Electric Rate Study
Final Report
December 2019

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MOUNTAIN LAKE
UTILITIES

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December 5, 2019

Mountain Lake Utility Commission
903 3rd Ave
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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:

- Implement 2020 rate adjustments to move classes closer to the cost of service with no overall revenue change
- Maintain the PCA calculation and the PCA base
- Maintain the qualifications for the Large Commercial class that were implemented during the last rate study. All non-residential customers with a peak demand of 20 kW or greater in three or more months out of the previous 12 months are included in this class.

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 significant capital expenditures in the last three years. 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

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MOUNTAIN LAKE MUNICIPAL UTILITIES
ELECTRIC RATE STUDY
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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 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

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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 1,040 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 2019 to 2023, 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 changing 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:

- Peak Demand (kW) – The maximum rate of power delivery, measured in a defined time period such as 30 minutes, expressed in 1,000 watt units.
- Energy (kWh) – 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).
- Load Factor – 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.
- Single Phase – 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.

ENERGY REQUIREMENTS

The table below shows annual peak demand, sum of monthly peak demands, and energy requirements for Mountain Lake from 2015 to 2023. In 2017 and 2018, Mountain Lake's energy requirements increased over 7.5% due to the expansion of a Large Commercial customer and some extreme weather conditions increasing the heating and air conditioning load. The study forecasts that energy requirements will decrease by 0.5% in 2019 due to weather normalization and then increase by 0.25% per year from 2020 to 2023. The system annual peak typically occurs in the summer months, and the annual peak is forecasted to be in July from 2020 through 2023. In the past three years, the annual peak has averaged 5,586 kW, while the average monthly peak was only 4,571 kW. The higher summer peaks are due to air conditioning usage by residential and commercial customers.

Historical and Forecasted Wholesale Energy Requirements and Retail Sales						
	Year	**Annual Peak Demand (kW)**	**Sum of Monthly Demands (kW)**	**% change**	**Energy Requirements (MWh)**	**% Change**
Historical	2015	4,744 July	50,807		25,415	
	2016	5,594 Aug.	53,458	5.2%	25,750	1.3%
	2017	5,319 July	55,001	2.9%	27,015	4.9%
	2018	5,844 Oct.	56,085	2.0%	27,757	2.7%
Forecast	2019	5,902 July	56,134	0.1%	27,618	(0.5%)
	2020	5,917 July	56,275	0.3%	27,687	0.3%
	2021	5,932 July	56,415	0.3%	27,756	0.3%
	2022	5,947 July	56,556	0.3%	27,826	0.3%
	2023	5,962 July	56,698	0.3%	27,895	0.3%

The chart on the following page shows the total forecasted energy requirements from 2020 to 2023 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 21% of Mountain Lake's energy requirements from 2020 through 2023. 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 include the following: WPPI Energy supplying about 14%; two successive 5x16 contracts with NextEra and Citigroup, supplying nearly 14% combined; and the Midcontinent Independent System Operator (MISO) market purchases supplying approximately 24% 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 over 11% of Mountain Lake's energy needs. The purchased power and local generation costs are further discussed in Section 2.

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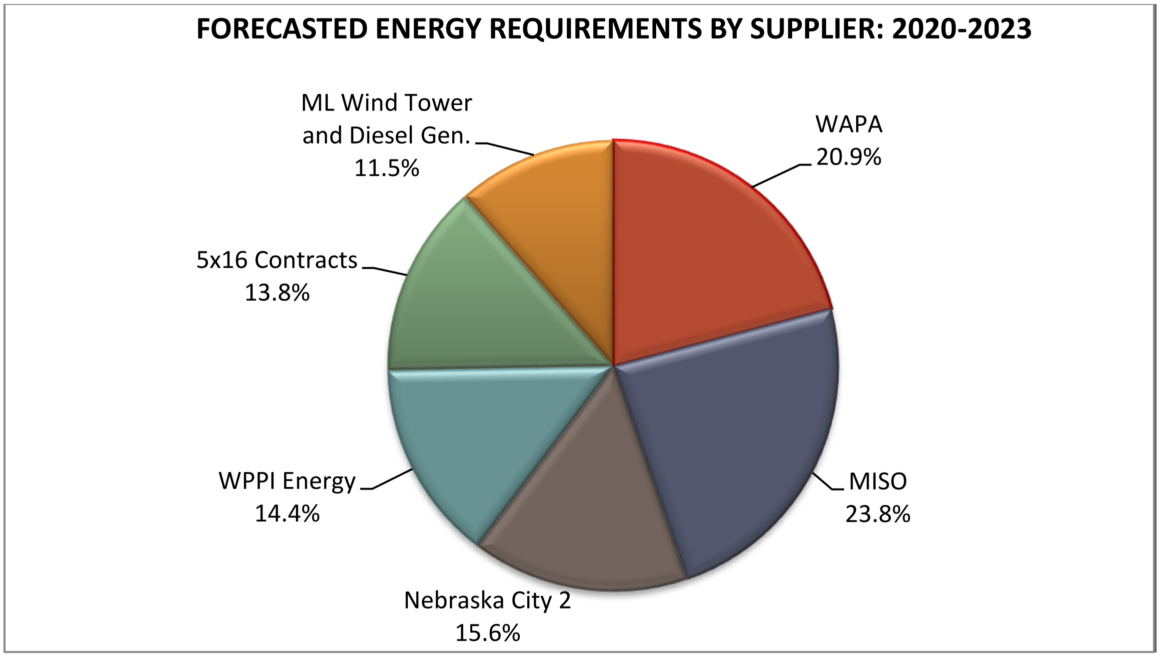
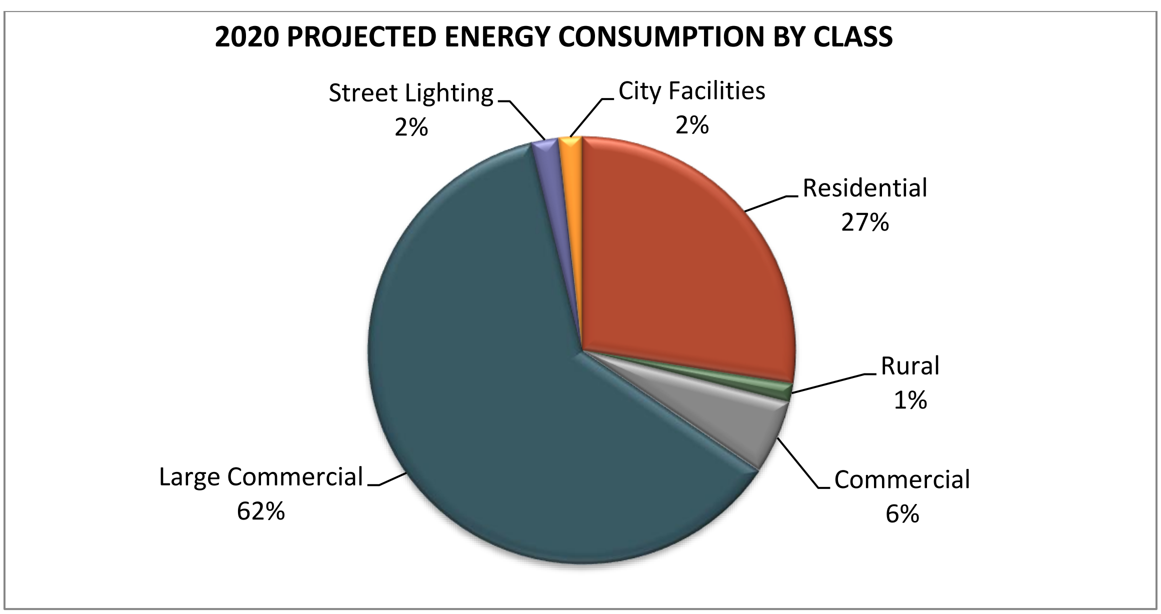


PROJECTED ENERGY CONSUMPTION BY CLASS

The projected energy consumption by class for 2020 is shown in the pie chart below. The breakdown shows that Residential customers, including the rural class, are projected to consume 28% 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 Large Commercial class is projected to have 62% of the energy sales in 2020 but only 5% of the total customers. City facilities also include the water and wastewater utilities' consumption.



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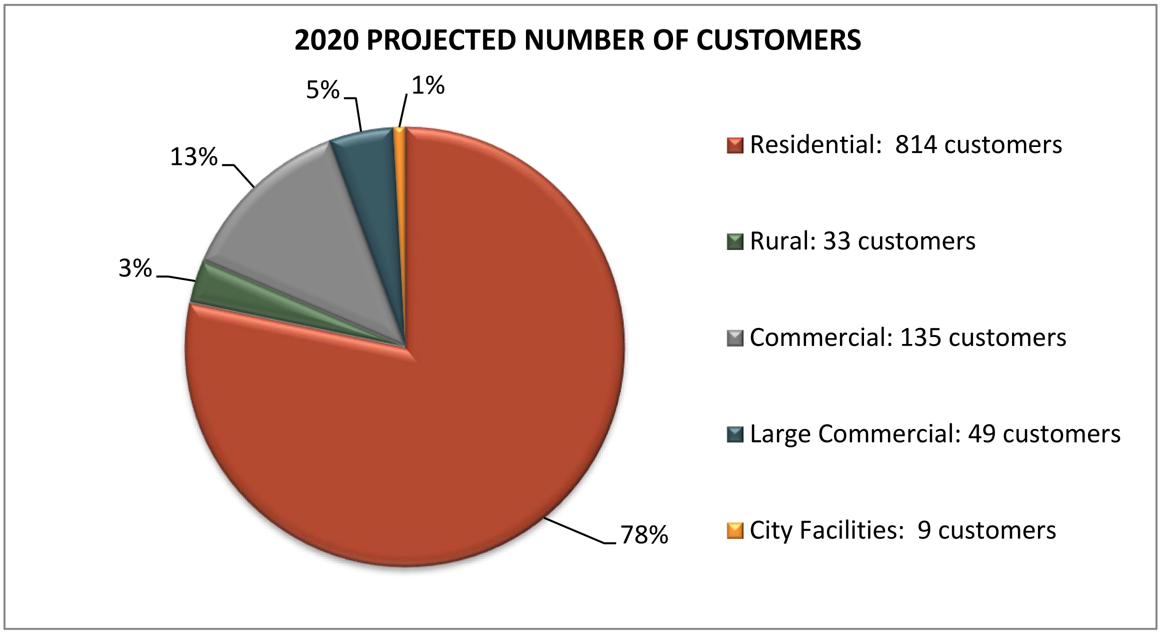
PROJECTED NUMBER OF CUSTOMERS BY CLASS

Based on discussions with staff, Mountain Lake expects one additional Large Commercial customer and one Municipal customer during 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 2020. The Residential class has 78% of the total number of customers.



SECTION 2

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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 2019 to 2023. 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. Exhibit 2-C provides details on the historical and projected purchased power, transmission, local production costs, and annual power cost adjustment.

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 ($0.0056) per kWh in 2019 to ($0.0004) per kWh in 2023, as shown in Exhibit 2-C.

Other operating revenue includes late payment, reconnect, and shut off fees, hanger notices, municipally-owned transmission line revenue, and conservation improvement plan (CIP) revenue. Other operating revenue is projected to increase from about $86,300 in 2018 to $130,000 by 2023. The majority of that increase is due to the transmission line revenue increasing by around $50,000 in 2020 due to additional transmission related labor costs being recovered.

Non-operating revenue consists of investment income that is estimated at 1.0% of cash reserves and refunds and reimbursements of $3,200 each year.

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. Revenue requirement projections were based on historical operating statements from 2016 through 2018, operating budgets for 2019 and 2020, estimated purchased power expenses, and discussions with Mountain Lake staff.

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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 held rates steady from 2010 through 2016 at a composite rate of $33.25 per MWh. In 2017 and 2018, WAPA reduced the composite rate by approximately 30%, resulting in a total savings of around $60,000 annually for Mountain Lake.

In 2018, the base component of the firm power demand and energy rates increased to $24 per MWh and the drought adder decreased to zero. The voltage discount of 5% of the total bill was also eliminated in 2018. With the new WAPA contract beginning in January 2021, the wheeling credit will also be eliminated. Preliminary indications show that WAPA is anticipating no additional rate changes throughout the study period.

WAPA Actual and Projected Wholesale Demand and Energy Rates			
Year	**Demand Rate ($/kW-month)**	**All Energy ($/MWh)**	**Wheeling Credit ($/kWh)**
2010-2016 (Actual)	$7.65	$19.05	($0.001)
2017 (Actual)	$6.50	$16.18	($0.001)
2018-2020 (Actual)	$5.25	$13.27	($0.001)
2021-2023 (Projected)	$5.25	$13.27	-

Other Power Supply Costs

Mountain Lake is projected to purchase nearly 14% of its energy requirements through two 5x16 On Peak contracts. The NextEra 5 x 16 contract at $45.70 per MWh expires in 2020 and will be replaced by a larger Citigroup 5 x 16 contract at $35.50 per MWh. The annual energy purchases will increase from 2,040 MWh to 4,009 MWh.

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 4,325 MWh per year from NC2 at an estimated price of $35.80 per MWh in 2019

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increasing to $38.80 per MWh by 2023. To diversify its resource mix, Mountain Lake contracted with WPPI Energy in Sun Prairie, Wisconsin, to receive over 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 $63.60 per MWh in 2019 to $68.80 per MWh by 2023.

Mountain Lake is projected to produce nearly 12% of its own energy from the municipally-owned wind turbine and a seldom run diesel generation plant. The remaining energy requirements, or approximately 24%, are projected to be purchased in the MISO market at an estimated average price of $22 per MWh. 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 $14,000 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 $19.00 per MWh in 2019 and gradually increasing to $21.40 per MWh by 2023, or 3% per year. Transmission costs have continued to increase in the last several years due to ITC Midwest seeking cost recovery for their significant capital investments that have been made to the regional transmission grid. Finally, Mountain Lake pays CMPAS for energy scheduling, member dues, agency fixed costs, and contract administration. In 2019, the member dues were reduced from $2,500 per month to $1,500 per month, while the scheduling charge was also reduced from $3.25 per MWh to $0.55 per MWh. Additionally, CMPAS eliminated the Agency Fixed Fees in 2019. The reduced fees and dues saves Mountain Lake over $90,000 per year and the amounts are expected to remain stable going forward.

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

Total power supply and transmission costs are expected to increase an average of 2.4% per year from 2019 through 2023. The table below shows the estimated purchased power and transmission expenses by supplier. The 2019 expenses are based on actual year to date costs provided by Mountain Lake.

