



Kirkwood Meadows

Public Utilities District

2021 Electric Rate Study

July 10, 2021

Executive Summary

Kirkwood Meadows Public Utility District (“KMPUD” or “District”) is a special district located within Alpine, Amador, and El Dorado Counties. The District currently services over 760 active electric connections and receives its power from both the CAISO grid and emergency standby diesel generation at the District Powerhouse.

Revenue for the electric utility comes primarily from rate revenue. This enterprise also receives property tax revenue. The electric utility also charges a fixed monthly rate (or “Base Rate”) in addition to a Usage Rate. The last rate study for the electric enterprise was conducted by the District in 2014.

Scope and Approach

The scope of the Study was to prepare multi-year financial plans, develop a consistent cost-of-service analyses, review the existing rate structures, and propose a 5-year rate schedule. The primary objectives of the Study were to identify future annual rate adjustments to rates to help ensure adequate revenues to meet the ongoing service requirements, District policies, and financial obligations; determine the cost of providing service to customers, and recommend specific modifications to the existing rate structures in order to ensure that the proposed rate equitably recovers the cost of providing service and comporting with industry standards and California’s legal requirements. The Study applied methodologies that are equitable and logical for rate setting.

Financial Plans

The Study produced robust financial plans that will help enable the utility to meet revenue requirements and financial performance objectives throughout the planning period while striving to minimize rate increases. Financial performance objectives include covering all anticipated operating, maintenance, debt service, and capital program costs; maintaining financial reserves in accordance with District policy; and meeting USDA Tier Ratio debt service obligations.

Based upon the financial data, assumptions, reserve targets, and debt obligations, the Study proposes rate realignment and adjustment. Rate structure changes are proposed to be effective August 1, 2021.

Cost of Service and Rate Design

Once the rate revenue requirements have been determined, the next step in the rate setting process is to evaluate the cost of providing this service to customers. A cost-of-service analysis evaluates the cost of providing service and proportionately allocates those costs to customer classes and rate structure components to ensure the proposed rate structure is aligned with the costs of providing electric service. This is necessary in order to be equitable among all ratepayers. The cost-of-service analysis and rate structure proposed by the Study is designed to:

- Fairly and equitably share debt service across all customers; and
- Fairly and equitably recover operational and capital costs through rates; and
- Provide financial stability and recovery of system fixed costs.

Electric Rates

The structure for the District's current electric rates includes a three-part structure that is comprised of a fixed Base Rate correlating to customers' "average usage over the last three years", a fixed Meter Charge, and a consumption-based Usage Rate.

The full schedule of the recommended electric rates is shown below. The fiscal year 2021/22 rates are effective beginning August 1, 2021, and subsequent rates are effective the beginning of each fiscal year (July 1) thereafter. The Board decided to utilize a base rate which covers approximately 70% of fixed costs; provides 100% renewable energy credits; and includes a State required 2.85% Public Benefit Charge in the Usage Rate.

This methodology is equitable, logical, and complies with all applicable laws.

The proposed adjustments to the rates proportionately assign costs to each customer class and customer based on service demands and will allow the District to continue to provide safe, reliable electric service to customers. They are as follows:

	Current Rates	FY 2021/22	FY 2022/23	FY 2023/24	FY 2024/25	FY 2025/26
Monthly Meter Charge (per meter)	\$ 2.94	\$ 3.03	\$ 3.12	\$ 3.21	\$ 3.31	\$ 3.41
Monthly Base Rate (per EDU)	\$ 14.93	\$ 119.00	\$ 119.54	\$ 120.07	\$ 120.61	\$ 121.16
Usage Rate (per kWh)	\$ 0.656	\$ 0.220	\$ 0.220	\$ 0.220	\$ 0.220	\$ 0.220

The electric rates will be noticed, adopted, and will include a detailed notice describing the proposed rates to be mailed to each affected property owner or customer.

