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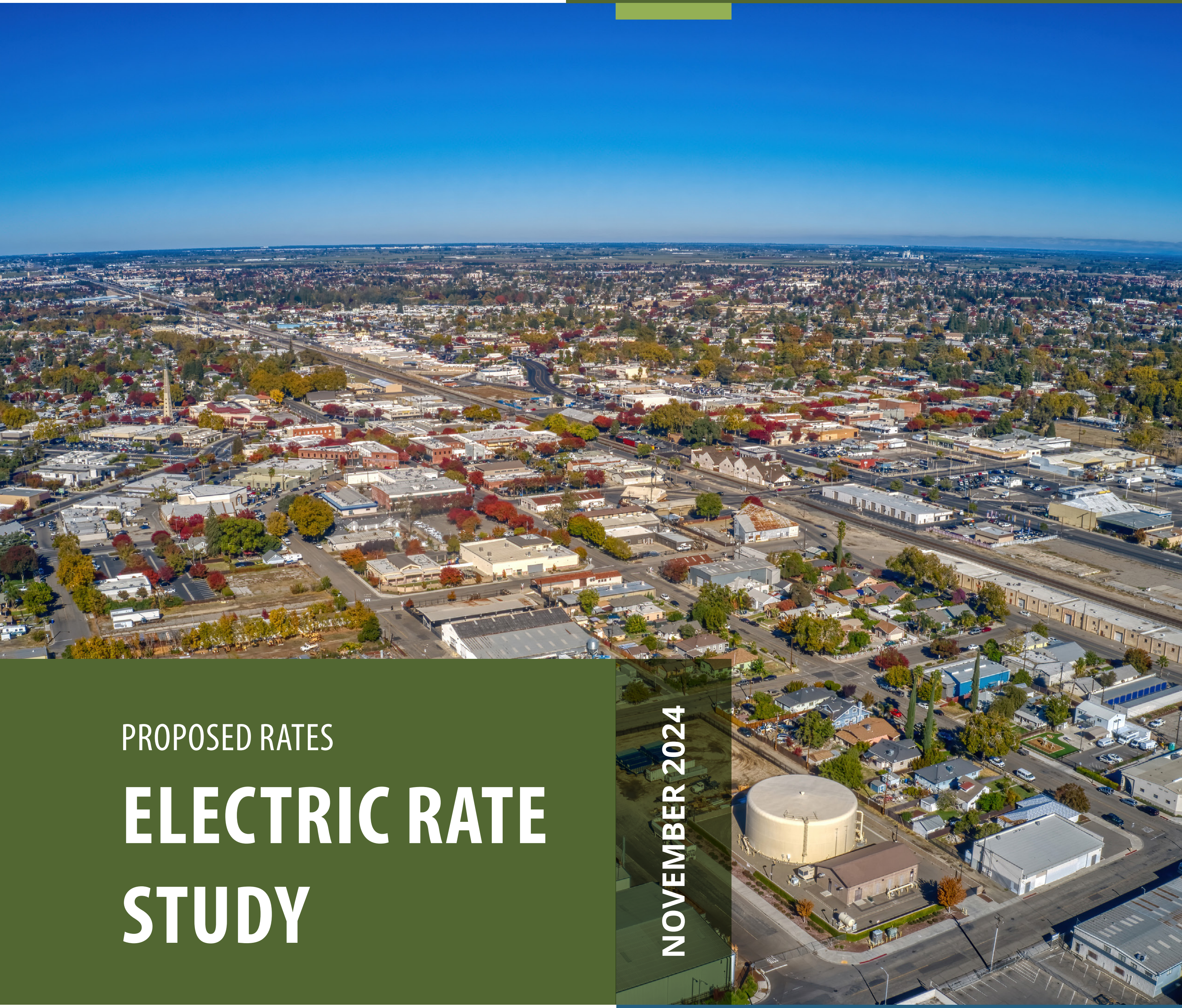

PROPOSED RATES

ELECTRIC RATE STUDY

NOVEMBER 2024

TID

WATER & POWER

Serving Central California since 1887

Prepared for:
Turlock Irrigation District

Proposed Rates | November 2024

Electric Rate Study

Turlock Irrigation District

Prepared by:

NewGen Strategies & Solutions

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Section 1
PROJECT SUMMARY

Introduction

Turlock Irrigation District (TID or the District) is located in the heart of California's Central Valley and has a proud history of providing the southern half of Stanislaus County and a portion of northern Merced County with low cost, reliable electric service and water for agriculture, drinking, and other uses.

