power Research (CPR) to develop a VOS rate. A study evaluated various cost and benefit components in an attempt to establish a more equitable rate for solar PV customers.

Austin Energy's VOS tariff is based on an algorithm that incorporates six value components:

- **Loss savings:** Reduction in line losses by producing power where it is generated.
- **Energy savings:** The offset of wholesale purchases.
- **Generation capacity savings:** Added capacity that DG brings to the utility's resource portfolio.
- **Fuel price hedge value:** No fuel price uncertainty associated with solar PV.
- **Transmission and distribution capacity savings:** Reduced peak loading on the T&D system, postponing the need for capital investments.
- **Environmental benefits:** Environmental footprint of solar PV is less than that of traditional fossil-fuel generation.[20]

[18] See Dan Haugen, "Minnesota becomes first state to set 'value of solar' tariff.,"Midwest Energy News, March 12, 2014, accessed at http://www.midwestenergynews.com/2014/03/12/minnesota-becomes-first-state-to-set-value-of-solar-tariff/.

[19] See, for example, Xcel Energy Services, Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System, (Denver, Co: Xcel Energy, 2013). For a broader survey of that looks at the value of solar on a national level, see Steven Fine, Ankit Saraf, Kiran Kuaraswamy, and Alex Anich, The True Value of Solar, ICF International, 2014.

[20] Karl R. Rabago, Leslie Libby, Tim Harvey, Benjamin L. Norris, and Thomas E. Hoff, Designing Austin Energy's Solar Tariff Using a Distributive PV Value Calculation (Austin, TX: Austin Energy, 2013), 2.

As explained by those who designed the rate, Austin Energy's VOS rate represents a "break-even value for a specific kind of distributed generation resource and a value at which the utility is economically neutral, whether it supplies such a unit of energy or obtains it from the customer." [21]

Proponents of VOS tout several benefits:

- A fairer, more accurate rate.
- A reduction in the payback period for solar customers.
- Conservation and efficiency encouraged by decoupling the credit from customer's consumption of energy.
- Greater assurance that Austin Energy is charging for the full cost of serving customers.[22]

The customer is billed for total consumption and then receives a credit from Austin Energy for PV production at the VOS rate. If the customer's production exceeds consumption in a given billing cycle, the customer receives a credit, which is rolled over to the next billing cycle.

Austin Energy implemented the VOS tariff in 2012 and has reviewed it every year. The value has fluctuated, declining from 2012 to 2013 and increasing a bit in 2014. The primary cause of the fluctuation is the variability of natural gas futures prices, as this impacts the energy savings and fuel price hedge value components within the algorithm.

In 2014, Austin Energy modified its review methodology to address concerns about the tariff's volatility. Instead of only looking at natural gas futures prices for one year out, the utility developed a "VOS factor" that incorporates a five-year rolling average. This factor is an average of the forward year plus the four previous years. The aim is to smooth out the tariff and keep the value reasonably stable.

Austin Energy has made other revisions. Originally any unused credits would be "zeroed out" at the end of the year, but now the utility allows credits to roll over for as long as the participant is an Austin Energy customer. The utility has removed the 20 kW cap it had originally placed on residential systems to be eligible for the tariff. Now all residential projects, regardless of size, will be on the VOS tariff. Austin Energy now permits leased systems to receive credits, while previously, only those who owned their systems were eligible.

[21] Ibid.

[22] Ibid., 4.

CASE STUDY

Lincoln Electric System's Value of Solar Study

Lincoln Electric System (LES), a Nebraska utility serving more than 130,000 end-use customers, joined the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) in 2009. In 2014, SPP changed its market design and became an integrated marketplace. SPP pays locational marginal prices (LMP) to LES for its generation, while LES pays SPP the LMP for all energy delivered by SPP to LES to supply its load. Distributed generation can reduce LES' load at certain times of the day, thus decreasing the amount of energy LES needs to buy from SPP.