TABLE OF CONTENTS

1.	INTRODUCTION	2
1.1.	UTILITY BACKGROUND	2
1.2.	SCOPE OF STUDY	3
1.3.	STUDY GOALS.....	4
1.3.1.	<i>Budget.....</i>	4
1.3.2.	<i>Fixed Costs</i>	5
1.3.3.	<i>Variable Costs.....</i>	5
1.3.4.	<i>Equivalent Dwelling Unit (“EDU”) Methodology</i>	6
1.3.4.1.	<i>EDU Calculation.....</i>	6
1.3.4.2.	<i>EDU Assignment and Duration.....</i>	7
1.3.4.2.1.	<i>Existing Customers</i>	7
1.3.4.2.2.	<i>Existing Structures with Ownership Transfers</i>	7
1.3.4.2.3.	<i>New Construction</i>	9
1.3.4.3.	<i>EDU Minimum</i>	9
1.3.5.	<i>Net Metering.....</i>	10
1.3.5.1.	<i>Average Monthly Utilization (“AMU”) for Customers with Net Metering</i>	13
2.	BUDGET	15
2.1.	ELECTRIC ENTERPRISE FINANCIAL PLAN	15
2.1.1.	<i>Beginning Fund Balances</i>	15
2.1.2.	<i>Reserve Targets</i>	15
2.1.3.	<i>Customer Growth</i>	15
2.1.4.	<i>Rate Revenues</i>	16
2.1.5.	<i>Non-Rate Revenues</i>	16
2.1.6.	<i>Operation & Maintenance Expenses.....</i>	16
2.1.7.	<i>Cost Escalation.....</i>	16
2.1.8.	<i>Existing Debt Service.....</i>	17
2.1.9.	<i>Capital Improvement Program</i>	17
2.1.10.	<i>Future Borrowing Assumptions.....</i>	18
3.	COST OF SERVICE & RATE DESIGN	19
3.1.	CURRENT ELECTRIC RATES	19
3.2.	PUBLIC BENEFITS CHARGE (“PBC”).....	19
3.3.	AVOIDED COSTS	20
3.3.1.	<i>Allocation of Avoided Costs.....</i>	21
3.3.2.	<i>Avoided Cost Calculation</i>	21
3.3.2.1.	<i>Financial Impacts to Customers - \$0.137/kWh</i>	22
3.3.3.	<i>Avoided Cost Calculation With 100% Renewable Energy</i>	22
3.3.3.1.	<i>Financial Impacts to Customers - \$0.147/kWh</i>	23
3.3.4.	<i>kWh Sold Over Budget.....</i>	24
3.4.	REDUCED PROPERTY TAX RELIANCE SCENARIOS	24
3.4.1.	<i>Financial Impacts to Customers – Replacing a Portion of Property Tax Revenue with Increased Usage Rate.....</i>	24
3.4.2.	<i>Financial Impacts to Customers – Replacing a Portion of Property Tax Revenue with Increased Base Rate</i>	25
3.4.3.	<i>Financial Impacts to Customers – Replacing a Portion of Property Tax Revenue with Combined Increased Base Rate & Usage Rate</i>	26
3.5.	PROPOSED ELECTRIC RATE SCHEDULES	27
4.	APPENDIX.....	28

1. INTRODUCTION

The Kirkwood Meadows Public Utility District (District) was formed in 1985 by an act of LAFCO (Local Agency Formation Commission) to provide Water and Wastewater services to the community of Kirkwood, California. Over the years, the District has taken on many other functions, including Electric service.

The District is governed by a five-member Board of Directors (Board) elected by registered voters in the District to serve staggered four-year terms. The Board Members are:

Eric Richert, President

Robert Epstein, Vice President & Treasurer

Peter Dornbrook, Secretary

Bertrand Perroud, Assistant Secretary

John Schroeder, Director

The Board adopts a budget annually for all departments, and the General Manager monitors procedures to assure that expenditures of the District do not exceed the appropriations by department and/or Enterprise of the major summary categories (salaries and benefits, operating services and supplies, capital outlay, and capital improvement projects) in conformance with the adopted policies set by the Board.

Kirkwood Meadows Public Utility District (“KMPUD or “District”) conducted a 2021 Electric Rate Study (Study). This report describes in detail the assumptions, procedures, and results of the Study, including conclusions and recommendations.

1.1. UTILITY BACKGROUND

KMPUD is a special district located within Alpine, Amador, and El Dorado Counties. KMPUD’s service area encompasses an area of approximately 1.875 square miles. The community size and operation of the District’s largest customer, Kirkwood Ski Resort, creates unique seasonal demands on the electric

utility, with peak activity and population occurring during snow season. There are normally approximately 150 full-time residents living within the District's service area, but seasonal daily population maximums may reach 8,000 – 9,000 persons during the winter months. The high-density village core area includes a combination of residential, lodging, and commercial uses serving residents and guests. The District services 769 active electric connections, of which 636 are residential and 133 are commercial. The residential accounts include 23 homeowner associations (HOAs). KMPUD receives its power from both the CAISO grid and diesel generation at the District Powerhouse.

Revenue for the electric utility comes primarily from rate revenue. The electric enterprise also receives property tax revenue and miscellaneous fee revenue. The last rate study for the electric enterprise was conducted by the District in 2014.

1.2. SCOPE OF STUDY

The scope of this Study was to review the most recently adopted District operational and capital budgets, develop a consistent cost-of-service analyses, review the existing rate structures, and propose 5-year rate schedules for the electric utility. The primary objectives of this Study were to:

- Review the existing multi-year budget for the electric enterprise that integrates operational and capital project funding needs and meet established District Reserve Policy goals and USDA Tier Ratios¹; and
- Identify future annual rate adjustments to electric rates to help ensure adequate revenues to meet the electric utility's ongoing service and financial obligations; and
- Determine the cost of providing electric service to customers using equitable and logical methodologies; and
- Recommend specific modifications to the existing rate structures in order to ensure that the proposed rates equitably recover the cost of providing service, provide for equitable sharing of annual debt service, and comporting with industry standards and California's legal requirements.

¹ See Appendix A

1.3. STUDY GOALS

KMPUD proposes changes to the current Base and Usage Rates for electricity to accomplish the following goals:

- Better balance our fixed income with our fixed expenses;
- Ensure fixed costs (debt) are equitably allocated across customers; and
- Create a rate structure that makes electricity competitive by lowering the Usage Rate of electricity, while making it cost effective to consider using over other fuels; and
- Consider changes to existing policy that reflect Federal, State, and local climate goals and requirements, as well as encouraging conversion to cleaner, electric energy; and
- Exclusive of the 6% revenue increase required to offset property tax shifting, target revenue neutrality with the same estimated unit sales; and
- Minimize changes in their annual costs for the majority of customers.