Estimated Purchased Power, Local Generation, and Transmission Expenses									
Year	**WAPA**	**Nebraska City 2**	**5x16 Contract**	**WPPI Energy**	**MISO Market & Wolf Wind**	**Mt. Lake Total Local Generation**	**Trans-mission**	**CMPAS Charges**	**Total Cost**
2019	$126,088	$154,835	$92,862	$254,985	$180,305	$195,792	$523,954	$33,447	$1,562,269
2020	$126,088	$157,932	$93,228	$260,085	$205,231	$196,605	$541,024	$33,485	$1,613,677
2021	$140,597	$161,090	$157,303	$265,287	$145,698	$197,429	$558,650	$33,523	$1,659,576
2022	$141,034	$164,312	$157,303	$270,592	$146,822	$198,265	$576,850	$33,561	$1,688,740
2023	$140,597	$167,598	$157,303	$276,004	$148,755	$198,681	$595,643	$33,599	$1,718,181

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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 0.1% in 2019 and is projected to increase by an average of 2.2% per year from 2020 through 2023.

Estimated Purchased Power and Transmission Prices per MWh and Total Cost per MWh (includes Congestion and Losses where applicable)									
Year	**WAPA**	**Neb. City 2**	**5x16 Contracts**	**WPPI Energy**	**MISO Market**	**Mt. Lake Wind**	**Trans-mission**	**Total Cost per MWh**	**% Increase**
2019	$21.40	$35.80	$45.70	$63.60	$20.20	$54.00	$19.00	$56.60	0.1%
2020	$21.40	$36.50	$45.70	$64.90	$23.00	$54.00	$19.60	$58.30	3.0%
2021	$23.90	$37.20	$35.50	$66.20	$22.00	$54.00	$20.20	$59.80	2.6%
2022	$23.90	$38.00	$35.50	$67.50	$22.00	$54.00	$20.80	$60.70	1.5%
2023	$23.90	$38.80	$35.50	$68.80	$22.00	$54.00	$21.40	$61.60	1.5%

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 2020 through 2023, or 4.0% 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 is projected at $23,400 per year, or 0.8% of operating revenues. The total transfer and value of discounted electric service is estimated to be 4.8% of operating revenues from 2020 through 2023.

The 2016 American Public Power Association national survey indicated the median percentage of transfers and related payments as a percentage of operating revenues was 5.6%. Meanwhile, in a study of 87 area municipal utility financial statements, MRES found that the median level of transfers and donated services as a percentage of operating revenues was 5.1% 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.

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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 2018 was $643,750. In 2009, $550,000 of bonds were issued to install a new feeder line. These bonds were later refinanced in 2015 at a lower rate. 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. Lastly, the 2017A bonds were issued to fund upgrades to the local generation and substation. The 2007B, 2012C, and 2015B bonds are projected to be paid in full in either 2023 or 2024. The 2017A issuance is projected to be paid in full in 2036, and principal payments on this issuance are scheduled to increase after the other three bonds are paid off. Finally, the electric utility has $248,000 in a restricted 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, 2018 Outstanding Balance**	**2019-2023 Principal Payments**	**2019-2023 Interest Expense**	**Dec. 31, 2023 Outstanding Balance**
2007B	ML Wind Turbine	$643,750	$643,750	N/A	$-
2012C	Distribution System	$310,000	$310,000	$23,183	$-
2015B	Feeder Dist. Line	$273,000	$235,000	$23,122	$38,000
2017A	NESHAP/Substation	$2,940,000	$75,000	$522,475	$2,865,000
	Total	$4,166,750	$885,000	$568,779	$2,903,000

Capital Expenditures

Based on Mountain Lake's five year capital improvement plan and discussions with staff, the capital expenditures are expected to total approximately $962,200 from 2019 to 2023. The following is a breakdown of the revenue-financed capital expenditures:

- Distribution System Improvements $474,000
- Routine Maintenance $199,400
- Local Generation $149,000
- Vehicles/Equipment $139,800

SUMMARY OF RESULTS

Based on the assumptions described in this section, MRES has projected the net income and cash reserves as shown in Exhibits 2-A and 2-B. Unrestricted reserves exclude $250,000 that is restricted for bond reserve covenants. The projections are discussed further in Section 4.

Exhibit 2-A

Mountain Lake Public Utilities
Electric Utility Operating Results
Current Rates

	Historical				Projected				
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Total System Retail kWh Sales	24,281,935	24,240,771	26,021,520	26,563,227	26,378,352	26,444,298	26,510,409	26,576,685	26,643,127
kWh % Change from Year to Year		-0.2%	7.3%	2.1%	-0.7%	0.2%	0.2%	0.3%	0.2%
OPERATING REVENUES									
Metered Electric Sales	$ 2,408,840	2,381,021	2,576,731	2,492,129	$ 2,738,368	$ 2,792,279	$ 2,840,778	$ 2,872,511	$ 2,904,528
Other Operating Revenues		77,329	88,842	82,888	114,576	132,884	132,012	130,920	129,863
Total Operating Revenues	2,408,840	2,458,350	2,665,573	2,575,017	2,852,943	2,925,163	2,972,790	3,003,431	3,034,391
OPERATING EXPENSES									
Purchased Power & Transmission	1,451,453	1,429,075	1,476,235	1,381,520	1,366,477	1,417,072	1,462,148	1,490,475	1,519,500
Production	80,742	110,932	76,802	111,855	107,200	98,700	101,661	104,711	107,852
Distribution	279,653	274,583	311,444	305,453	389,973	436,248	440,915	454,143	467,767
Administrative & General	193,249	170,394	238,093	186,330	188,508	194,879	200,314	205,913	211,679
Depreciation Expense	284,932	282,753	275,161	284,766	290,399	301,277	307,222	312,769	316,841
Total Operating Expense	2,290,029	2,267,737	2,377,736	2,269,924	2,342,557	2,448,177	2,512,261	2,568,010	2,623,639
NET OPERATING INCOME	118,811	190,613	287,837	305,093	510,386	476,986	460,529	435,421	410,752
NON-OPERATING REVENUES (EXPENSES)									
Interest Income	34,609	9,243	15,958	21,761	13,163	16,412	16,273	17,503	18,659
Refunds and Reimbursements	18,562	40,849	18,129	3,558	3,200	3,200	3,200	3,200	3,200
CAPX Transmission Revenues	7,305	7,056	4,234	1,997	480	-	-	-	-
Interest Expense	(50,074)	(37,448)	(28,780)	(110,593)	(120,977)	(117,671)	(114,136)	(111,169)	(107,826)
Amortization Expense	-	(7,805)	-	-	-	-	-	-	-
Cost of Issuance	-	-	(12,095)	-	-	-	-	-	-
Total Non-Operating Revenue (Expense)	10,402	11,895	(2,554)	(83,277)	(104,134)	(98,059)	(94,663)	(90,466)	(85,967)
TRANSFER TO THE GENERAL FUND	(120,000)	(152,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)	(120,000)
NET INCOME	**$ 9,213**	**$ 50,508**	**$ 165,283**	**$ 101,816**	**$ 286,251**	**$ 258,928**	**$ 245,867**	**$ 224,955**	**$ 204,785**
Net Income as a % of Oper. Revenue	0.4%	2.1%	6.2%	4.0%	10.0%	8.9%	8.3%	7.5%	6.7%
Debt Service Coverage					225%	221%	220%	213%	209%

Mountain Lake Public Utilities

Exhibit 2-B

Electric Utility Cash Reserves

Current Rates

	Historical: Annual Financial Report				Estimated				
	2015	2016	2017	2018	2019	2020	2021	2022	2023
NET INCOME	$ 9,213	$ 50,508	$ 165,283	$ 101,816	$ 286,251	$ 258,928	$ 245,867	$ 224,955	$ 204,785
LESS: Revenue-Financed Capital Expenditures	(167,429)	(792,406)	(2,323,973)	(850,177)	(169,000)	(326,333)	(178,353)	(166,404)	(122,153)
LESS: Bond Principal Payment 2017A					(15,000)	(15,000)	(15,000)	(15,000)	(15,000)
LESS: Bond Principal Payment 2015B Refunding					(45,000)	(44,000)	(48,000)	(47,000)	(51,000)
LESS: Bond Principal Payment 2012C					(60,000)	(60,000)	(60,000)	(65,000)	(65,000)
LESS: Bond Principal Payment 2007B					(128,750)	(128,750)	(128,750)	(128,750)	(128,750)
ADD: Depreciation Expense					290,399	301,277	307,222	312,769	316,841
ADD: UPES Sale					166,000	-	-	-	-
ADDITION (REDUCTION) IN RESERVES					**$ 324,901**	**$ (13,879)**	**$ 122,986**	**$ 115,570**	**$ 139,724**
Beginning of Year Unrestricted Reserves		$ 1,936,594	$ 1,373,564	$ 2,348,814	$ 1,316,318	$ 1,641,219	$ 1,627,340	$ 1,750,326	$ 1,865,896
Addition (Reduction) in Reserves		(563,030)	975,250	(1,032,496)	324,901	(13,879)	122,986	115,570	139,724
End of Year Unrestricted Reserves	**$ 1,936,594**	**$ 1,373,564**	**$ 2,348,814**	**$ 1,316,318**	**$ 1,641,219**	**$ 1,627,340**	**$ 1,750,326**	**$ 1,865,896**	**$ 2,005,619**
Reserves as % of Operating Revenues	**80%**	**56%**	**88%**	**51%**	**58%**	**56%**	**59%**	**62%**	**66%**
Cash Balance									
Unrestricted	1,936,594	1,373,564	2,348,814	1,316,318	1,641,219	1,627,340	1,750,326	1,865,896	2,005,619
Designated									
Restricted for Bond Reserve	$ 248,250	$ 248,250	$ 248,250	$ 248,250	248,250	248,250	248,250	248,250	248,250
Total Cash Reserves	$ 2,184,844	$ 1,621,814	$ 2,597,064	$ 1,564,568	$ 1,889,469	$ 1,875,590	$ 1,998,576	$ 2,114,146	$ 2,253,869

Exhibit 2-C

Mountain Lake Municipal Utilities									
Historical and Projected Purchased Power and Local Generation Costs									
	Historical				Projected				
Generation and Transmission Costs	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Member Dues	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000	$ 18,000
CMPAS Scheduling Charge	$ 57,642	$ 55,180	$ 58,269	$ 75,490	$ 15,107	$ 15,145	$ 15,183	$ 15,221	$ 15,259
CMPAS Contract Administration	$ 16,074	$ 8,952	$ 15,686	$ 10,599	$ 11,000	$ 11,000	$ 11,000	$ 11,000	$ 11,000
CMPAS Agency Fixed Fees	$ 10,800	$ 10,800	$ 19,200	$ 19,200	$ -	$ -	$ -	$ -	$ -
NC2 - MWH Energy	$ 148,020	$ 163,388	$ 152,856	$ 161,467	$ 154,835	$ 157,932	$ 161,090	$ 164,312	$ 167,598
MISO Energy Purchases	$ 73,641	$ 104,145	$ 207,940	$ 151,684	$ 166,305	$ 191,231	$ 131,698	$ 132,822	$ 134,755
NextEra 5x16 Contract	$ 137,284	$ 95,465	$ 92,480	$ 93,587	$ 92,862	$ 93,228	$ -	$ -	$ -
5x16 Citi Group	$ -	$ -	$ -	$ -	$ -	$ -	$ 157,303	$ 157,303	$ 157,303
Xcel Energy Time of Day Contract	$ 89,906	$ 65,856	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WPPI Energy	$ 230,849	$ 234,581	$ 238,488	$ 252,591	$ 254,985	$ 260,085	$ 265,287	$ 270,592	$ 276,004
Wolf Wind Project	$ 18,642	$ 15,373	$ 11,488	$ 8,200	$ 14,000	$ 14,000	$ 14,000	$ 14,000	$ 14,000
Mountain Lake Wind Turbine	$ 177,444	$ 175,753	$ 175,298	$ 160,433	$ 170,100	$ 170,100	$ 170,100	$ 170,100	$ 170,100
WAPA Allocation	$ 183,853	$ 186,456	$ 145,821	$ 124,450	$ 124,279	$ 124,279	$ 138,787	$ 139,225	$ 138,787
ITC Midwest - Transmission	$ 451,124	$ 471,435	$ 510,402	$ 462,612	$ 523,954	$ 541,024	$ 558,650	$ 576,850	$ 595,643
FTR Credit - WAPA	$ (1,691)	$ (8,377)	$ (1,785)	$ 713	$ (1,691)	$ (1,691)	$ (1,691)	$ (1,691)	$ (1,691)
WAPA Congestion & Losses	$ 3,843	$ -	$ -	$ -	$ 3,500	$ 3,500	$ 3,500	$ 3,500	$ 3,500
Agency Capacity	$ -	$ (4,873)	$ (4,460)	$ (10,660)	$ (10,660)	$ (10,660)	$ (10,660)	$ (10,660)	$ (10,660)
Misc. Adjustment	$ -	$ 55	$ 34	$ -	$ -	$ -	$ -	$ -	$ -
Total Purchased Power Costs	**$ 1,627,431**	**$ 1,604,189**	**$ 1,651,717**	**$ 1,540,366**	**$ 1,536,577**	**$ 1,587,172**	**$ 1,632,248**	**$ 1,660,575**	**$ 1,689,600**
Mountain Lake Power Plant Fuel	$ 9,049	$ 10,596	$ 5,413	$ 14,654	$ 12,480	$ 12,896	$ 13,312	$ 13,728	$ 14,144
Power Plant O&M Costs	$ 27,663	$ 13,130	$ 13,402	$ 12,827	$ 13,212	$ 13,609	$ 14,017	$ 14,437	$ 14,437
Total Power Plant Costs	**$ 36,712**	**$ 23,726**	**$ 18,815**	**$ 27,481**	**$ 25,692**	**$ 26,505**	**$ 27,329**	**$ 28,165**	**$ 28,581**
Total Costs - Energy Charge Calc	**$ 1,664,143**	**$ 1,627,915**	**$ 1,670,532**	**$ 1,567,847**	**$ 1,562,269**	**$ 1,613,677**	**$ 1,659,576**	**$ 1,688,740**	**$ 1,718,181**
Percentage Change	0.4%	-2.2%	2.6%	-6.1%	-6.1%	3.3%	2.8%	1.8%	1.7%
Energy Purchased / Generated - kWh									
NC2	4,100,300	4,511,000	4,053,600	4,766,600	4,325,000	4,325,000	4,325,000	4,325,000	4,325,000
MISO	3,247,567	3,730,605	7,783,715	6,641,444	8,253,335	8,314,380	5,986,265	6,037,346	6,125,220
NextEra 5x16 Contract	2,048,000	2,040,000	2,016,000	2,048,000	2,032,000	2,040,000			
Xcel Energy Time of Day	2,762,900	2,127,000	-	-	-	-	-	-	-
WPPI Energy	4,135,400	4,232,100	4,039,100	4,238,500	4,009,200	4,009,200	4,009,200	4,009,200	4,009,200
5x16 Citigroup	-	-	-	-	-	-	4,437,333	4,437,333	4,437,333
Mountain Lake Wind Turbine	3,285,999	2,900,745	3,246,265	2,742,576	3,150,000	3,150,000	3,150,000	3,150,000	3,150,000
WAPA Allocation	5,763,500	6,135,750	5,850,000	5,815,000	5,807,000	5,807,000	5,807,000	5,825,310	5,807,000
Mountain Lake Power Plant	71,000	73,000	26,800	4,800	41,600	41,600	41,600	41,600	41,600
Adjustment	-	-	-	1,500,000	-	-	-	-	-
Total Energy Purchased/Generated	**25,414,666**	**25,750,200**	**27,015,480**	**27,756,920**	**27,618,135**	**27,687,180**	**27,756,398**	**27,825,789**	**27,895,354**
Percentage Change	-3.4%	1.3%	4.9%	2.7%	-0.5%	0.25%	0.25%	0.25%	0.25%
Less: Transmission Loss Adj. (95.3%)	(1,194,489)	(1,210,259)	(1,269,728)	(1,304,575)	(1,298,052)	(1,301,297)	(1,304,551)	(1,307,812)	(1,311,082)
Add: PCA Calc Adj				1,620,000					
Total Sales for PCA Calculation	**24,220,177**	**24,539,941**	**25,745,752**	**28,072,345**	**26,320,083**	**26,385,883**	**26,451,848**	**26,517,977**	**26,584,272**
Costs - Cents / kWh (includes congestion/losses)									
NC2	3.61	3.62	3.77	3.39	3.58	3.65	3.72	3.80	3.88
MISO	2.27	2.79	2.67	2.28	2.02	2.30	2.20	2.20	2.20
NextEra 5x16 Contract	6.70	4.68	4.59	4.57	4.57	4.57	-	-	-
Xcel Energy Time of Day	3.25	3.10	-	-	-	-	-	-	-
WPPI Energy	5.58	5.54	5.90	5.96	6.36	6.49	6.62	6.75	6.88
Citigroup 5x16	-	-	-	-	-	-	3.55	3.55	3.55
Mountain Lake Wind	5.40	6.06	5.40	5.85	5.40	5.40	5.40	5.40	5.40
WAPA	3.19	3.04	2.49	2.14	2.14	2.14	2.39	2.39	2.39
Transmission	1.78	1.84	1.89	1.67	1.90	1.96	2.02	2.08	2.14
Local Generation - Fuel only	12.75	14.52	20.20	305.28	30.00	31.00	32.00	33.00	34.00
Power Cost Adjustment Calculation									
Purchased & Local Power Avg. Costs	6.55	6.32	6.18	5.65	5.66	5.83	5.98	6.07	6.16
Cost plus Trans. Loss Adj. (95.3%)	**6.87**	**6.63**	**6.49**	**5.59**	**5.94**	**6.12**	**6.27**	**6.37**	**6.46**
Less: PCA Base Cost	3.16	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Annual Average PCA	**3.71**	**0.13**	**(0.01)**	**(0.91)**	**(0.56)**	**(0.38)**	**(0.23)**	**(0.13)**	**(0.04)**

