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March 30, 2016

Mountain Lake Utility Commission
PO Box C
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Members of the Mountain Lake Utility Commission:

Missouri River Energy Services (MRES) is pleased to submit this electric rate study report for Mountain Lake Municipal Utilities. This study had four principal objectives:

- To determine whether estimated total revenues will be sufficient to cover estimated revenue requirements and provide a reserve for replacements and contingencies
- To determine the cost to serve each customer class
- To design retail rates for the various classes, including analyzing the power cost adjustment (PCA) base and the calculation methodology
- To review the competitive position of Mountain Lake through utility rate comparisons

The key rate study recommendations include:
- Implementation a 4.0% overall increase in April 2016 and 4.5% overall increases in January 2017, 2018, and 2019
- Modify the PCA calculation and increase the PCA base, which will lower the monthly adjustments on customer's bills under proposed rates
- Simplify most class rate structures by implementing a single energy or demand rate
- Rename the Industrial class to the Large Commercial class and define the qualifications for the class to include all non-residential customers with a peak demand of 20 kW in three or more months out of the previous 12 months.

The proposed rates were designed to recover operating expenses and to fund capital expenditures and debt service obligations while rebuilding reserves throughout the study period after high capital expenditures in 2016. Section 4 of this report contains all of the recommendations, **but further adjustments to the rates may be necessary in future years if operating costs, system characteristics, or the financial needs of the utility change drastically.**

MRES appreciated the opportunity to prepare this study for Mountain Lake Municipal Utilities and would like to thank your staff for its valuable assistance.

Respectfully submitted,

Missouri River Energy Services

MOUNTAIN LAKE MUNICIPAL UTILITIES
ELECTRIC RATE STUDY
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APPENDIX – Proposed Rates for 2016 through 2019

This rate study was completed in accordance with the agreed upon terms as set forth in the Proposal Letter and Exhibit A, Scope of Services between Missouri River Energy Services and its member, Mountain Lake. In completing this study, Missouri River Energy Services has relied on the data and materials provided by Mountain Lake and others to be accurate, and has not independently verified their accuracy. The analysis, conclusions, and recommendations contained in this report constitute the opinions of Missouri River Energy Services based on the data and materials provided. Final responsibility for the implementation of the recommendations in this report rests with the Mountain Lake staff and the governing board.

SECTION 1 – RATE STUDY INTRODUCTION AND POWER REQUIREMENTS

INTRODUCTION

The Mountain Lake Municipal Utilities (Mountain Lake), under the direction of the Utility Commission, provides electric service to about 1,055 customers. Mountain Lake is a member of Central Municipal Power Agency/Services (CMPAS) located in Blue Earth, Minnesota. CMPAS provides several services to Mountain Lake, including consulting and scheduling services for power supply and transmission service. Missouri River Energy Services (MRES), located in Sioux Falls, South Dakota, was engaged to perform a review of the Mountain Lake electric rates, including an analysis of revenues and revenue requirements for the study period of 2015 to 2019, the allocation of costs to serve each customer class based on a Test Year, and the design of retail rates.

The study was prompted, in part, by the need to evaluate the adequacy of revenues due to rising power supply and operating costs along with planned capital expenditures and debt service obligations. The study also analyzed current and projected reserve levels for the study period to determine if reserves would maintain the optimal level determined by Mountain Lake staff. Furthermore, the study was to determine if each class is paying an appropriate share of the costs, and the study reviewed the current qualifications for each class.

KEY DEFINITIONS

In this report, there are several key electric utility terms used. Following are definitions for some of these terms:

- <u>Peak Demand (kW)</u> – The maximum rate of power delivery, measured in a defined time period such as 30 minutes, expressed in 1,000 watt units.
- <u>Energy (kWh)</u> – Power multiplied by time. The usage of ten 100 watt light bulbs for one hour equals one kWh. One thousand kWh equals one megawatt-hour (MWh).
- <u>Load Factor</u> – Equals average demand for a given time period (kWh per hour) divided by peak demand. A higher load factor indicates more consistent and efficient use of power and the distribution system. Customers such as grocery stores and medical facilities often have higher load factors, while schools, grain elevators, and manufacturing facilities with only one shift or intermittent equipment usage often have lower load factors.
- <u>Single Phase</u> – The customer is served from one voltage source. This type of service is used for most residential and smaller commercial customers.

- Three Phase – The customer is served by three voltage sources. This is used by commercial customers that have larger loads and/or have large motors.
- Power Factor – The ratio of real power (kW) to apparent power (kVA). A circuit with a lower power factor requires higher currents to transfer a given quantity of real power than a circuit with a higher power factor.

ENERGY REQUIREMENTS

The table below shows the annual energy requirements and the retail sales for Mountain Lake from 2011 to 2019. In 2015, Mountain Lake's energy requirements decreased to below the 2011 energy requirements level primarily due to the mild weather most of the year. The study forecasts that energy requirements will increase by 1.0% in 2016 and by 0.5% per year from 2017 to 2019.

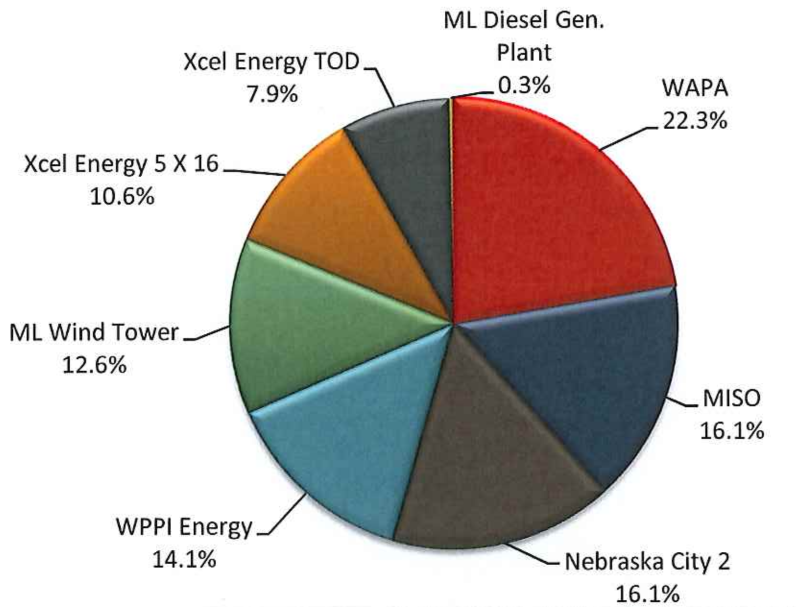
From 2011 through 2015, the retail sales percentage change is slightly different from the energy requirements percentage change for the same year due to the fluctuating distribution line loss percentages, which have ranged from 2.8% to 5.2%. Distribution line losses include energy dissipated in the conductors, transformers, and other equipment in the local distribution system along with unmetered energy, if any. The study forecasted the annual line loss at 5%.

Historical and Forecasted Wholesale Energy Requirements and Retail Sales						
	Year	Energy Requirements (MWh)	Percentage Change	Distribution Line Loss Percentage	Retail Sales (MWh)	Percentage Change
Historical	2011	25,910		5.1%	24,659	
	2012	26,033	0.5%	3.7%	25,102	1.8%
	2013	26,083	0.2%	2.8%	25,383	1.1%
	2014	26,310	0.9%	5.2%	25,004	(1.5%)
	2015	25,415	(3.0%)	4.8%	24,261	(3.0%)
Forecast	2016	25,669	1.0%	5.0%	24,446	0.8%
	2017	25,797	0.5%	5.0%	24,569	0.5%
	2018	25,926	0.5%	5.0%	24,692	0.5%
	2019	26,056	0.5%	5.0%	24,815	0.5%

The chart on the following page shows the total forecasted energy requirements from 2016 to 2019 broken down by supplier. Mountain Lake receives an allocation from the Western Area Power Administration (WAPA), which operates several hydroelectric plants on the Missouri River. The allocation is forecasted to be approximately 22% of Mountain Lake's energy requirements from 2016 through 2019. Mountain Lake also has a contract for 600 kW from the Nebraska City 2 (NC2) power plant, which is located about 50 miles south of

Omaha, Nebraska. Mountain Lake is expected to receive about 16% of its requirements from NC2. The other power supply contracts in place include the following: WPPI Energy supplying about 14%; Xcel Energy supplying over 10% with the 5x16 contract and nearly 8% with the Time of Day (TOD) contract; and the Midcontinent Independent System Operator (MISO) market purchases supplying approximately 16% of the energy requirements. Mountain Lake owns an 8 MW diesel generation plant and a wind turbine, which was constructed in 2007. The municipally-owned generation is forecasted to supply nearly 13% of Mountain Lake's energy needs. The purchased power and local generation costs are further discussed in Section 2.

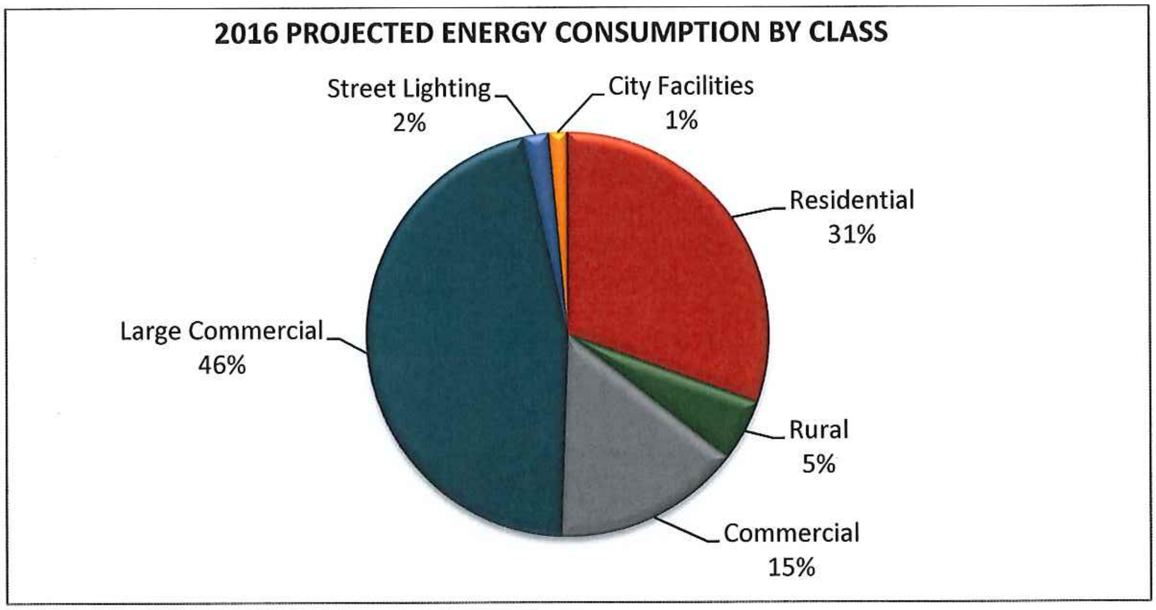
FORECASTED ENERGY REQUIREMENTS BY SUPPLIER: 2016-2019



PROJECTED ENERGY CONSUMPTION BY CLASS

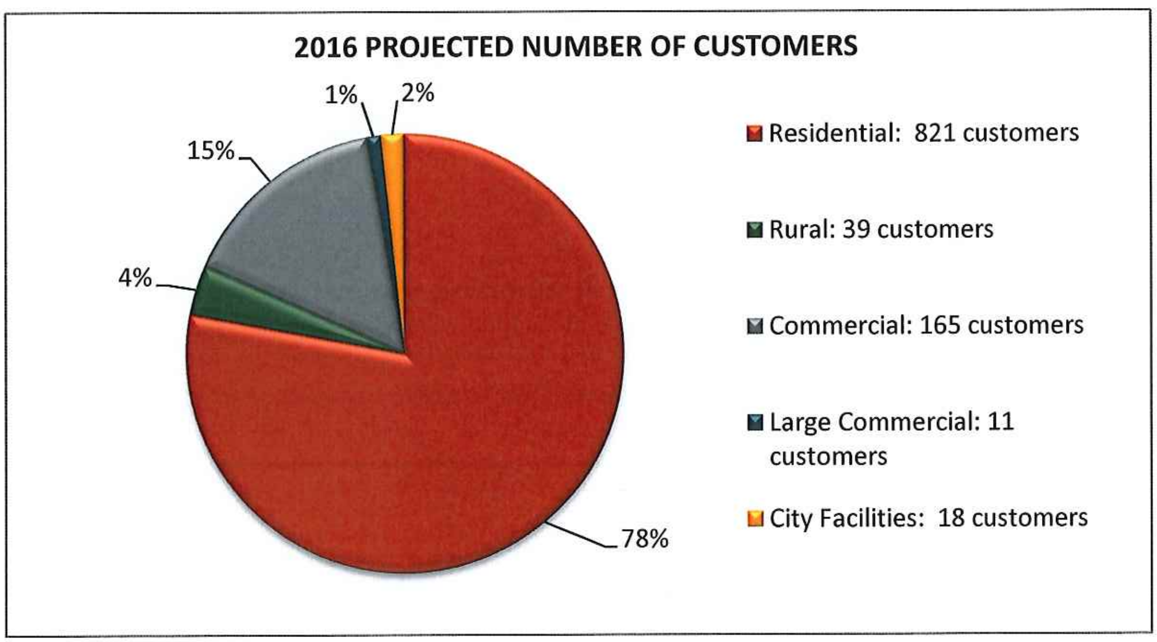
The projected energy consumption by class for 2016 is shown in the pie chart at the top of the following page. The breakdown shows that Residential customers are projected to consume 31% of the energy requirements. The average consumption by the Residential class in other regional utilities is approximately 42% of the total system energy consumption. The Industrial class is projected to have 46% of the energy sales in 2016 but only 1% of the total customers. City facilities also include the water and wastewater utilities' consumption.

PROJECTED ENERGY CONSUMPTION BY CLASS (Continued)



PROJECTED NUMBER OF CUSTOMERS BY CLASS

Based on discussions with staff, Mountain Lake expects the total number of customers to remain stable throughout the study period. However, the number of customers may vary slightly from year to year. The chart below breaks down the projected number of customers by class for 2016. The Residential class has 78% of the total number of customers.



SECTION 2 – PROJECTED NET INCOME AND CASH RESERVES

MRES worked with Mountain Lake staff to estimate the annual revenues and the expenditures, "revenue requirements", for the five-year study period of 2015 to 2019. Revenue requirements must be compared to revenues to determine whether the electric utility will recover all of its costs and provide a margin for a reserve for system replacements, contingencies, and rate stabilization. The analyses and assumptions used in developing these estimates are described on the following pages. Exhibits 2-A and 2-B at the end of this section present the projected net income and cash reserves.

ESTIMATED REVENUES

Estimated revenues consist of metered electric sales, other operating revenue, and non-operating revenues. Metered sales were estimated based on current retail rates along with the demand and energy forecasts and the customer class growth projections discussed in Section 1. The metered sales revenues include the power cost adjustments that are projected to increase from $0.0384 per kWh in 2016 to $0.0404 in 2019, as shown in Exhibit 2-C.

Other operating revenue includes late payment fees, capacity sold to another utility, municipally-owned transmission line revenue, and conservation improvement plan (CIP) revenue. Other operating revenue is projected to increase from about $88,500 in 2015 to $93,800 by 2019.

Non-operating revenue consists of investment income that is estimated at 0.5% of cash reserves and refunds and reimbursements of $7,000 in 2015 and $3,000 each year thereafter. Mountain Lake, along with other CMPAS members, jointly invested a CAPX 2020 transmission project located in the upper Midwest. Mountain Lake began receiving revenues for their investment in 2014, which are estimated to be $12,730 per year for the study period.

ESTIMATED REVENUE REQUIREMENTS

The revenue requirements of the electric utility consist of purchased power, transmission service, and local generation expenses, other operating expenses, transfers to the general fund, debt service, and capital expenditures and equipment purchases. Revenue requirement projections were based on historical operating statements from 2011 through 2014, operating budgets for 2015 and 2016, estimated purchased power expenses, and discussions with Mountain Lake staff.

Purchased Power, Transmission Service, and Municipally-Owned Generation Expenses

The wholesale purchased power and transmission service expenses, along with the municipally-owned wind turbine and diesel generation plant production costs, are based on several assumptions, including the energy requirements as outlined in Section 1. Exhibit 2-C provides details on the historical and projected purchased power supply and transmission service costs by supplier along with the local generation costs.

WAPA Wholesale Power Rates

WAPA more than doubled its rates from 2004 through 2010 due to prolonged drought conditions. Due to the drought conditions receding along with other reasons, WAPA has not increased rates since 2010. Beginning in 2015, approximately 35% of the composite rate is due to the repayment of drought deficits. In 2016, Mountain Lake's retail customers are projected to pay approximately $62,600 in drought-related costs, or approximately 2.7% of metered electric sales revenue. The drought portion of the rate is analyzed annually and can be adjusted each January, if needed, by up to 0.2 cents per kWh without a formal public process. According to WAPA, the remaining deficit is projected to be paid in full by 2017 if the region sees median water conditions. The rate study assumed WAPA rates will remain stable through 2019; however, recent discussions by WAPA indicate that they may consider lowering the total rate after the deficits are paid in full, which is unknown at this time.

WAPA Actual and Projected Wholesale Demand and Energy Rates		
Year	Demand Rate ($/kW-month)	All Energy ($/MWh)
2010-2016 (Actual)	$7.65	$19.05
2017-2019 (Projected)	$7.65	$19.05

Other Power Supply Costs

Mountain Lake is projected to purchase about 18.5% of its energy requirements through two contracts with Xcel Energy. The Xcel 5 x 16 contract has been renewed for 2016 through 2020. The annual energy purchases under this contract are 2,040 MWh, and the price decreased from $67.50 per MWh to $45.70 per MWh on January 1, 2016. Mountain Lake is also expected to purchase an estimated 2,900 MWh per year from 2016 to 2019 under the Time of Day (TOD) contract. The average price of the TOD energy is estimated to be $41 per MWh in 2016 and increase to $44 per MWh by 2019.

Mountain Lake also has a contract to purchase 600 kW of base load power from the NC2 coal plant that became operational in 2009. NC2 is considered a base load resource, which means Mountain Lake receives power from the plant 24 hours a day, every day of the year except for the hours the plant is not operating. The study assumed Mountain Lake would purchase about 4,150 MWh per year from NC2 at an estimated price of $43.10 per MWh in 2016 increasing to $46.70 per MWh by 2019. To diversify its resource mix, Mountain Lake contracted with WPPI Energy in Sun Prairie, Wisconsin, to receive about 14% of its energy requirements, or 3,650 MWh per year, from the Point Beach Nuclear Plant in Two Rivers, Wisconsin. The WPPI Energy contract is estimated to increase from $57 per MWh in 2016 to $60 per MWh by 2019.

Mountain Lake is projected to produce nearly 13% of its own energy from the municipally-owned wind turbine and a seldom run diesel generation plant. The remaining energy requirements, or approximately 16%, are projected to be purchased in the MISO market at an estimated average price of $30 per MWh in 2016 increasing to $33 per MWh by 2019. Finally, Mountain Lake has a contract to purchase a small quantity of energy from the Wolf Wind Project, which is then sold back into the MISO market at a net cost estimated at $18,500 per year.

Transmission Service Costs

Transmission service is purchased from the MISO market in the ITC Midwest pricing zone. The cost of transmission services is estimated at $18.50 per MWh in 2016 and gradually increasing to $20.20 per MWh by 2019, or 6% per year. Transmission costs have increased considerably in the past five years due to ITC Midwest seeking cost recovery for their significant capital investments they have made to the regional transmission grid. Finally, Mountain Lake pays CMPAS for energy scheduling, member dues, agency fixed costs, and other special projects fees.

Total Power Supply, Transmission Service, and Municipally-Owned Generation Costs

Total purchased power costs are expected to increase an average of 3.1% per year from 2016 through 2019. The table below shows the estimated purchased power and transmission expenses by supplier. The 2015 expenses are actual unaudited costs provided by Mountain Lake.

Estimated Purchased Power, Local Generation, and Transmission Expenses									
Year	WAPA	Nebraska City 2	Xcel Energy Total	WPPI Energy	MISO Market & Wolf Wind	Mt. Lake Total Local Generation	Trans-mission	CMPAS Charges	Total Cost
2015	$183,853	$162,300	$227,190	$230,849	$92,283	$214,156	$438,996	$114,516	$1,664,143
2016	$178,070	$178,975	$205,978	$208,050	$137,497	$216,053	$475,295	$111,634	$1,712,351
2017	$178,070	$179,805	$208,728	$211,700	$145,442	$218,407	$506,221	$111,935	$1,761,109
2018	$178,070	$188,940	$211,478	$215,350	$153,665	$220,788	$539,167	$112,238	$1,820,496
2019	$178,070	$193,923	$214,228	$219,000	$162,167	$223,195	$574,264	$112,543	$1,878,189

The next table breaks down the cost per MWh from the various power supply sources and the transmission provider. The total cost per MWh increased by 4% in 2015 and is projected to increase by an average of 2.4% per year from 2016 through 2019.