1.3.1.BUDGET

The audited fiscal year 2019-2020 saw actual usage of 6,277,386 kWh which equates to usage revenue of \$3,898,857 and Base Rate revenue of \$195,640. Sources of cash include power sales, property taxes, and cash reserves. Cash reserves for electricity are targeted at \$2,000,000. Currently annual interest payments are estimated at approximately \$1,600,000 and depreciation costs are approximately \$1,650,000. The depreciation costs are approximately the same as principal payments on debt.

Each subsequent year of the budget includes allowance for Cost of Living Adjustments, Salary & Wages increases, etc. and is used in calculating financial need in each of the revenue scenarios.

1.3.2.FIXED COSTS

A primary goal is to meet our financial obligations in the event of a force majeure or significant ski area closure. We have two obligations. One is to meet our Tier ratios that are defined within our loan agreements with RUS². The second is to ensure sufficient cash for our debt service payments and operational obligations.

The District has two sources of revenue and three sources of cash. Revenues can either come from sales of power defined to be the monthly fixed Base Rate and the variable Usage Rate or revenue can come from property taxes allocated to electricity. The latter is expected to be limited to approximately \$450,000 per year. In prior years up to \$660,000 was allocated to electricity.

Another goal of this Study is to be both revenue neutral, exclusive of the 6% revenue increase required to offset property tax shifting, and to have, to the greatest extent possible, the minimum impact on our customers' annual cost of electricity. The exception is the consideration of the minimum annual customer contribution to equitably cover the costs of the infrastructure and debt service.

Multiple scenarios were analyzed relative to fixed costs; Cost Allocation method (similar to Water & Wastewater rate studies), Avoided Costs method, and the Cost of Goods Sold method.

1.3.3.VARIABLE COSTS

The usage portion of electricity is currently \$0.656/kWh which includes an "avoided cost" of \$0.137/kWh. The "avoided cost" is the savings to the District for not purchasing and delivering a kWh.

Shifting total revenues between usage and Base Rates does not lower the costs of power for KMPUD customers. However, if we can encourage customers to use electric heating instead of propane or wood, and electric vehicles instead of gasoline, this represents a cleaner, greener Kirkwood. In addition, the increase in overall electric consumption enables us to lower the overall rates since the annual fixed costs are spread across a larger base. This is true because we have the

² See Appendix A

capacity to significantly increase electric consumption without adding any fixed costs. Thus, encouraging new electric heat, especially on new construction, and more EV charging which is both a financial and environmental benefit. However, to compete with propane and gasoline, the cost of power needs to be lower.

Therefore, the scenarios analyzed used Usage Rates as close to District incurred cost as possible.

1.3.4.EQUIVALENT DWELLING UNIT (“EDU”) METHODOLOGY

1.3.4.1.EDU Calculation

Per Ordinance 16-01, the District currently calculates EDUs for each electric customer on an annual basis where 1 EDU is equivalent to the average electric usage of all customers, including commercial, for the prior 3 fiscal years (July 1 to June 30).

To calculate an individual customer’s EDUs, their average annual usage for the previous 3 fiscal years is divided by the average annual usage for all electric customers for the previous 3 fiscal years, as shown below.

3 Year Avg. of Individual Customer Usage / 3 Year Avg. of All Customer Usage = ## EDUs

The proposed calculation is revised to mirror industry standards which generally only considers residential customers “dwellings”. EDUs will be calculated over a five (5) year period as discussed later in the Study, and calculated as:

5 Year Avg. of Individual Customer Usage / Avg. All Residential Customer Usage = ## EDUs

For the purposes of this Study, the “Average All Residential Customer Usage” was calculated using the period from July 1, 2017 through June 30, 2020, yielding an average annual EDU equal to 230 kWh.

Going forward, the EDU measurement period would be changed to April 1 through March 31, so as to simplify the budgeting process and EDU calculations.

1.3.4.2.EDU Assignment and Duration

Per Ordinance 16-01, the District currently does not merge previous customer usage with new customer usage. Instead, each new residential customer is assigned 1 EDU until they have at least 12 months of usage data on July 1, and at that time the District recalculates their EDU based on that usage. Usage is recalculated on an annual basis and the EDU is adjusted. The minimum EDU is 1 and EDU are rounded to the nearest 0.1 EDU.

The District has recently made improvements to its Report Server system that allows it to track customer usage by parcel, rather than by customer. Therefore, this Study proposes that when a parcel changes ownership, the EDUs be based on historical usage for the parcel.

1.3.4.2.1.Existing Customers

For existing customers with at least three years of data as of March 31, 2021, their EDU assignment will begin based on the most recent 36 month Average Monthly Utilization (“AMU”) from April 1, 2018 to March 31, 2021. Then, after each of the next two, subsequent years (fiscal years 2021/22 and 2022/23), the customers annual use will be averaged into their AMU until the final AMU is calculated based on 5 years data from April 1, 2018 to March 31, 2023. Calculations for accounts with one or more entire years without electrical usage will exclude no-usage. An AMU is assigned to each residence, including those in a multi-family units.

1.3.4.2.2.Existing Structures with Ownership Transfers

For existing or future customers of with less than three years of data ending March 31, 2021 their usage would be based on a combination of their AMU and the prior owners AMU. The calculation would utilize the prior owner’s AMU for the first year. In each subsequent year the new owner’s AMU will be calculated until there are five full years of usage at which time their EDU would be set as in 1.3.4.2.1 above. Once established as proposed, AMUs would remain fixed.