SECTION 3

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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 2020 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 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,

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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 and 2017A bond series payment, and the transfer to the City of Mountain Lake. The entire 20015B 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 and 2017A 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

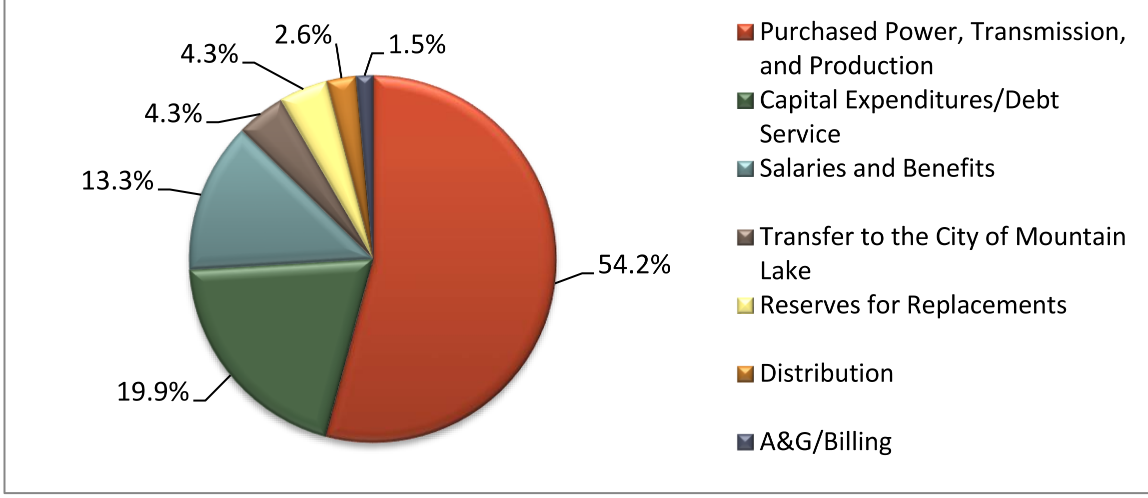
Certain revenues and expenses are not categorized to the seven components above but rather are allocated to these components based on percentage of direct labor spent on each area to the total cost of labor. Allocated in this manner are items such as portion of administrative and general expenses. Other operating revenues 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 54.2% of the retail rates recover purchased power, transmission, and production costs, which are not directly controlled at the local level with the exception of the local generation costs. The

transfer to the City of Mountain Lake equals 4.3% of the total costs. The other 41.5% of the total revenues are available to fund local electric utility operations and maintenance costs, capital expenditures, and debt service payments while maintaining sufficient reserves.

BREAKDOWN OF REVENUE REQUIREMENTS



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 class were used to estimate the demand allocators for this class. For the other classes, demand allocators were based on the system characteristics of Mountain Lake in relation to the specific classes of service.

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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 and Rural customers should see a slight increase while the Commercial and Large Commercial customers should see a small decrease. 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. 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**
Residential	$0.127	$0.126	$0.001	**1.0%**
Commercial	$0.131	$0.133	($0.002)	**(1.4%)**
Large Commercial	$0.093	$0.095	($0.002)	**(2.1%)**
Rural	$0.127	$0.125	$0.002	**1.2%**
Municipal	$0.108	$0.081	$0.027	**33.3%**
Street Lights	$0.100	$0.077	$0.023	**31.1%**
Total	**$0.105**	**$0.105**	**$0.000**	**0.0%**

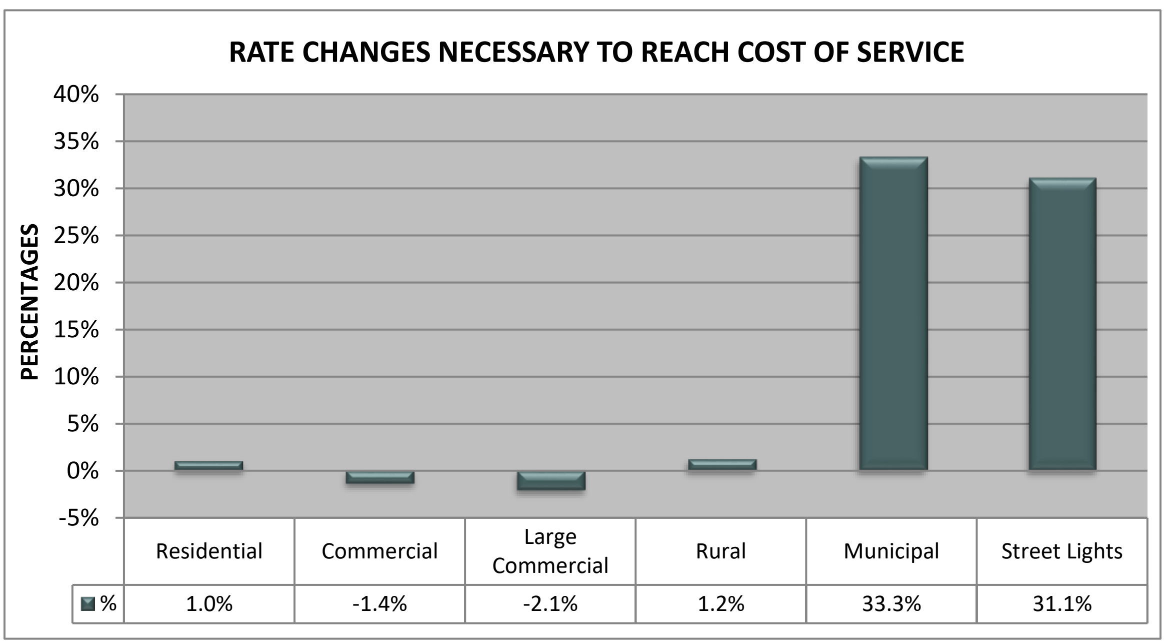

Exhibit 3-A

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
Purchased Power & Transmission									
Nebraska City 2 Purchases	$ 157,932	78,966	78,966						50% 12CP, 50% Energy
MISO Market Purchases	138,705	-	138,705						100% Energy
Excel Energy: 5 X 16 Contract	157,303	62,921	94,382						40% 12CP, 60% Energy
WPPI Purchases	260,085	130,042	130,042						50% 12CP, 50% Energy
WPPI Capacity Sold (B)	(10,660)	(10,660)							100% 12CP
Wolf Wind	14,000		14,000						100% Energy
WAPA Allocation	124,279	53,813	70,466						40% 12CP, 60% Energy
ITC Midwest Transmission	542,833	542,833							100% 12CP
CMPAS Agency and Scheduling Fees	44,145		44,145						100% Energy
Mountain Lake Wind Tower Maintenance	61,800	6,180	55,620						10% 12CP, 90% Energy
Land Rent for Wind Turbine	4,000	400	3,600						10% 12CP, 90% Energy
Moutain Lake Transmission Line Revenue (B)	(80,000)	(80,000)							100% 12CP
Operating Expenses (A)									
Production									
Supplies, repairs, maintenance	86,700	86,700							100% 12CP
Fuel Oil/Diesel	12,000		12,000						100% Energy
Distribution									
Salaries and Employee Benefits	275,528	27,738		113,146	113,146		17,336	4,161	Per distribution labor requirements
Plant Breaker Testing	6,000	6,000							100% 12CP
Meetings, Meals and Travel	100			50	50				50% CP, 50% CF
Telephone	720			360	360				50% CP, 50% CF
Street Lighting and Signal	3,000							3,000	100% SL
Repairs and Maintenance: Misc	51,500			23,250	23,250			5,000	Per repair and maintenance expense requirements
Repair and Maintenance: Meters	10,000						10,000		100% MR
Tree Replacement	5,000			2,500	2,500				50% 12CP, 50% CF
Miscellaneous	13,500			6,750	6,750				50% 12CP, 50% CF
Wells and Lift Station Power	2,000			1,000	1,000				50% 12CP, 50% CF
Conservation Improv. Program									
CIP Program Expenses	25,150			12,575	12,575				50% 12CP, 50% CF
CIP 1.5% Surcharge Revenues	(42,000)			(21,000)	(21,000)				50% 12CP, 50% CF
Administrative and General									
A&G Salaries and Benefits	93,383	1,783		7,272	7,272	75,676	1,114	267	Direct and indirect rev. and exp. allocation factors (D)
Utility Commission Salaries	1,000	82		333	333	188	51	12	Indirect revenue and expense allocation factors (C)
Motor Fuels	3,500			1,000	1,000		1,000	500	Per fuels expense requirement
Postage	5,000					5,000			100% CS
Professional Services	5,000	409		1,667	1,667	940	255	61	Indirect revenue and expense allocation factors (C)
General Liability Insurance	30,500	2,493		10,170	10,170	5,735	1,558	374	Indirect revenue and expense allocation factors (C)
Capital Improvement: Other Projects	24,000			12,000	12,000				50% 12 CP, 50% CF
Capital Outlay: Equipment	10,000			5,000	5,000				50% 12 CP, 50% CF
Office and Computer Supplies, Utilities	26,000	2,125		8,669	8,669	4,889	1,328	319	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	82,048	33,273	48,774						Per depreciation schedule
Distribution - Demand-Related Facilities	32,360			32,360					Per depreciation schedule
Distribution - Customer Facilities	31,611				31,611				Per depreciation schedule
Meter Reading	1,375						1,375		Per depreciation schedule
Street Lighting	7,607							7,607	Per depreciation schedule
Contributions for Customer Facilities (B)	(3,200)				(3,200)				100% CF
Other Operating Revenues (B)	(13,500)	(1,104)		(4,501)	(4,501)	(2,538)	(690)	(166)	Indirect revenue and expense allocation factors (C)
Investment Income (B)	(16,000)	(1,308)		(5,335)	(5,335)	(3,009)	(817)	(196)	Indirect revenue and expense allocation factors (C)
2012C Bond Series Payment: Distribution	66,085			33,043	33,043				50% 12 CP, 50% CF
2015B Bond Series Payment: Feeder	49,716			49,716					100% 12 CP
2017A Bond Principal and Interest	119,870			59,935	59,935				50% 12 CP, 50% CF
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	120,000	25,760	37,761	25,053	24,473	-	1,064	5,889	Per depreciation schedule
Revenue Requirements	**$ 2,788,724**	**$ 981,322**	**$ 844,336**	**$ 435,013**	**$ 380,768**	**$ 86,881**	**$ 33,575**	**$ 26,829**	

(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).

Mountain Lake Municipal Utilities
Allocation Factors

Exhibit 3-B

Allocation Factors	Total	Residential	Commercial/ City Facilities	Large Commercial	Rural	Street Lighting
Demand Allocation Factors						
12-Month Coincident Peak (kW)	56,380	18,767	5,108	31,386	968	151
Percentage - CP	100%	33.3%	9.1%	55.7%	1.7%	0.3%
Energy Allocation Factors						
Annual Energy Requirements (kWh)	27,683,241	7,667,676	2,031,892	17,005,169	397,167	581,337
Percentage - E	100%	27.7%	7.3%	61.4%	1.4%	2.1%
Customer Facilities Allocation Factors						
Average number of customers	1,466	814	145	48	33	426
Weighting factor		1.0	1.6	26.0	1.3	0.1
Weighted number of customers	2,380	814	232	1,248	43	43
Percentage - CF	100%	34.2%	9.7%	52.4%	1.8%	1.8%
Customer Service Allocation Factors						
Average number of customers	1,041	814	145	48	33	1
Weighting factor		1.0	1.0	2.0	1.0	1.0
Weighted number of customers	1,089	814	145	96	33	1
Percentage - CS	100%	74.7%	13.3%	8.8%	3.0%	0.1%
Metering Service Allocation Factors						
Average number of customers	1,041	814	145	48	33	1
Weighting factor		1.0	1.0	2.0	1.5	1.0
Weighted number of customers	1,106	814	145	96	50	1
Percentage - MR	100%	73.6%	13.1%	8.7%	4.5%	0.1%

Mountain Lake Municipal Utilities
Allocation of Revenue Requirements

Classification	Total	Residential	Commercial	Large Commercial	Rural	City Facilities	Street Lighting
Generation & Transmission 12 CP Demand	$ 981,322	$ 326,653	$ 67,485	$ 546,291	$ 16,856	$ 21,414	$ 2,623
Energy	844,336	233,863	47,044	518,656	12,114	14,928	17,731
Distribution 12 CP Demand	435,013	144,803	29,916	242,167	7,472	9,493	1,163
Customer Facilities	380,768	130,256	33,353	199,705	6,865	3,772	6,817
Customer Service	86,881	64,941	10,930	7,659	2,633	638	80
Metering	33,575	24,722	4,161	2,916	1,503	243	30
Street Lighting (Direct Allocation)	26,829	-	-	-	-	-	26,829
Revenue Requirements	**$ 2,788,724**	**$ 925,239**	**$ 192,888**	**$ 1,517,394**	**$ 47,443**	**$ 50,489**	**$ 55,272**
Class Revenues	$ 2,788,908	$ 915,947	$ 195,697	$ 1,550,347	$ 46,872	$ 37,872	$ 42,173
Difference (Rev. Req. Less Revenues)	$ (184)	$ 9,291	$ (2,809)	$ (32,953)	$ 571	$ 12,617	$ 13,099
Cost of Service Adjustment Percentage	**0.0%**	**1.0%**	**-1.4%**	**-2.1%**	**1.2%**	**33.3%**	**31.1%**

SECTION 4

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SECTION 4 – PROPOSED RATES

Several factors were considered in determining the proposed 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

RATE DESIGN

The analysis outlined in Section 2 indicated that projected revenues should cover operating costs while also funding capital expenditures and building reserves. The analysis showed reserves should continue increasing to over $2 million by 2023. Over the last four years, Mountain Lake has made progressive cost of service adjustments to better align how costs are recovered and enhance equitability between rate classes. The cost of service results shown on page 3-5 show that minor adjustments could be made between classes to ensure cost based rates.