Estimated Purchased Power and Transmission Prices per MWh and Total Cost per MWh (includes Congestion and Losses where applicable)										
Year	WAPA	Neb. City 2	Xcel Energy 5 x 16	Xcel Energy TOD	WPPI Energy	MISO Market	Mt. Lake Wind	Trans-mission	Total Cost per MWh	% Increase
2015	$31.00	$39.60	$67.50	$32.50	$55.82	$22.68	$54.00	$17.20	$65.50	4.0%
2016	$31.00	$43.10	$45.70	$41.00	$57.00	$30.00	$54.00	$18.50	$66.70	1.9%
2017	$31.00	$43.30	$45.70	$42.00	$58.00	$31.00	$54.00	$19.60	$68.30	2.3%
2018	$31.00	$45.50	$45.70	$43.00	$59.00	$32.00	$54.00	$20.80	$70.20	2.8%
2019	$31.00	$46.70	$45.70	$44.00	$60.00	$33.00	$54.00	$22.00	$72.10	2.7%

Other Operating Expenses

Other operating expenses include production, distribution, administrative and general, and depreciation expense. Most operating expenses are expected to increase by 3% annually and depreciation expense is based on planned capital expenditures during the study period.

Transfer to the General Fund and Discounted Cost Electric Service

The electric utility is expected to transfer $120,000 per year to the City of Mountain Lake's general fund from 2016 through 2019, or 4.7% of operating revenues. The utility also provides discounted cost electric service to the water and sewer utilities, the City of Mountain Lake facilities, and the street lighting usage. The total value of the reduced energy costs to these meters was approximately $33,500 in 2015, or 1.4% of operating revenues. The total transfer and value of discounted electric service is estimated to be 5.8% of operating revenues from 2016 through 2019.

The 2012 American Public Power Association national survey indicated the median percentage of transfers and related payments as a percentage of operating revenues was 5.5%. Meanwhile, in a study of 68 area municipal utility financial statements, MRES found that the median level of transfers and donated services as a percentage of operating revenues was 6% of operating revenues. Transfers and related payments can include payments in lieu of taxes, franchise fees, free or reduced cost city and enterprise services, interest free loans to other entities, use of electric utility employees, and use of vehicles, equipment, materials, and supplies. Contributions from other city funds or entities to the electric utility are netted against the amount the electric utility provides.

Debt Service

In 2007, Mountain Lake received Clean Renewable Energy Bonds (CREBs) from the U.S. Internal Revenue Service to finance the municipally-owned wind turbine over 15 years. Mountain Lake originally issued $2.06 million and the outstanding balance at end of 2015 was $1.03 million. The payment includes the interest expense; therefore, it is not broken out in the table below. In 2009, $550,000 of bonds was issued to install a new feeder line. Lastly, the 2012C bonds are the accumulation of several bonds issued in past years that have been paid down and new funds issued over time for various distribution system improvements. All of the bonds are projected to be paid in full in either 2023 or 2024. $250,000 has been restricted in a bond reserve fund to comply with the bond covenant requirements and these funds are not included in the available reserves on Exhibit 2-B.

Outstanding Debt Balances and Payments					
Bond Series	**Purpose**	**Dec. 31, 2015 Outstanding Balance**	**2016-2019 Principal Payments**	**2016-2019 Interest Expense**	**Dec. 31, 2019 Outstanding Balance**
2007C	Mountain Lake Wind Turbine	$1,030,000	$515,000	N/A	$515,000
2009B	Feeder Dist. Line	$375,000	$140,000	$63,905	$235,000
2012C	Distribution System	$480,000	$230,000	$34,375	$250,000
Total		$1,885,000	$885,000	$98,280	$1,000,000

Capital Expenditures and Equipment Purchases

Based on the Mountain Lake's five year capital improvement plan and discussions with staff, the capital expenditures are expected to total approximately $3,115,000 from 2015 to 2019. Mountain Lake will upgrade each of the five engines at the power plant by May 1, 2016 to comply with the Environmental Protection Agency's reciprocating internal combustion engine (RICE) regulations. By being compliant with the regulations, the power plant will emit less air pollutants including carbon monoxide, nitrogen oxide, and particulates resulting in cleaner air. The following is a breakdown of the revenue-financed capital expenditures:

Revenue-Financed Capital Expenditures:

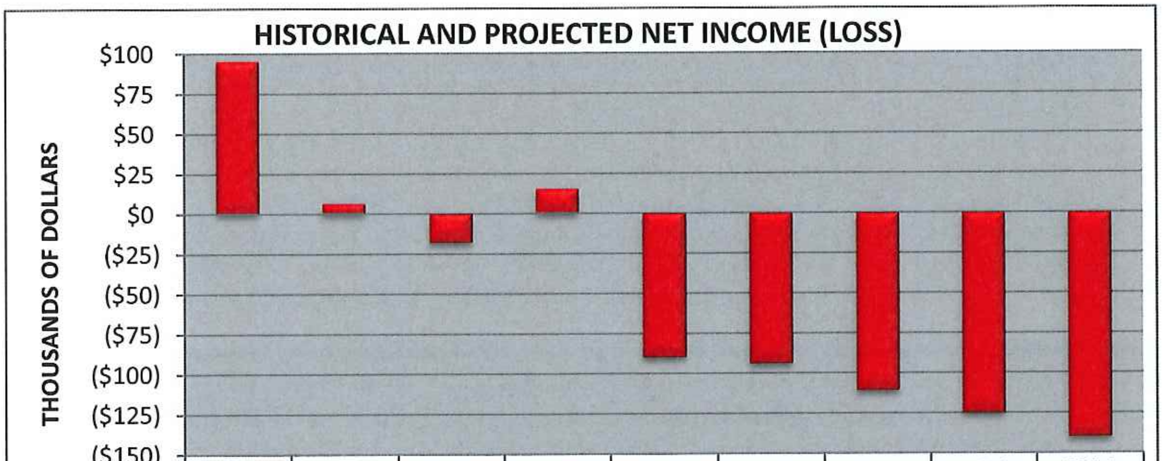
- Upgrade 5 engines to RICE standards $350,000
- Distribution system improvements $280,000
- Digger derrick $180,000
- Vehicles $120,000
- Pole replacement & tree trimming $80,000
- Electric meters $40,000
- Other Items $65,000

Debt-Financed Capital Expenditures:

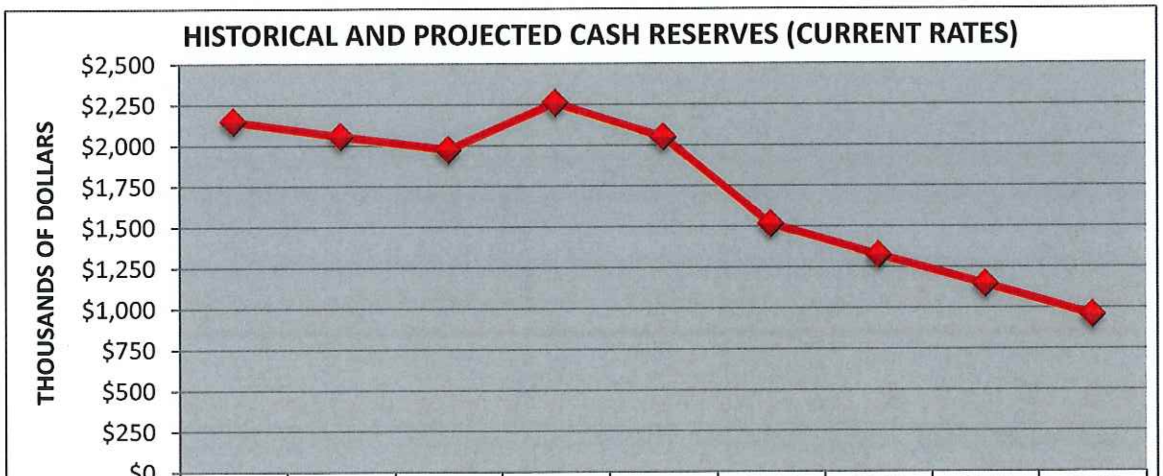
In addition to the revenue-financed capital expenditures, Mountain Lake is beginning to plan for a substation project estimated to cost $2 million, to be financed with bonds. Due to uncertainties regarding the timing and final cost, the debt service has not been included in the projections. MRES can update the projections after the costs have been determined. Mountain Lake expects some related customer load growth which was also not included, and these sales may provide additional margins to offset a portion of the debt service.

SUMMARY OF RESULTS

Based on the assumptions described in this section, MRES has projected the net income (loss) and cash reserves as shown in Exhibits 2-A and 2-B. Under current rates, the electric utility would have increasing net losses from 2016 through 2019. Meanwhile, cash reserves would decrease by nearly $1.1 million to $953,000 from 2015 to 2019. Reserves exclude $250,000 that is restricted for bond reserve covenants.



	2011	2012	2013	2014	2015	2016	2017	2018	2019
Current	$95	$6	($18)	$15	($90)	($94)	($111)	($125)	($140)



	2011	2012	2013	2014	2015	2016	2017	2018	2019
Cash	$2,145	$2,053	$1,970	$2,256	$2,048	$1,514	$1,321	$1,144	$953

Mountain Lake Public Utilities
Electric Utility Operating Results
(Current Rates: Implemented in January 2015)

	Historical: Annual Financial Report				Estimated				
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total System Retail kWh Sales	24,658,684	25,102,329	25,383,193	25,004,453	24,260,586	24,446,488	24,568,721	24,691,564	24,815,022
kWh % Change from Year to Year		1.8%	1.1%	-1.5%	-3.0%	0.8%	0.5%	0.5%	0.5%
OPERATING REVENUES									
Metered Electric Sales	$ 2,284,131	$ 2,259,784	$ 2,354,482	$ 2,423,693	$ 2,314,427	$ 2,362,329	$ 2,415,150	$ 2,478,605	$ 2,540,380
Other Operating Revenues	68,309	73,926	80,530	-	88,494	89,738	90,944	92,384	93,792
Total Operating Revenues	2,352,440	2,333,710	2,435,012	2,423,693	2,402,921	2,452,067	2,506,095	2,570,989	2,634,172
OPERATING EXPENSES									
Purchased Power & Transmission	1,194,736	1,214,469	1,382,638	1,343,630	1,449,987	1,496,298	1,542,702	1,599,708	1,654,995
Production	140,573	84,131	108,833	98,635	92,500	95,275	98,133	101,077	104,110
Distribution	270,784	258,048	284,677	263,763	297,350	306,211	315,397	324,859	334,605
Administrative & General	246,810	286,543	255,441	304,508	207,993	213,861	219,905	226,130	232,542
Depreciation Expense	264,322	285,330	282,149	285,008	288,275	303,258	309,258	314,258	319,258
Total Operating Expense	2,117,225	2,128,521	2,313,738	2,295,543	2,336,105	2,414,903	2,485,395	2,566,033	2,645,509
NET OPERATING INCOME	235,215	205,189	121,274	128,150	66,816	37,164	20,700	4,956	(11,338)
NON-OPERATING REVENUES (EXPENSES)									
Interest Income	27,531	13,210	(10,256)	2,641	11,281	8,988	6,320	5,357	4,472
Taxes and Special Assessments	1,375	13,611	497	-	-	-	-	-	-
Refunds and Reimbursements	-	-	30,203	32,406	7,000	3,000	3,000	3,000	3,000
CAPX Transmission Revenues	-	-	-	10,945	12,730	12,730	12,730	12,730	12,730
Interest Expense	(41,432)	(82,118)	(31,420)	(31,608)	(29,958)	(27,953)	(25,928)	(23,528)	(20,873)
Amortization Expense	(7,807)	(7,807)	(7,805)	(7,805)	(7,805)	(7,805)	(7,805)	(7,805)	(7,805)
Total Non-Operating Revenue (Expense)	(20,333)	(63,104)	(18,781)	6,579	(6,751)	(11,039)	(11,682)	(10,246)	(8,475)
TRANSFER TO THE GENERAL FUND	(120,000)	(136,360)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)
NET INCOME (LOSS)	$ 94,882	$ 5,725	$ (17,507)	$ 14,729	$ (59,935)	$ (93,876)	$ (110,983)	$ (125,289)	$ (139,813)
Net Income (Loss) as a % of Oper. Revenue	4.0%	0.2%	-0.7%	0.6%	-2.5%	-3.8%	-4.4%	-4.9%	-5.3%
Debt Service Coverage					107%	101%	95%	89%	83%

Mountain Lake Public Utilities
Electric Utility Cash Reserves
(Current Rates: Implemented in January 2015)

	Historical: Annual Financial Report				Estimated				
	2011	2012	2013	2014	2015	2016	2017	2018	2019
NET INCOME (LOSS)	$ 94,882	$ 5,725	$ (17,507)	$ 14,729	$ (59,935)	$ (93,876)	$ (110,983)	$ (125,289)	$ (139,813)
LESS: Revenue-Financed Capital Expenditures	(167,429)	(260,654)	(48,921)	(14,412)					
Upgrade 5 Engines to meet RICE Standards					-	(350,000)	-	-	-
Distribution System Improvements					-	(20,000)	(20,000)	(120,000)	(120,000)
Pole Line Replacement & Tree Trimming					-	(20,000)	(20,000)	(20,000)	(20,000)
Electric Meters					-	(10,000)	(10,000)	(10,000)	(10,000)
Digger Derrick					(90,000)	(90,000)	-	-	-
Meg. Generator Set, Engine 1 & 3					-	(5,000)	-	-	-
Engine Room Ceiling					-	(10,000)	(10,000)	-	-
Clean Fuel Tank					-	(10,000)	-	-	-
Underground Project					-	(15,000)	-	-	-
Relay Cleaning					-	(7,000)	-	-	-
Fence Lot					(8,000)	-	-	-	-
Vehicles					-	-	(120,000)	-	-
LESS: Bond Principal Payment 2012C	(193,750)	(823,750)	(213,750)	(218,750)	(55,000)	(55,000)	(55,000)	(60,000)	(60,000)
LESS: Bond Principal Payment 2009B		645,000	-		(35,000)	(30,000)	(35,000)	(35,000)	(40,000)
LESS: Bond Principal Payment 2007B		-			(128,750)	(128,750)	(128,750)	(128,750)	(128,750)
ADD: Depreciation Expense	264,322	285,330	282,149	285,008	288,275	303,258	309,258	314,258	319,258
ADD: Amortization Expense	7,807	7,807	7,805	-	7,805	7,805	7,805	7,805	7,805
ADD: Other Adjustments	-	48,450	(93,343)	219,903	(128,000)	-	-	-	-
ADDITION (REDUCTION) IN RESERVES	**$ 5,832**	**$ (92,092)**	**$ (83,567)**	**$ 286,478**	**$ (208,606)**	**$ (533,563)**	**$ (192,670)**	**$ (176,976)**	**$ (191,500)**
Beginning of Year Unrestricted Reserves		$ 2,145,408	$ 2,053,316	$ 1,969,749	$ 2,256,227	$ 2,047,621	$ 1,514,059	$ 1,321,389	$ 1,144,413
Addition (Reduction) in Reserves		(92,092)	(83,567)	286,478	(208,606)	(533,563)	(192,670)	(176,976)	(191,500)
End of Year Unrestricted Reserves	**$ 2,145,408**	**$ 2,053,316**	**$ 1,969,749**	**$ 2,256,227**	**$ 2,047,621**	**$ 1,514,059**	**$ 1,321,389**	**$ 1,144,413**	**$ 952,913**
Reserves as % of Operating Revenues	**91%**	**88%**	**81%**	**93%**	**85%**	**62%**	**53%**	**45%**	**36%**
Cash Balance									
Undesignated	2,145,408	2,053,316	1,969,749	2,256,227	2,047,621	1,514,059	1,321,389	1,144,413	952,913
Restricted for Bond Reserve	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000	250,000
Total Cash Reserves	$ 2,395,408	$ 2,303,316	$ 2,219,749	$ 2,506,227	$ 2,297,621	$ 1,764,059	$ 1,571,389	$ 1,394,413	$ 1,202,913

Mountain Lake Municipal Utilities

Historical and Projected Purchased Power and Local Generation Costs

	Historical					Projected			
Generation and Transmission Costs	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Member Dues	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000
CMPAS Scheduling Charge	$ 65,658	$ 70,292	$ 62,860	$ 53,267	$ 57,642	$ 60,322	$ 60,623	$ 60,926	$ 61,231
CMPAS Contract Administration	$ -	$ 8,276	$ 21,636	$ 21,636	$ 16,074	$ 10,512	$ 10,512	$ 10,512	$ 10,512
CMPAS Agency Fixed Fees	$ 10,800	$ 10,800	$ 10,800	$ 10,800	$ 10,800	$ 10,800	$ 10,800	$ 10,800	$ 10,800
NC2 - MWH Energy	$ 126,466	$ 130,056	$ 120,567	$ 96,844	$ 100,671	$ 116,263	$ 116,263	$ 124,567	$ 128,719
NC2 Debt Service	$ 43,789	$ 44,468	$ 47,770	$ 47,762	$ 47,349	$ 47,349	$ 47,349	$ 47,349	$ 47,349
NC2 Transmission	$ -	$ 3,425	$ 13,293	$ 15,385	$ 14,280	$ 15,363	$ 16,194	$ 17,024	$ 17,855
MISO Energy Purchases	$ 86,429	$ 63,436	$ 142,010	$ 108,499	$ 73,641	$ 118,997	$ 126,942	$ 135,165	$ 143,667
Xcel Energy 5x16 Contract	$ 80,580	$ 129,981	$ 125,155	$ 126,691	$ 137,284	$ 93,228	$ 93,228	$ 93,228	$ 93,228
Xcel Energy Time of Day Contract	$ 278,998	$ 219,058	$ 131,025	$ 115,765	$ 89,906	$ 112,750	$ 115,500	$ 118,250	$ 121,000
WPPI Energy	$ -	$ 57,585	$ 190,044	$ 182,609	$ 230,849	$ 208,050	$ 211,700	$ 215,350	$ 219,000
Wolf Wind Project	$ 38,635	$ 53,062	$ 44,425	$ 21,041	$ 18,642	$ 18,500	$ 18,500	$ 18,500	$ 18,500
Mountain Lake Wind Turbine	$ 176,679	$ 182,250	$ 179,616	$ 175,364	$ 177,444	$ 176,310	$ 176,310	$ 176,310	$ 176,310
WAPA Allocation	$ 176,187	$ 178,109	$ 178,569	$ 167,411	$ 183,853	$ 178,870	$ 178,870	$ 178,870	$ 178,870
ITC Midwest - Transmission	$ 337,121	$ 339,422	$ 396,907	$ 408,853	$ 436,844	$ 473,486	$ 504,411	$ 537,357	$ 572,455
FTR Credit - WAPA	$ 26,370	$ (5,342)	$ (15,263)	$ 9,477	$ (1,691)	$ (1,691)	$ (1,691)	$ (1,691)	$ (1,691)
WAPA Congestion & Losses	$ -	$ 969	$ 7,894	$ (9,590)	$ 3,843	$ 3,500	$ 3,500	$ 3,500	$ 3,500
PCA Correction per Mountain Lake	$ 4,400	$ -	$ -	$ 22,899	$ -	$ -	$ -	$ -	$ -
Total Purchased Power Costs	**$ 1,482,112**	**$ 1,515,847**	**$ 1,687,310**	**$ 1,604,714**	**$ 1,627,431**	**$ 1,672,609**	**$ 1,719,012**	**$ 1,776,018**	**$ 1,831,305**
Mountain Lake Power Plant Fuel	$ 19,516	$ 8,721	$ 15,520	$ 31,192	$ 9,049	$ 11,250	$ 12,750	$ 14,250	$ 15,750
Power Plant O&M Costs	$ 13,012	$ 10,383	$ 16,483	$ 22,299	$ 27,663	$ 28,492	$ 29,347	$ 30,228	$ 31,135
Total Power Plant Costs	**$ 32,528**	**$ 19,104**	**$ 32,002**	**$ 53,491**	**$ 36,712**	**$ 39,742**	**$ 42,097**	**$ 44,478**	**$ 46,885**
Total Costs - Energy Charge Calc	**$ 1,514,640**	**$ 1,534,951**	**$ 1,719,312**	**$ 1,658,205**	**$ 1,664,143**	**$ 1,712,351**	**$ 1,761,109**	**$ 1,820,496**	**$ 1,878,189**
Percentage Change		1.3%	12.0%	-3.6%	0.4%	2.9%	2.8%	3.4%	3.2%
Energy Purchased / Generated - kWh									
NC2	3,807,700	4,195,400	4,115,000	4,528,000	4,100,300	4,152,240	4,152,240	4,152,240	4,152,240
MISO	1,141,601	1,231,854	4,085,876	3,808,373	3,247,567	3,966,573	4,094,917	4,223,903	4,353,533
Xcel Energy 5x16 Contract	1,888,800	2,040,000	2,032,000	2,040,000	2,048,000	2,040,000	2,040,000	2,040,000	2,040,000
Xcel Energy Time of Day	9,871,800	8,011,400	2,952,700	2,889,500	2,762,900	2,750,000	2,750,000	2,750,000	2,750,000
WPPI Energy	-	1,184,200	3,551,700	3,655,500	4,135,400	3,650,000	3,650,000	3,650,000	3,650,000
Wolf Wind Project	-	-	-	-	-	-	-	-	-
Mountain Lake Wind Turbine	3,464,284	3,573,531	3,529,015	3,247,488	3,285,999	3,265,000	3,265,000	3,265,000	3,265,000
WAPA Allocation	5,778,601	5,708,928	5,747,000	5,583,000	5,763,500	5,770,000	5,770,000	5,770,000	5,770,000
Mountain Lake Power Plant	73,000	87,500	69,800	133,700	71,000	75,000	75,000	75,000	75,000
Total Energy Purchased/Generated	**26,025,786**	**26,032,813**	**26,083,091**	**26,309,624**	**25,414,666**	**25,668,813**	**25,797,157**	**25,926,143**	**26,055,773**
Percentage Change		0.0%	0.2%	0.9%	-3.4%	1.0%	0.5%	0.5%	0.5%
Less: Transmission Loss Adj. (95.3%)	(1,223,212)	(1,223,542)	(1,225,905)	(1,236,552)	(1,194,489)	(1,206,434)	(1,212,466)	(1,218,529)	(1,224,621)
Total Sales for PCA Calculation	**24,802,574**	**24,809,271**	**24,857,186**	**25,073,072**	**24,220,177**	**24,462,378**	**24,584,690**	**24,707,614**	**24,831,152**
Costs - Cents / kWh (includes congestion/losses)									
NC2	4.47	4.24	4.41	3.53	3.96	4.31	4.33	4.55	4.67
MISO	7.57	5.15	3.48	2.85	2.27	3.00	3.10	3.20	3.30
NSP 5 X 16	4.27	6.37	6.16	6.21	6.70	4.57	4.57	4.57	4.57
NSP Time of Day	2.83	2.73	4.44	4.01	3.25	4.10	4.20	4.30	4.40
WPPI	n/a	4.86	5.35	5.00	5.58	5.70	5.80	5.90	6.00
Mountain Lake Wind	5.10	5.10	5.09	5.40	5.40	5.40	5.40	5.40	5.40
WAPA	3.05	3.12	3.11	3.00	3.19	3.10	3.10	3.10	3.10
Transmission	1.30	1.31	1.53	1.56	1.72	1.85	1.96	2.08	2.20
Local Generation - Fuel only	44.56	21.83	22.23	23.33	12.75	15.00	17.00	19.00	21.00
Power Cost Adjustment Calculation									
Purchased & Local Power Avg. Costs	5.820	5.90	6.59	6.30	6.55	6.67	6.83	7.02	7.21
Cost plus Trans. Loss Adj. (95.3%)	**6.107**	**6.19**	**6.92**	**6.61**	**6.87**	**7.00**	**7.16**	**7.37**	**7.56**
Less: PCA Base Cost	3.160	3.16	3.16	3.16	3.16	3.16	3.16	3.16	3.16
Annual Average Power Cost Adjustment	**2.947**	**3.03**	**3.76**	**3.45**	**3.71**	**3.84**	**4.00**	**4.21**	**4.40**
Proposed Power Cost Adjustment Calculation									
Total Power Supply & Local Power Costs						$ 1,712,351	$ 1,761,109	$ 1,820,496	$ 1,878,189
Projected Retail kWh Sales						24,446,488	24,568,721	24,691,564	24,815,022
Cost per Retail kWh						7.00	7.17	7.37	7.57
Proposed PCA Base Cost						6.50	6.50	6.50	6.50
Annual Average Power Cost Adjustment						**0.50**	**0.67**	**0.87**	**1.07**

SECTION 3 – COST-OF-SERVICE STUDY

The purpose of this study is to determine the cost of providing service to each customer class so that these costs can be compared to actual customer revenues. The cost-of-service analysis has been based on the following factors:

- Test Year revenue requirements and revenues using current rates
- Total system and customer class demand and energy requirements
- Actual and assumed customer service characteristics
- Information obtained from customer records

Test Year revenue requirements were mostly based on projected 2016 expenses. These revenue requirements are classified to cost components and allocated to each customer class based upon service characteristics. These allocated costs are then compared to revenues to determine if current rates recover the appropriate level of revenues from each customer class.