In the last 7 years, 270 properties have changed ownership, some more than once. Of those, 121 have 36 months, or more, of usage data. This Study compares the

previous owner’s usage to the new owner’s usage on these 121 transfers. For this analysis, the 1st, 2nd, and 3rd year averages of the New Owners, after transfer, and the resultant 3-year average was used.

The following table considers the adequacy and appropriateness of the allocations under this method by comparing the new owner’s usage to the previous owner’s usage for the 121 sales that have 36 months, or more, of usage data under the new ownership.

EDU Change		Previous Owner (0.5 Min) vs. Rolling 3 Yr. Avg. (0.5 Min)
< (1.0)	Underallocation	3
(1.0) to (0.8)	Underallocation	2
(0.8) to (0.6)	Underallocation	7
(0.6) to (0.4)	Underallocation	7
(0.4) to (0.2)	Underallocation	12
(0.2) to 0	Underallocation	11
0	No Change	37
0 to 0.2	Overallocation	21
0.2 to 0.4	Overallocation	6
0.4 to 0.6	Overallocation	7
0.6 to 0.8	Overallocation	4
0.8 to 1.0	Overallocation	2
> 1.0	Overallocation	2
Subtotal		121
Maximum Underallocation		-1.6
Maximum Overallocation		1.9

The table above indicates that Previous Owner usage is a reasonably accurate predictor of future usage with 72% of customers being between -0.4 to 0.4 EDU change; 57% between -0.2 and 0.2 EDU change; and 31% with no change.

1.3.4.2.3. New Construction

Existing residences were broken into three (3) categories: High Density Condominiums, Low Density Condominiums, and Single Family. These are defined as:

- High Density Condominium means there are at least 8 units per building.
 - The average EDU for this type, over the last 3 years is 0.8 EDU/unit.

- Low Density Condominium means there are 3 to 7 units per building.
 - The average EDU for this type, over the last 3 years is 1.1 EDU/unit.

- Single Family means there are 1 to 2 units per building.
 - The average EDU for this type, over the last 3 years is 1.4 EDU/unit.

This Study sets the initial new Residential construction EDUs based on the calculations of average use for the three categories of residents. The calculation would utilize 1 year of the new residential category EDU, averaged each subsequent period from April to March with the new owner's AMU until such time as the customer has at least five years of usage ending March 31 at which time their EDU would be set as in 1.3.4.2.1 above. Once established as proposed, AMUs would remain fixed.

Current and future Commercial use would continue to be fixed as per current policy, based on anticipated usage calculations and similar facilities.

1.3.4.3. EDU Minimum

Per Ordinance 16-01, the District currently calculates EDUs for each electric customer on an annual basis in 0.1 increments with a minimum of 1.0. This Study evaluated the impacts of different minimum EDUs, recognizing the potential capacity demands of each connection while balancing that with the desire to minimize impacts to the largest percentage of customers possible.

In Water & Wastewater industry standard calculations; apartments, hotel rooms, and condominiums are generally assigned a factor of 0.8 to 0.9 EDUs in recognition of their smaller footprint and generally smaller potential capacity demands. This similarly applies to electricity and was one of the recommendations offered by the District's Out Valley Project and current Electrical Engineer David Rightley.

After reviewing several different options, this Study has determined that a minimum EDU of 0.5 equitably distributes fixed costs as well as minimizes impact to most customers.

1.3.5.NET METERING

There are currently 9 homes in Kirkwood that have solar and participate in the Net Energy Metering ("NEM") program. Publicly owned electric utilities (POUs), such as KMPUD, must offer a standard tariff or contract to their customers that provides for net energy metering (NEM) until the POU's total rated generating capacity used by NEM customers exceeds five percent (5%) of the POU's aggregate customer peak demand. The POU NEM requirements are specific in Public Utilities Code ("PUC") section 2827 and the POU's NEM program subject to the oversight of the POU's governing board. Per PUC Section 2827(b)(10), "Rate-making authority" means, for an electrical corporation, the [CPUC], for an electrical cooperative, its rate-setting body selected by its shareholders or members, and for a local publicly owned electric utility, the local elected body responsible for setting the rates of the local publicly owned utility (emphasis added). In contrast, the investor owned utilities are subject to the NEM rules adopted by the California Public Utilities Commission ("CPUC"), e.g., NEM 1.0, NEM 2.0, or any successor program. Section 2827 does not give the CPUC any authority over the NEM programs of POUs nor are POUs subject to the NEM decisions adopted by the CPUC.

Under the current KMPUD NEM rules, a kWh generated by the home in excess of the home's instantaneous usage is purchased by KMPUD at the current Usage Rate (\$0.656/kWh) and is used to meet instantaneous demand for other customers. All payments are deferred until the end of the fiscal year at which point a true-up occurs. If annual generation is less than demand, then the customer is

billed at the Usage Rate for the shortfall. If annual generation exceeds demand, the excess results in a credit to the customer at the current “avoided cost” rate of \$0.13 cents.