While LES has not implemented VOS, it engaged in a three-month study to determine a true VOS rate, based in part on its move to the SPP market. The purpose of the study was to provide a "frame of reference" to determine the price point at which the LES renewables program would have no net impact on rates over 20 years.[23] The study examined a base case and a solar case. The solar case was modeled on assumptions of how much solar DG would be installed on the LES system. The goal was to derive a DG compensation figure that would put the cost of the solar on par with the costs incurred in the base case, and fairly compensate solar generators without burdening other customers.

The study examined the costs and benefits of distributed solar generation as it affects various components of LES's LMP-based cost of serving its load, including energy, transmission congestion, and marginal transmission losses, as well as environmental benefits and distribution system benefits.

There was a significant benefit in reduced energy costs (approximately $35 per MWh, or 3.5 cents per KWh). However, solar DG in the LES service territory actually causes slightly increased charges by SPP for transmission congestion and marginal transmission losses. LES believes this is due to relevant power flows in the SPP marketplace, which currently move predominantly from north to south. The southern part of SPP can't effectively handle all of the northern generation because of congestion. The market deals with this by lowering the LMP in the north, thus reducing the prices paid to prevailing generation and prices charged to serve load.

This means that Nebraska, which is in the northern part of SPP, is more favorable to load than to generation, and therefore distributed resources create more of a cost than a benefit for the congestion component of the analysis.

After weighing all the costs and benefits, the study estimated the cumulative benefit of DG to be $37.64 per MWh (or 3.7 cents per KWh) for every MWh generated over a 20-year period. The study concluded that if solar PV owners were compensated at that rate for their excess generation, it would have no net impact on rates over 20 years.

The study also examined LES's one-time capacity payment and concluded that western facing installations contributed more value, particularly during peak periods. Therefore, LES increased its one-time solar capacity payment from $275 per kW to $375 per kW for southern facing installations and $475 per kW for western facing installations.

This study informed Lincoln's new rate structure for renewable generation. As LES developed its rates, it was guided by four principles:

- Projects/programs must "pass a reasonable level of economic scrutiny."
- Projects/programs had to be able to scale up without creating unacceptable financial impacts.
- Projects/programs "should provide incentives and pay energy rates that are reasonably commensurate with the benefits provided to the system."
- LES must migrate to a rate structure that more closely aligns to how it incurs fixed and variable costs.[24]

[23] See presentation from Scott Benson, Manger, Resource & Transmission Planning for LES, available at https://www.youtube.com/watch?v=GH_3_tEXSH0&feature=youtu.be

On June 1, 2014, a new rate plan went into effect. It is a tiered structure system, with a declining payback as certain thresholds are reached. Solar-generating customers with systems smaller than 25 kW will continue to receive net metering credits at the full retail rate. All production from larger systems up to 100 kW, as well as net metering customers with excess generation, will be compensated at the same retail rate. Once 1 MW of cumulative distributed capacity has been installed, DG customers will receive half the retail rate as a credit for surplus generation. LES will establish a rate, as yet to be determined, for anyone who installs DG after 2 MW of aggregate distributed resources have been installed.[25] The payment rates for tier I and II customers are guaranteed for at least ten years.

The LES rate study determined that the VOS was below the current retail rate. Therefore, the new renewable generation rates reflect a conscious decision to incent solar and renewable development. LES plans to conduct future studies to re-evaluate the VOS as circumstances change. These studies will inform the net metering credit rate after the 2 MW threshold has been reached.

Lessons Learned

Though LES and Austin Energy diverged in the attributes included in their VOS studies, both provide sound examples of how VOS works and how it can be used to inform utility decision making even if a utility does not implement a VOS-based rate.

The Austin Energy VOS rate was determined to be close to Austin's retail rate, while LES's VOS rate is roughly half of its retail rate — indicating that many factors impact rate analysis. While both utilities are located in an RTO, different market structures, energy prices, and congestion points lead to variations in the value of solar. A kWh of distributed solar provides a greater benefit to Austin Energy relative to its costs than a kWh of distributed solar provides to LES.