CLASSIFICATION OF COSTS

To allocate costs to customer classifications, costs must first be categorized to components. The seven cost components and the types of costs assigned to each are as follows:

Generation and Transmission 12-Month Coincident Peak Demand Component – The costs of purchasing sufficient power to meet the aggregate demand of all the customers at the time of the 12 monthly system peaks. Coincident peak demand costs do not generally vary with the level of energy used. These costs include capacity-related purchased power and transmission costs along with all of the production expenses with the exception of fuel. These costs also include a portion of distribution, revenue-financed capital expenditures, and reserves for replacements along with 10% of the 2007B bond series payment. The transmission revenues for the CAPX transmission investment and for the municipally-owned transmission line off-set the transmission cost requirements.

Energy Component – The costs of supplying electricity to meet customer requirements. These costs will vary directly with the usage of electricity. This includes only the energy-related portion of purchased power costs and the fuel costs for the municipally-owned diesel power plant. The costs also include 90% of the 2007B bond series payment for the local wind tower and a portion of the revenue-financed capital expenditures and reserves for replacements.

Distribution System 12-Month Coincident Peak Demand Component – The costs of operating and maintaining an electric system that with meet the individual peak demands of each customer class during the system peaks. These costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements. The costs also include 50% of the conservation improvement program expenses and revenues (off-set), the 2012C bond series payment, and the transfer to the City of Mountain Lake. The entire 2009B bond series payment is also included in these costs.

Customer Facilities Component – The costs of providing and maintaining transformers, distribution secondary lines, and customer service drops. Customer facilities costs vary directly with the maximum demand of the customer and the type of facilities the customer requires. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements. The costs also include 50% of the conservation improvement program expenses and revenues (off-set), the 2012C bond series payment, and the transfer to the City of Mountain Lake. The contribution for customer facilities off-sets the revenue requirements.

Customer Service Component – The costs associated with billing, collections, and customer assistance. Customer service costs do not vary greatly with peak demand or energy usage of the customer. The costs include a portion of administrative and general.

Metering Component – The costs of reading meters to determine monthly bills and providing and maintaining customer meters. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements.

Street Lights Component – The costs of operating and maintaining street lighting services. The costs include a portion of distribution, administrative and general, revenue-financed capital expenditures, and reserves for replacements.

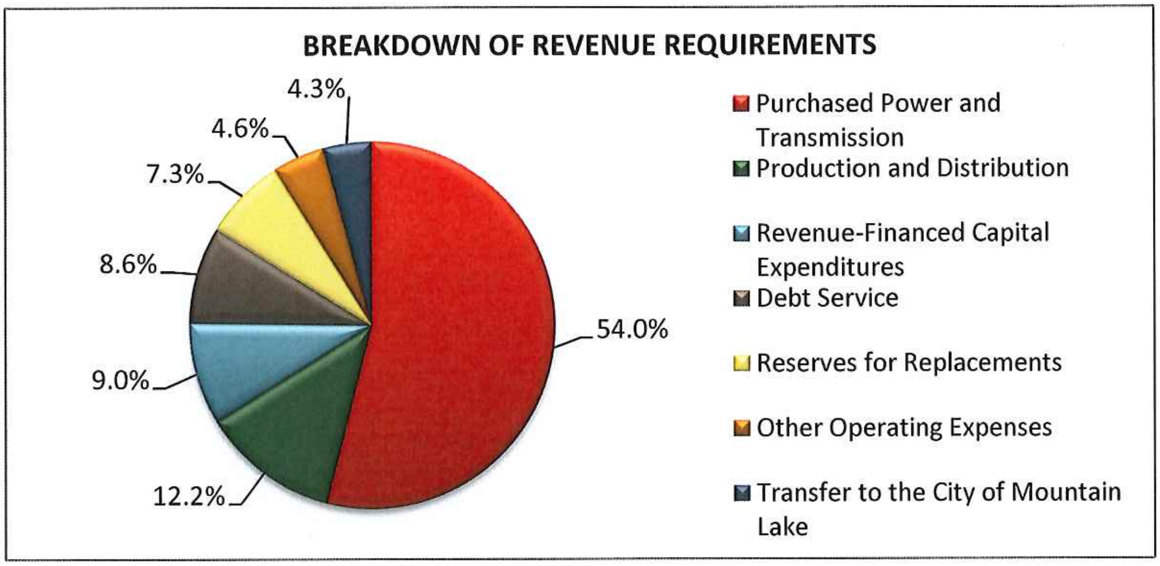
Indirect Revenues and Expenses

Certain revenues and expenses are not categorized to the seven components above but rather are allocated to these components based on percentage of direct labor spent on each area to the total cost of labor. Allocated in this manner are items such as portion of administrative and general expenses, revenue-financed capital expenditures, and reserves for replacements. Other operating expenses and investment income reduce the revenue requirements and are also allocated based on direct labor.

Summary of the Revenue Requirements Classifications

Exhibit 3-A at the end of this section shows the detailed classifications of the test year revenue requirements. A breakdown of the revenue requirements is also shown in the chart on the following page. The projected revenue requirements breakdown shows that

54% of the retail rates recover purchased power and transmission costs, which are not directly controlled at the local level with the exception of the local generation costs. Debt service is 8.6% and the transfer to the City of Mountain Lake equals 4.3% of the total costs. The other 33.1% of the total revenues are available to fund local electric utility production, distribution, and other operating costs, revenue-financed capital expenditures and rebuild reserves throughout the study period.



ALLOCATION TO CUSTOMER CLASSIFICATIONS

MRES has determined allocation factors for the Test Year based on actual and assumed customer service characteristics. These allocation factors represent historically accepted ratemaking principles and are based on fully distributed, embedded cost allocation procedures. While these principles may still be useful in establishing a baseline cost level upon which to set rates, it is important to note that in a competitive market, some of the allocated costs may not be recovered.

The following summarizes the allocation factors used in the cost-of-service study. See Exhibit 3-B at the end of this section for the development of the factors.

Coincident Peak Demand Allocations

The 12-month coincident peak demand is the estimated class demand at the time of each monthly system peak. This factor is used to allocate the monthly wholesale demand and transmission costs and demand-related distribution costs.

Monthly billing demands for the Large Commercial and Rural Large Commercial classes were used to estimate the demand allocators for this class. The Rural Large Commercial class includes five demand metered customers that have a monthly peak demand greater than 20 kW and are currently in the Rural class. For the other classes, demand allocators were based on the system characteristics of Mountain Lake in relation to the specific classes of service. The City Facilities class includes not only the city facilities but also the water and sewer utilities' meters.

Energy Allocations

Purchased and locally produced energy costs have been allocated based on the annual sales by customer class.

The following three allocations utilize weighted percentages that were developed by analyzing the number of customers in each class and the resources used to serve each class. The weighting factors were based on the experience of other utilities and Mountain Lake staff observations.

Customer Facilities Allocations

Customer facilities allocations are based on the complexity and size of the transformers, distribution secondary lines, and service lines used to serve the various customer classes.

Customer Service Allocations

Customer service allocations are based on the amount of labor and materials for customer billing and collection.

Metering Allocations

Metering allocations are based on the time spent reading and maintaining the meters of the various customer classes. These costs vary between classes that have and do not have a demand meter installed. The costs also vary between in-town customers and rural customers.

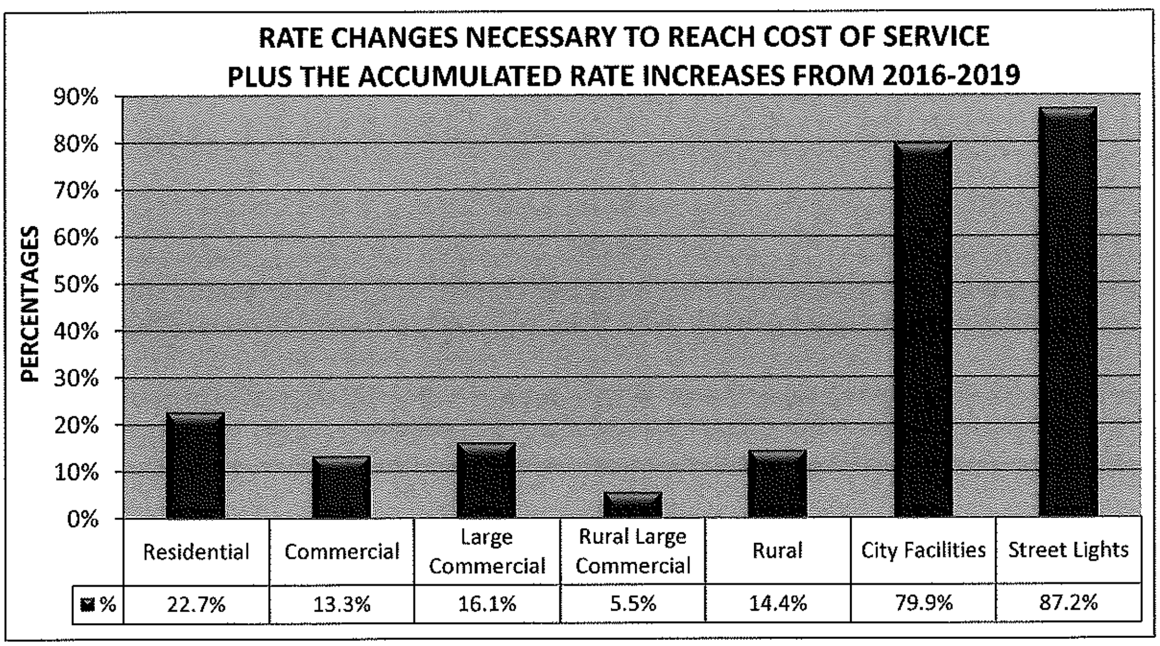
Based upon the cost classifications and allocation methods described above, MRES has estimated the cost to serve each customer class during the Test Year. A summary of the results is shown on the following page, and the detailed results are shown on Exhibit 3-C at the end of this section.

SUMMARY OF RESULTS

The cost-of-service study indicated that Residential customers should see a larger increase than the Commercial and Large Commercial customers. The Rural Large Commercial class should also see a much lower increase than all of the other classes. Lastly, the study also indicated that the City of Mountain Lake should pay higher rates to cover all the costs of providing service to city facilities, including the water and sewer utilities, and street lights.

The percentages in the far right column below indicate the changes that would be necessary in each class to set rates in line with the costs of service along with the proposed overall increases totaling a cumulative 19% over four years. In addition to the cost of service results, other factors are also considered when determining proposed rate plan.

Cost of Service Results by Class				
Customer Classification	**Cost per kWh**	**Revenue per kWh**	**Cost Less Revenue**	**Cost of Service Results Including Overall Rate Increases**
Residential	$0.130	$0.106	$0.024	**22.7%**
Commercial	$0.126	$0.111	$0.015	**13.3%**
Large Commercial	$0.100	$0.086	$0.014	**16.1%**
Rural Large Commercial	$0.120	$0.114	$0.006	**5.5%**
Rural	$0.133	$0.116	$0.017	**14.4%**
City Facilities	$0.127	$0.070	$0.057	**79.9%**
Street Lights	$0.132	$0.070	$0.062	**87.2%**
Total	**$0.115**	**$0.096**	**$0.019**	**19.0%**



Mountain Lake Municipal Utilities
Classification of Test Year Requirements

Exhibit 3-A

Revenue Requirements	Total	Generation/ Transmission 12 CP Demand	Energy	Distribution System 12 CP Demand	Customer Facilities (CF)	Customer Service (CS)	Metering (MR)	Street Lighting (SL)	Basis for Classification
Purchased Power & Transmission									
Nebraska City 2 Purchases	$ 178,975	89,487	89,487						50% 12CP, 50% Energy
MISO Market Purchases	118,997	-	118,997						100% Energy
Excel Energy: 5 X 16 Contract	93,228	37,291	55,937						40% 12CP, 60% Energy
Excel Energy: Time of Day Contract	112,750	22,550	90,200						20% 12CP, 80% Energy
WPPI Purchases	208,050	104,025	104,025						50% 12CP, 50% Energy
WPPI Capacity Sold (B)	(7,125)	(7,125)							100% 12CP
Wolf Wind	18,500		18,500						100% Energy
WAPA Allocation	178,870	71,548	107,322						40% 12CP, 60% Energy
ITC Midwest Transmission	475,295	475,295							100% 12CP
CMPAS Agency and Scheduling Fees	111,634		111,634						100% Energy
Mountain Lake Wind Tower Maintenance	58,700	5,870	52,830						100% Energy
Land Rent for Wind Turbine	4,000	400	3,600						100% Energy
Moutain Lake Transmission Line Revenue (B)	(25,500)	(25,500)							100% 12CP
CAPX Transmission Investment Revenue (B)	(12,730)	(12,730)							100% 12CP
Operating Expenses (A)									
Production									
Supplies, repairs, maintenance	79,820	79,820							100% 12CP
Fuel Oil/Diesel	14,420		14,420						100% Energy
Distribution									
Salaries and Employee Benefits	157,840	26,887		57,410	57,410		12,099	4,033	Per distribution labor requirements
Plant Breaker Testing	6,180	6,180							100% 12CP
Meetings, Meals and Travel	200			100	100				50% CP, 50% CF
Telephone	515			258	258				50% CP, 50% CF
Street Lighting and Signal	3,605							3,605	100% SL
Repairs and Maintenance: Misc	41,200			18,100	18,100			5,000	Per repair and maintenance expense requirements
Repair and Maintenance: Meters	15,450						15,450		100% MR
Tree Replacement	5,150			2,575	2,575				50% 12CP, 50% CF
Miscellaneous	16,480			8,240	8,240				50% 12CP, 50% CF
Wells and Lift Station Power	2,060			1,030	1,030				50% 12CP, 50% CF
Conservation Improv. Program									
CIP Program Expenses	42,905			21,453	21,453				50% 12CP, 50% CF
CIP 1.5% Surcharge Revenues	(50,440)			(25,220)	(25,220)				50% 12CP, 50% CF
Administrative and General									
A&G Salaries and Benefits	62,925	1,611		3,440	3,440	53,467	725	242	Direct and indirect rev. and exp. allocation factors (D)
Other Employee Benefits	11,780	1,508		3,220	3,220	2,927	679	226	Indirect revenue and expense allocation factors (C)
Utility Commission Salaries	1,300	166		355	355	323	75	25	Indirect revenue and expense allocation factors (C)
Motor Fuels	3,605			1,053	1,053		1,000	500	Per fuels expense requirement
Postage	5,150					5,150			100% CS
Professional Services	10,300	1,319		2,815	2,815	2,559	593	198	Indirect revenue and expense allocation factors (C)
General Liability Insurance	23,690	3,033		6,476	6,476	5,886	1,365	455	Indirect revenue and expense allocation factors (C)
Capital Improvement: Other Projects	24,720			12,360	12,360				50% 12 CP, 50% CF
Capital Outlay: Equipment	10,300			5,150	5,150				50% 12 CP, 50% CF
Office and Computer Supplies, Utilities	13,210	1,691		3,611	3,611	3,282	761	254	Indirect revenue and expense allocation factors (C)

Exhibit 3-A

Mountain Lake Municipal Utilities
Classification of Test Year Requirements

Revenue Requirements	Total	Generation/ Transmission 12 CP Demand	Energy	Distribution System 12 CP Demand	Customer Facilities (CF)	Customer Service (CS)	Metering (MR)	Street Lighting (SL)	Basis for Classification
Revenue-Financed Capital Expenditures									
Local Generation	137,792	59,106	78,686						37% 12 CP, 63% Energy
Distribution - Demand-Related Facilities	50,362			50,362					100% 12 CP
Distribution - Customer Facilities	52,657				52,657				100% CF
Meter Reading	910						910		100% MR
Street Lighting	12,099							12,099	100% SL
Administrative & General	402	52		110	110	100	23	8	Indirect revenue and expense allocation factors (C)
Contributions for Customer Facilities (B)	(3,000)				(3,000)				100% CF
Other Operating Revenues (B)	(17,350)	(2,221)		(4,743)	(4,743)	(4,311)	(999)	(333)	Indirect revenue and expense allocation factors (C)
Investment Income (B)	(8,900)	(1,139)		(2,433)	(2,433)	(2,211)	(513)	(171)	Indirect revenue and expense allocation factors (C)
2012C Bond Series Payment: Distribution	64,900			32,450	32,450				50% 12 CP, 50% CF
2009B Bond Series Payment: Feeder	48,000			48,000					100% 12 CP
2007B Bond Series Payment: Wind Tower	128,750	12,875	115,875						10% 12 CP, 90% Energy
Transfer to the City of Mountain Lake	120,000			60,000	60,000				50% 12 CP, 50% CF
Contributions to Reserves for Replacements	205,000	40,642	70,500	40,694	42,549	81	774	9,761	Per depreciation schedule
Revenue Requirements	$ 2,807,630	$ 992,640	$ 1,032,013	$ 346,866	$ 300,016	$ 67,254	$ 32,941	$ 35,901	

(A) Expenses are adjusted to level of typical year.
(B) These amounts offset revenue requirements.
(C) Indirect revenue and expenses are allocated based on breakdown of direct labor expenses.
(D) A portion of this expense was classified directly to one of the above allocators. The remaining portion was allocated based on the indirect expense allocation factors described in (C).