Meters installed at net metering customer residences measure power taken from the grid, but do not measure “behind-the-meter” power, which is power generated and consumed immediately on-site. When NEM customers consume a kWh concurrent with generating a kWh, the usage is hidden “behind the meter”. Instantaneous demand exceeding the solar or wind generation output is met by supplying the customer power from our own power sources, the same as other customers. KMPUD also measures the generation that the home supplies that is surplus at the time. That power is distributed to other KMPUD customers and displaces power from the grid.

From July 2013 through March 2021, solar installations at Kirkwood generated 157,352 kWh. Of the 157,352 kWh generated, approximately 32,000 were in excess of customer demand at true-up and were purchased at \$0.13/kWh for \$4,200. The remaining 125,000 were purchased by KMPUD as part of the District’s NEM offset process where a solar customers generation is allowed to offset their consumption at retail rates within the true-up period. The 125,000 kWh purchased at the Usage Rate of \$0.67 were purchased in lieu of buying power at \$0.13. In other words, that power was purchased at an additional cost of \$0.54/kWh for a total cost of \$67,000 to the non-NEM KMPUD customers.

In large systems outside of Kirkwood, there are system benefits to distributed generation as it reduces local impacts of distribution and can help defer subsystem upgrades. Those can be significant benefits, but they are very dependent on the local situation. In the case of KMPUD, there are no local benefits since we have a small distribution system and cannot export power to the CAISO grid.

The District estimates that the majority (over 90%) of the power consumed by a solar home over the year is supplied by the KMPUD generation sources and not the rooftop solar.

The District desires to encourage solar or wind generation for those homes who want it, but also needs to avoid significant cost shifting from one home to another, while being financially neutral to whether a home installs solar or wind generation. In order to encourage customers to choose electricity over propane or wood and to encourage electric vehicles, KMPUD is proposing that the Usage Rate be set to the avoided-cost rate of \$0.147/kWh. An advantage of this proposal is that KMPUD customers are less impacted by the purchase of local solar generation over the purchase of power from the grid. This means that solar and non-solar homes are treated the same as required under Proposition 26.

The primary statutory guidance on whether the proposed structure is allowable is found in PUC Section 2827(g), which has three parts:

- “[E]ach net energy metering contract or tariff shall be identical, with respect to rate structure, all retail rate components, and any monthly charges, to the contract or tariff to which the same customer would be assigned if the customer did not use a renewable electrical generation facility, except that eligible customer-generators shall not be assessed standby charges on the electrical generating capacity or the kilowatt-hour production of a renewable electrical generation facility.”
- “The charges for all retail rate components for eligible customer-generators shall be based exclusively on the customer-generator's net kilowatt-hour consumption over a 12-month period, without regard to the eligible customer-generator's choice as to from whom it purchases electricity that is not self-generated.”
- “Any new or additional demand charge, standby charge, customer charge, minimum monthly charge, interconnection charge, or any other charge that would increase an eligible customer-generator's costs beyond those of other customers who are not eligible customer-generators in the rate class to which the eligible customer-generator would otherwise be assigned if the customer did not own, lease, rent, or otherwise operate a renewable

electrical generation facility is contrary to the intent of this section, and shall not form a part of net energy metering contracts or tariffs.”

The proposed structure for establishing the base rate meets the first and third sentence because the calculation to determine the base rate is the same for both NEM and non-NEM customers and the charge would not be higher for NEM customers than for non-customers.

The second sentence of Section 2827(g) only applies to the volumetric rate components, such as the Public Benefits Charge, and does not prohibit the use of the customer’s historical consumption to develop the amount of a fixed charge. This interpretation is supported by the wording of Section 2827(g), where in the first sentence it uses the phrasing “rate structure, all retail rate components, and any monthly charges,” which affirms that monthly charges are separate from retail rate components. If all “monthly charges” were also considered “retail rate components,” then there would no need to separately list monthly charges in that sentence. This interpretation would mean that the monthly charges would need to be identical but would not need to be based only on the net consumption.

The economics of installing future rooftop solar change significantly with the proposed rates. Customer considering rooftop solar would need to focus primarily on non-economic benefits.

One final point, a significant growth in rooftop solar could produce more power than there is demand during midday in summer. This would make it impossible to safely operate the power system without significant investment in battery storage.

1.3.5.1. Average Monthly Utilization (“AMU”) for Customers with Net Metering

The AMU for solar customers was calculated to reflect an assumed ten (10) year return on investment (“ROI”) from the date of installation. For solar customers who have solar systems that have been installed for more than 10 years, the AMU is re-calculated based on electric usage only during the most recent five year period. (Instantaneous generation and usage are not included.)

Although not required by the KMPUD adopted NEM rules, in an effort to allow solar customers who installed within the last 10 years under the old rate structure to achieve ROI, the AMU for solar customers who have solar systems that have been operational for less than 10 years as of March 31, 2021 is calculated by subtracting the average monthly solar generation from the average monthly electric usage. This net AMU calculation will remain in place until the solar customer reaches 10 years of installation, after which, the AMU calculation will revert to electric usage only.

The AMU calculation for net-metering customers who install solar or wind generation after August 1, 2021 would not be based on electric usage since the customer's decision to install solar would be based on the new rate structure.

2. BUDGET

This District utilized the adopted budget which provides budgeted operating costs for the current fiscal year, a multi-year capital improvement program (CIP), and outstanding debt service obligations.

2.1. ELECTRIC ENTERPRISE FINANCIAL PLAN

The following sections describe the financial plan for the District's Electric Enterprise.