Based on the analysis outlined in this report, the rate study recommends no overall revenue change, however, individual customers would see small changes. The current and proposed rates are discussed next and are shown on page 4-3. 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. <u>Increase the monthly customer charges for Residential and Rural customers.</u> 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.

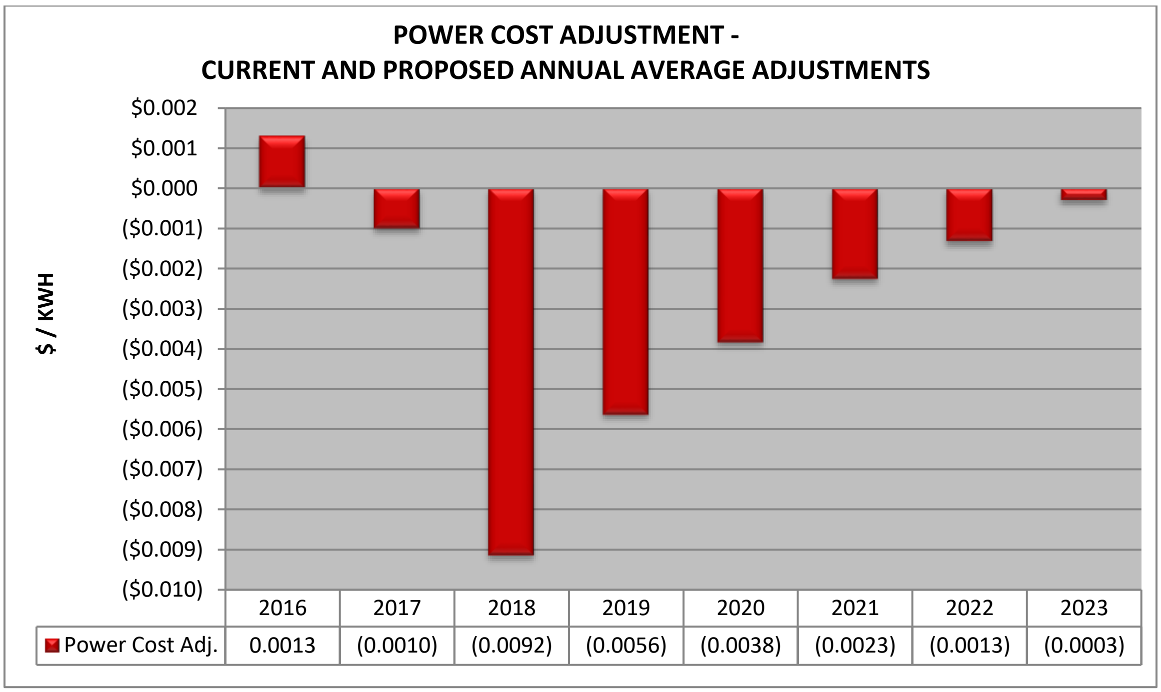
   Higher customer charges also help to prepare the utility for the possibility of customers adding distributed energy resources in the future. Many utilities have been steadily increasing their customer charges in recent years. Based on a review of residential customer charges for approximately 110 area municipal utilities, the average charge is over $13 per month in 2019, and the average is expected to steadily increase in the future.

2. <u>Maintain the PCA base factor of $0.0650 per kWh and continue the current calculation to determine the monthly PCA</u>. The PCA allows the utility to recover varying purchased power supply, transmission, and local generation costs from its customers between formal rate adjustments. The calculation to determine the monthly PCA is as follows:

`

- Purchased Power Costs + Local Production Costs = Total Power Costs
- Total Energy Purchased and Generated times 95.3% Loss Factor = Approximate Retail kWh Sales
- 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

The graph below shows the historical and projected PCA during the study period. Several factors played into the large PCA credit in 2018 including two one-time true ups from MISO, lower CMPAS fees, a 30% overall WAPA decrease, and a calculation adjustment. The PCA is projected to increase throughout the study period as purchased power and transmission costs increase.



3. <u>Maintain the qualifications for the Large Commercial class that were implemented during the last rate study. The qualifications include any non-residential customer with a peak demand of 20 kW or more in three or more months out of the previous 12 months</u>. The customers that qualify for the Large Commercial class would remain in the class for a minimum of 12 months.

   The cost of service study indicated that the demand rate should be around $22 per kW and the energy rate about $0.032 per kWh. The proposed rates will continue to shift this class in the direction indicated by the cost-of-service analysis.

Proposed Electric Rate Recommendations (Continued)

4. <u>Increase the energy rate for the City Facilities and Street Lighting class.</u> The city facilities, including the water and wastewater treatment plants, are currently paying a discounted energy rate compared to the Commercial and Large Commercial classes. 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. The City rates have been steadily increased each year since 2016, and this transition would continue with the proposed 2020 rates.

   Street lighting usage will continue to be billed in the City Facilities class. The electric utility has recently completed the conversion of high pressure sodium lights (HPS) to light emitting diode (LED) lamps. Higher installation and fixture costs coupled with lower electric usage increases the cost per kWh to serve the street lights.

5. <u>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.</u>

Current and 2020 Proposed Rates

Customer Class	Rate Components	Current Rates	Current Rates with PCA	2020 Proposed Rates	Proposed Rates with PCA	2020 % Change
Overall Revenue Change						**0.0%**
2020 Power Cost Adjustment	Adjustment Base Factor Average Adjustment	$0.0650 (0.0056)		$0.0650 (0.0038)		
Residential	Customer Charge Energy Charge – per kWh	$13.00 $0.1125	$0.1069	$14.00 $0.1130	$0.1092	1.5%
Rural	Customer Charge Energy Charge – per kWh	$16.50 $0.1115	$0.1059	$17.00 $0.1130	$0.1092	1.6%
Commercial	Customer Charge Energy Charge – per kWh	$24.00 $0.1100	$0.1044	$24.00 $0.1090	$0.1052	(0.8%)
Large Commercial (Over 20 kW)	Customer Charge Demand Charge – per kW Energy Charge – per kWh	$55.00 $12.40 $0.0635	$0.0579	$55.00 $14.00 $0.0580	$0.0542	(1.3%)
City Facilities & Street Lighting	Customer Charge Energy Charge – per kWh	$24.00 $0.0800	$0.0744	$24.00 $0.0860	$0.0822	8.1%
Conservation Improvement Plan	Surcharge – % of Electric Bill	1.5%		1.5%		

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CUSTOMER BILLS AND AVERAGE REVENUE PER KWH GRAPHS

Exhibits 4-A through 4-C at the end of this section contain graphs of customer bills for the Residential and Commercial classes, and average revenue per kWh for the Large Commercial class. The averages on Exhibit 4-C can be used to calculate the bills by knowing the load factor of the Large Commercial customers. The rates per kWh for this exhibit are calculated using a monthly demand of 20 kW and load factors ranging from 20% to 75%.

Finally, Exhibit 4-D shows a cost per kWh comparison between the Commercial and Large Commercial classes with load factors ranging from 20% to 75% based on a customer demand of 20 kW. This shows that most customers with a load factor above 42% would pay a lower cost per kWh in the Large Commercial class.

All of these graphs are calculated under current and 2020 proposed rates including the projected 2020 PCA of ($0.00384) per kWh and the 1.5% conservation surcharge.

RETAIL RATE RECOMMENDATION RESULTS

As a result of the proposed 2020 rates, a typical Residential customer using 800 kWh per month would see an increase of $1.42 per month, or 1.4%. Meanwhile, a Residential heating customer using 1,600 kWh would see an increase of $1.83 per month, or 1.0%.

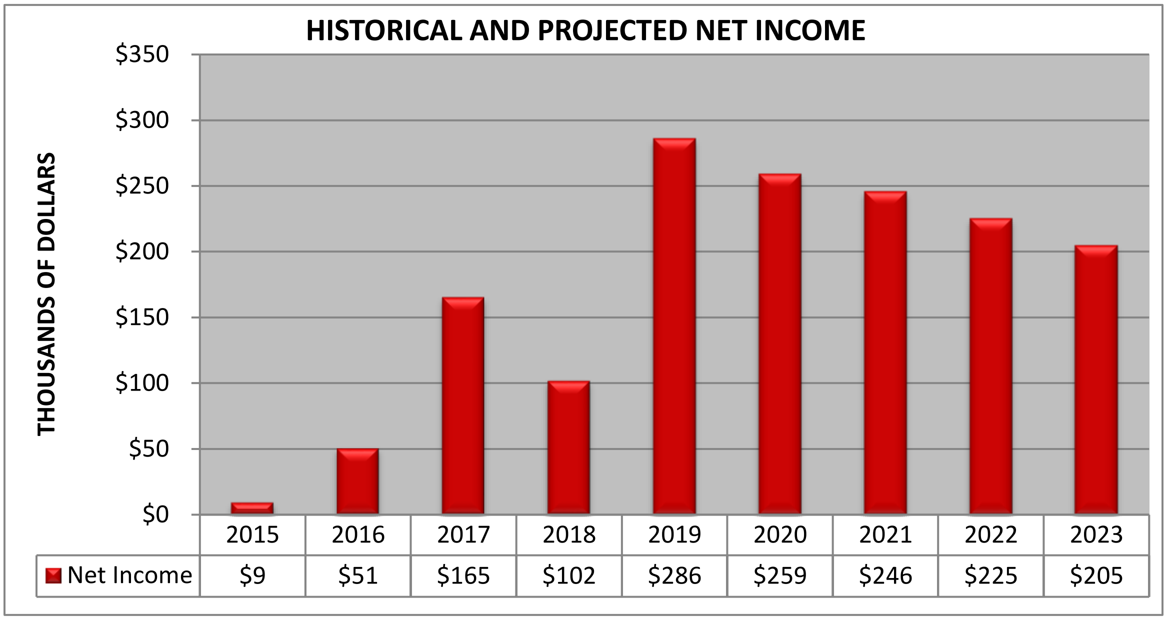
Most Commercial customers would see a decrease between 0.5% and 0.9%. Finally, Large Commercial customers would see impacts ranging from a 3% decrease to a 3% increase based on their monthly load factor. Customers with higher load factors will typically see a larger decrease.

City facilities and Street Lighting would see an average increase of 8.1% in 2019 due to increasing the energy rate closer to the Commercial class rate.

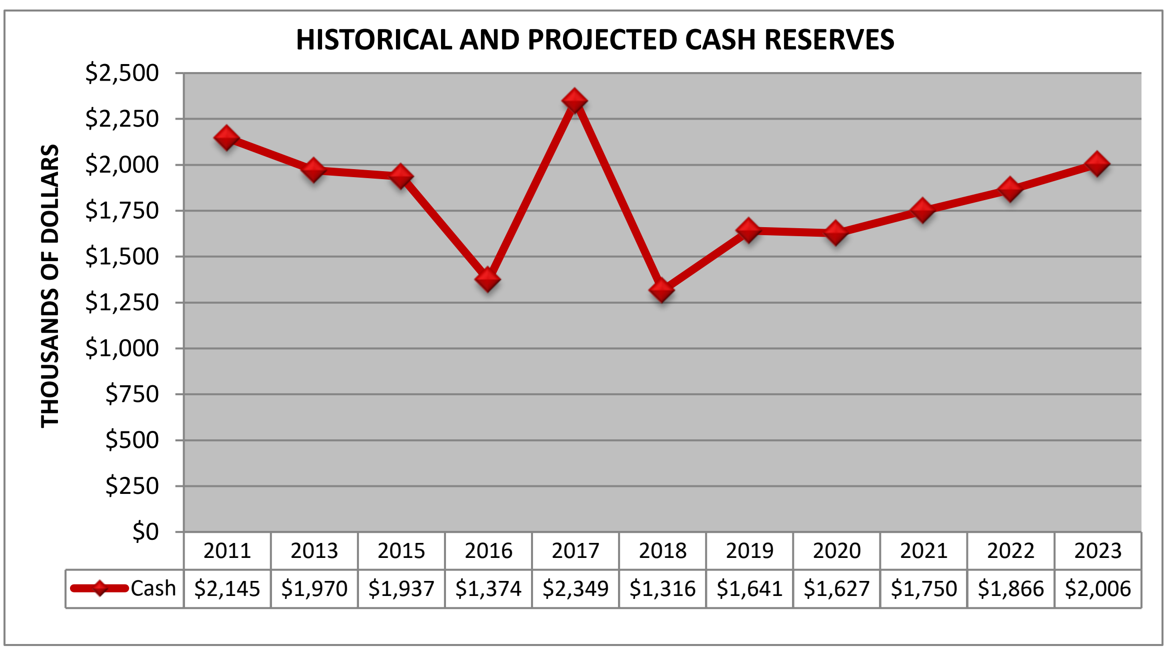
HISTORICAL AND PROJECTED OPERATING RESULTS

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 2-A and 2-B. Depending on any changes to the key assumptions, other rate adjustments may be necessary. Net income is projected to peak at $286,000 in 2019, and then income would slowly decrease each year throughout the study period to around $205,000 by 2023.

HISTORICAL AND PROJECTED OPERATING RESULTS (continued)



The next graph shows that under current proposed rates, cash reserves are projected to increase from around $1.3 million in 2018 to just over $2 million by 2023. The cash balance temporarily jumped in 2017 due to some remaining 2017A bond proceeds that were later spent in 2018. In 2019, Mountain Lake received $166,000 from CMPAS for its share of the proceeds from the sale of Utilities Plus Energy Services. An additional $248,000 of cash is restricted for bond payments and is not included in the graph below.