The VOS is also significantly dictated by the utility's power purchase arrangements. If a utility has "take or pay" purchase power contracts, declining sales will not reduce fixed costs. A utility that procures a larger portion of its power on the market might better be able to reduce costs through reduced sales[26] and derive greater VOS. However, that choice will expose the utility's customers to spot market price volatility.

VOS may vary even within a single system. For example, solar rooftop PV might have more value in a congested urban center than in a less constrained suburban area if solar allows deferral of distribution system upgrades.[27] Therefore a utility might consider developing localized factors in its VOS rate, establishing different values for different sub-regions within its system. This would have to be balanced against the desire to have simpler, more easily understood rates.

Even if a utility decides not to immediately implement a VOS rate, there is a value in measuring the costs and benefits of DG. LES was able to quantify the VOS, and decide to incent a certain amount of distributed solar development before reducing the rate close to the VOS rate.

A utility should know what the costs associated with DG are, so it can make informed decisions when establishing rates for DG customers.

[24] See presentation from Jason Fortik, Vice President of Power Supply for LES, available at https://www.youtube.com/watch?v=fOfkxil4G4w&feature=youtu.be

[25] For a detailed summary of LES' net metering rate schedule, see http://www.les.com/residential/rates/rate-schedules.

[26] American Public Power Association, Distributed Generation: What Public Power Utilities Need to Know (Arlington, VA: APPA, 2015), 19.

[27] Taylor et al, 46. Technological considerations, including whether the PV system has tracking mechanisms, could also be factored in the VOS.

Demand Charges

Demand charges are typically applied only to commercial and industrial customers, based on each customer's peak usage.[28] The demand charge assigns a cost to the customer for the relative strain the customer places on system resources. A customer with flatter demand — using electricity at a more or less constant rate — imposes less of a strain on a utility's capacity resources, and incurs a smaller demand charge as a percentage of the total bill.

Predictability of the customer's usage patterns helps the utility better, procuring power either through purchases or generation to meet the expected demand. Customers with greater variability in their load profiles, particularly those who use a greater amount of electricity at peak system periods, place greater strain on the utility, which must quickly ramp up or ramp down its generation resources to meet the shifting demand.

Residential DG customers have distinct load profiles. On sunny days, they might not consume any electricity from the utility during the day, particularly at peak sun times (late morning to early afternoon in many locations), and in fact, may be net exporters to the utility. The DG customer's net demand intensifies gradually as the sun goes down. The utility's peak system-wide demand may occur after the DG system's peak output, meaning that the DG customer is demanding more utility generation just as other customers are also starting to demand more electricity.

The impact on utility capacity costs of a DG customer's demand may be equivalent to or even greater than that of a typical customer because the DG customers transitions from exporting electricity to the utility to taking electricity from it within a single day.

The cumulative system-wide impact of this phenomenon can be seen in the so-called California duck curve.[29] The distribution utility must quickly ramp up its resources to meet not only additional demand, but also compensate for the solar generation that is now being lost. The economic impact of this usage pattern can be **compounded in a capacity market where prices might rise dramatically during periods of congestion and high demand.**

Some utilities have chosen to address these issues by implementing residential demand charges, particularly for DG customers.

[28] Typically the charge is based on the maximum kW-demand over a 15-minute interval during the billing cycle.

[29] See for example California ISO Fast Fact, accessed at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. In California, the combination of night-time wind generation and heavy penetration of solar PV has dramatically increased the morning and late afternoon load ramps that must be met through conventional generation.

CASE STUDY

Lakeland Electric's Residential Demand Charge

Lakeland Electric serves 121,387 customers (more than 100,000 residential customers) in central Florida. Lakeland generates almost all the energy needed to meet its customers' load requirements, operating 218 MWs of coal-fired capacity, 774 MWs of natural gas capacity, and 55 MWs of oil-fired capacity. Lakeland is a winter peaking utility, with a winter peak of 612 MW in 2012, and a summer peak of 590 MW.

Lakeland had been operating under a traditional net metering tariff for a number of years. Customers with solar PV installations were charged for each kWh received from Lakeland during the month, and were given a credit for each kWh sent to Lakeland. The credit was at the same rate as the energy charge. Approximately 100 solar installations were interconnected to Lakeland's system as of December 31, 2014.