2.1.1.BEGINNING FUND BALANCES

The FY 2020/21 beginning fund balances for Fund 50 are:

Operating Reserve	\$ 954,309
LAIF	\$ 1,518,830
Capital Reserve	\$ 102,010
COP Reserve	\$ 79,580
Total Unrestricted	\$ 2,654,729

2.1.2.RESERVE TARGETS

Reserves for electric were previously established by the Board in order to (a) comply with contractual obligations (e.g., USDA Tier Ratios and loan covenants), (b) protect the utility from unexpected financial events, and (c) accommodate operational and capital program cash flow needs.

2.1.3.CUSTOMER GROWTH

Future customer growth can affect a rate study in terms of (1) anticipated capacity charge revenue (connection fees) and (2) increases in rate revenue due to a larger customer base. This Study assumes that the District's Electric Enterprise will grow, whether by new construction or conversion from propane use by existing customers, by 3% over the next five years.

2.1.4.RATE REVENUES

Rate revenue is the revenue generated from customers for electric service. Rate revenue is collected through a fixed “Base Rate”, a fixed “Meter Charge”, and a variable “Usage Rate”. This Study proposes shifting revenue from Usage to Base Rate along with adopting annual rate revenue adjustments that will meet the District’s revenue requirements. Budgeted and projected rate revenues are listed later in this Study.

2.1.5.NON-RATE REVENUES

In addition to rate revenue, the Electric Enterprise receives other revenue, including miscellaneous fees, interest earnings on investments, and property tax revenue. Property tax revenue collected by the District is first allocated as needed to the District’s Electricity Utility (per an agreement with RUS for the electric transmission loans) and then allocated to other District departments as available. Based on commitments made in the recent Water & Wastewater rate increases, there is, on average a maximum of \$450,000, available to the Electric Enterprise annually.

2.1.6.OPERATION & MAINTENANCE EXPENSES

The combined operating and maintenance expenses include all ongoing transmission, distribution, generation, and administrative expenses. The annual operating and maintenance costs for this Study are based on the Electric Enterprise’s FY 2019/20 budget and are adjusted for future years based on inflation.

2.1.7.COST ESCALATION

Annual cost escalation factors for the various types of expenses were developed based upon a review of historical inflation trends, published inflation forecasts, industry experience, and discussions with District staff. During the projection period, all operations and capital expenses are projected to increase at 3.0% per year.

2.1.8.EXISTING DEBT SERVICE

The Electric Enterprise currently has outstanding debt through USDA RUS which in Fiscal Year 2019/2020 had principal payments of \$2,152,807 and interest payments of \$1,841,427. The annual debt service varies annually based on maturity of notes over the next 35 years, but average interest payments are approximately \$1,600,000. USDA loan covenants require the District to maintain minimum Tier Ratios³ under various criteria, which are satisfied by the proposed scenarios.

2.1.9.CAPITAL IMPROVEMENT PROGRAM

	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Capacity Component					
Powerhouse Gates	15,000				
Total Electric Capacity Expense	15,000	0	0	0	0
Replacement Component					
Transformer Cabinet Replacement	20,000				
Diesel Fuel Tank Manifold	10,000				
Transformer Retaining Walls	6,000				
Fremont Court Transformer	8,000				
Snowmobiles	36,000				
Switchgear Battery Replacement	6,000				
Riser Vaults (8)	10,000	10,000	10,000	10,000	
Service Lines	4,000		4,000		4,000
CEMS Screen Replacement		3,000		3,000	
Meadow line replacement		150,000			
Powerhouse Radiator Roof				200,000	
Distribution System FCIs					12,500
Phase 3 Loop Road Project					
Service Truck (Split with Propane)					
Total Electric Replacement Expense	100,000	163,000	14,000	213,000	16,500
Total Electric Capital Expense	115,000	163,000	14,000	213,000	16,500

³ See Appendix A

2.1.10.FUTURE BORROWING ASSUMPTIONS

This Study does not propose any new debt for the Electric Enterprise to finance the costs of future capital projects. Debt financing is not utilized because none of the capital projects during the planning period are expected to materially impact cash reserves and it is more cost effective to fund ongoing rehabilitation and replacement projects on a pay-as-you-go basis.

3. COST OF SERVICE & RATE DESIGN

Once the respective rate revenue requirements have been determined, the next step in the rate setting process is to evaluate the cost of providing these services to individual customer classes. A cost-of-service analysis evaluates the cost of providing service and proportionately allocates those costs to customer classes and rate structure components to ensure the proposed rate structure is aligned with the costs of providing electric service.

The following sections present detailed descriptions of the cost-of-service and rate structure methodology used for electric and the corresponding proposed rate schedules. Note that no change or modification is proposed for monthly Meter Charges.

3.1. CURRENT ELECTRIC RATES

EDU = 726 kWh

Minimum EDU = 1.0

	Per Customer	Monthly Sum	Annual Sum
Current Base Rate	\$ 14.93	\$ 18,407	\$ 220,879
Current Usage Rate	\$ 0.656	\$ 385,073	\$ 4,620,875
Subtotal			\$ 4,841,754

3.2. PUBLIC BENEFITS CHARGE (PBC”)

California Public Utilities Code Section 385(a) states that each Publicly Owned Utility (“POU”) “shall establish a non-bypassable, usage based charge on local distribution service of not less than the lowest expenditure level of the three largest electrical corporations in California on a percent of revenue basis, calculated from each utility’s total revenue requirement for the year ended December 31, 1994, and each utility’s total annual public benefit programs expenditures.” This has to be a one-time, fixed percentage of 2.85% of the customer’s electric usage. The PBC must be collected from all customers and should be collected on the basis of either energy sales or energy demand, or a combination of the two. Net energy metering customer are only assessed the PBC on their net consumption.