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Importance of Cash Reserves

Maintaining adequate reserve levels is important for several reasons. Reserves would provide for unanticipated expenses or contingencies that may arise. Reserves also provide the utility with greater flexibility when determining whether to pay for capital expenditures through revenues and reserves, or debt financing, which has additional servicing costs associated with it. An adequate reserve level would also provide for short-term rate stabilization if a large commercial or industrial customer closed or drastically changed their operations, which would result in a smaller customer base from which to recover costs. Cash reserves are also a significant factor used by bond rating agencies for evaluating utilities such as Mountain Lake.

In a study of 87 area municipal electric utility financial statements, MRES found that the median level of unrestricted cash reserves as a percentage of operating revenues was 53% for these utilities. More than one third of those utilities have cash reserves exceeding 65% of operating revenues. Mountain Lake's unrestricted electric cash reserves are projected at 66% of operating revenues in 2023.

Mountain Lake internally designates its reserves into the following categories and approximate amounts:

- Operations fund includes reserves needed for daily operating costs, including wholesale power and transmission costs and conservation improvement funds. The designated reserves for operations and conversation improvement are $780,000, or around 32% of the budgeted expenses for 2020.

- Transmission line fund includes $850,000 of reserves set aside to reduce the risk of owning the 69 kV transmission line coming into Mountain Lake.

- Bond payment fund includes annual principal and interest payment to meet the debt service obligations, which is $250,000.

Debt Service Coverage

The debt service covenants include maintaining at least a 125% debt service coverage ratio for all four outstanding bond series discussed in Section 2. Under the proposed rate plan the debt service coverage would decrease from 225% in 2019 to 209% by 2023. Debt service coverage is defined as a ratio between the current year's available cash for debt service and the debt service obligations.

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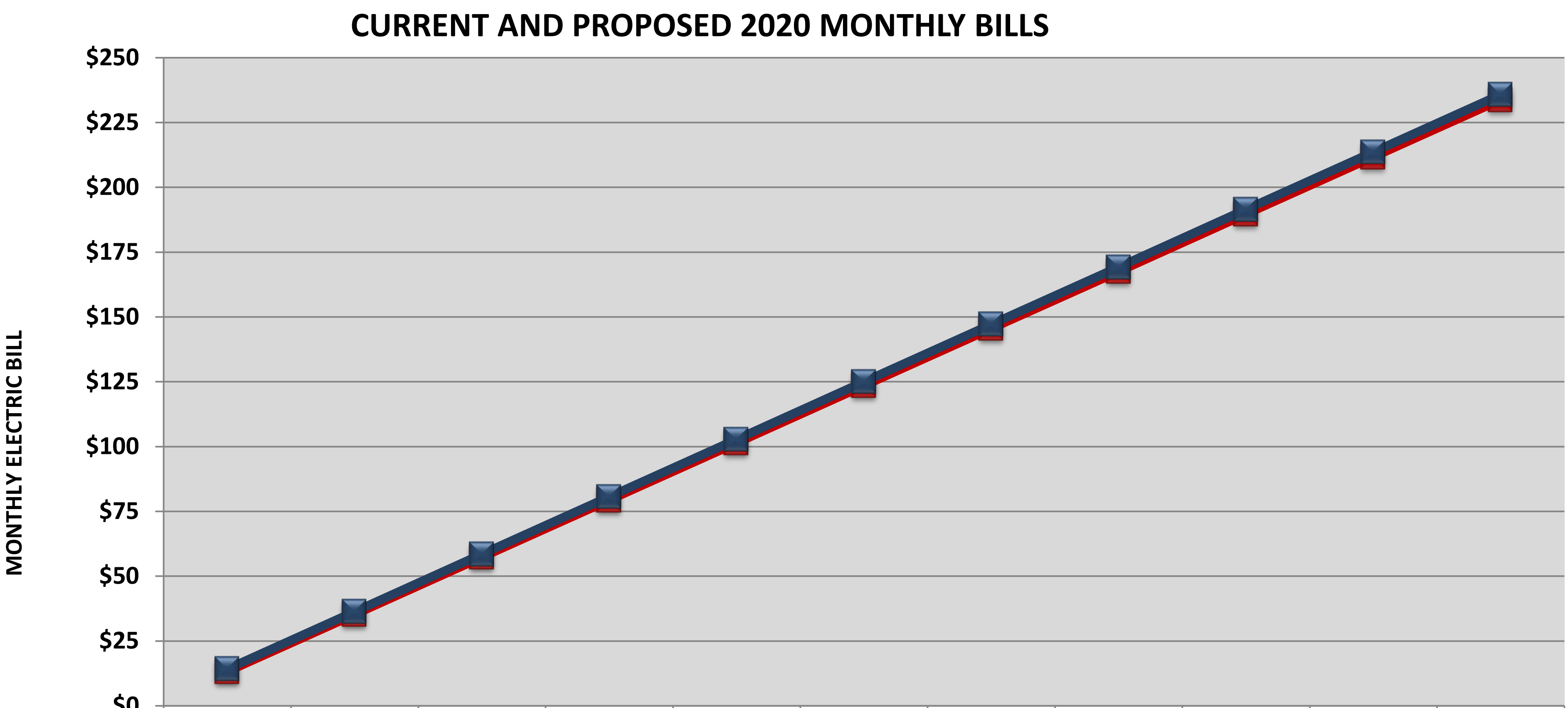
BENEFITS OF A PUBLIC POWER SYSTEM

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. Another benefit is the operating transfer to the City of Mountain Lake to help support city services that may otherwise not be funded. 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.

MONTHLY BILLS

Residential Monthly Bills

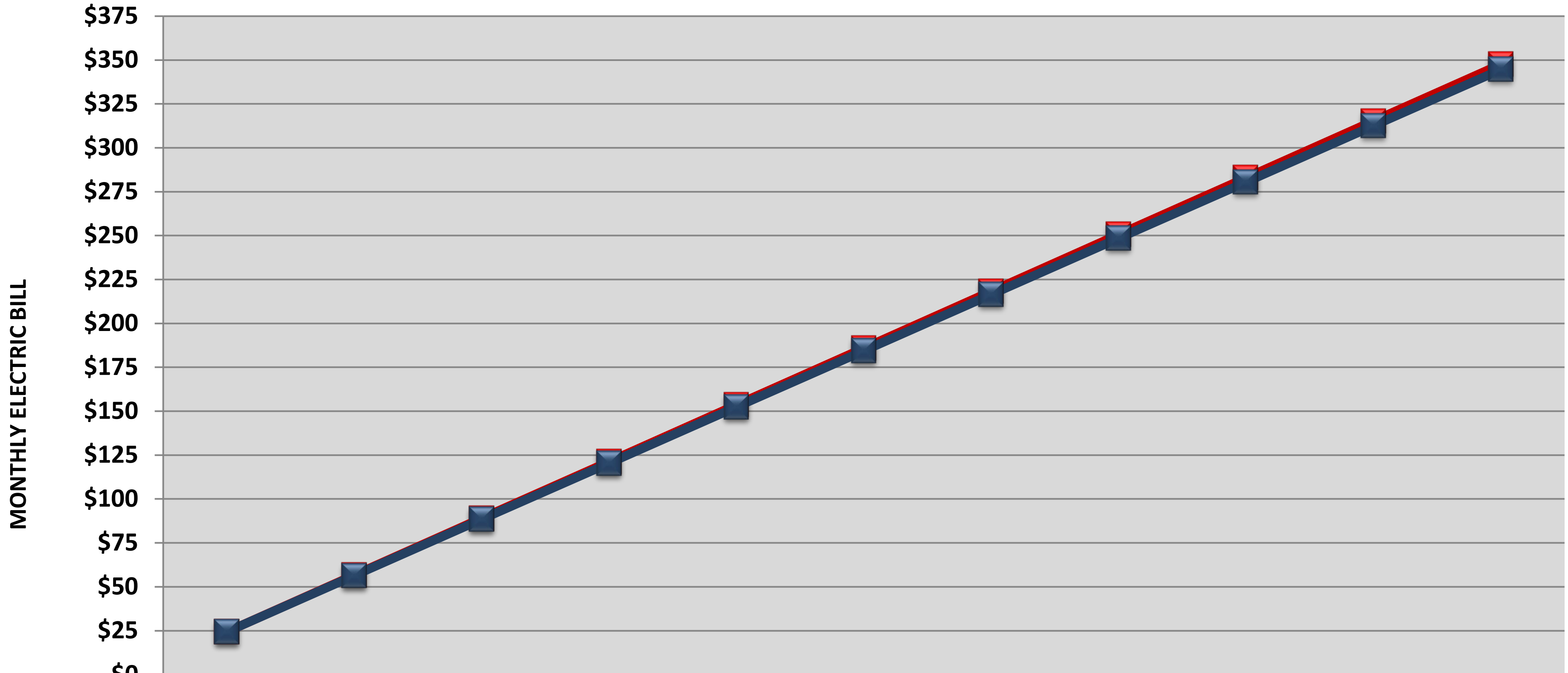


	-	200	400	600	800	1,000	1,200	1,400	1,600	1,800	2,000
Current Rates	$13.20	$35.25	$57.31	$79.37	$101.42	$123.48	$145.54	$167.60	$189.65	$211.71	$233.77
Proposed Rates	$14.21	$36.37	$58.53	$80.69	$102.85	$125.00	$147.16	$169.32	$191.48	$213.64	$235.80
% Increase	7.7%	3.2%	2.1%	1.7%	1.4%	1.2%	1.1%	1.0%	1.0%	0.9%	0.9%
$ Increase	$1.02	$1.12	$1.22	$1.32	$1.42	$1.52	$1.62	$1.73	$1.83	$1.93	$2.03

KWH

Commercial Monthly Bills

CURRENT AND PROPOSED 2020 MONTHLY BILLS

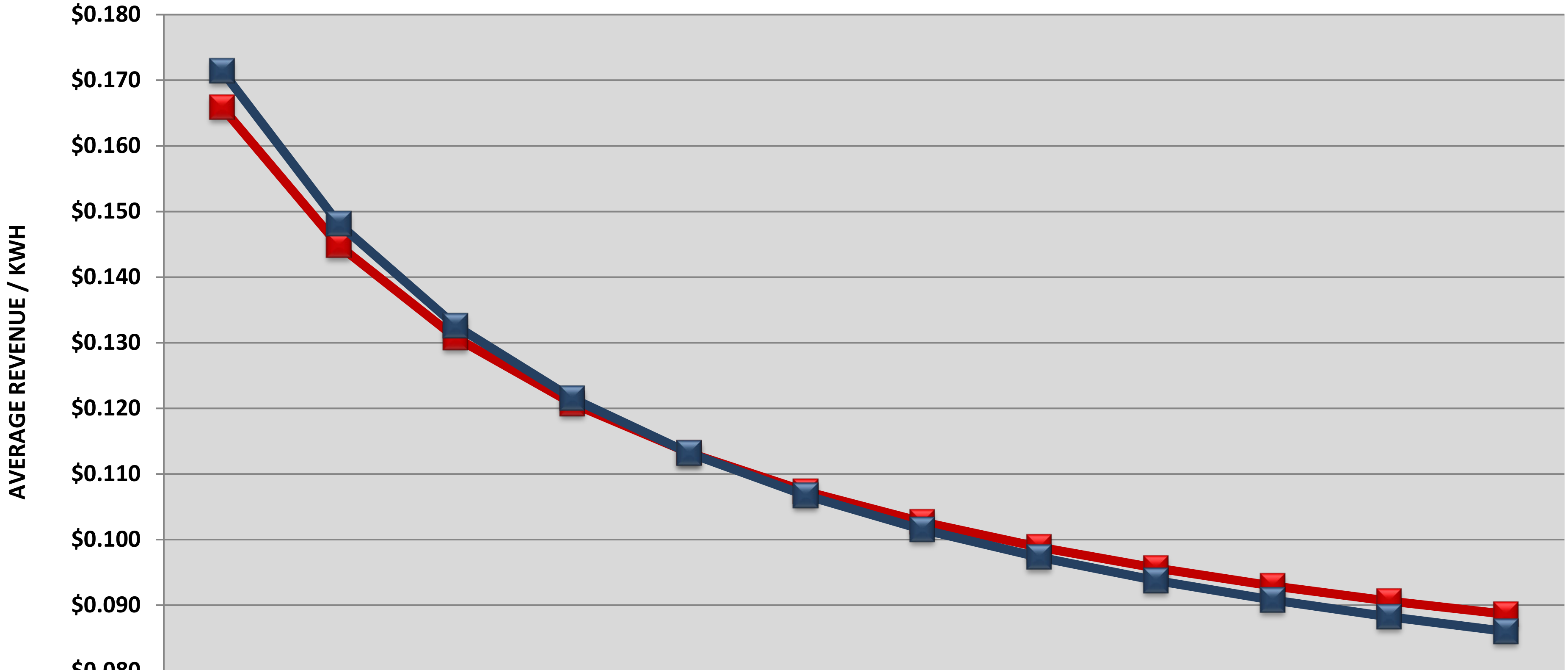


	-	300	600	900	1,200	1,500	1,800	2,100	2,400	2,700	3,000
Current Rates	$24.36	$56.68	$89.01	$121.33	$153.66	$185.98	$218.31	$250.63	$282.96	$315.28	$347.61
Proposed Rates	$24.36	$56.38	$88.40	$120.42	$152.44	$184.46	$216.48	$248.50	$280.52	$312.54	$344.56
% Change	0.0%	-0.5%	-0.7%	-0.8%	-0.8%	-0.8%	-0.8%	-0.9%	-0.9%	-0.9%	-0.9%
$ Change	$-	$(0.30)	$(0.61)	$(0.91)	$(1.22)	$(1.52)	$(1.83)	$(2.13)	$(2.44)	$(2.74)	$(3.04)