Lakeland did not have much DG but conducted a rate analysis to measure the efficacy of its net metering program. The utility wanted to better align its revenue with its costs, and it found that the existing program failed to do so.

As a result of the rate analysis, Lakeland modified its net metering program and established a new tariff. Owners (or leasers) of PV systems on the new tariff will be on a demand pricing rate schedule. **Residential customers will pay a $4.80 per kW-month demand rate. Solar output will still be credited at the energy rate, but the energy rate will now be lower.**

The demand charge is based on the customer's "maximum 30-minute integrated kilowatt demand in the month."[30] This kilowatt demand is intended to be a fair representation of the capacity that the utility is required to stand ready to supply to the customer.

The new tariff applies to new DG customers who sign an interconnection agreement starting October 1, 2015. Existing net metered DG customers will have ten more years on the current energy-only rate.

The purpose of this modified tariff is to better align revenue to costs. Residential demand charges will ensure solar PV customers receive a billing credit for surplus energy they provide to the utility, while paying a fixed charge for demands they place on the utility system, especially during peak hours.

Fixed Charges

Utilities can recover fixed costs by increasing the monthly fixed customer charge. A utility could increase its base customer charge for all customers or elect to add a fixed surcharge to DG customer bills to recoup more of the fixed system costs the utility incurs to serve these customers.

This method is not without controversy as parties have protested proposed increases in several states.[31] However, it is a mechanism that, if properly applied and accepted, can better align rates with costs.

[30] http://www.lakelandelectric.com/Portals/LakelandElectric/Docs/Publications/Rate%20Tariffs/201502/files/assets/common/downloads/publication.pdf . See Residential demand service, sheet number 6.3.1.

[31] See for example the debate in Missouri: http://www.utilitydive.com/news/utilities-solar-advocates-at-odds-over-missouri-net-metering-bill/386351/; the controversy of APS's proposal in Arizona: Michael Copley. "Demand charge under APS rooftop solar proposal would add up to $80 in monthly fees." SNL: Electric Utility Report, July 15, 2013; the Idaho PUC rejecting a customer charge increase: Idaho Public Utilities Commission. "Most of Idaho net metering proposals denied." Case No. IPC-E-12-27, Order No. 32846, July 3, 2013; Louisiana PSC rejecting a customer charge increase: Amanda H. Miller. "Louisiana PSC upholds net metering." Clean Energy Authority, July 1, 2013. Accessed at: http://www.cleanenergyauthority.com/solar-energy-news/louisaana-psc-upholds-net-metering-070113.; and the discussion around Wisconsin utilities increasing their fixed charge: http://www.midwestenergynews.com/2014/11/11/wisconsin-fixed-charge-decision-a-sign-of-more-to-come/.

CASE STUDY

Sacramento Municipal Utility District's Rate Restructuring

The Sacramento Municipal Utility District (SMUD), which serves just over 600,000 customers, of which just under 540,000 are residential customers, increased its fixed charge to recover the cost of service.

SMUD's net metering program was formally adopted by its board in 2008. Like most net metering programs, SMUD credited its solar customers for surplus generation at the same kWh rate that it charged them for electricity it provided to their homes or businesses. SMUD also established a ten-year rebate program — with a stepped payout declining over time — to incent solar development.

Legislation passed in California — AB 920 — discouraged the practice of paying customers at the full retail rate for surplus generation. As a result, SMUD adopted a system where it paid net generators annually at the net metering surplus compensation (NMSC) value. The NMSC value is based on SMUD's wholesale power supply cost, which is about half of the retail rate. Net metered customers retain the option of rolling over their generation credits to cover kWh supplied by SMUD to the customer in the next month.