Exhibit 3-B

Mountain Lake Municipal Utilities
Allocation Factors

Allocation Factors	Total	Residential	Commercial/ City Facilities	Large Commercial	Rural Large Commercial	Rural	Street Lighting
Demand Allocation Factors							
12-Month Coincident Peak (kW)	47,291	16,062	9,174	19,171	1,933	813	139
Percentage - CP	100%	34.0%	19.4%	40.5%	4.1%	1.7%	0.3%
Energy Allocation Factors							
Annual Energy Requirements (kWh)	24,446,488	7,269,774	4,085,086	11,355,053	867,428	361,846	507,301
Percentage - E	100%	29.7%	16.7%	46.4%	3.5%	1.5%	2.1%
Customer Facilities Allocation Factors							
Average number of customers	1,480	821	183	11	5	34	426
Weighting factor		1.0	2.7	75.0	18.0	1.4	0.1
Weighted number of customers	2,320	821	494	825	90	48	43
Percentage - CF	100%	35.4%	21.3%	35.6%	3.9%	2.1%	1.8%
Customer Service Allocation Factors							
Average number of customers	1,055	821	183	11	5	34	1
Weighting factor		1.0	1.0	2.0	2.0	1.0	1.0
Weighted number of customers	1,071	821	183	22	10	34	1
Percentage - CS	100%	76.7%	17.1%	2.1%	0.9%	3.2%	0.1%
Metering Service Allocation Factors							
Average number of customers	1,055	821	183	11	5	34	1
Weighting factor		1.0	1.0	2.0	2.0	1.5	1.0
Weighted number of customers	1,088	821	183	22	10	51	1
Percentage - MR	100%	75.5%	16.8%	2.0%	0.9%	4.7%	0.1%

Exhibit 3-C

Mountain Lake Municipal Utilities
Allocation of Revenue Requirements

Classification	Total	Residential	Commercial	Large Commercial	Rural Large Commercial	Rural	City Facilities	Street Lighting
Generation & Transmission 12 CP Demand	$ 992,640	$ 337,144	175,888	$ 402,393	$ 40,573	$ 17,056	16,668	$ 2,917
Energy	1,032,013	306,895	157,525	479,356	36,619	15,275	14,928	21,416
Distribution 12 CP Demand	346,866	117,811	61,462	140,611	14,178	5,960	5,824	1,019
Customer Facilities	300,016	106,156	58,114	106,673	11,637	6,155	5,773	5,508
Customer Service	67,254	51,555	10,424	1,381	628	2,135	1,068	63
Metering	32,941	24,857	5,026	666	303	1,544	515	30
Street Lighting (Direct Allocation)	35,901	-	-	-	-	-	-	35,901
Revenue Requirements	**$ 2,807,630**	**$ 944,417**	**$ 468,440**	**$ 1,131,081**	**$ 103,937**	**$ 48,125**	**$ 44,775**	**$ 66,855**
Class Revenues	$ 2,358,395	$ 769,974	$ 413,454	$ 973,811	$ 98,491	$ 42,057	$ 24,894	$ 35,714
Difference (Rev. Req. Less Revenues)	$ 449,235	$ 174,443	$ 54,986	$ 157,270	$ 5,446	$ 6,069	$ 19,881	$ 31,141
Cost of Service Adjustment Percentage	**19.0%**	**22.7%**	**13.3%**	**16.1%**	**5.5%**	**14.4%**	**79.9%**	**87.2%**

SECTION 4 – PROPOSED RATES

Several factors were considered in determining the proposed rates:

- Current rates
- Projected net income and cash reserves (Section 2)
- Costs to serve each customer class (Section 3)
- Rate comparisons (Section 5)
- Mountain Lake policies and objectives

Mountain Lake Municipal Utilities has not had a rate study and cost of service analysis completed for several years. During this time, power supply and transmission costs and contracts have changed, including Mountain Lake building a wind turbine to supply a portion of its energy needs. The combination of fixed and variable operating costs of the utility have also likely changed over time. In addition to the changing costs, Mountain Lake's customers, their service requirements, and how they use electricity have probably changed over the years. Most certainly, the electric industry as a whole is quickly changing with new federal and state regulations being imposed on utilities and generation plants, distributed generation resources, such as solar panels, being installed by customers, the creation of energy markets and regional transmission organizations along with several other dynamics.

The proposed rate design recommended from 2016 through 2019 should better prepare Mountain Lake to better recover its costs in a more equitable way from its customers while maintaining financial health of the utility and adequate reserves.

RATE DESIGN

Rate increases will be necessary to adequately fund planned revenue-financed capital expenditures and to meet debt service obligations while rebuilding cash reserves back to the current level of nearly $2 million by 2019. Reserves are projected to decrease in 2016 primarily due to paying for the upgrades to the power plant in order to be compliant with EPA regulations. Rate increases will also be necessary to recover increasing operating expenses. Along with the rate increases, the power cost adjustment base will be increased resulting in lower adjustments on customer bills.

Based on the analysis outlined in this report, the rate study recommends a 4.0% overall increase in April 2016 and 4.5% overall increases in January 2017, 2018, and 2019. The proposed rates are discussed next, and the 2016 rates are shown on page 4-5. The recommended rates for all four years are shown in the Appendix. Further adjustments may be necessary during the study period if operating costs, retail energy sales, or the financial needs of the utility change drastically.

Proposed Electric Rate Recommendations

1. Increase the monthly customer charges for Residential, Commercial and Rural customers, and add a customer charge for the Large Commercial and City Facilities and Street Lighting classes. The customer charge, which does not include any kWh usage, recovers the costs of serving customers in areas such as meter installation and maintenance and customer billing, along with a portion of facilities costs.

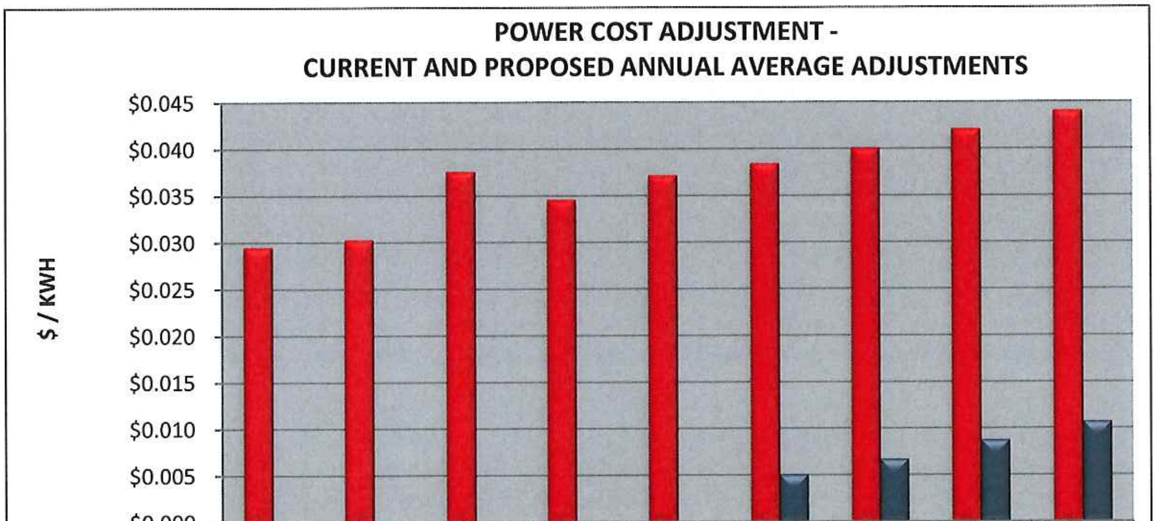
   Higher customer charges also help to prepare the utility for the possibility of customers adding distributed energy resources in the future. Many utilities have been steadily increasing their customer charges in recent years. Based on a review of residential customer charges for approximately 100 area municipal utilities, the average charge is around $11 per month in 2015, and the average is expected to steadily increase in the future.

2. Increase the PCA base factor from $0.0316 per kWh to $0.0650 per kWh and modify the calculation to determine the monthly PCA. The PCA allows the utility to recover varying purchased power supply, transmission, and local generation costs from its customers between formal rate adjustments. The result of these recommendations would be lower adjustments, on average, on customer bills. The revenue lost by increasing the PCA base factor would be recovered in the 2016 proposed retail energy and demand rates. The recommended calculation to determine the monthly PCA is as follows:

   - Purchased Power Costs + Local Production Costs = Total Power Costs
   - Total Power Costs / Total Retail kWh Sales = Power Costs per kWh Sold
   - Power Costs per kWh Sold less 6.5 cent PCA base = Adjustment for the next customer billing month

   MRES has provided Mountain Lake an Excel spreadsheet based on the recommended method to calculate the monthly PCA under proposed rates. MRES also recommends that if the calculation would indicate a negative PCA for the month, the credit should be passed along to the customers. The historical and projected annual average PCA's under current and proposed rates are shown in the graph on the next page. In addition to the recommended overall revenue increases for the study period, customers' bills are also projected to increase between 1.4% and 2.1% annually due to the projected PCA increasing over time. These increases would occur under both current and proposed rates. If the power supply cost projections in Section 2 vary from the assumptions, the projected PCA could be lower or higher than shown in the graph.

Proposed Electric Rate Recommendations (Continued)



	2011	2012	2013	2014	2015	2016	2017	2018	2019
Current Rates	0.0295	0.0303	0.0376	0.0345	0.0371	0.0384	0.0400	0.0421	0.0440
Proposed Rates						0.0050	0.0067	0.0087	0.0107

3. Replace the inverted energy rate structure with a single energy rate for the Residential, Rural, and Commercial classes and increase the energy rate. While an inverted block rate structure provides a conservation price signal to the customers, the current price difference of $0.005 per kWh between the first and second blocks is minimal and likely not impacting customer behavior. Most of the increase in the energy rate is due to increasing the PCA base.

4. Rename the Industrial class to the Large Commercial class and implement the qualifications as any non-residential customer with a peak demand of 20 kW or more in three or more months out of the previous 12 months. The customers that qualify for the Large Commercial class would remain in the class for a minimum of 12 months. The study estimates that 11 Industrial customers would continue to remain in the class. The study has also determined that 13 Commercial customers and five Rural customers who operate a commercial business would move to the Large Commercial class at this time.

   The other rate changes for the Large Commercial class include eliminating the minimum demand bill of $369 that included the first 60 kW each month. All demand over 60 kW is currently billed at $4.65 per kW. The proposed demand rate would be applied to all metered demand for the month. For instance, if a customer had a peak demand of 75 kW, under current rates, they would be billed $369 for the first 60 kW and $4.65 per kW for the remaining 15 kW. Under the 2016 proposed demand rate, all 75 kW would be billed at $7.00 per kW. In conjunction with the demand rate changes, increase the energy rate. While the base energy rate is proposed to be increased, the effective rate, which includes the power cost adjustment, is proposed to slightly decrease as shown in the table on page 4-5.

The cost of service study indicated that the demand rate should be over $24 per kW and the energy rate about $0.042 per kWh. The proposed rate plan will begin to shift the rates in the direction indicated by the cost-of-service analysis; however, it may take several years to accomplish this.

5. Increase the energy rate for the City Facilities and Street Lighting class. The city facilities, including the water and wastewater treatment plants, are currently paying a significantly discounted energy rate compared to the Commercial and Large Commercial classes. Gradually, the city facilities should be placed in one of the commercial classes based on their monthly peak demand. Most area utilities have eliminated discounts for city and other utility department usage so that all customers pay the same rate for similar usage characteristics.

   Street lighting usage will continue to be billed in the City Facilities class. The City of Mountain Lake plans to pay for the replacement of the high pressure sodium lamps with light emitting diode (LED) lamps over the next five years or so to reduce energy consumption and provide better night lighting to the community. The utility will continue to maintain and provide power to the lights.

6. Maintain the Conservation Improvement Plan surcharge of 1.5% of the total bill to provide funding for energy efficiency and other conservation programs offered by Mountain Lake.

7. Obtain demand readings for Commercial and Rural customers exceeding 4,000 kWh per month. The demand readings are already available for many of these customers, but not all of them. This information would be useful in evaluating potential future rate changes and to determine if other Commercial customers would qualify for the Large Commercial class.

8. Eliminate the Conservation Break discount of $1 or $2 per month as this is no longer applicable to most customers.

9. Define the qualifications for each rate class, terms of service, and the rates on Mountain Lake's approved rate schedule that is publicly available. Other items that should be included are the power cost adjustment provision, late payment fees, and terms and conditions. The current schedule already has some of the fees listed, but does not provide other necessary detail. MRES has provided staff with a rate schedule example that may be modified to best fit your needs.

Current and 2016 Proposed Rates						
Customer Class	**Rate Components**	**Current Rates**	**Current Rates with PCA**	**2016 Proposed Rates**	**Proposed Rates with PCA**	**2016 % Change**
Overall Revenue Increase						**4.0%**
2016 Power Cost Adjustment	Adjustment Base Factor Average Monthly Adjustment	$0.0316 0.0384		$0.0650 0.0050		
Residential	Customer Charge Energy Charge – per kWh 0-900 kWh Over 900 kWh	5.00 0.0600 0.0650	 $0.0984 0.1034	7.00 0.0990	 $0.1040	 7.2%
Rural	Customer Charge Energy Charge – per kWh All kWh 0-1,000 kWh Over 1,000 kWh	6.50 0.0700 0.0750	 0.1084 0.1134	9.00 0.1060	 0.1110	 -8.0% (A)
Commercial	Customer Charge Energy Charge – per kWh All kWh 0-1,200 kWh Over 1,200 kWh	8.50 0.0675 0.0700	 0.1059 0.1084	12.00 0.1040	 0.1090	 0.2% (B)
Large Commercial (Over 20 kW)	Customer Charge Demand Charge – per kW All kW First 60 kW Over 60 kW Energy Charge – per kWh	- 369.00 4.65 0.0350	 0.0734	40.00 7.00 0.0680	 0.0730	 4.6%
City Facilities & Street Lighting	Customer Charge Energy Charge – per kWh	- 0.0320	 0.0704	12.00 0.0680	 0.0730	8.2%
Conservation Improvement Plan	Surcharge - % of Electric Bill	1.5%		1.5%		
Conservation Break Credit	150 kWh or Less per Month 151-200 kWh per Month	$2.00 $1.00		Eliminate		

(A) Customers remaining in the Rural class will have an average increase of 4.3%, while customers moving to the Large Commercial class will have an average decrease of 13.3%.

(B) Customers remaining in the Commercial class will have an average increase of 5.2%, while customers moving to the Large Commercial class will have an average decrease of 7.2%.

RETAIL RATE RECOMMENDATION RESULTS

As a result of the proposed 2016 rates, a typical Residential customer using 700 kWh per month would see an increase of $6.04 per month, or 8.1%. Meanwhile, a Residential heating customer using 1,600 kWh would see an increase of $7.65 per month, or 4.5%. Rural residential customers would see their bill increase by an average of 4.3%, and the Rural customers moving to the Large Commercial class would see an average decrease of 13.3%.

Commercial customers would see an increase between 2.6% and 7.5%. Meanwhile, Commercial customers moving to the Large Commercial class would see an average decrease of 7.2%. Finally, Large Commercial customers would see a wide range of impacts between a decrease of up to 10% to an increase of up to 17%. The impact primarily depends on if the customer paid the minimum bill of $369 per month under current rates and also their monthly load factor.

City facilities and Street Lighting would see an average increase of 8.2% in 2016 mostly due to adding the customer charge.

CUSTOMER BILLS AND AVERAGE REVENUE PER KWH GRAPHS

Exhibits 4-B through 4-H at the end of this section contain graphs of customer bills for the Residential, Rural, and Commercial classes, and average revenue per kWh for the Rural and Commercial customers moving to the Large Commercial class and for the Large Commercial class. The averages on Exhibits 4-D and 4-F can be used to calculate the bills under current and proposed rates of the Rural and Commercial customers, respectively, moving to the Large Commercial class by knowing the load factor of these customers. The average revenue per kWh on 4-G and 4-H can also be used to calculate the Large Commercial bills. The rates per kWh for Exhibits 4-G and 4-H are calculated using the monthly consumption of 15,000 kWh per month and 50,000 kWh per month, respectively, and load factors ranging from 15% to 75%.

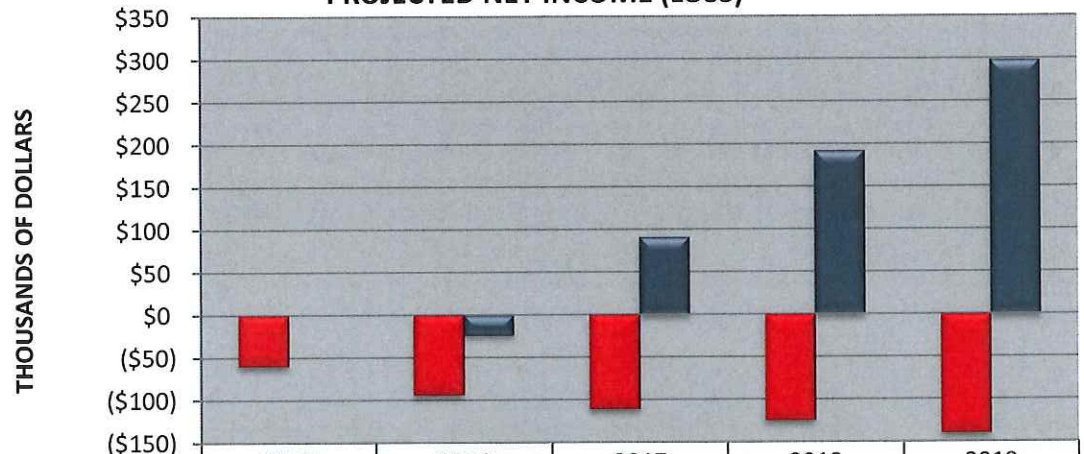
All of these graphs are calculated under current and 2016 proposed rates. Under current rates, the tables include an average PCA of $0.0384 per kWh, and under proposed rates, the tables include an average PCA of $0.0050 per kWh.

HISTORICAL AND PROJECTED OPERATING RESULTS

Based on the assumptions described in Section 2, MRES has projected the net income and cash reserves as shown on the graphs on the following page and in Exhibit 4-A. Depending on any changes to the key assumptions, other rate adjustments may be necessary. Under the proposed four year rate plan, net income is projected to increase each year throughout the study period to about $298,000 by 2019.

HISTORICAL AND PROJECTED OPERATING RESULTS (continued)

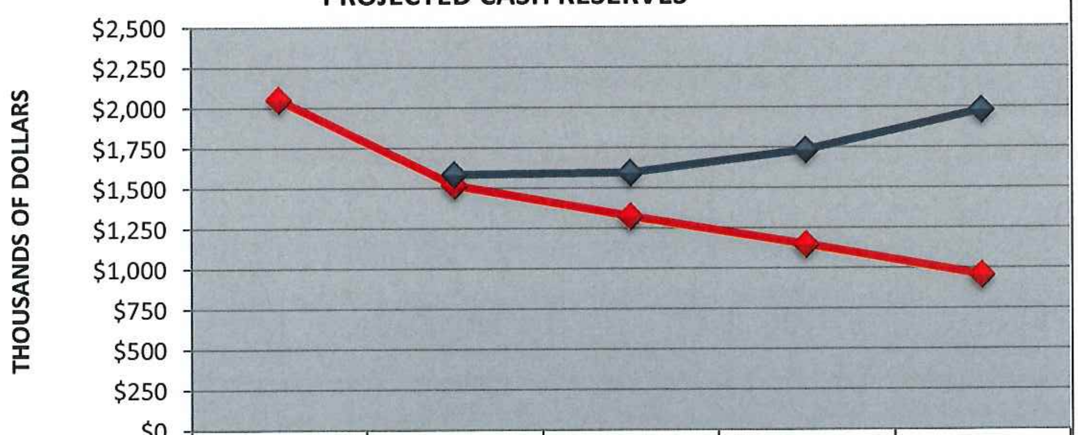
PROJECTED NET INCOME (LOSS)



	2015	2016	2017	2018	2019
Current Rates	($60)	($94)	($111)	($125)	($140)
Proposed Rates		$(24)	$91	$192	$298

The next graph shows projected cash reserves under current and proposed rates. Reserves are projected to decrease in 2016 primarily due to the diesel engine upgrades to meet the RICE standards. Under proposed rates cash would gradually rebuild throughout the study period to approximately $1.98 million in 2019, which is near the 2015 reserve level.

PROJECTED CASH RESERVES



	2015	2016	2017	2018	2019
Current Rates	$2,048	$1,514	$1,321	$1,144	$953
Proposed Rates		$1,584	$1,593	$1,733	$1,979

Importance of Cash Reserves

Maintaining adequate reserve levels is always important, and especially in the electric utility industry, because it is very capital intensive. In a study of 68 area municipal electric utility financial statements, MRES found that the median level of cash reserves as a percentage of operating revenues was 52% for these utilities. One third of these utilities have cash reserves exceeding 65% of operating revenues. Under proposed rates, Mountain Lake's electric cash reserves are projected at 64% of operating revenues in 2019. Based on discussions with Mountain Lake staff, they would like to increase reserves back to approximately $2 million by 2019. Cash reserves would also provide for unanticipated expenses or contingencies that may arise.

Mountain Lake internally designates its reserves into the following categories:

- Operations fund includes reserves needed for daily operating costs, including wholesale power and transmission costs. The designated reserves for operations are $675,000, or 25% of the budget for 2015.

- Transmission line fund includes $840,000 of reserves set aside to reduce the risk of owning the 69 kV transmission line coming into Mountain Lake.

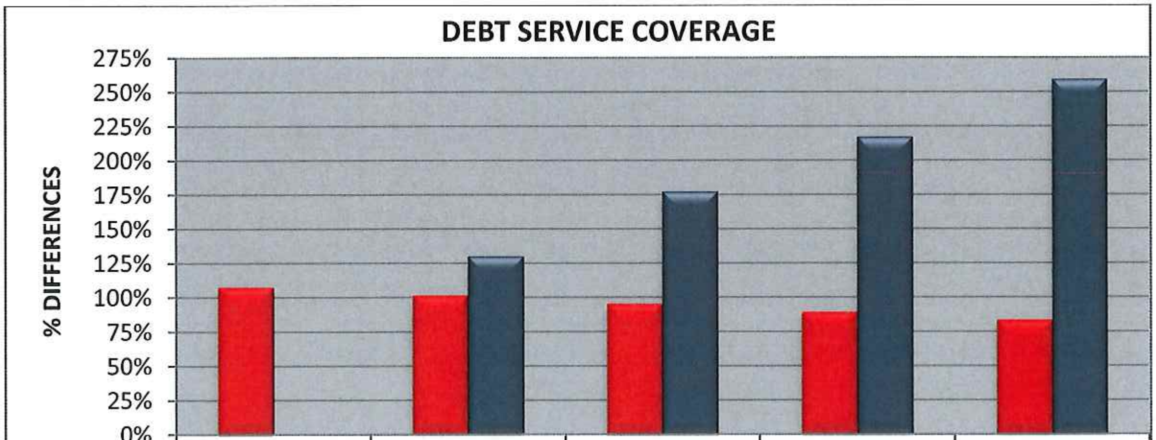
- Bond payment fund includes one year's annual principal and interest payment to meet the debt service obligations, which is $250,000. This fund is in addition to the restricted bond reserve fund required for the bond covenants.