KWH

Large Commercial Monthly Bill: Average Cost per kWh at 20 kW

CURRENT AND PROPOSED 2020 BILLS



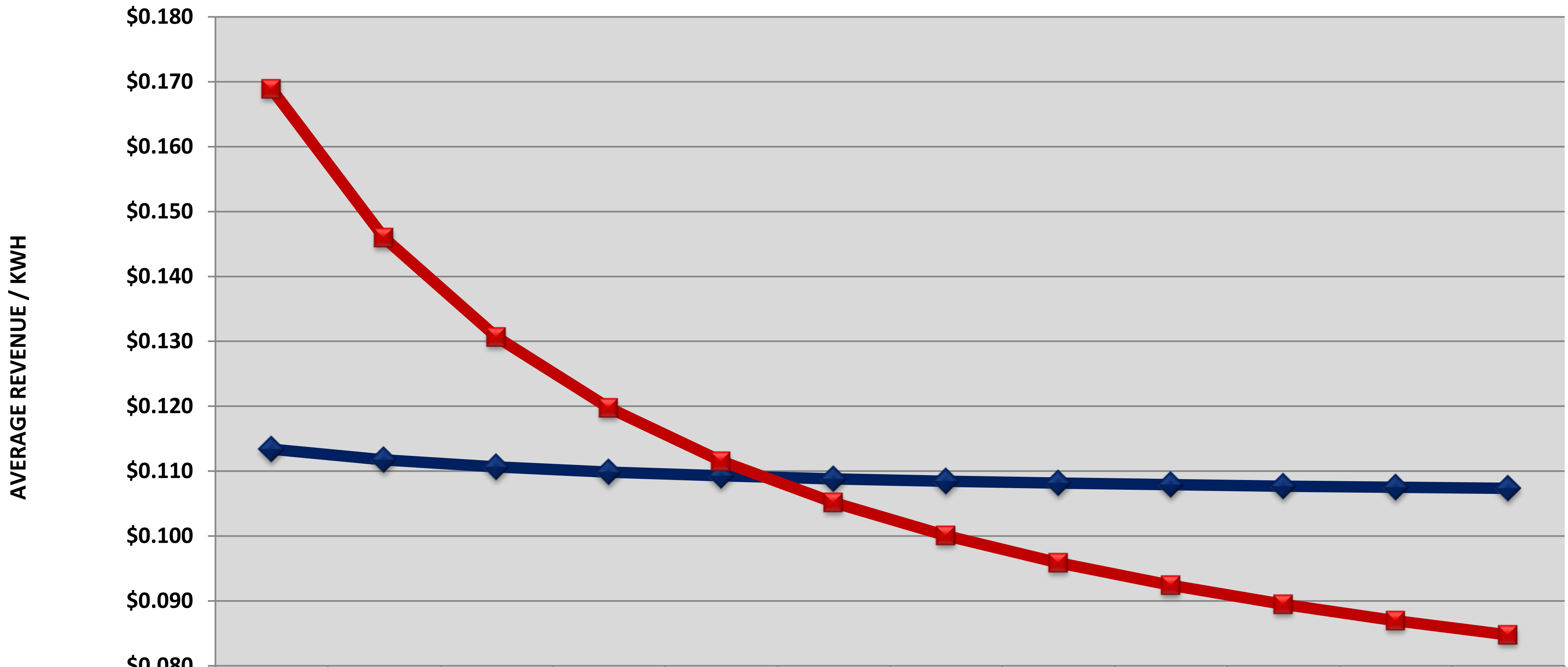
	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Current Rates	$0.166	$0.145	$0.131	$0.121	$0.113	$0.107	$0.103	$0.099	$0.096	$0.093	$0.091	$0.089
Proposed Rates	$0.171	$0.148	$0.133	$0.122	$0.113	$0.107	$0.102	$0.097	$0.094	$0.091	$0.088	$0.086
% Change	3.3%	2.3%	1.4%	0.6%	0.0%	-0.6%	-1.1%	-1.6%	-2.0%	-2.3%	-2.7%	-3.0%
$ / kWh Change	$0.006	$0.003	$0.002	$0.001	$(0.000)	$(0.001)	$(0.001)	$(0.002)	$(0.002)	$(0.002)	$(0.002)	$(0.003)

LOAD FACTOR

Exhibit 4-D

Commercial vs. Large Commercial Monthly Bill: Average Cost per kWh at 20 kW

PROPOSED 2020 BILLS



	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%
Commercial	0.113	0.112	0.111	0.110	0.109	0.109	0.108	0.108	0.108	0.108	0.108	0.107
Large Commercial	0.169	0.146	0.131	0.120	0.112	0.105	0.100	0.096	0.092	0.089	0.087	0.085
% Difference	49.0%	30.6%	18.1%	9.0%	2.1%	-3.4%	-7.7%	-11.3%	-14.4%	-16.9%	-19.1%	-21.1%

LOAD FACTOR

SECTION 5

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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.

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SUMMARY OF UTILITY COMPARISON RESULTS

Exhibits 5-A through 5-E at the end of this section contain comparisons between Mountain Lake and the regional utilities whose rates are shown in Exhibits 5-F through 5-H. For utilities with seasonal rates, the bills are the weighted average of all 12 months. For Mountain Lake, the proposed rates for 2020 from Section 4 were used in these comparisons. The comparisons are based on the following levels of usage per month:

- Residential – Average usage of 750 kWh
- Commercial – Average usage of 1,400 kWh
- Large Commercial – 48,250 kWh and demand of 242 kW (27% Load Factor)
- Large Commercial – 38,500 kWh and demand of 93 kW (57% Load Factor)
- Large Commercial – 831,000 kWh and demand of 1,544 kW (74% Load Factor)

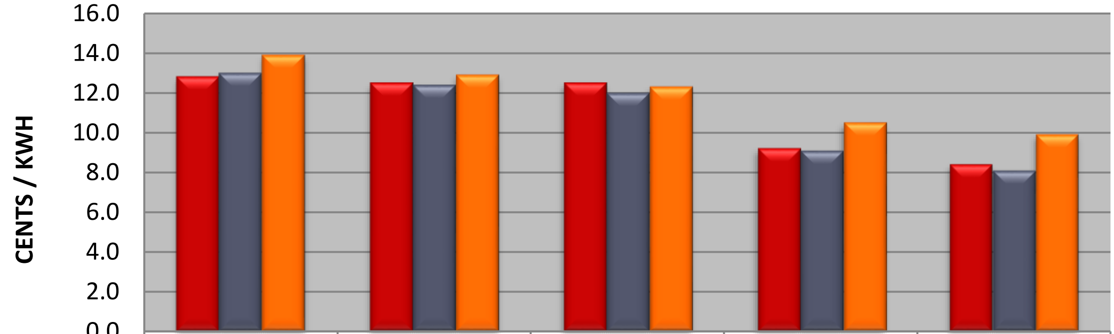
The top portion of each exhibit shows bills calculated using the various utilities' rates, and the bottom portion shows the percentage differences between other utilities and the current Mountain Lake rates.

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 2020 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 bills are mostly higher than the Mountain Lake bills. Mountain Lake's bills will likely become even more competitive over time as rates are projected to remain stable for several years. Meanwhile, other utilities, especially investor-owned utilities, may have other cost pressures and need to increase their rates in coming years. Xcel Energy and Minnesota Power recently filed rate cases with the Minnesota Public Utilities Commission each requesting a 15% overall rate increase over the next three years due to higher costs associated with renewable power and other grid investments.

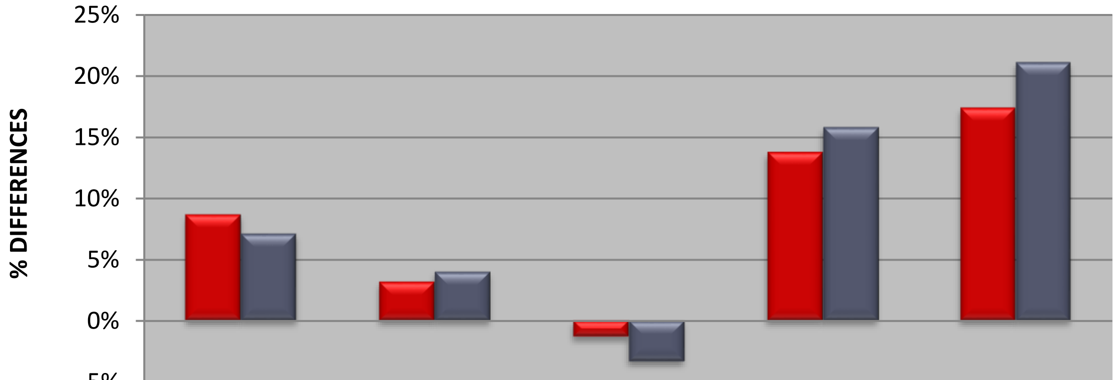
SUMMARY OF UTILITY COMPARISON RESULTS (Continued)

COMPARISON OF MOUNTAIN LAKE TO THE REGIONAL UTILITY MEDIAN COST PER KWH



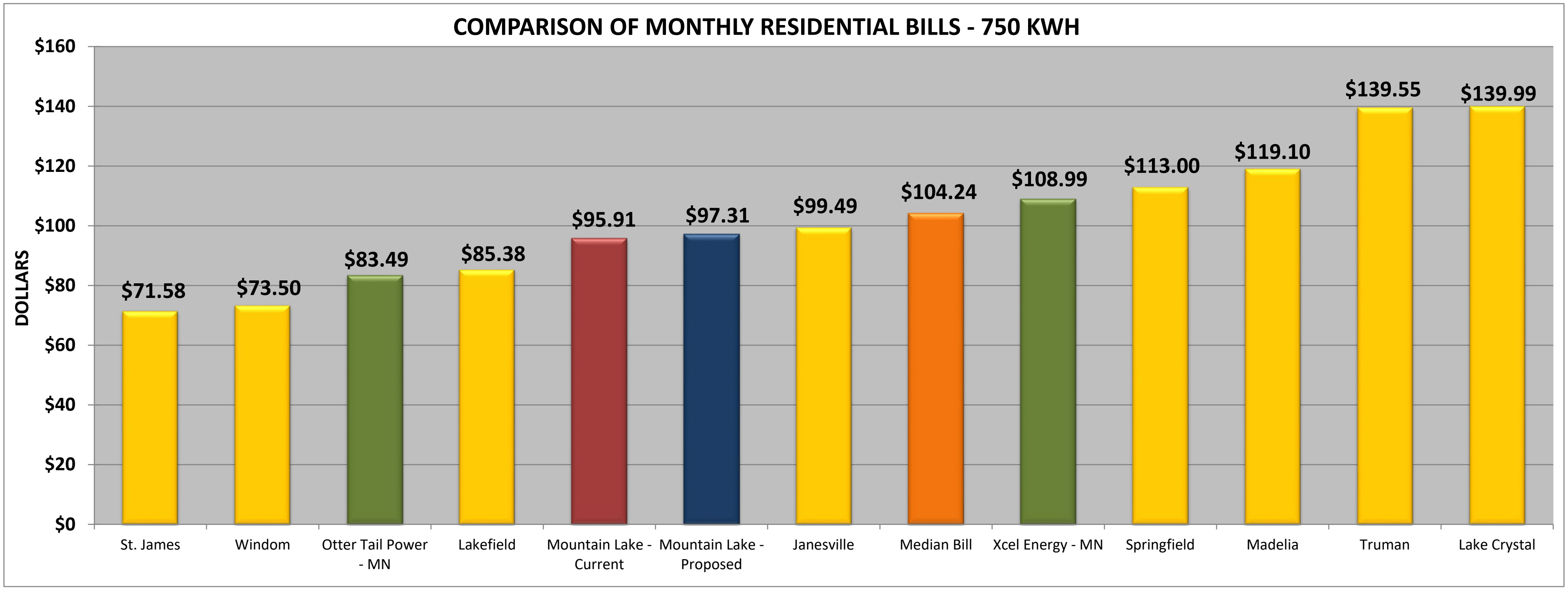
	Residential - 750 kWh	Commercial - 1,400 kWh	Large Commercial - 27% LF	Large Commercial - 57% LF	Large Commercial - 74% LF
Current	12.8	12.5	12.5	9.2	8.4
Proposed	13.0	12.4	12.0	9.1	8.1
Median	13.9	12.9	12.3	10.5	9.9

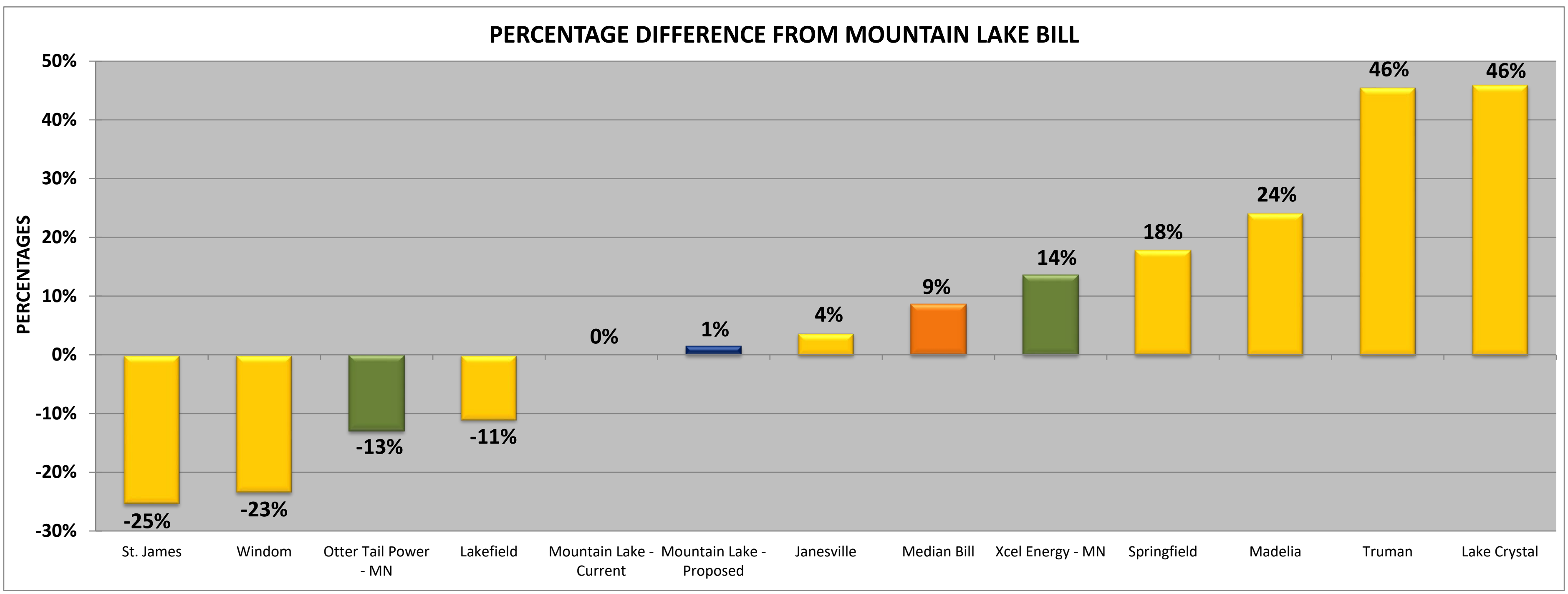
PERCENTAGE DIFFERENCE BETWEEN THE REGIONAL UTILITY MEDIAN VALUES AND MOUNTAIN LAKE RATES