SMUD also changed its monthly customer charge, also known as a system infrastructure charge, for all customers. In 2011, SMUD determined, based on a cost study, that its marginal cost of serving a customer was about $26. **The utility wanted to better align rates with costs, so it decided increase its system infrastructure fixed charge for residential and small commercial customers to a point that was closer to the marginal cost. The fixed charge increase was offset by a reduction in energy charges.[32] The SMUD Board approved the proposal with a phase-in of the fixed charge over a five-year period.**

These changes were made as SMUD began a full rollout of its smart meter plan. Today, virtually all SMUD customers have smart meters. While this does not directly affect how SMUD charges and credits its DG customers, smart meters provide flexibility to perform analysis on rates and rate structures, which may indirectly affect DG customers.[33]

SMUD began redesigning its rate structure in 2011, consolidating its tiered-rate structure down from three to two tiers for residential customers, and introducing time-varying rates for small commercial customers. SMUD also redefined its seasonal period and created a four-month summer period to prepare residential customers for future peak pricing plans.[34]

In 2013, SMUD began a restructuring of its residential rates that will culminate in universal time-based pricing beginning in 2018. The General Manager report states:

> **The gradual, multi-year transition will bring all customers in line with the true cost of electricity and will avoid some customers paying more than it costs for SMUD to serve them. SMUD's goal is to gradually transition from tiered pricing, which is the current structure, to time-based pricing. The transition will span four years with full time-based pricing planned to begin in 2018.[35]**

While SMUD's rate changes do not directly address DG, a time-based pricing structure will affect the rate at which DG customers are compensated for excess generation.

SMUD has adopted a **phased-in approach that allows customers to grow accustomed to the new rate design.** Customer education is particularly important when it comes to significant modifications to residential rates that may shift charges from one set of customers to another.

[32] For more information on the system infrastructure fixed charge, see https://www.smud.org/en/about-smud/company-information/document-library/documents/GM-Rate-Report-Addendum-2-06-16-11.pdf.

[33] See SmartPricing Options Final Evaluation, the final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study, issued September 5, 2014, available at https://www.smartgrid.gov/sites/default/files/doc/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

[34] General Manager's Report and Recommendation on Rates and Services, April 7, 2011, available at https://www.smud.org/en/about-smud/company-information/document-library/documents/GMRateReport-Vol1-04-07-11.pdf.

[35] General Manager's Report and Recommendation on Rates and Services, May 2, 2013, available at https://www.smud.org/en/about-smud/company-information/document-library/documents/2013-GM-Rate-Report-Vol-1.pdf.

CASE STUDY

City of Whitehall's Customer Charge Increase

The City of Whitehall, a public power utility in Wisconsin serving fewer than 1,000 customers, increased its monthly customer charge, shifting recovery of some of its fixed distribution costs away from its variable energy rate.

A cost-of-service study had shown that approximately 29 percent of Whitehall's charges were fixed, but the utility was collecting only 9 percent of its revenue through its monthly customer charge. It therefore sought to increase its customer charge on single-phase residential and general service bills from $8 to $16 per month.

In testimony before Wisconsin's Public Service Commission (PSC), the utility explained:

> **Whitehall's proposal better aligns the fixed charges received from customers with the fixed costs the utility incurs to provide those customers with access to the electric system. Further, Whitehall's proposal more fairly and equitably spreads the costs of service among its residential and general service customers.**[36]

The PSC ultimately agreed to the increase to $16 only for customers on Whitehall's flat energy rate. For customers on the utility's optional time-of-use plan, the customer charge was increased to only $10, to see if this would incent other customers to move from the flat rate to the TOU plan.

One potential variation to the customer charge is a **minimum bill.** This is not a set charge applied to all customer bills. But a utility could establish a minimum amount, say $20 per month, for a customer bill. If a customer accrues at least $20 in variable energy charges, they would not have to pay any portion of that minimum charge. This minimum charge would apply only if the customer's net usage falls under the minimum amount. If the customer's net usage is zero, then the customer would pay exactly $20 as their minimum bill.[37]

Separate Metering

An alternative to net metering is **a buy-sell approach in which the customer purchases all energy consumed on site at the utility's retail rate, and then separately sells all its surplus rooftop generation to the utility at avoided cost.**[38] This is similar to the VOS approach, in which consumption and generation are treated as completely separate services with different price points and rate designs. The difference is that instead of a detailed methodology to determine a specific rate, the utility would just pay the PV customer the wholesale rate, or some other similar rate, for all energy exported to the utility by the customer.