- Conservation improvement fund includes funds received through the 1.5% surcharge on customers' bills to fund the energy efficiency incentives and programs in Mountain Lake. The current balance of the fund is about $92,000.

Debt Service Coverage

The debt service covenants include maintaining at least 125% debt service coverage ratio for all three outstanding bond series discussed in Section 2. Mountain Lake should meet the requirements from 2016 through 2019 under the proposed rate plan as shown on the graph on the following page. Under current rates, the utility will likely not meet the covenant during the study period. Debt service coverage is defined as a ratio between the current year's available cash for debt service and the debt service obligations.

Debt Service Coverage (Continued)



	2015	2016	2017	2018	2019
Current	107%	101%	95%	89%	83%
Proposed		130%	177%	217%	259%

BENEFITS OF A PUBLIC POWER SYSTEM

The City of Mountain Lake, its residents, and businesses receive many benefits by being served by a public power system. One of the many benefits is that the Mountain Lake Utility Commission has local control of the electric rates and the utility's policies and objectives. Other advantages of having a public power system in Mountain Lake are local customer service and the ability to issue tax-exempt financing when necessary for improvements, which is typically at a lower cost of financing. Lastly, shared billing services and equipment with other city utilities helps keep the total operating costs lower for all of these services.

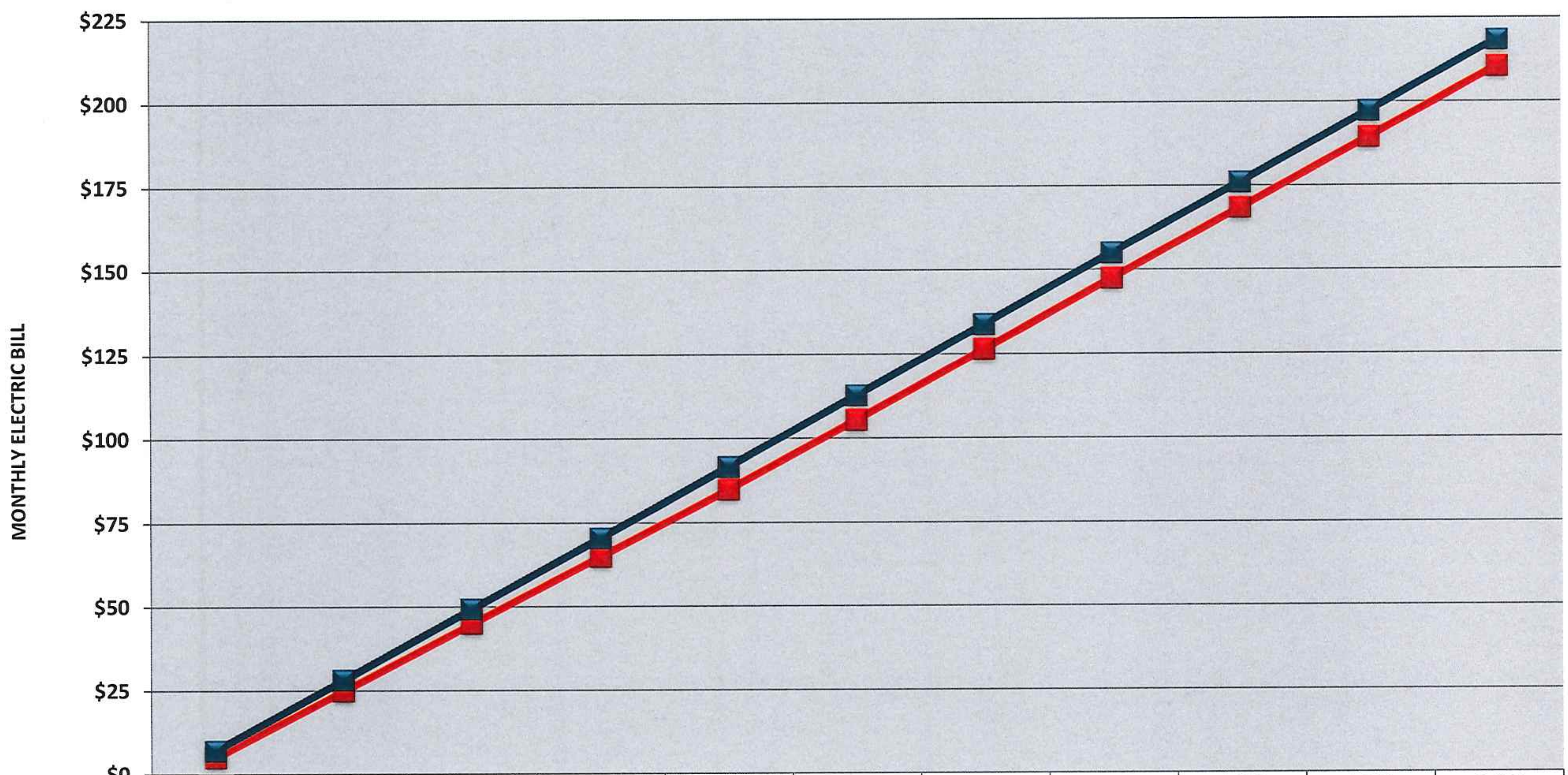
Mountain Lake Public Utilities
Electric Utility Operating Results
(Proposed Rates: 4% in April 2016 and 4.5% in January of 2017, 2018, and 2019)

			Estimated		
	2015	2016	2017	2018	2019
Total System Retail kWh Sales	24,260,586	24,446,488	24,568,721	24,691,564	24,815,022
kWh % Change	-3.0%	0.8%	0.5%	0.5%	0.5%
OPERATING REVENUES					
Metered Electric Sales	$ 2,314,427	$ 2,431,844	$ 2,616,507	$ 2,794,286	$ 2,975,671
Other Operating Revenues	88,494	89,738	90,944	92,384	93,792
Total Operating Revenues	2,402,921	2,521,582	2,707,451	2,886,669	3,069,463
OPERATING EXPENSES					
Purchased Power & Transmission	1,449,987	1,496,298	1,542,702	1,599,708	1,654,995
Production	92,500	95,275	98,133	101,077	104,110
Distribution	297,350	306,211	315,397	324,859	334,605
Administrative & General	207,993	213,861	219,905	226,130	232,542
Depreciation Expense	288,275	303,258	309,258	314,258	319,258
Total Operating Expense	2,336,105	2,414,903	2,485,395	2,566,033	2,645,509
NET OPERATING INCOME	66,816	106,679	222,056	320,637	423,954
NON-OPERATING REVENUES (EXPENSES)					
Interest Income	11,281	8,988	6,668	6,713	7,413
Refunds and Reimbursements	7,000	3,000	3,000	3,000	3,000
CAPX Transmission Revenues	12,730	12,730	12,730	12,730	12,730
Interest Expense	(29,958)	(27,953)	(25,928)	(23,528)	(20,873)
Amortization Expense	(7,805)	(7,805)	(7,805)	(7,805)	(7,805)
Total Non-Operating Revenue (Expense)	(6,751)	(11,039)	(11,335)	(8,889)	(5,534)
TRANSFER TO THE GENERAL FUND	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)
NET INCOME (LOSS)	**$ (59,935)**	**$ (24,361)**	**$ 90,721**	**$ 191,747**	**$ 298,419**
Net Income (Loss) as a Percent of Oper. Revenue	-2.5%	-1.0%	3.4%	6.6%	9.7%
Debt Service Coverage	107%	130%	177%	217%	259%

Electric Utility Cash Reserves

			Estimated		
	2015	2016	2017	2018	2019
NET INCOME (LOSS)	$ (59,935)	$ (24,361)	$ 90,721	$ 191,747	$ 298,419
LESS: Revenue-Financed Capital Expenditures	(98,000)	(537,000)	(180,000)	(150,000)	(150,000)
LESS: Bond Principal Payment 2012C	(55,000)	(55,000)	(55,000)	(60,000)	(60,000)
LESS: Bond Principal Payment 2009B	(35,000)	(30,000)	(35,000)	(35,000)	(40,000)
LESS: Bond Principal Payment 2007B	(128,750)	(128,750)	(128,750)	(128,750)	(128,750)
ADD: Depreciation Expense	288,275	303,258	309,258	314,258	319,258
ADD: Amortization Expense	7,805	7,805	7,805	7,805	7,805
LESS: Other Adjustments	(128,000)	-	-	-	-
ADDITION (REDUCTION) IN RESERVES	**$ (208,606)**	**$ (464,048)**	**$ 9,034**	**$ 140,060**	**$ 246,732**
Beginning of Year Unrestricted Reserves	$ 2,256,227	$ 2,047,621	$ 1,583,573	$ 1,592,608	$ 1,732,668
Addition (Reduction) in Reserves	(208,606)	(464,048)	9,034	140,060	246,732
End of Year Unrestricted Reserves	**$ 2,047,621**	**$ 1,583,573**	**$ 1,592,608**	**$ 1,732,668**	**$ 1,979,400**
Reserves as Percentage of Operating Revenues	**85%**	**63%**	**59%**	**60%**	**64%**

RESIDENTIAL - CURRENT AND 2016 PROPOSED MONTHLY BILLS

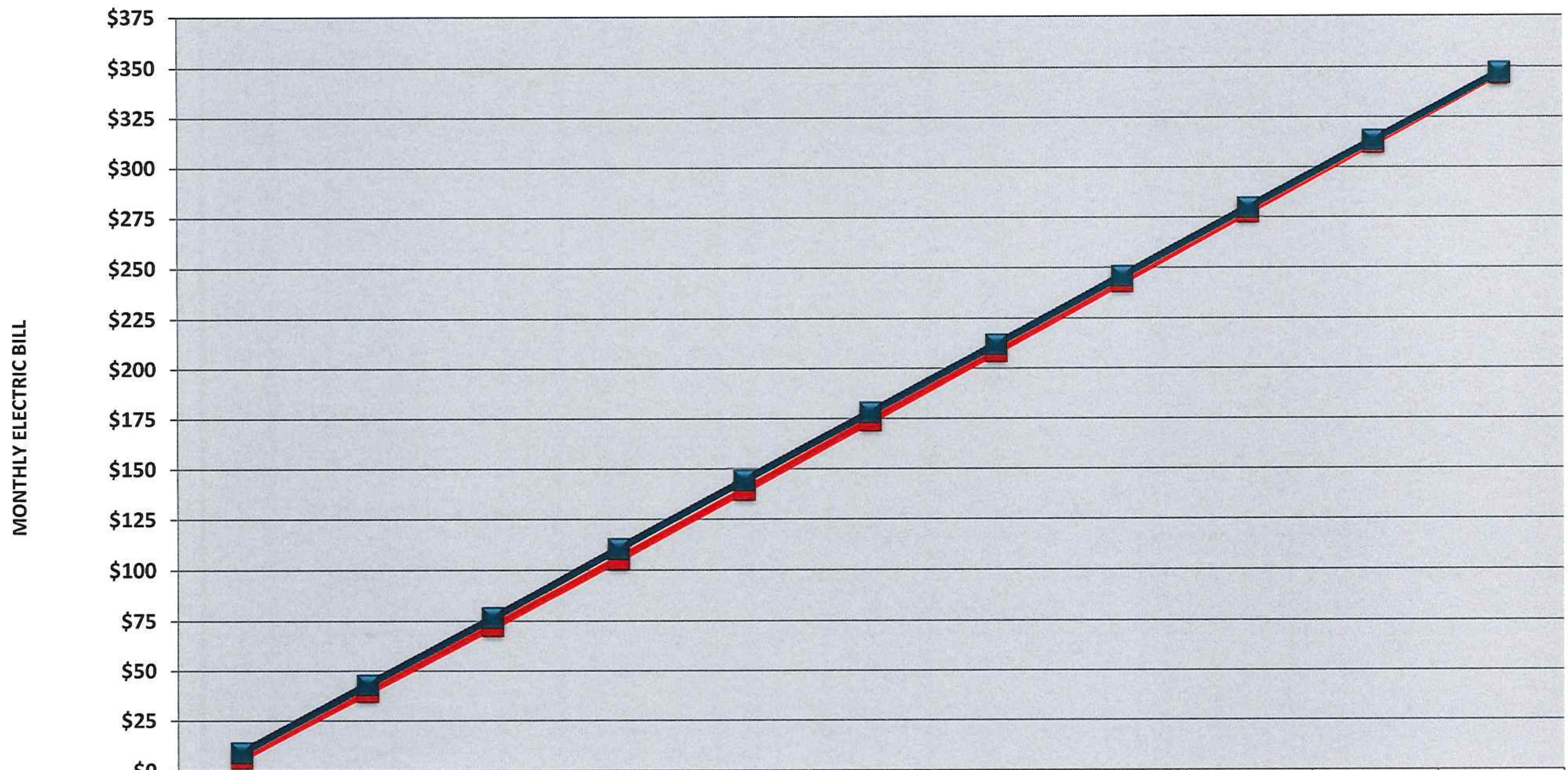


	-	200	400	600	800	1,000	1,200	1,400	1,600	1,800	2,000
Current Rates	$5.08	$25.05	$45.03	$65.00	$84.98	$105.46	$126.45	$147.44	$168.43	$189.42	$210.41
Proposed Rates	$7.11	$28.23	$49.35	$70.47	$91.59	$112.71	$133.83	$154.95	$176.07	$197.19	$218.32
% Increase	40.0%	12.7%	9.6%	8.4%	7.8%	6.9%	5.8%	5.1%	4.5%	4.1%	3.8%
$ Increase	$2.03	$3.18	$4.32	$5.47	$6.61	$7.25	$7.38	$7.51	$7.65	$7.78	$7.91

KWH

Exhibit 4-B

RURAL - CURRENT AND 2016 PROPOSED MONTHLY BILLS

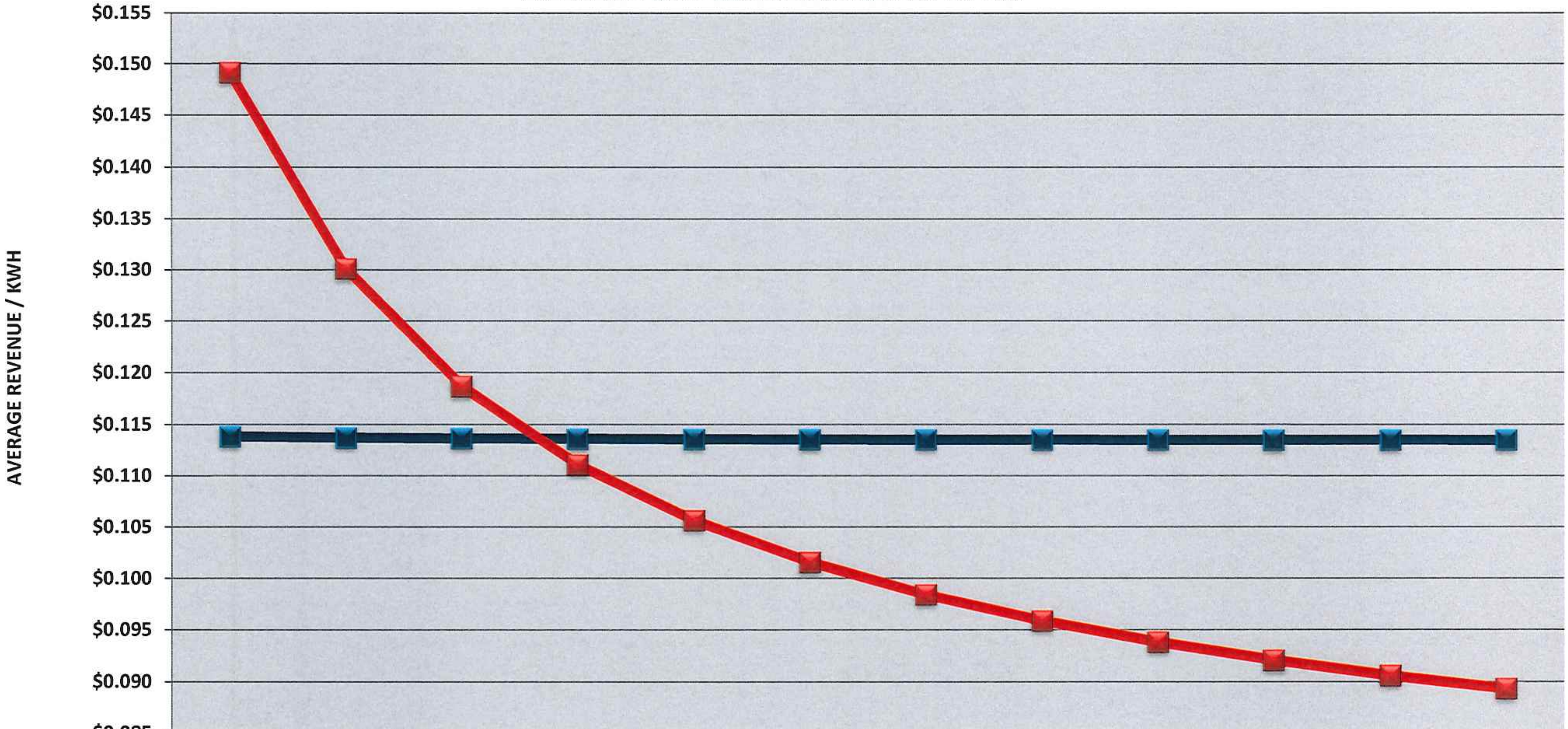


KWH	-	300	600	900	1,200	1,500	1,800	2,100	2,400	2,700	3,000
Current Rates	$6.60	$39.61	$72.61	$105.62	$139.64	$174.17	$208.70	$243.23	$277.76	$312.30	$346.83
Proposed Rates	$9.14	$42.95	$76.76	$110.57	$144.38	$178.19	$212.01	$245.82	$279.63	$313.44	$347.25
% Increase	38.5%	8.4%	5.7%	4.7%	3.4%	2.3%	1.6%	1.1%	0.7%	0.4%	0.1%
$ Increase	$2.54	$3.34	$4.15	$4.95	$4.74	$4.02	$3.30	$2.58	$1.86	$1.14	$0.43

KWH

Exhibit 4-C

CURRENT RURAL MOVING TO THE 2016 PROPOSED LARGE COMMERCIAL AVERAGE REVENUE PER KWH AT 30 KW

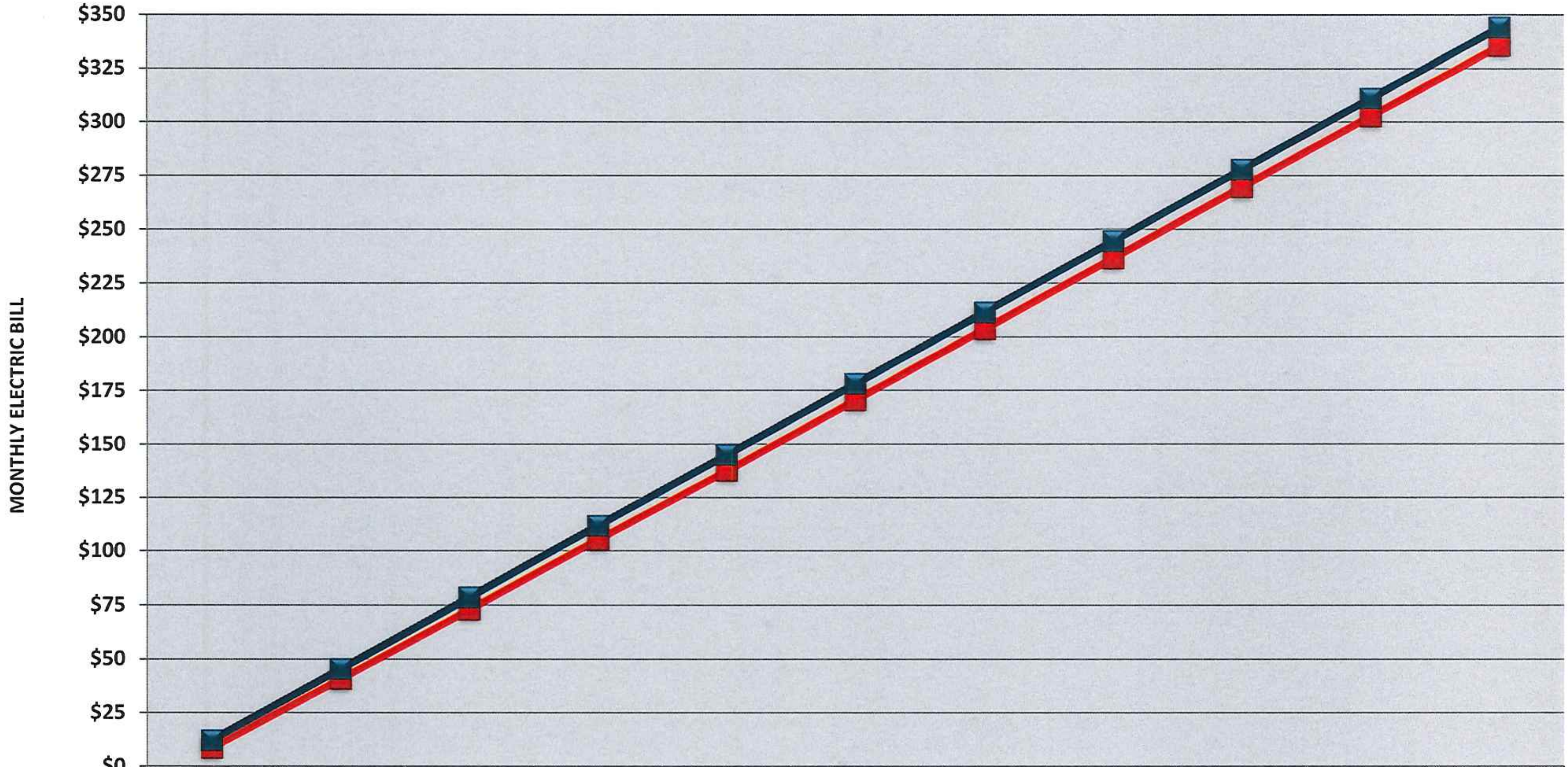


	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%
Rural	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.114	0.113
Large Comm.	0.149	0.130	0.119	0.111	0.106	0.102	0.098	0.096	0.094	0.092	0.091	0.089
% Change	31.0%	14.4%	4.4%	-2.2%	-7.0%	-10.6%	-13.3%	-15.6%	-17.4%	-18.9%	-20.2%	-21.3%
$ / kWh Change	0.035	0.016	0.005	(0.003)	(0.008)	(0.012)	(0.015)	(0.018)	(0.020)	(0.021)	(0.023)	(0.024)