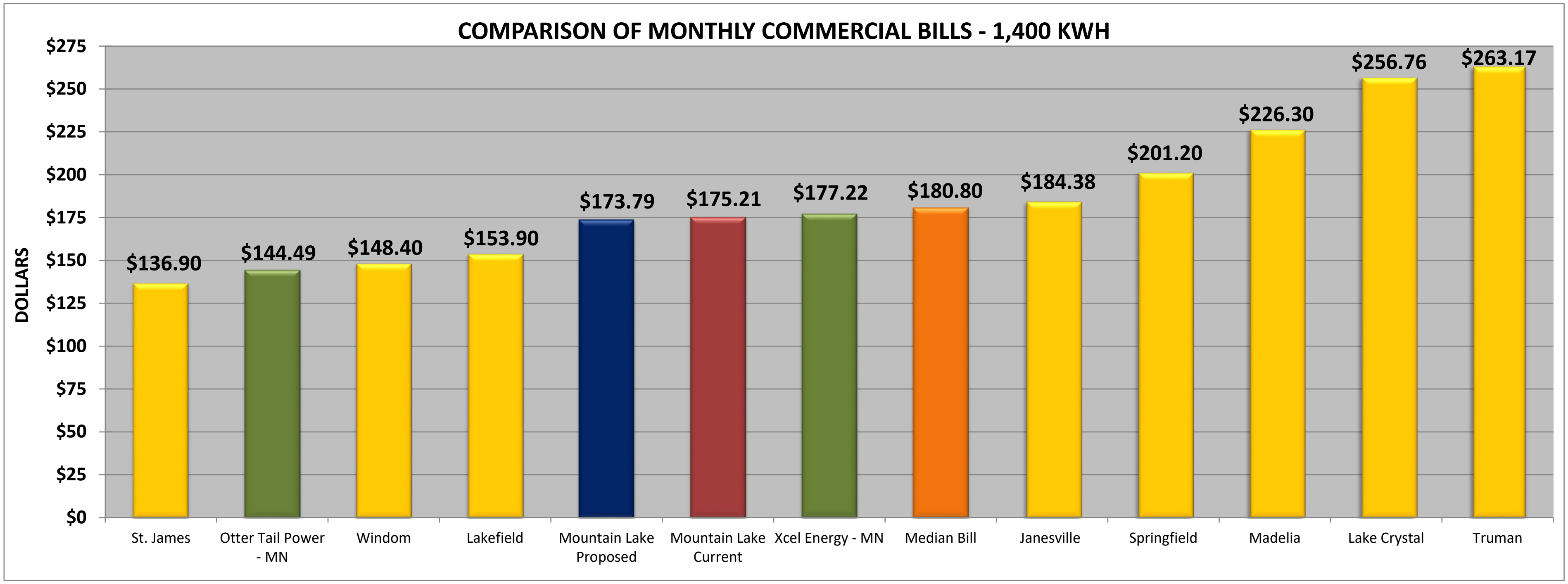
	Residential - 750 kWh	Commercial - 1,400 kWh	Large Commercial - 27% LF	Large Commercial - 57% LF	Large Commercial - 74% LF
Current	8.7%	3.2%	-1.3%	13.8%	17.4%
Proposed	7.1%	4.0%	-3.3%	15.8%	21.1%

COMPARISON GRAPHS

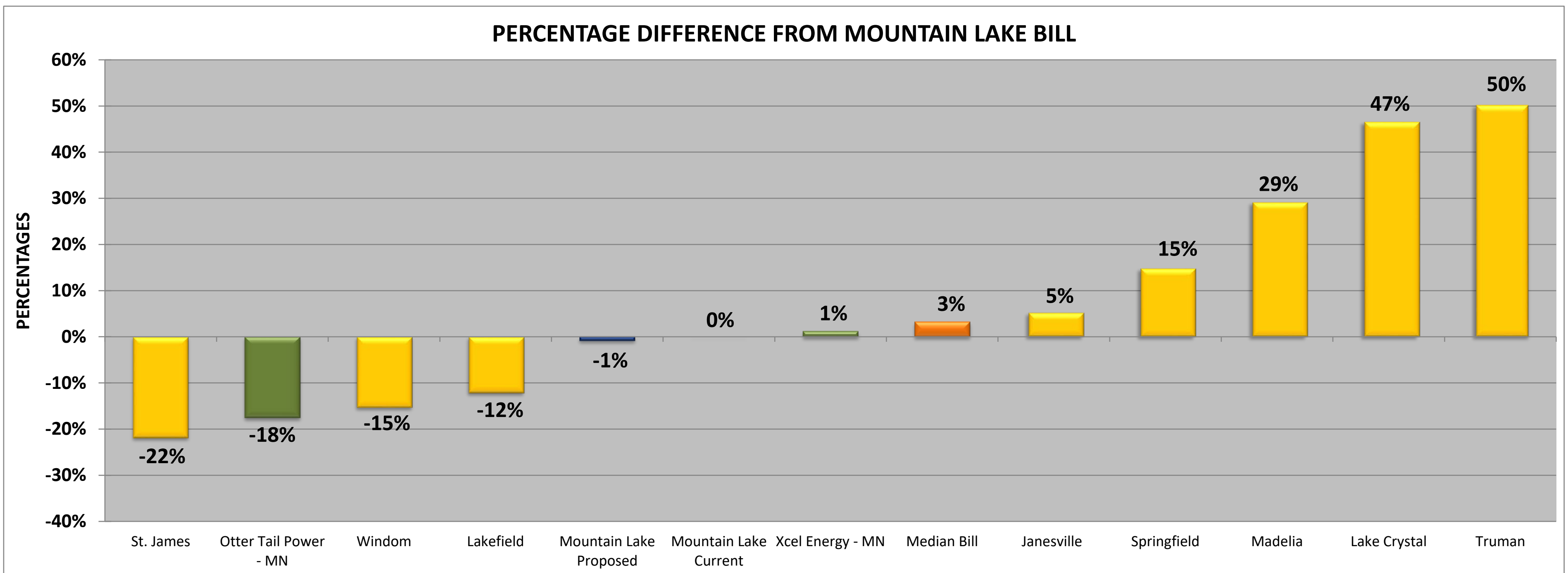




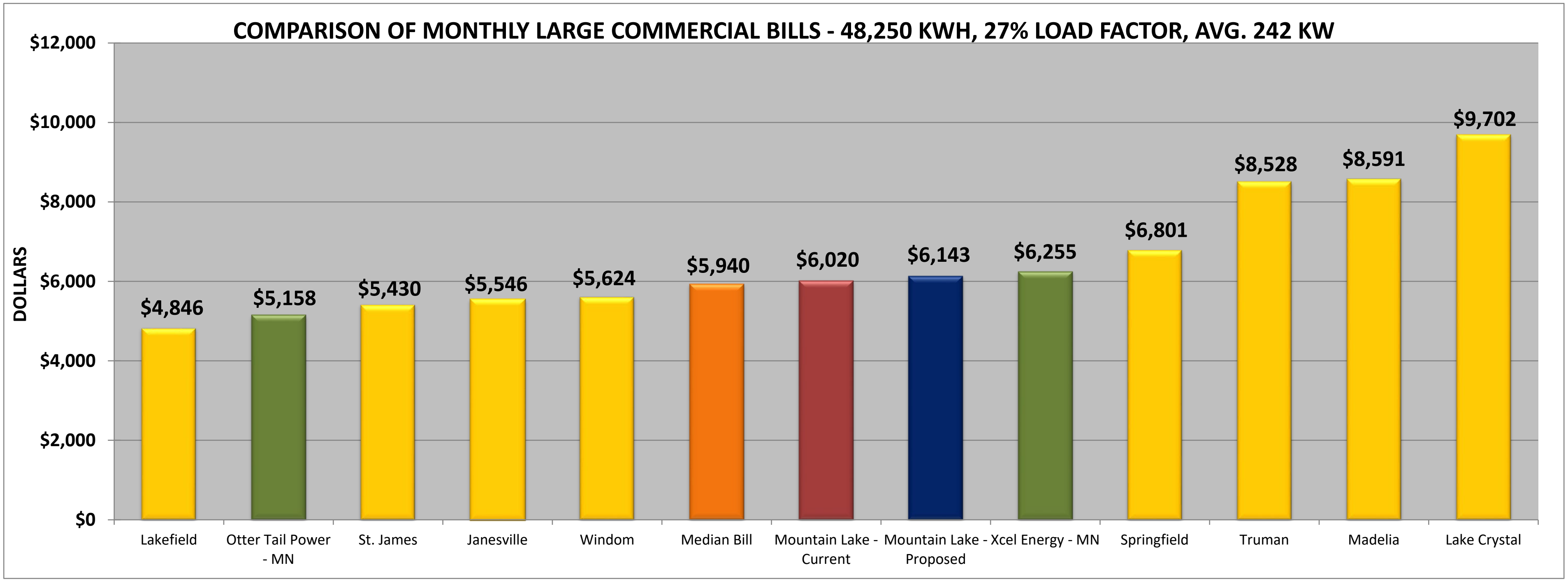
December 2019 - Comparison based on current rates, subject to change. Exhibit 5-A Provided by Missouri River Energy Services

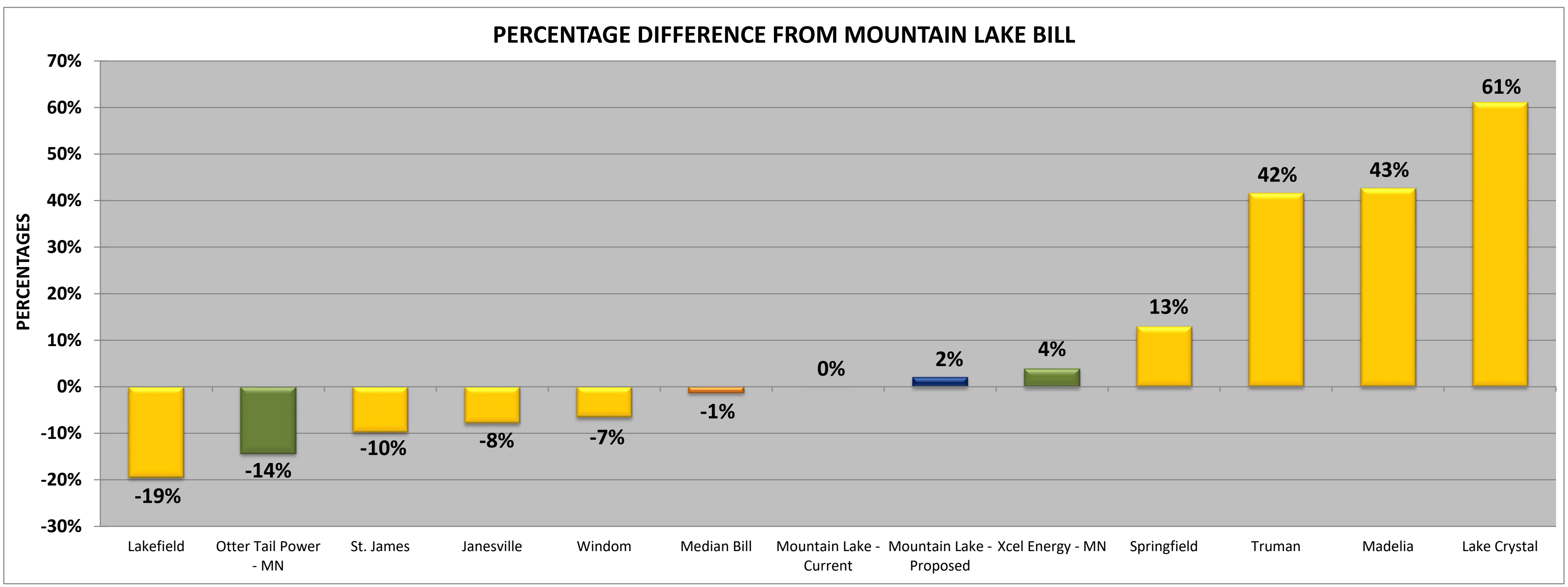


COMPARISON OF MONTHLY COMMERCIAL BILLS - 1,400 KWH
DOLLARS
$0
$25
$50
$75
$100
$125
$150
$175
$200
$225
$250
$275
$136.90
$144.49
$148.40
$153.90
$173.79
$175.21
$177.22
$180.80
$184.38
$201.20
$226.30
$256.76
$263.17
St. James
Otter Tail Power - MN
Windom
Lakefield
Mountain Lake Proposed
Mountain Lake Current
Xcel Energy - MN
Median Bill
Janesville
Springfield
Madelia
Lake Crystal
Truman