[36] Application at page 3, Application of the City of Whitehall, Trempealeau County, Wisconsin as an Electric Public Utility, for Authority to Increase Rates (Wisconsin Public Service Commission filed March 4, 2015) (Docket No. 6490-ER-106)

[37] Jim Kennerly, "The Minimum Bill: A First Step to Fair Utility Rates in a Distributed Energy Age," PV Solar, September 10, 2014, accessed at http://www.pvsolarreport.com/minimum-bill-first-step-to-fair-utility-rates/. .

CASE STUDY

Santee Cooper's Net Billing Program

The South Carolina Public Service Authority, also known as Santee Cooper, supplies electricity to more than 172,000 retail customers as well as to 27 large industrial facilities, and to other power systems, including the state's 20 electric cooperatives.

Santee Cooper adopted a net billing program in response to the revisions in the Public Utility Regulatory Policy Act (PURPA) made via the Energy Policy Act of 2005. The utility adapted rates for DG customers to minimize cost shifts.

Santee Cooper's net billing rate applies to customer-side generation with a nameplate rating that cannot exceed the estimated maximum monthly kW demand of the residence or 20 kW, whichever is less. Additionally, customers on this rate pay a $24 per month customer charge as well as an on-peak demand charge of $11.34/kW per month, and off-peak demand charge of $4.85/kW per month.

Santee Cooper separately meters electricity supplied to the customer and electricity supplied by the customer. The energy credit to customers for surplus generation and the energy charge paid by customers are based on the time of day. There are different on-peak and off-peak energy charges, with a seasonal component — the summer on-peak charge is different from the winter on-peak charge. **At the end of the billing cycle, Santee Cooper nets all of the charges to the customer against all of the credits that the customer has accumulated.**

Ashley Brown offers a modification to separate metering:

If utilities pay all energy producers, large or small, central or distributed, at the locational market price, it has the advantage of bundling both transmission costs or savings and energy costs. It is a rather level playing field for all generators, with a slight advantage to solar PV DG because, again, it assures purchase without assured delivery.[39]

Under this rate design, distributed generators would essentially be treated the same as wholesale power producers. This method also has the effect of stripping away the connection between the utility's retail rates and its payments to distributed generators.

Other Net Metering Variations

Without demand or added fixed charges, net metering is an inefficient way to align costs and revenues. However, it can be adjusted in a way that better aligns revenue with costs.

[38] Borlick and Wood, Net Energy Metering, 12.=

[39] Brown, "Net Metering".

CASE STUDY

Concord Light's Wholesale Credit Rate

Concord Light in Massachusetts serves 8,100 total customers and approximately 6,800 residential customers. The utility credits excess generation at less than the retail rate. Concord subtracts each customer's excess production from the customer's electricity purchases, and bills them the net amount at the end of a billing cycle.

> **If a customer produces more generation than is purchased in a given month, that customer receives a credit equal to the price that Concord pays the New England Independent System Operator (ISO-NE) for energy on the spot market.**

The spot market price in 2012 was under 4 cents per kWh and was projected to be the same for 2013. **This is substantially lower than the residential retail rate**, which ranges from approximately 14 to 17 cents per kWh.[40]

Concord also combines a distribution charge with its net metering tariff. The distribution charge goes up incrementally as the customer PV system size increases. The monthly charge for the smallest unit (2-4 kW) is $3.60 per month. Twenty percent of each customer bill goes toward maintaining the distribution system and to cover the utility's distribution operating costs. The distribution charge ensures that these costs are shared among all Concord customers, even those who generate some of their own electricity.