For purposes of this Study, the 2.85% PBC is included in all proposed Usage Rates. These funds shall be accounted for separately in order to track how these funds are spent.

3.3. AVOIDED COSTS

In consultation with Severin Borenstein, Professor of Business Administration and Public Policy at the U.C. Berkeley Haas School of Business and faculty director of the Energy Institute at Haas, this Study sets the Usage Rate equal to the District's actual cost. The reasons this method was used are:

- Electricity is the cleanest form of energy available in California and by pricing it at our actual cost for an incremental kWh, we remove all artificial price barriers from customers deciding to use electricity instead of propane.
- This would eliminate the need for separate metering systems for electric heat and EV charging thus lowering the customer's capital costs.
- This would reduce or eliminate economic barriers to the use of electric heating and EV charging and other beneficial uses. It is very likely to encourage customer retrofits as well as positively impact new construction.

3.3.1.ALLOCATION OF AVOIDED COSTS

	Audited 2019/20 Financials	Meter Charge	Base Rate	Usage Rate	Meter Charge	Base Rate	Usage Rate
Operating Expenses							
Salaries & Benefits	\$ 191,513	5%	95%	0%	\$ 9,576	\$ 181,937	\$ -
Operations & Maintenance	\$ 295,057	0%	0%	100%	\$ -	\$ -	\$ 295,057
Contract Services	\$ 5,209	0%	0%	100%	\$ -	\$ -	\$ 5,209
Operating Expenses	\$ 13,170	0%	0%	100%	\$ -	\$ -	\$ 13,170
Power							
Purchased Power	\$ 409,747	0%	0%	100%	\$ -	\$ -	\$ 409,747
Diesel	\$ 103,350	0%	0%	100%	\$ -	\$ -	\$ 103,350
Allocation Into Fund							
General & Administration	\$ 331,269	5%	95%	0%	\$ 16,563	\$ 314,706	\$ -
Capital							
Interest Expense	\$ 1,841,427	0%	100%	0%	\$ -	\$ 1,841,427	\$ -
Capital Spending	\$ 53,335	0%	100%	0%	\$ -	\$ 53,335	\$ -
Subtotal Operating Expenses	\$ 3,244,077				\$ 26,139	\$ 2,391,405	\$ 826,533
Depreciation	\$ 1,530,121	0%	100%	0%	\$ -	\$ 1,530,121	\$ -
Total Expenses	\$ 4,774,198				\$ 26,139	\$ 3,921,526	\$ 826,533

3.3.2.AVOIDED COST CALCULATION

This Study calculates the avoided cost using data from FY 2019/20.

Avoided Cost/kWh FY 2019/20

Metered kWh	6277386
Purchased Power	\$ 409,747
35.8% Renewable Energy Credit Purchases	\$ 33,000
Average Cost of Purchased Power	\$ 0.071
Operations and Maintenance	\$ 295,057
Contract Services	\$ 5,209
Operating Expenses	\$ 13,170
Diesel	\$ 103,350
Total Supplies/Operating Expenses per kWh	\$ 0.066
Avoided Costs per kWh	\$ 0.137

3.3.2.1.FINANCIAL IMPACTS TO CUSTOMERS - \$0.137/KWH

	Per Customer	Monthly Sum	Annual Sum
New Base Rate	\$ 127.00	\$ 317,195	\$ 3,806,342
New Usage Rate	\$ 0.137	\$ 77,424	\$ 929,092
Subtotal			\$ 4,735,434

RESIDENTIAL (*INCLUDES 2 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	130
(\$10) to \$0	324
\$0 to \$10	78
\$10 to \$20	45
\$20 to \$40	42
\$40 to \$60	9
>\$60	8

COMMERCIAL (*INCLUDES 4 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	13
(\$10) to \$0	23
\$0 to \$10	23
\$10 to \$20	14
\$20 to \$40	19
\$40 to \$60	14
>\$60	25

3.3.3.AVOIDED COST CALCULATION WITH 100% RENEWABLE ENERGY

Alternatively, this Study also considered calculating the avoided cost using data from

FY 2019/20 and 100% Renewable Energy Credits. 100% Renewable Energy Credits is defined as offsetting all purchased power, less surplus solar generated by District customers.