LOAD FACTOR

Exhibit 4-D

COMMERCIAL - CURRENT AND 2016 PROPOSED MONTHLY BILLS

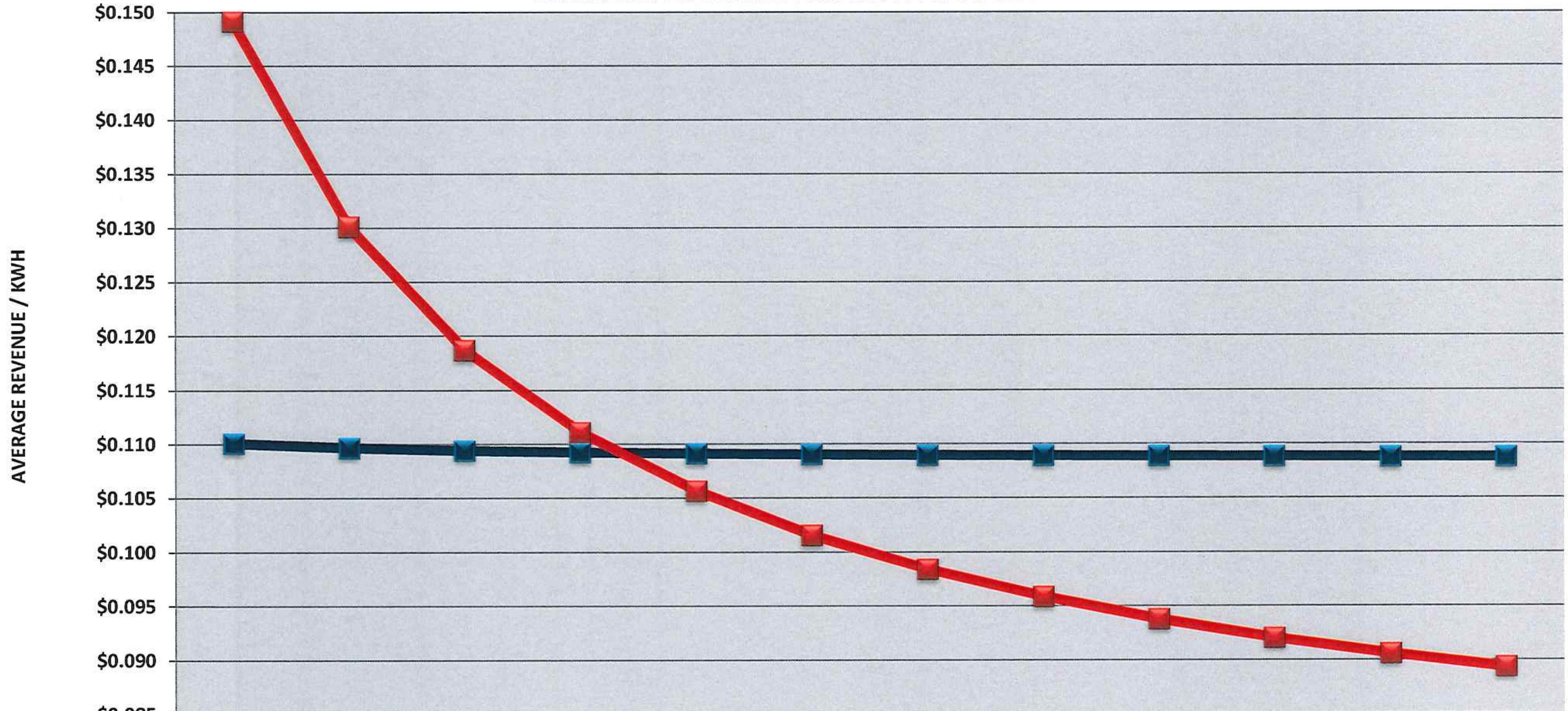


	-	300	600	900	1,200	1,500	1,800	2,100	2,400	2,700	3,000
Current Rates	$8.63	$40.87	$73.12	$105.37	$137.61	$170.62	$203.63	$236.64	$269.64	$302.65	$335.66
Proposed Rates	$12.18	$45.38	$78.59	$111.79	$145.00	$178.20	$211.40	$244.61	$277.81	$311.02	$344.22
% Increase	41.2%	11.0%	7.5%	6.1%	5.4%	4.4%	3.8%	3.4%	3.0%	2.8%	2.6%
$ Increase	$3.55	$4.51	$5.47	$6.43	$7.38	$7.58	$7.78	$7.97	$8.17	$8.37	$8.56

KWH

Exhibit 4-E

CURRENT COMMERCIAL MOVING TO THE PROPOSED LARGE COMMERCIAL AVERAGE REVENUE PER KWH AT 30 KW

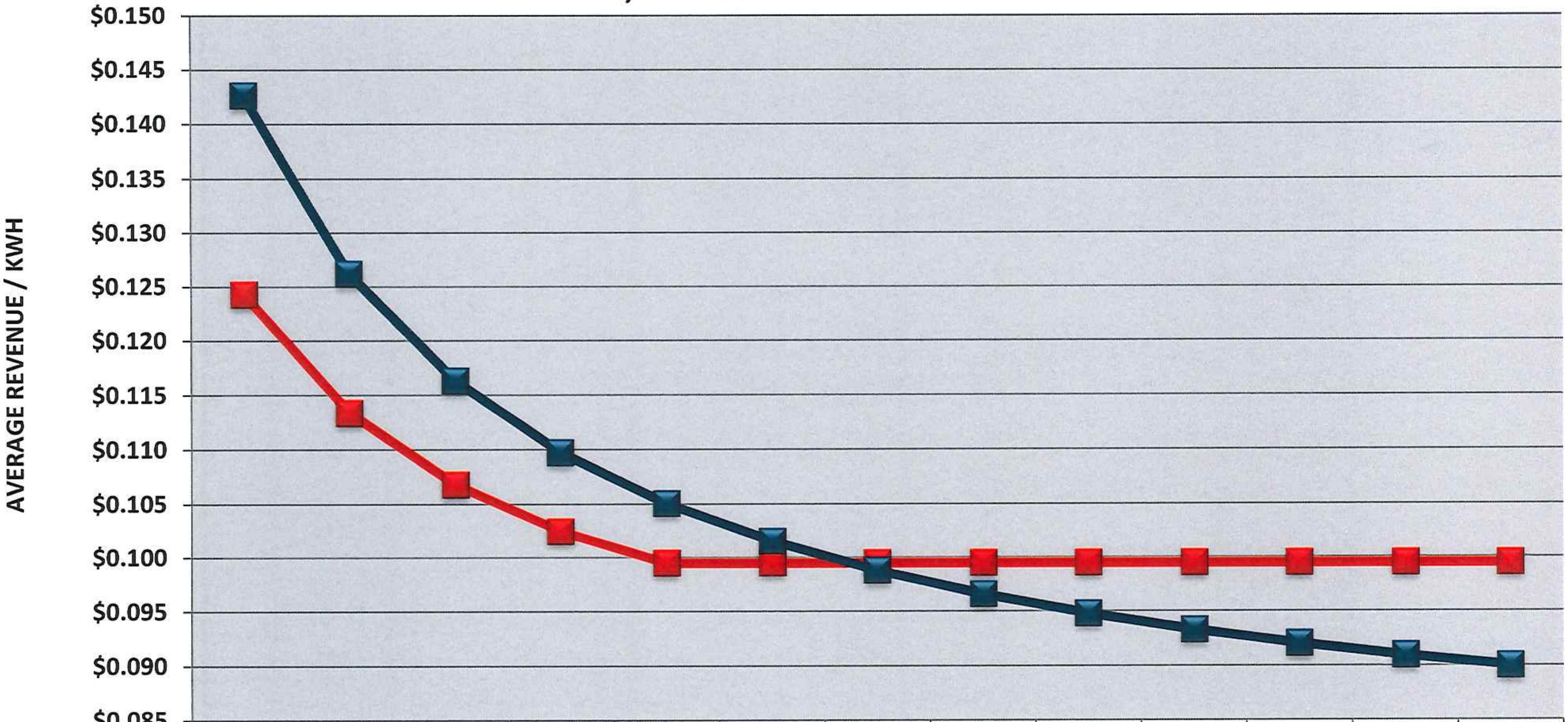


	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%
Commercial	0.110	0.110	0.109	0.109	0.109	0.109	0.109	0.109	0.109	0.109	0.109	0.109
Large Comm.	0.149	0.130	0.119	0.111	0.106	0.102	0.098	0.096	0.094	0.092	0.091	0.089
% Change	35.5%	18.7%	8.5%	1.7%	-3.2%	-6.8%	-9.7%	-12.0%	-13.8%	-15.4%	-16.7%	-17.8%
$ / kWh Change	0.039	0.020	0.009	0.002	(0.003)	(0.007)	(0.011)	(0.013)	(0.015)	(0.017)	(0.018)	(0.019)

LOAD FACTOR

Exhibit 4-F

LARGE COMMERCIAL - CURRENT AND 2016 PROPOSED AT 15,000 KWH PER MONTH

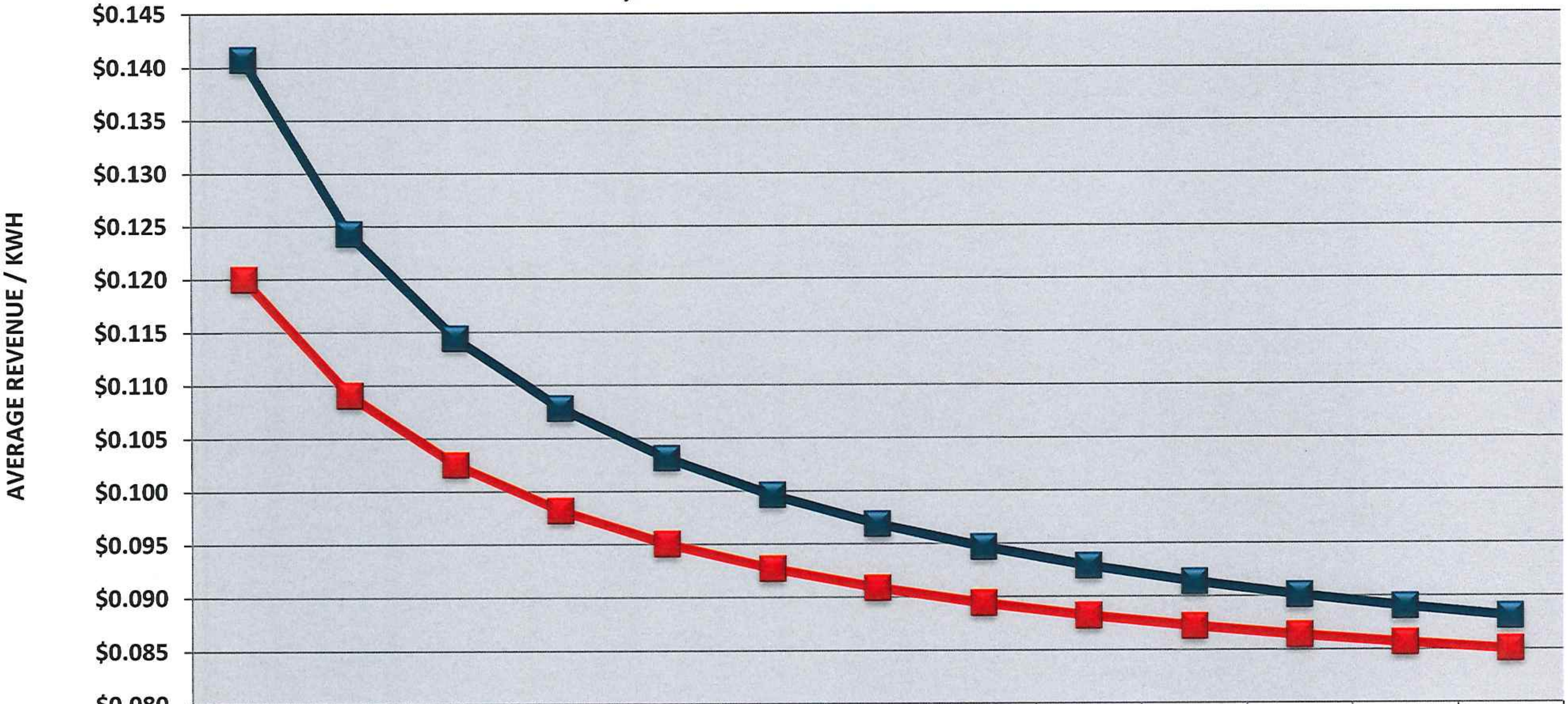


	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Current Rates	$0.124	$0.113	$0.107	$0.102	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099	$0.099
Proposed Rates	$0.143	$0.126	$0.116	$0.110	$0.105	$0.102	$0.099	$0.097	$0.095	$0.093	$0.092	$0.091	$0.090
% Change	14.8%	11.3%	8.9%	7.1%	5.6%	2.1%	-0.7%	-2.9%	-4.7%	-6.2%	-7.5%	-8.6%	-9.5%
$ / kWh Change	$0.02	$0.01	$0.01	$0.01	$0.01	$0.00	$(0.00)	$(0.00)	$(0.00)	$(0.01)	$(0.01)	$(0.01)	$(0.01)

LOAD FACTOR

Exhibit 4-G

LARGE COMMERCIAL - CURRENT AND 2016 PROPOSED AT 50,000 KWH PER MONTH



	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Current Rates	$0.120	$0.109	$0.103	$0.098	$0.095	$0.093	$0.091	$0.089	$0.088	$0.087	$0.086	$0.086	$0.085
Proposed Rates	$0.141	$0.124	$0.114	$0.108	$0.103	$0.100	$0.097	$0.095	$0.093	$0.091	$0.090	$0.089	$0.088
% Change	17.3%	13.9%	11.6%	9.8%	8.5%	7.5%	6.6%	5.9%	5.3%	4.8%	4.3%	3.9%	3.6%
$ / kWh Change	$0.021	$0.015	$0.012	$0.010	$0.008	$0.007	$0.006	$0.005	$0.005	$0.004	$0.004	$0.003	$0.003

LOAD FACTOR

Exhibit 4-H

SECTION 5 – RATE COMPARISONS WITH OTHER ELECTRIC UTILITIES

Historically, in a non-competitive environment where utility franchise territories were protected, a utility could reasonably set rates on a cost-of-service plus margin basis, or the utility could diverge from the cost study and set rates according to local policy objectives. However, some portions of the country have now been opened to retail competition. Although retail competition may be many years away in this area, it is still important to understand the competitive position of the utility for other reasons such as economic development. The information in this section is also useful in examining the various methods used by the utilities to recover costs from the different classes.

DIFFERENCE OF RATES AMONG MEMBER UTILITIES

Electric rates vary from utility to utility due to several factors. Some of the differences may be explained by the following factors:

- The percentage of power purchased from the WAPA in comparison to the power purchased from other suppliers
- The cost of transmission services
- The equitability of the rates across the various customer classes
- The blend of retail customers, such as the percentage of Commercial and Large Commercial energy sales
- The percentage of revenues that is transferred to other non-electric funds
- The amount of expenses that may be subsidized by other utilities, for example, the electric utility paying for other city utilities' labor and/or other expenses
- The amount of funds spent in recent years on capital improvement projects, which correlates to the condition and reliability of the distribution system
- The amount of annual debt service, along with the covenants and restricted reserves
- The level of cash reserves and the governing board's philosophy towards reserves

RATE CLASSES INCLUDED IN THE COMPARISONS

To compare Mountain Lake with other utilities, MRES chose rates that would be charged to customers in the Residential, Commercial, and Large Commercial rate groups. The rates chosen were the basic rates offered by the utilities that would be applicable to the majority of the customers in the classes. These rates are not representative of all the different types of rates that are available.

SUMMARY OF UTILITY COMPARISON RESULTS

Exhibits 5-A through 5-F at the end of this section contain comparisons between Mountain Lake and the regional utilities whose rates are shown in Exhibits 5-G through 5-I. For utilities with seasonal rates, the bills are the weighted average of all 12 months. For Mountain Lake, the proposed rates for 2016 from Section 4 were used in these comparisons. The comparisons are based on the following levels of usage per month:

- Residential – Average usage of 700 kWh
- Residential Heating – Average usage of 1,600 kWh in the winter months only
- Commercial – Average usage of 1,400 kWh
- Large Commercial – 67,900 kWh and demand of 285 kW (33% Load Factor)
- Large Commercial – 39,100 kWh and demand of 96 kW (56% Load Factor)
- Large Commercial – 708,130 kWh and demand of 1,286 kW (76% Load Factor)

The top portion of each exhibit shows bills calculated using the various utilities' rates, and the bottom portion shows the percentage differences between other utilities and the current Mountain Lake rates.

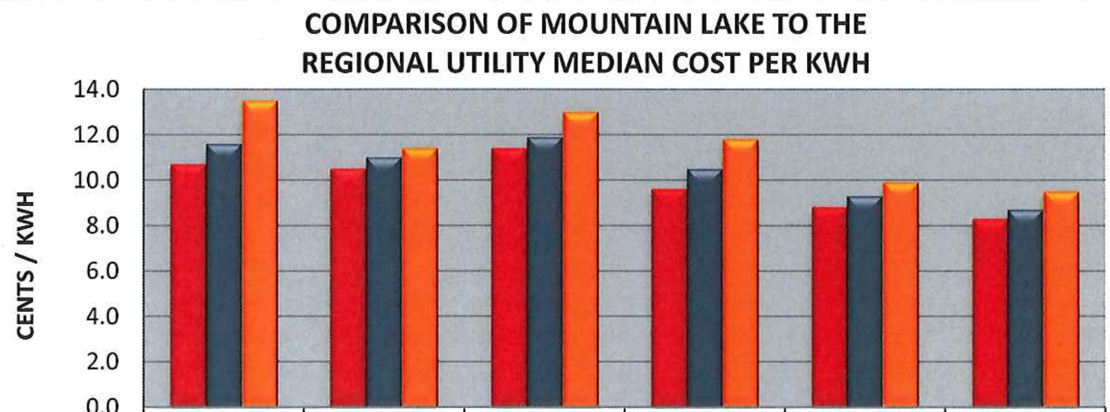
The two graphs on the following page summarize the rate comparison information. The first graph compares cents per kWh for each class using the calculated bills and three sets of values: current Mountain Lake rates, proposed 2016 rates, and the median bill of 10 regional utilities.

The second graph shows the percentage differences between both the Mountain Lake current and proposed rates and the median bill of the 10 utilities. This graph indicates that under current rates, the median bill for a Residential customer using 700 kWh per month is 26% higher than Mountain Lake's bill while the median bill for a Commercial customer is only about 14% higher than Mountain Lake's bill.

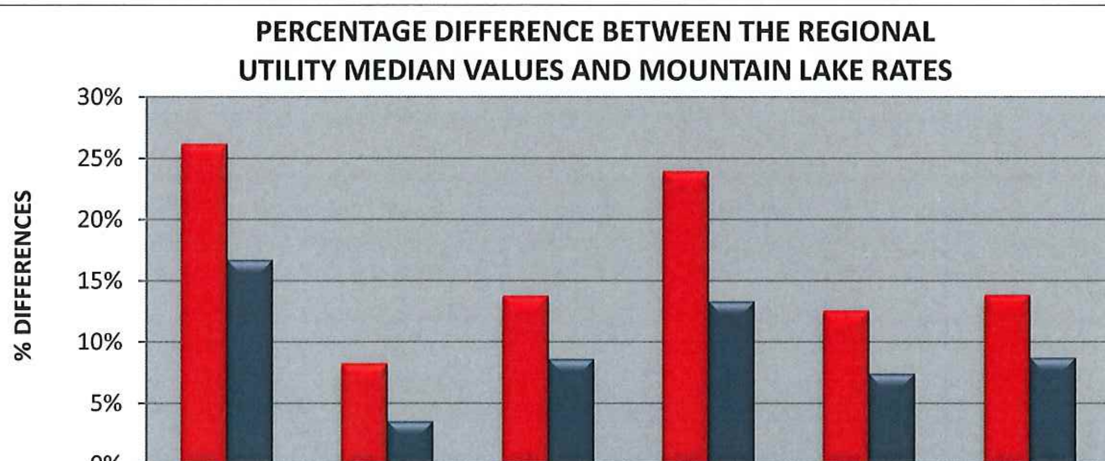
The second graph also indicates that under current rates, the median bills for the Large Commercial class are between 12% and 24% higher than the Mountain Lake bills. Due to the current rate structure for the Large Commercial class, as the customer's load factor increases, the customer becomes less competitive in comparison to the median bill. Under the proposed rates, the median bills will be between 7% and 13%, which is a much narrower gap for all load factors than under the current rates.