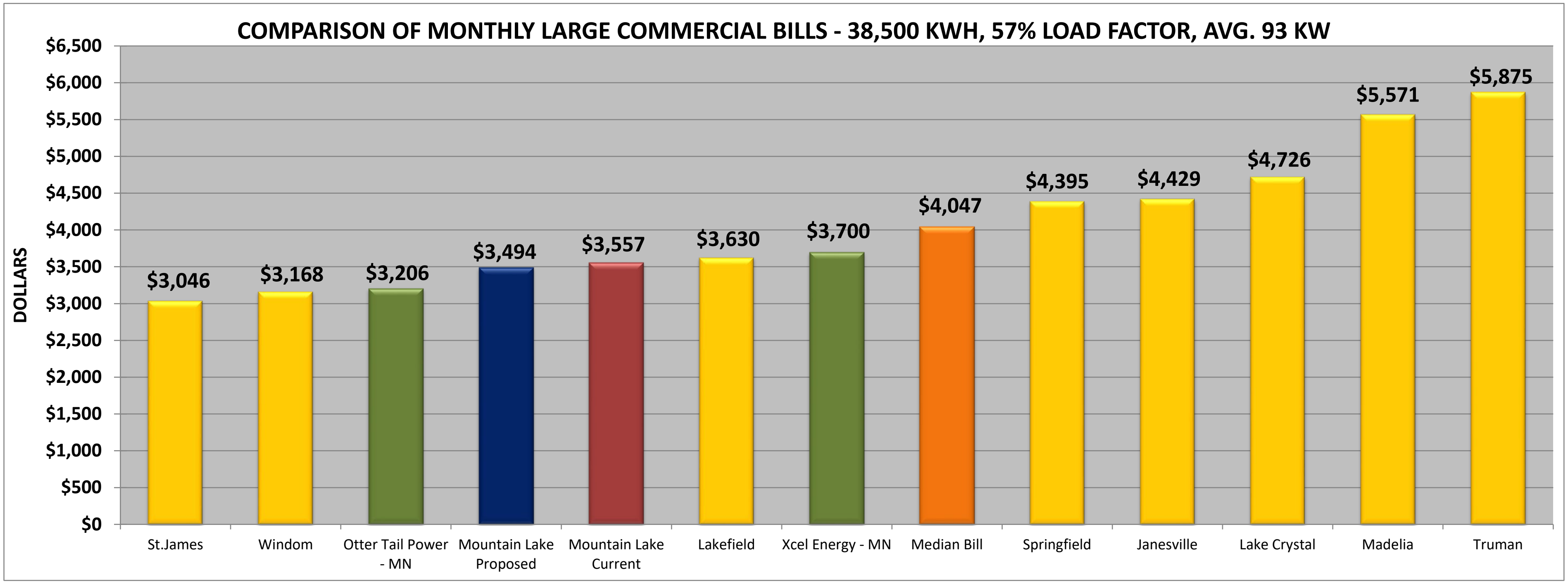


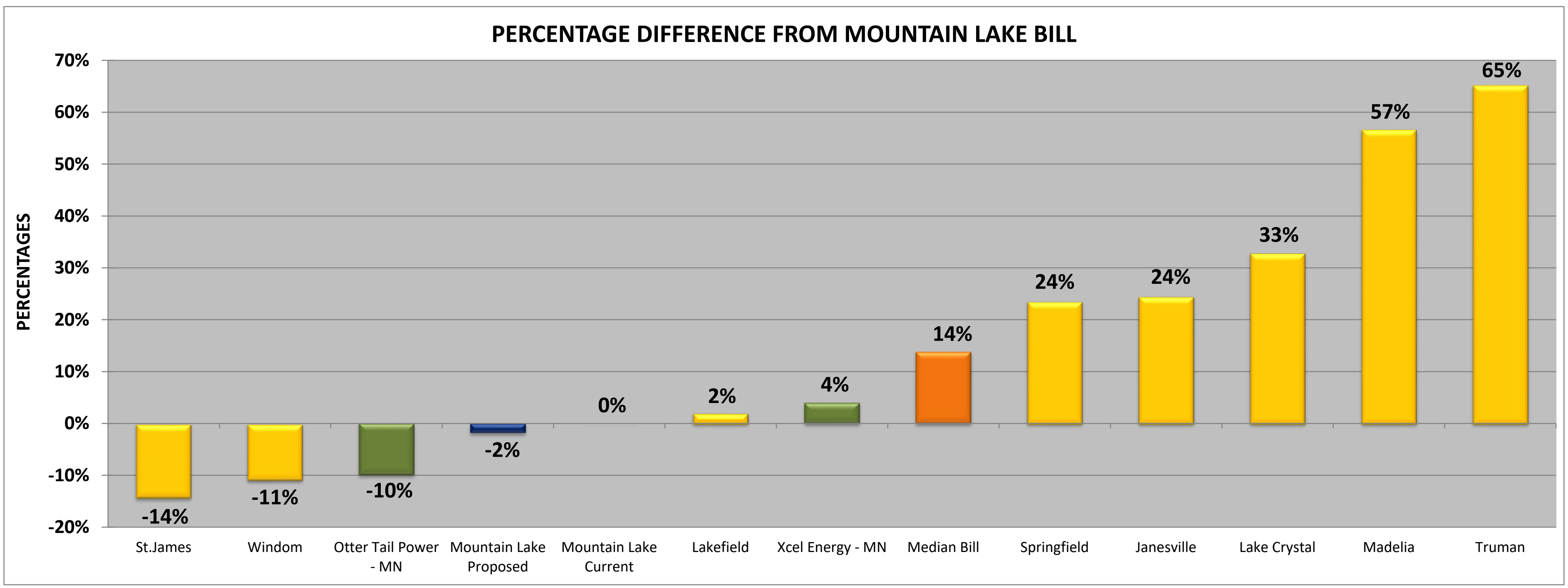
PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-40%
-22%
-18%
-15%
-12%
-1%
0%
1%
3%
5%
15%
29%
47%
50%
St. James
Otter Tail Power - MN
Windom
Lakefield
Mountain Lake Proposed
Mountain Lake Current
Xcel Energy - MN
Median Bill
Janesville
Springfield
Madelia
Lake Crystal
Truman

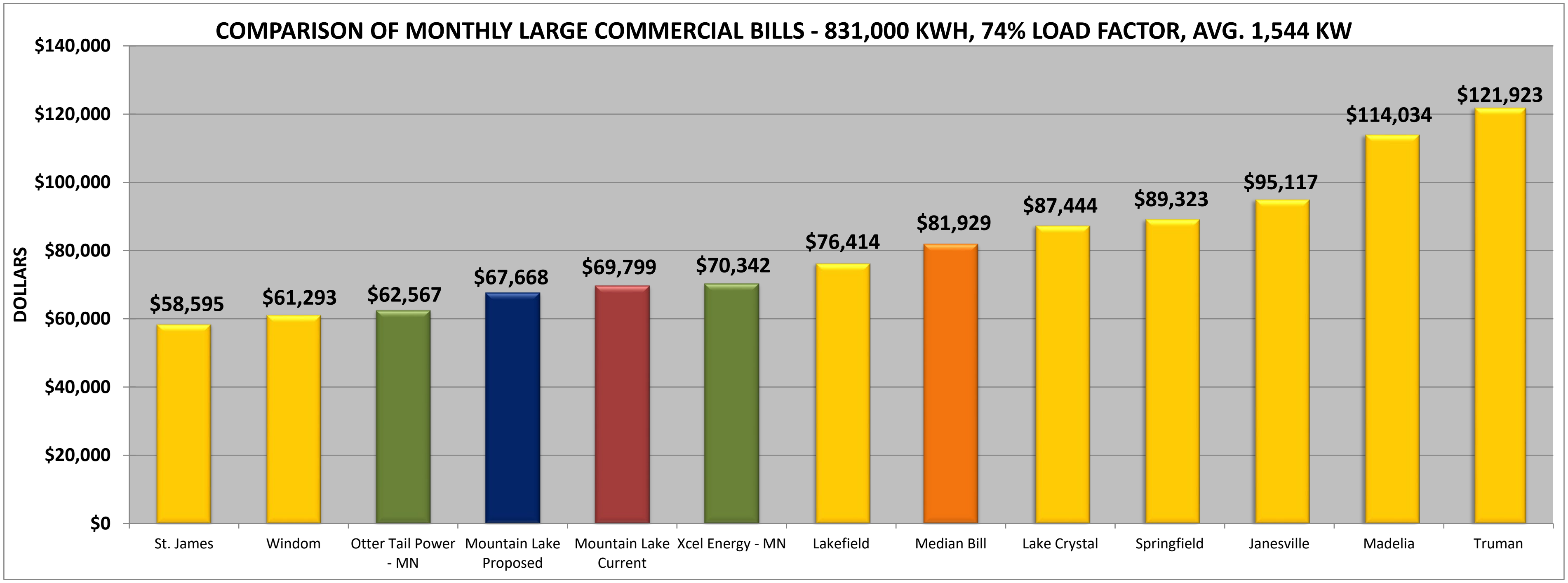


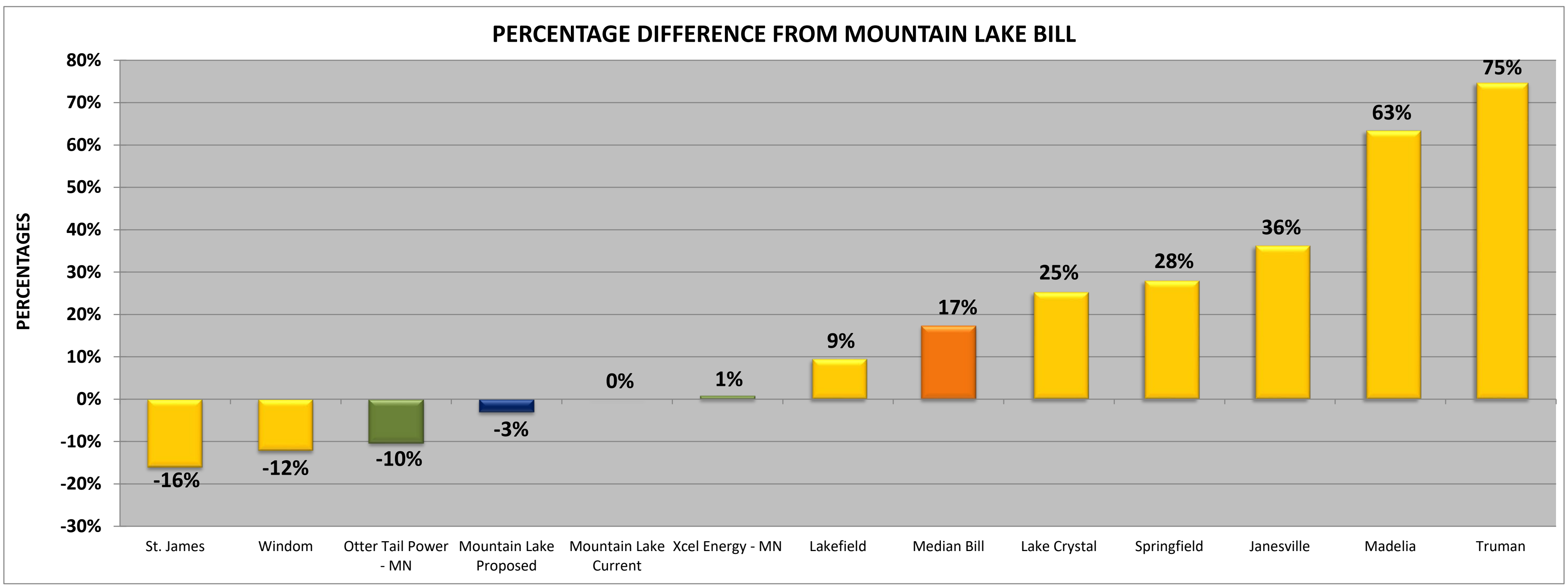


December 2019 - Comparison based on current rates, subject to change. Exhibit 5-C Provided by Missouri River Energy Services


COMPARISON OF MONTHLY LARGE COMMERCIAL BILLS - 38,500 KWH, 57% LOAD FACTOR, AVG. 93 KW
DOLLARS
$6,500
$6,000
$5,500
$5,000
$4,500
$4,000
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
$3,046
$3,168
$3,206
$3,494
$3,557
$3,630
$3,700
$4,047
$4,395
$4,429
$4,726
$5,571
$5,875
St.James
Windom
Otter Tail Power - MN
Mountain Lake Proposed
Mountain Lake Current
Lakefield
Xcel Energy - MN
Median Bill
Springfield
Janesville
Lake Crystal
Madelia
Truman


PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
70%
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-14%
-11%
-10%
-2%
0%
2%
4%
14%
24%
24%
33%
57%
65%
St.James
Windom
Otter Tail Power - MN
Mountain Lake Proposed
Mountain Lake Current
Lakefield
Xcel Energy - MN
Median Bill
Springfield
Janesville
Lake Crystal
Madelia
Truman


COMPARISON OF MONTHLY LARGE COMMERCIAL BILLS - 831,000 KWH, 74% LOAD FACTOR, AVG. 1,544 KW
DOLLARS
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$0
$58,595
$61,293
$62,567
$67,668
$69,799
$70,342
$76,414
$81,929
$87,444
$89,323
$95,117
$114,034
$121,923
St. James
Windom
Otter Tail Power - MN
Mountain Lake Proposed
Mountain Lake Current
Xcel Energy - MN
Lakefield
Median Bill
Lake Crystal
Springfield
Janesville
Madelia
Truman


PERCENTAGE DIFFERENCE FROM MOUNTAIN LAKE BILL
PERCENTAGES
80%
70%
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
-30%
-16%
-12%
-10%
-3%
0%
1%
9%
17%
25%
28%
36%
63%
75%
St. James
Windom
Otter Tail Power - MN
Mountain Lake Proposed
Mountain Lake Current
Xcel Energy - MN
Lakefield
Median Bill
Lake Crystal
Springfield
Janesville
Madelia
Truman

Residential Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$13.00	$0.1125 1.5%	All Conservation Improv. (% of bill)	($0.00380)
Otter Tail Power – MN	9.75	0.10540 0.08640 0.00726	All (June-Sep.) All (Oct.-May) Other Adjustments: per kWh	(0.00168)
Xcel Energy – MN Standard Service Electric Space Heating	 10.98 12.98	 0.10301 0.08803 0.05988 0.00980 0.497%	 All (June – Sep.) All (Oct. – May) Space Heating All (Oct. – May) Other Adjustments: per kWh Renewable Energy Std. (% of bill)	 0.02732
Janesville, MN	13.00	0.10700 5.0%	All Franchise Fee (% of bill)	0.00200
Lake Crystal, MN	10.99	0.17200	All	-
Lakefield, MN	11.50	0.10300 0.09700	All (June – August) All (September – May)	-
Madelia, MN	5.00	0.14628 1.5%	All Conservation Improv. (% of bill)	0.00350
Springfield, MN	13.50	0.12400 0.08600 1.5%	All Heating (Oct.-April) Conservation Improv. (% of energy charges)	0.00440
St. James, MN	12.25	0.07910	All	-
Truman, MN	11.50	0.14400 0.13200	All Over 600 (October – May)	 0.02833
Windom, MN In City Limit	 12.00	 0.07900	 All	 0.00300

Commercial Rates

Utility	Monthly Service Charge	Energy Charge (per kWh)	Energy Block (kWh)	Energy Adjustment (per kWh)
Mountain Lake, MN	$24.00	$0.11000 1.5%	All Conservation Improv. (% of bill)	($0.00380)
Otter Tail Power – MN	18.50	0.09708 0.07808 0.00726	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh	(0.00168)
Xcel Energy – MN	11.27	0.09256 0.07757 0.00786 0.497%	All (June-Sep.) All (Oct.-May) Other Adjustments per kWh Renewable Energy Std. (% of bill)	0.02766
Janesville, MN	23.00	0.10700 5.0%	All Franchise Fee (% of bill)	0.00200
Lake Crystal, MN	20.16	0.16900	All	-
Lakefield, MN	14.00	0.01040 0.09800	All (June – August) All (September – May)	-
Madelia, MN	8.50	0.14968 1.5%	All Conservation Improv. (% of bill)	0.00350
Springfield, MN	22.00	0.12000 1.5%	All Conservation Improv. (% of energy charges)	0.00440
St. James, MN Single-phase Three-phase	 16.50 29.00	0.08600	All	-
Truman	19.50	0.14800 0.13200	0-1,200 Over 1,200	0.02833
Windom, MN Single-phase Three-phase	 21.00 39.00	 0.08800 0.08300	 0-8,000 Over 8,000	0.00300

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	$55.00	$12.40	All	$0.0635 1.5%	All Con. Improv. (% of bill)	($0.00380)
Otter Tail Power – MN 20 kW-80 kW	27.00	3.63 1.39 0.97	June-Sep. Oct.-May Facility Chg.	0.07123 0.07469 0.00726	All (June-Sept.) All (Oct.-May) Other Adjustments	(0.00168)
Over 80 kW	80.00 (Min. 350.00)	10.56 8.56 0.55 0.45 (0.433)	June-Sep. Oct.-May Facility Chg. <1,000 Facility Chg. >1,000 Other Adj.	0.04976 0.05218 0.00819	All (June-Sept.) All (Oct.-May) Other Adjustments	(0.00168)
Xcel Energy – MN Less than 1 MW	29.24	14.79 10.49 1.017	June–Sep. Oct.–May 50% Ratchet Other Adj.	0.033407 (0.01518) 0.00323 0.497%	All Over 400 kWh/kW Other Adjustments Renew. Energy Std.	0.02680
Janesville, MN	23.00	-	All	0.10700 5.0%	All Franchise Fee	0.00200
Lake Crystal, MN	25.68	30.25	All	0.04900	All	-
Lakefield, MN	22.00	4.50 2.00	June – August September - May	0.08700	All	-
Madelia, MN Large Commercial Industrial	 12.50 100.00	 12.68 17.30	 All All	 0.10814 0.09022 1.5%	 All All Con. Improv. (% of bill)	 0.00350
Springfield, MN	35.00	10.40	All	0.08250 1.5%	All Con. Improv. (% of energy charges)	0.00440
St. James, MN	54.00	13.00	All	0.04630	All	-
Truman, MN	27.50	9.35	All	0.10100	All	0.02833
Windom, MN	45.00	13.30	All	0.04600	All	0.00300