The District retained NewGen Strategies and Solutions, LLC (NewGen) to develop cost of service (COS) and proposed Rate Design Studies (Studies) for its electric and water services. The Studies determined the total cost of providing electric and water services, the allocation of costs to the various customer classes, and the design of rates to safeguard the financial integrity of the District and to support the District's financial policies. The total cost of providing services includes costs to generate or purchase power, operations and maintenance (O&M) expenses, debt service, and other cash capital outlays required to operate and maintain the system with high reliability.

One purpose of the Studies was to evaluate the revenues and costs for the District to serve its customers and to determine if the water and electric operations are appropriately recovering their costs. Additionally, the Studies were conducted to review the cost allocations utilized by the District to determine if they are reasonable. A final objective for the Studies was to quantify the rate impact due to proposed changes in rates for each customer class. This Electric Rate Study Report (Electric Report) focuses on the electric operations of the District; a separate report has been prepared to provide a summary of the water operations. The purpose of this Electric Report is to present the processes, analyses, and recommendations related to the Electric Rate Study (referred to herein as the Study).

The District's fiscal year (FY) is from January 1 to December 31. Unless otherwise stated in this Electric Report, all data presented herein is shown in FYs. The Study included an analysis of estimated revenue requirements, an unbundled COS analysis based on the forecasted period FY 2027 (Test Year, or TY), a rate analysis, and the development of proposed new electric rate structures for certain customer classes. District billing data was obtained for 2021 and was augmented with Advanced Metering Infrastructure (AMI) and Automated Meter Reading (AMR) data from 2021. Budgeted values for 2024 were used to create a base year, to which known and measurable changes were made to create the 2027 TY. Demand cost allocators were developed from 2021 billing data and adjusting for growth to represent TY 2027. Various policy issues related to the District's electric and water operations were identified and discussed as part of the Studies. The District provided, and NewGen studied, the majority of the system-specific data utilized, including load information. Analyses were performed in accordance with generally accepted industry practices for publicly owned electric utilities, including those recommended by the American Public Power Association (APPA) and the National Association of Regulatory Commissioners (NARUC).[1]

Our Electric Report contains five sections as follows:

- **Section 1 – Project Summary**: Provides an overview of the Study and the District.
- **Section 2 – Revenue Requirement**: Discusses the development of the revenue requirement.

[1] *Cost of Service Procedures; A cost allocation manual*. APPA, *Electric Utility Cost Allocation Manual*. NARUC, January 1992.

- **Section 3 – Cost of Service**: Provides the COS results for the electric system.
- **Section 4 – Rate Design**: Presents the proposed electric rates.
- **Section 5 – Conclusions and Recommendations**: Summarizes conclusions and recommendations.

Turlock Irrigation District Utility Operations

The District was established in 1887 as the first publicly owned irrigation district in the State of California, and today it is one of only four irrigation districts that provide retail electric service to their customers. TID delivers irrigation water through 250 miles of canals and irrigates approximately 150,000 acres of farmland. TID owns and operates an integrated electric system that includes generation, transmission, and distribution assets that serve over 92,000 customer accounts across a 662 square mile area.

During the TY, the District is projected to serve its retail customers with average annual electricity sales of approximately 2.3 million megawatt-hours (MWh; 1 MWh is 1,000 kilowatt-hours [kWh]) per year and approximately 6.6 million gallons of water for domestic and public facility water service and 380,000 acre-feet of water for irrigation customers.

Turlock Water Sources

The District obtains its water from a variety of sources, including one of the oldest water rights in the State of California. Water resources include Don Pedro Reservoir, Turlock Lake, and other sources, as well as regulated reservoirs.

Turlock Water Operations

The District's water department services customers through its irrigation and domestic services. Please see the companion report developed by NewGen and titled "Turlock Irrigation District – Water Cost of Service and Rate Study," referred herein as the Water Rate Study, for additional information on the COS and Rate Design process for the District's water operations.