Under the proposed rates, all customer bills will be more equitable while continuing to be below the utility median. Furthermore, other utilities are experiencing cost pressures and will also likely increase rates in coming years.

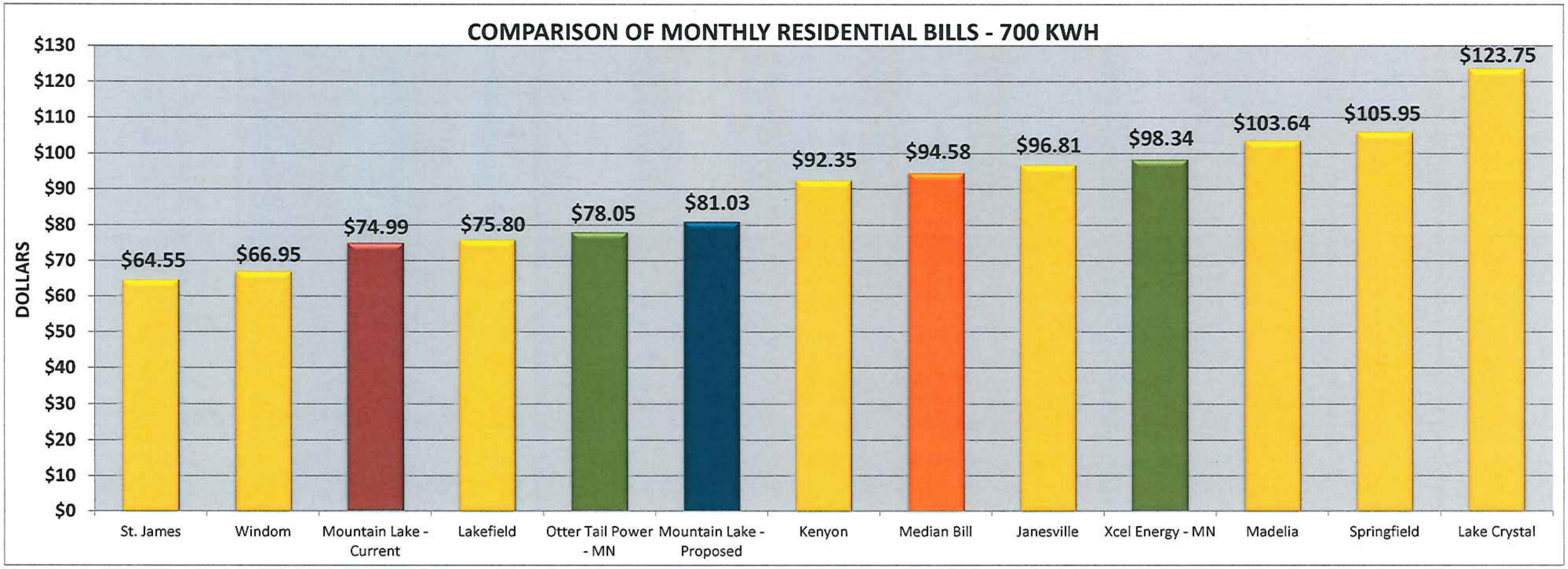
SUMMARY OF UTILITY COMPARISON RESULTS (Continued)

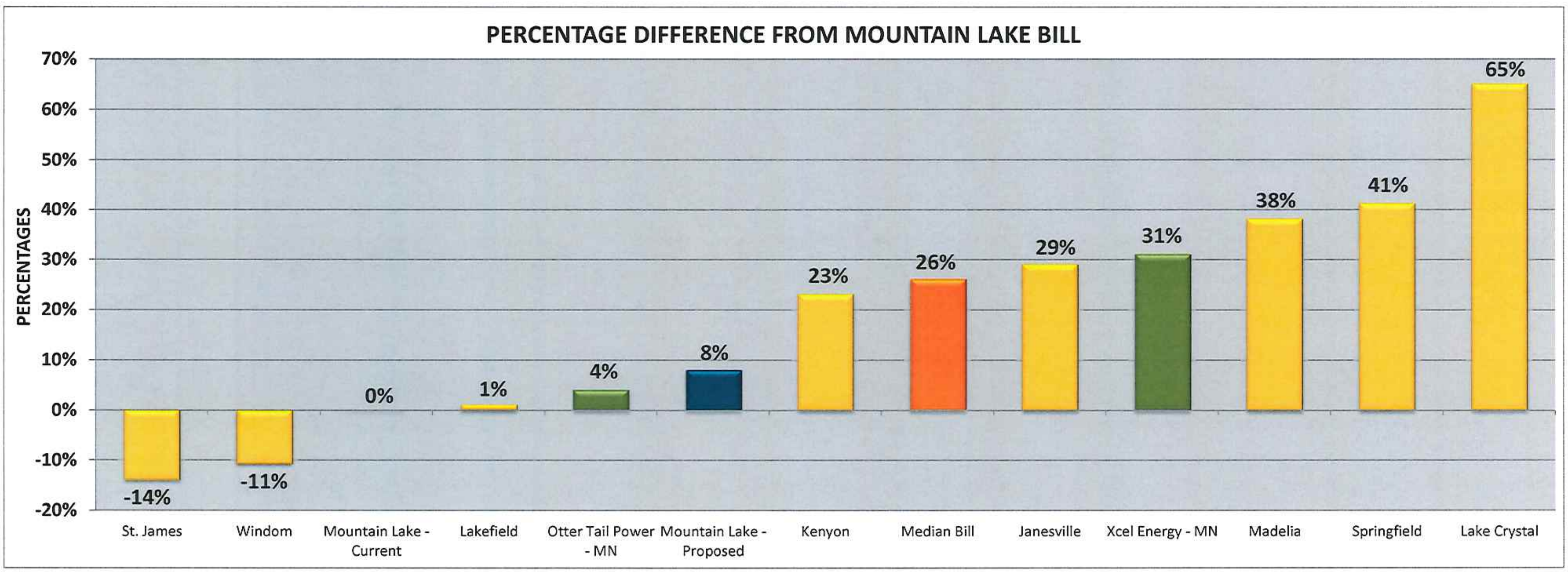


	Residential - 700 kWh	Residential Heating - 1,600 kWh	Commercial - 1,400 kWh	Large Commercial - 33% LF	Large Commercial - 56% LF	Large Commercial - 76% LF
Current	10.7	10.5	11.4	9.6	8.8	8.3
Proposed	11.6	11.0	11.9	10.5	9.3	8.7
Median	13.5	11.4	13.0	11.8	9.9	9.5



	Residential - 700 kWh	Residential Heating - 1,600 kWh	Commercial - 1,400 kWh	Large Commercial - 33% LF	Large Commercial - 56% LF	Large Commercial - 76% LF
Current	26.1%	8.2%	13.7%	23.9%	12.5%	13.8%
Proposed	16.7%	3.5%	8.6%	13.3%	7.4%	8.7%

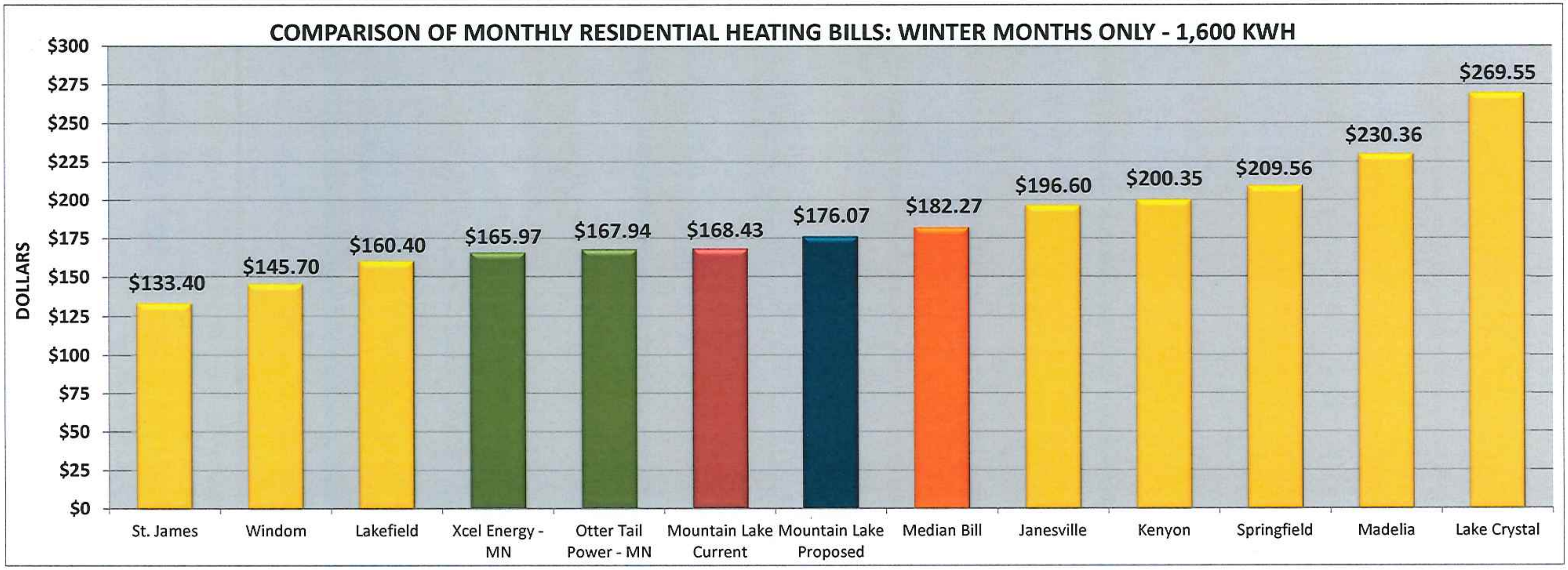


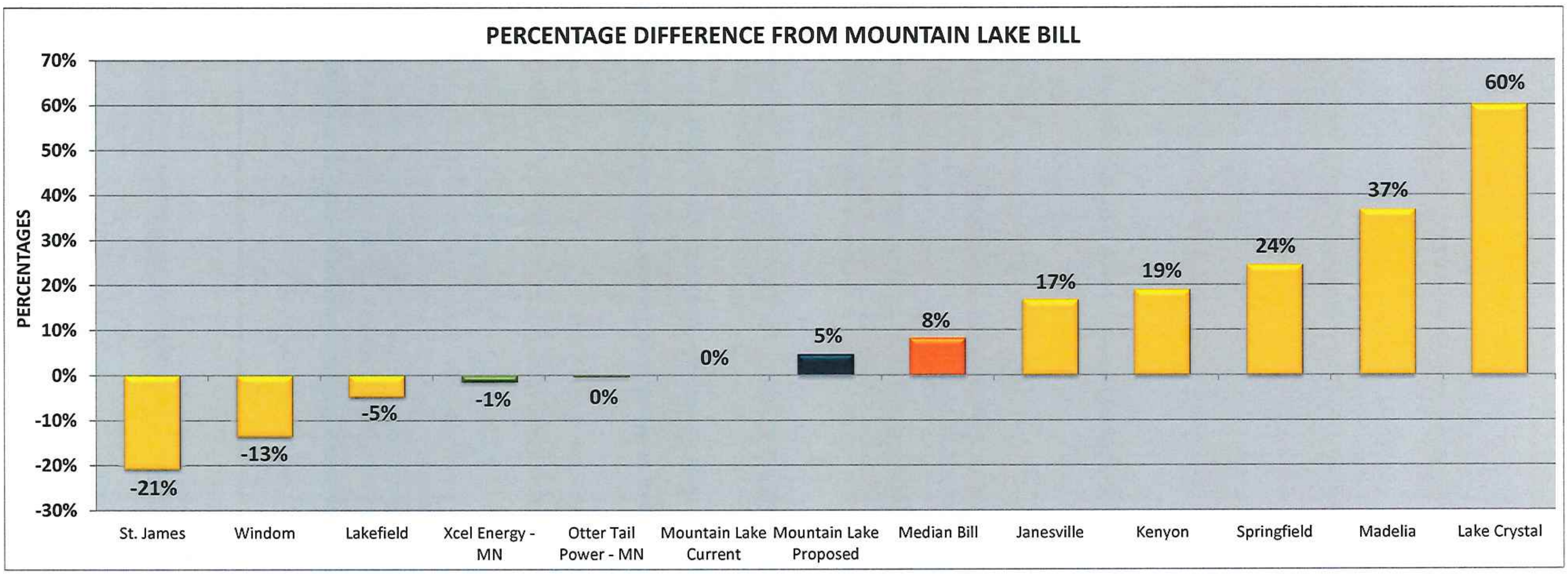


March 2016 - Comparison based on current rates, subject to change.

Exhibit 5-A

Provided by Missouri River Energy Services

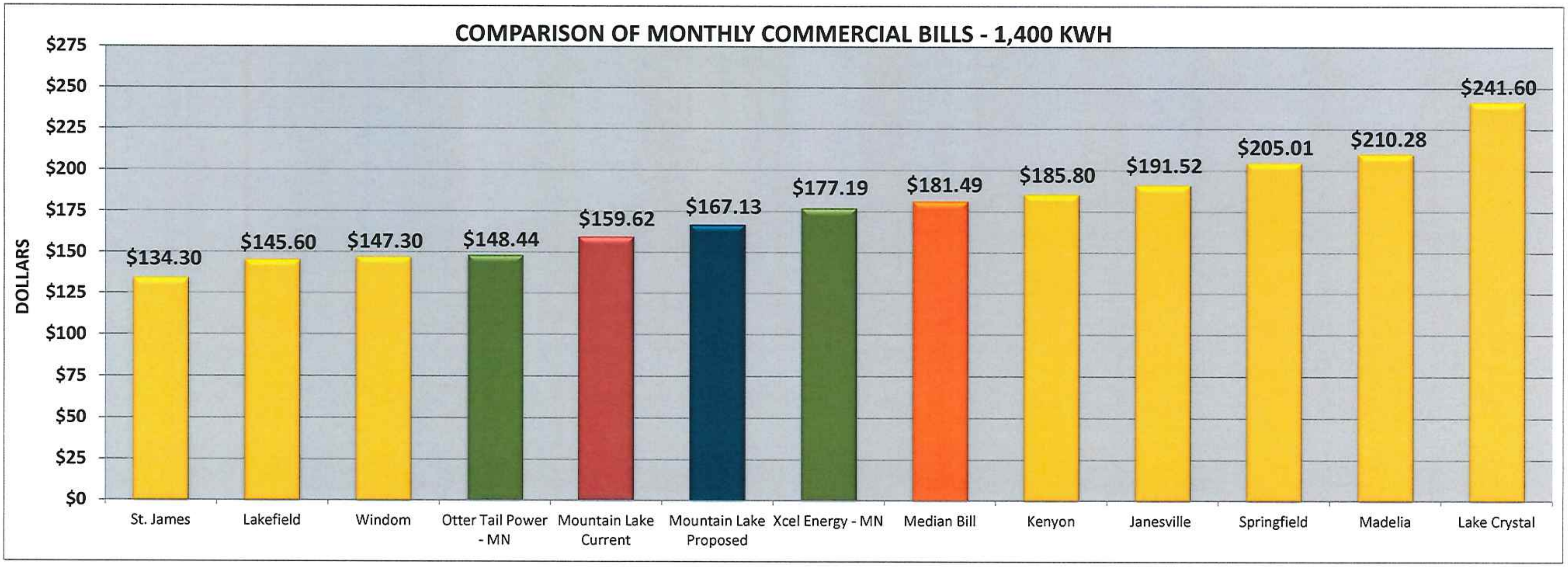


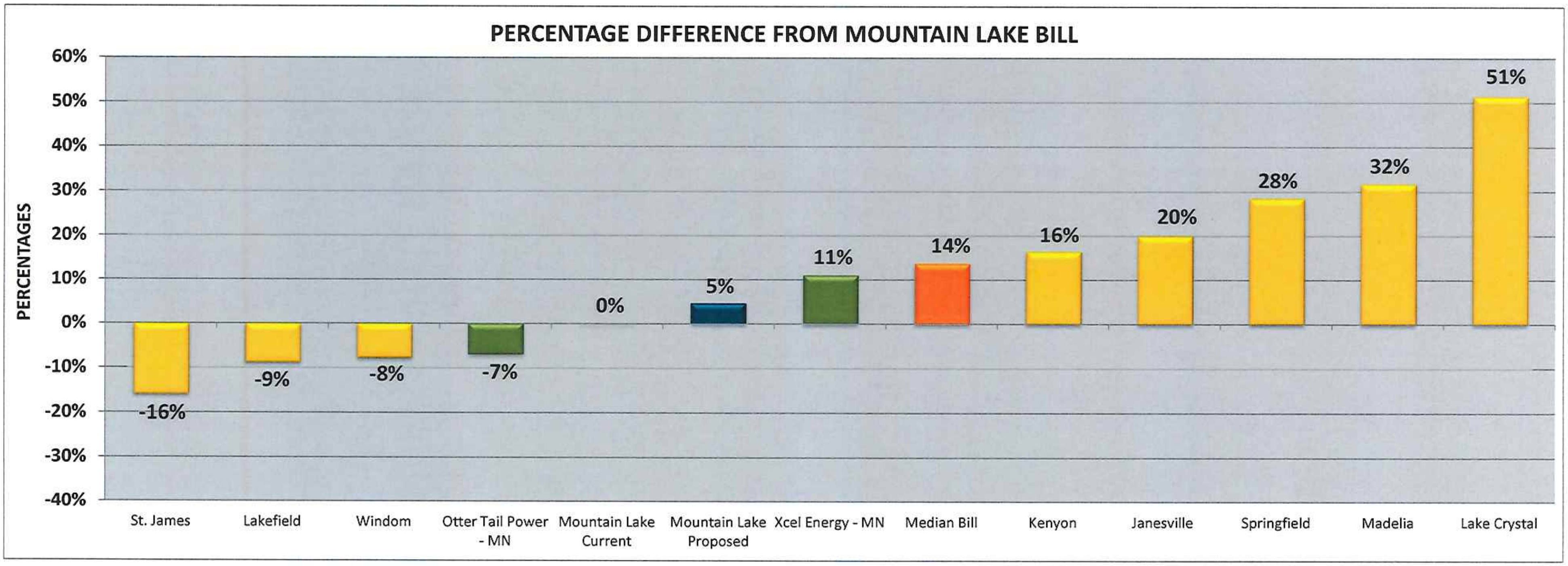


March 2016 - Comparison based on current rates, subject to change.