New Braunfels Utilities in Texas also combines a monthly customer charge, delivery charge, and cost of power charge with its net metering rate. It also has a minimum monthly bill, which is laid out in its net metering tariff as follows:

> The minimum monthly bill shall be the customer charge plus the delivery charge per installed kW of generation, and any special charges or adjustments.[41]

[40] "Concord Light: Residential Solar PV Net Metering Policy Acknowledgement." Accessed at: http://www.concordma.gov/pages/ConcordMA_LightPlant/Netmeteringpolicyacknowledgement081613.pdf

[41] New Braunfels net metering tariff, accessed at http://www.nbutexas.com/Portals/11/pdf/Electric%20Rates%203-09.pdf.

SECTION 4

Customer Education

Communicating to customers about changes to rates and rate structures is critical, especially for a customer-owned public power utility. In the case of rate design related to DG, both DG and non-DG customers need to understand why the decisions have been made.

Utilities must explain the relationship between costs and rates to gain customer understanding and support. On its website, Concord Light explains why the utility continues to accrue fixed costs to serve its solar customers:

Customers with solar PV systems continue to receive all of the services provided by the electricity distribution system in town and by Concord Light. Customers' adoption of solar does not reduce Concord Light's costs for maintaining local infrastructure and providing services. The customer acknowledges that the distribution charge is a condition of receiving net metering credits from Concord Light.[42]

Engaging customers helps to gain their acceptance. For example, Lakeland Electric held a series of workshops with elected officials, stakeholders, and citizens' groups and invited public comments before implementing its demand charges. Stakeholder reaction to the increased customer charge and the demand charge has been mostly positive.

After completing its VOS study, LES held public stakeholder meetings to explain the process and ratemaking decision. The meeting videos are posted on YouTube and linked from the LES website.[43] The website also contains links to reports and other documents that further explain net metering and solar rooftop PV.

An American Public Power Association guidebook, *Distributed Generation: A Guidebook for Public Power Utilities*,[44] suggests that utilities should conduct meetings with key stakeholders and customers on contemplated changes to rate design, and communicate strategic plans with lenders and oversight boards.

The guidebook provides details on how to conduct a customer education program on the implications of installing DG. The program should include information on potential rate increases, changes in rate design, standard terms in DG contracts and leases, how to vet third party vendors, DG equipment, and safety and reliability issues connected to DG.

Such programs can benefit the utility, too, as the guidebook notes:

> **The utility can learn about customers' DG preferences and willingness to pay for currently embedded utility services such as reliability and distribution system maintenance.**

[42] Concord Light: Residential Solar PV Net Metering Policy Acknowledgement.

[43] Videos can be accessed at http://www.les.com/savings-energy/solar-customer-owned-gen.

[44] APPA, 27.

Conclusion

We are beyond the initial stages of DG. More and more customers are installing DG, and there is no sign that this trend will slow in the immediate future.[45] Utilities can no longer afford to take a wait and see approach when it comes to rate design, nor should they assume that their existing rate design — especially a net metering design that was adopted before the escalation in the number of DG installations — will suffice to recover the utility's revenue requirements and send good price signals to its customers.

This report describes a variety of rate design options for public power utilities to consider. No single design will work for all utilities. Community needs, market structure, state policies, and myriad other considerations will influence each utility's ultimate decision.

It is also important to keep in mind that, as is always the case with rate design, there will be tradeoffs. Ken Costello offers advice to regulators that applies equally to utilities:

> **Public utility regulation always involves compromising different objectives. For example, to improve economic efficiency, how much higher would rates become for certain customers? Are these two outcomes, taken together, fair to all customers and in the public interest? How much would economic efficiency have to increase to compensate for the higher rates? No single rate mechanism is superior to other mechanisms in advancing all of the regulatory objectives.**[46]

No single approach is right for rate design. Rate setters must balance between simplicity and accuracy, align costs and prices, promote conservation, and consider many more factors. While some rate designs may be better suited to proper cost alignment, utilities must carefully consider whether they are well suited to customers.

Communication and engagement are essential components of the rate-setting process.

[45] Although the potential reduction in the solar investment tax credit could dampen the marketplace to some degree.

[46] Ken Costello, "Evaluating Alternate Rate Mechanisms: A Conceptual Approach for State Utility Commissions," Electricity Journal Volume 27, Issue 4 (2014), 24.

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