Avoided Cost with 100% RECs/kWh FY 2019/20

Metered kWh	6277386
Purchased Power	\$ 409,747
100% Renewable Energy Credit Purchases	\$ 94,161
Average Cost of Purchased Power	\$ 0.080
Operations and Maintenance	\$ 295,057
Contract Services	\$ 5,209
Operating Expenses	\$ 13,170
Diesel	\$ 103,350
Total Supplies/Operating Expenses per kWh	\$ 0.066
Avoided Costs per kWh	\$ 0.147

3.3.3.1.FINANCIAL IMPACTS TO CUSTOMERS - \$0.147/KWH

	Per Customer	Monthly Sum	Annual Sum
New Base Rate	\$ 127.00	\$ 317,195	\$ 3,806,342
New Usage Rate	\$ 0.147	\$ 83,076	\$ 996,909
Subtotal			\$ 4,803,251

RESIDENTIAL (*INCLUDES 2 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	76
(\$10) to \$0	307
\$0 to \$10	124
\$10 to \$20	59
\$20 to \$40	53
\$40 to \$60	9
>\$60	8

COMMERCIAL (*INCLUDES 4 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	8
(\$10) to \$0	21
\$0 to \$10	20
\$10 to \$20	10
\$20 to \$40	19
\$40 to \$60	15
>\$60	38

3.3.4.KWH SOLD OVER BUDGET

The avoided cost per kWh is calculated to cover O&M costs, minus diesel, when the budgeted units sold target is met. For every kWh over budget that is sold in either of the above scenarios, approximately \$0.05 is generated above the budgeted revenue target. Any excess revenue made from kWh sales above budget could be applied to debt service.

3.4. REDUCED PROPERTY TAX RELIANCE SCENARIOS

During the June 12, 2021 Board meeting, the Board determined that in order to meet the assumptions and requirements of the 2019 Water/Wastewater Rate Study, that the Electric Fund would need to eliminate reliance on approximately \$270,000 of property taxes currently utilized annually to meet RUS loan covenants. This will result in an approximate increase of 6% total electric revenue. The following three scenarios considered different ways to meet this necessity.

3.4.1.FINANCIAL IMPACTS TO CUSTOMERS – REPLACING A PORTION OF PROPERTY TAX REVENUE WITH INCREASED USAGE RATE

	Per Customer	Monthly Sum	Annual Sum
New Base Rate	\$ 127.00	\$ 310,871	\$ 3,730,447
New Usage Rate	\$ 0.190	\$ 105,344	\$ 1,264,125
Subtotal			\$ 4,994,573

RESIDENTIAL (*INCLUDES 2 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	5
(\$10) to \$0	141
\$0 to \$10	218
\$10 to \$20	121
\$20 to \$40	108
\$40 to \$60	32
>\$60	10

COMMERCIAL (*INCLUDES 4 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	0
(\$10) to \$0	15
\$0 to \$10	12
\$10 to \$20	9
\$20 to \$40	19
\$40 to \$60	12
>\$60	62

3.4.2.FINANCIAL IMPACTS TO CUSTOMERS – REPLACING A PORTION OF PROPERTY TAX REVENUE WITH INCREASED BASE RATE

	Per Customer	Monthly Sum	Annual Sum
New Base Rate	\$ 136.50	\$ 334,125	\$ 4,009,496
New Usage Rate	\$ 0.147	\$ 81,503	\$ 978,037
Subtotal			\$ 4,987,534

RESIDENTIAL (*INCLUDES 2 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	8
(\$10) to \$0	142
\$0 to \$10	216
\$10 to \$20	118
\$20 to \$40	108
\$40 to \$60	34
>\$60	9

COMMERCIAL (*INCLUDES 4 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	0
(\$10) to \$0	16
\$0 to \$10	11
\$10 to \$20	9
\$20 to \$40	19
\$40 to \$60	12
>\$60	62

3.4.3.FINANCIAL IMPACTS TO CUSTOMERS – REPLACING A PORTION OF PROPERTY TAX REVENUE WITH COMBINED INCREASED BASE RATE & USAGE RATE

	Per Customer	Monthly Sum	Annual Sum
New Base Rate	\$ 119.00	\$ 291,098	\$ 3,493,174
New Usage Rate	\$ 0.220	\$ 122,034	\$ 1,464,403
Subtotal			\$ 4,957,576

RESIDENTIAL (*INCLUDES 2 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	5
(\$10) to \$0	158
\$0 to \$10	228
\$10 to \$20	124
\$20 to \$40	94
\$40 to \$60	21
>\$60	5

COMMERCIAL (*INCLUDES 4 INACTIVE METERS)

Monthly Net Change	Customers
(\$20) to (\$10)	0
(\$10) to \$0	17
\$0 to \$10	12
\$10 to \$20	8
\$20 to \$40	21
\$40 to \$60	12
>\$60	59

3.5. PROPOSED ELECTRIC RATE SCHEDULES

The Board voted unanimously at the June 28, 2021 Board meeting to proceed with the \$119 / \$0.22/kWh model for a final public hearing July 10, 2021.

The proposed rate schedule assumes a 3.0% CPI annually applied only to Base Rate fixed costs, excluding debt service and depreciation, and the Monthly Meter Charge. Based on approximately \$1,600,000 of annual debt service payments and \$1,650,000 of depreciation, fixed costs of \$554,228, or approximately 15%, under the Avoided Costs methodology are subject to CPI.

	Current Rates	FY 2021/22	FY 2022/23	FY 2023/24	FY 2024/25	FY 2025/26
Monthly Meter Charge (per meter)	\$ 2.94	\$ 3.03	\$ 3.12	\$ 3.21	\$ 3.31	\$ 3.41
Monthly Base Rate (per EDU)	\$ 14.93	\$ 119.00	\$ 119.54	\$ 120.07	\$ 120.61	\$ 121.16
Usage Rate (per kWh)	\$ 0.656	\$ 0.220	\$ 0.220	\$ 0.220	\$ 0.220	\$ 0.220

4. APPENDIX