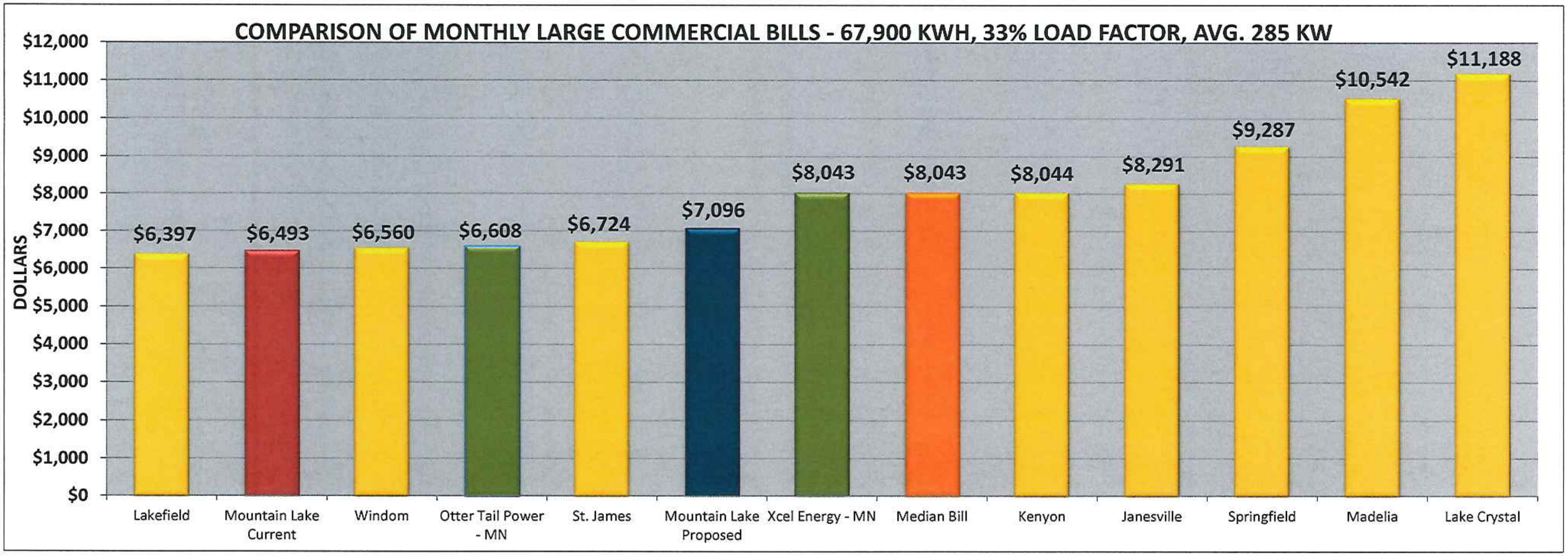
Exhibit 5-B

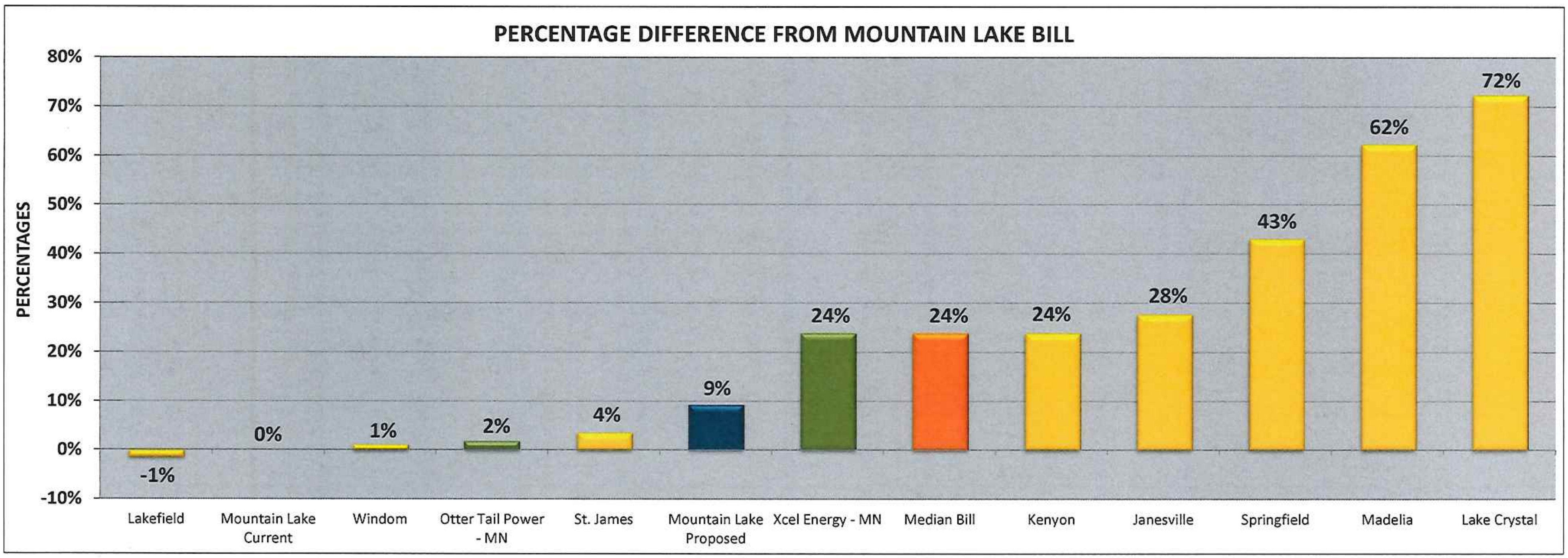
Provided by Missouri River Energy Services



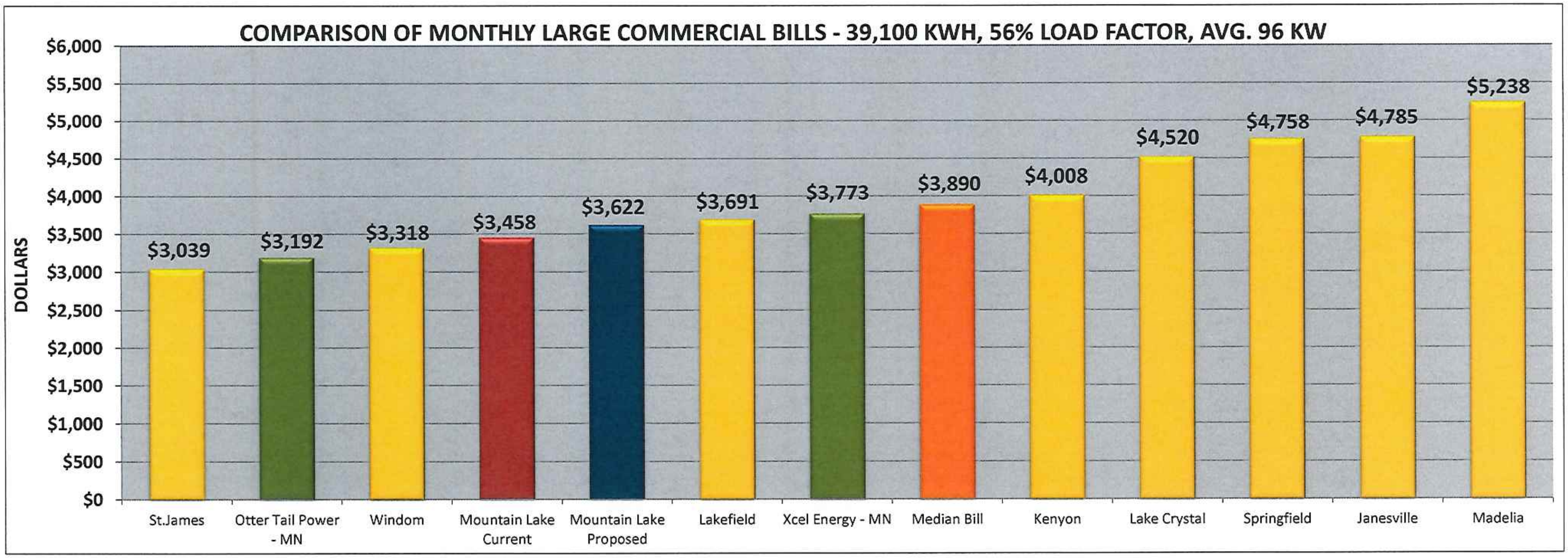


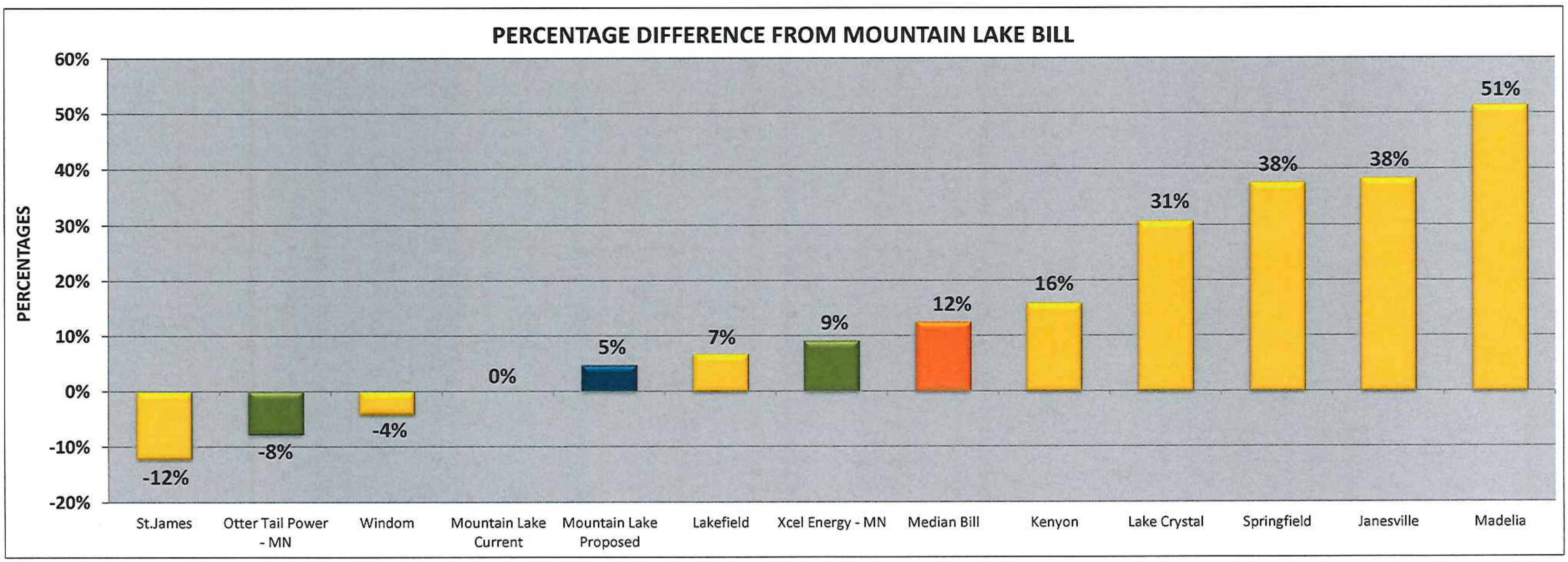
March 2016 - Comparison based on current rates, subject to change. Exhibit 5-C Provided by Missouri River Energy Services





March 2016 - Comparison based on current rates, subject to change. Exhibit 5-D Provided by Missouri River Energy Services

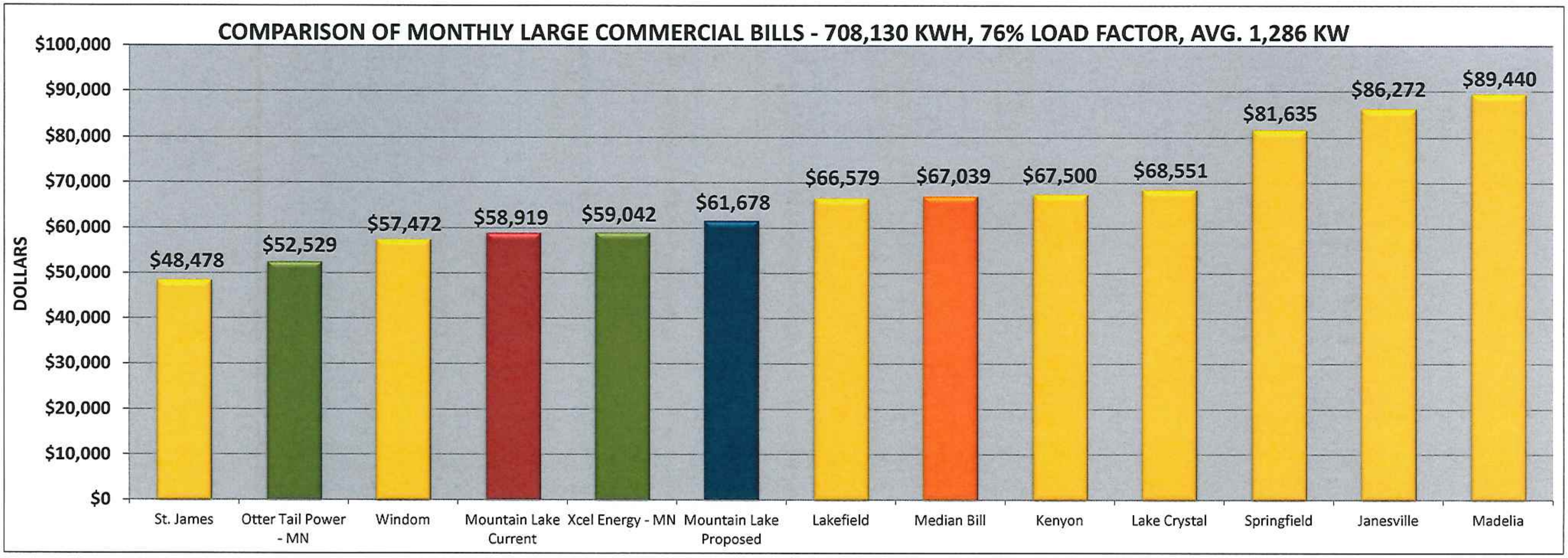


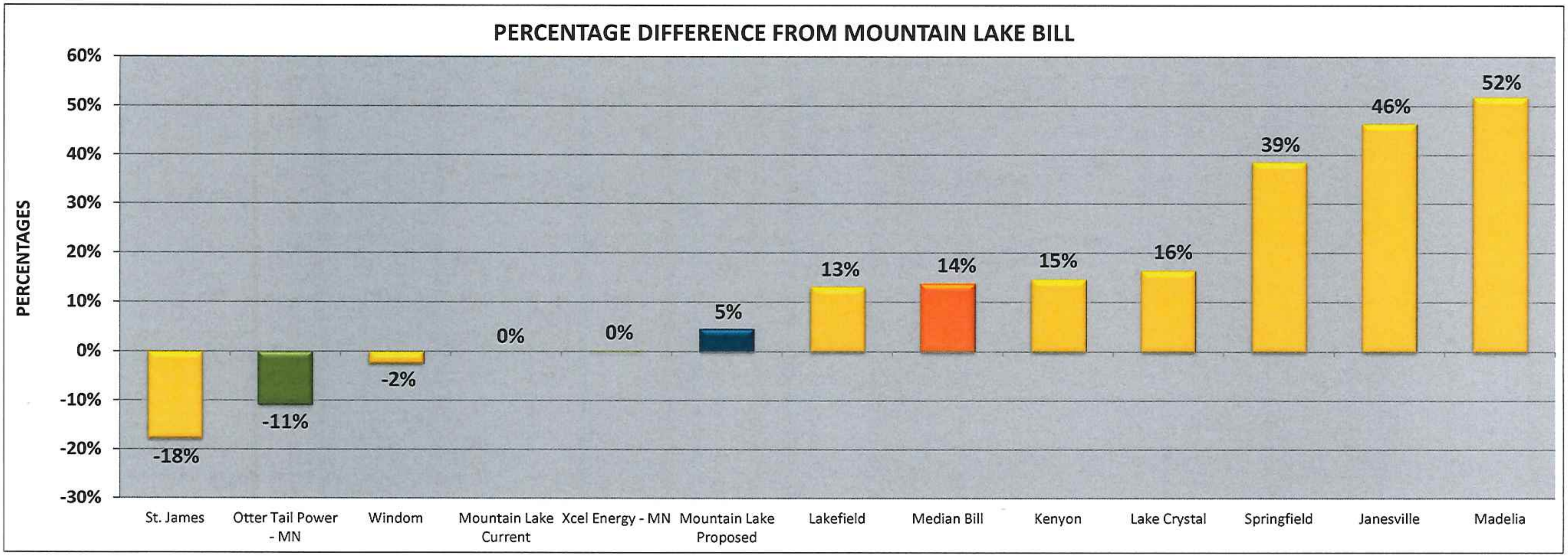


March 2016 - Comparison based on current rates, subject to change.

Exhibit 5-E

Provided by Missouri River Energy Services





March 2016 - Comparison based on current rates, subject to change. Exhibit 5-F Provided by Missouri River Energy Services

Residential Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$5.00	$0.06000 0.06500 1.5%	0-900 Over 900 Conservation Improv. (% of bill)	$0.03840
Otter Tail Power – MN	8.50	0.07976 0.08192 0.00930 7.006%	All (June-Sep.) All (Oct.-May) Other Adjustments: per kWh Environmental Cost (% of bill)	0.00232
Xcel Energy – MN Standard Service Electric Space Heating	 10.74 12.74	 0.09395 0.08040 0.05819 0.00552 7.75%	 All (June – Sep.) All (Oct. – May) Space Heating All (Oct. – May) Other Adjustments: per kWh Interim Increase (% of bill)	 0.02693
Janesville, MN	11.00	0.11100 5.0%	All Franchise Fee (% of bill)	0.00500
Kenyon, MN	8.35	0.12000	All	-
Lake Crystal, MN	10.35	0.16200	All	-
Lakefield, MN	10.00	0.09400	All	-
Madelia, MN	5.00	0.13722 1.5%	All Conservation Improv. (% of bill)	0.00150
Springfield, MN	11.00	0.11800 0.08600 3.0%	All Heating (Oct.-April) Conservation Improv. (% of energy charges)	0.01410
St. James, MN	11.00	0.07650	All	-
Windom, MN In City Limits Rural	 5.70 14.00	 0.07900	 All	 0.00850

Commercial Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$8.50	$0.06750 0.07000 1.5%	0-1,200 Over 1,200 Conservation Improv. (% of bill)	$0.03840
Otter Tail Power – MN	15.50	0.07579 0.07784 0.00930 7.006%	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh Environmental Costs (% of bill)	0.00232
Xcel Energy – MN	10.97	0.08787 0.07432 0.00536 7.75%	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh Interim Increase (% of bill)	0.02781
Janesville, MN	20.00	0.11100 5.0%	All Franchise Fee (% of bill)	0.00500
Kenyon, MN	22.00	0.11700	All	-
Lake Crystal, MN	19.00	0.15900	All	-
Lakefield, MN	14.00	0.09400	All	-
Madelia, MN	8.50	0.14041 1.5%	All Conservation Improv. (% of bill)	0.00150
Springfield, MN	18.00	0.11600 3.0%	All Conservation Improv. (% of energy charges)	0.01410
St. James, MN Single-phase Three-phase	 16.00 28.00	 0.08450	 All	 -
Windom, MN Single-phase Three-phase	 15.00 20.00	 0.08600 0.08100	 0-8,000 Over 8,000	 0.00850

Large Commercial Rates

Utility	Monthly Service Charge	Demand Charge (per kW)	Demand Block (kW-mos.)	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$-	$369.00 4.65	First 60 kW Over 60 kW	$0.03500 1.5%	All Con. Improv. (% of bill)	$0.03840
Otter Tail Power – MN 20 kW-80 kW	19.00	1.22 1.02 0.60	June-Sep. Oct.-May Facility Chg.	0.06791 0.07353 0.00930 7.006%	All (June-Sep.) All (Oct.-May) Other Adjustments Envir. Cost (% of bill)	0.00232
Over 80 kW	40.00 (Min. 350.00)	7.22 6.07 0.33 2.058	June-Sep. Oct.-May Facility Chg. Other Adj.	0.04618 0.05000 0.00287 7.006%	All (June-Sep.) All (Oct.-May) Other Adjustments Envir. Cost (% of bill)	0.00232
Xcel Energy – MN Less than 1 MW	28.54	14.07 9.96 0.906	June–Sep. Oct.–May 50% Ratchet Other Adj.	0.03201 (0.0140) 0.00228 7.75%	All Over 400 kWh per kW Other Adjustments Interim Increase (% of bill)	0.02680
Janesville, MN	20.00	-	All	0.11100 5.0%	All Franchise Fee	0.00500
Kenyon, MN	45.00	9.50	All	0.07800	All	-
Lake Crystal, MN	24.20	28.50	All	0.04500	All	-
Lakefield, MN	14.00	-	All	0.09400	All	-
Madelia, MN Large Commercial Industrial	 12.50 100.00	 11.28 15.40	 All All	 0.10243 0.08546 1.5%	 All All Con. Improv. (% of bill)	 0.00150
Springfield, MN	28.00	8.90	All	0.08250 3.0%	All Con. Improv. (% of energy charges)	0.01410
St. James, MN	50.00	12.60	All	0.04550	All	-
Windom, MN	25.00	6.95	All	0.06000	All	0.00850

Appendix

Mountain Lake Proposed Electric Rates

	2016 Rates	2016 % Change	2017 Rates	2017 % Change	2018 Rates	2018 % Change	2019 Rates	2019 % Change
Overall Increase		4.0%		4.5%		4.5%		4.5%
Power Cost Adjustment (PCA)								
PCA Base	$ 0.0650		$ 0.0650		$ 0.0650		$ 0.0650	
Average Annual Adjustment (A)	$ 0.0050	1.4%	$ 0.0067	1.7%	$ 0.0087	2.1%	$ 0.0107	1.9%
Residential								
Customer Charge	$ 7.00	7.2%	$ 9.00	6.0%	$ 11.00	6.1%	$ 13.00	6.0%
Energy Charge - per kWh								
All kWh	$ 0.0990		$ 0.1030		$ 0.1075		$ 0.1125	
Rural								
Customer Charge	$ 9.00	-8.0%	$ 11.50	3.6%	$ 14.00	3.9%	$ 16.50	3.8%
Energy Charge - per kWh		(B)						
All kWh	$ 0.1060		$ 0.1075		$ 0.1095		$ 0.1115	
Commercial								
Customer Charge	$ 12.00	0.2%	$ 16.00	4.6%	$ 20.00	4.4%	$ 24.00	4.2%
Energy Charge - per kWh		(C)						
All kWh	$ 0.1040		$ 0.1060		$ 0.1080		$ 0.1100	
Large Commercial (Over 20 kW)								
Customer Charge	$ 40.00	4.6%	$ 45.00	3.3%	$ 50.00	3.4%	$ 55.00	3.4%
Demand Charge								
All kW - per kW	$ 7.00		$ 8.75		$ 10.55		$ 12.40	
Energy Charge - per kWh	$ 0.0680		$ 0.0665		$ 0.0650		$ 0.0635	
City Facilities & Street Lighting								
Customer Charge	$ 12.00	8.1%	$ 16.00	6.7%	$ 20.00	6.3%	$ 24.00	5.9%
Energy Charge - per kWh	$ 0.0680		$ 0.0720		$ 0.0760		$ 0.0800	
Conservation Improvement Plan								
Surcharge - % of Electric Bill	1.5%		1.5%		1.5%		1.5%	

(A) The PCA percentage increase is in additon to the overall revenue increase for each year. The PCA percentage change may change from the projected percentage change due to actual power supply and transmission costs being lower or higher than the projected costs.

(B) Customers remaining in the Rural class will have an average increase of 4.3%, while the customers moving to the Large Commercial class will have an average decrease of 13.3% in 2016.

(C) Customers remaining in the Commercial class will have an average increase of 5.2%, while the customers moving to the Large Commercial class will have an average decrease of 7.2% in 2016.