Turlock Generation

The District generates or obtains power from a variety of sources, including natural gas, hydroelectric, wind, solar, biomass, and geothermal resources. The natural gas power plants include the Almond Power Plant, the Almond 2 Power Plant, and the Walnut Energy Center. Hydroelectric (hydro) facilities include the Don Pedro dam and generating station, which the District shares with Modesto Irrigation District (MID), as well as several small-scale gravity-fed hydro facilities along the various systems of canals used for irrigation purposes.

Wholesale Power Markets

The District transacts on an hourly and sub-hourly basis with the California Independent System Operator (CAISO), as well as available bilateral markets.

Turlock Transmission/Distribution

The District operates high voltage transmission systems that consists of 230 kilovolt-ampere (kVa), 115 kVa, and 69 kVa transmission lines connected to a system of approximately 45 electric substations throughout its service territory. Some of the larger transmission assets are jointly owned by the District and other entities. The District's distribution system consists of a total of approximately 2,235 circuit miles of conductor operated at 12 kVa.

Projected Energy Requirements

TID's electric consumption used for the TY period in the Study is shown in Table 1-1, rounded to the nearest thousand kWh. Total consumption reflects sales to District retail customers plus system losses of approximately 5.5%. Energy production and sales to customers were based on the District's projected energy sales during the Study period.

Table 1-1
Estimated Annual Energy Requirements

Test Year	Retail Sales (kWh)	System Losses (kWh)	Total Net Energy for Load (kWh)
2027 TY	2,309,941,000	129,385,000	2,439,327,000

System Demand

The District peaks during the summer months, typically between June and September. Figure 1-1 below provides a representation of the District peak load by month for 2021.

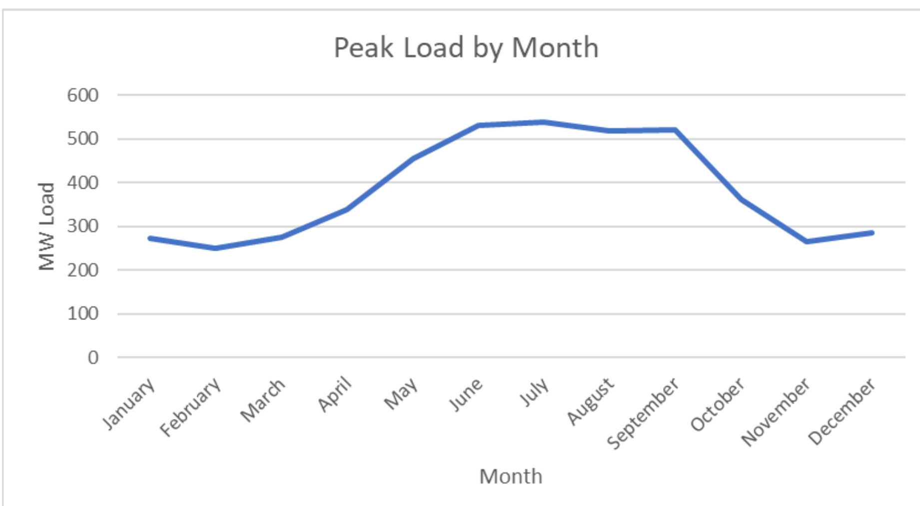

Figure 1-1. System Demand – Peak Load by Month

Usage Characteristics by Class

The COS analysis examined detailed customer usage characteristics by customer class. Table 1-2 summarizes these characteristics for the existing customer classes, including estimated revenue generated during the TY by each class (with no rate changes) and the number of customers in each class, according to the District's electric utility statistics. A description of the customer classes by type, including subclasses, is provided in Section 4.

Table 1-2
Test Year Summary of Electric Utility Characteristics by Customer Class

Class/Service	Class Code(s) (1)	TY Retail kWh Sales	TY No. of Customers (2)	TY Revenue at Current Rates (3)	Avg. Annual kWh Sales per Customer	Avg. Annual Revenue per Customer
Residential	DE/DG/DT	856,687,000	77,600	$136,259,000	11,040	$1,756
Small Commercial	CE/CT/CG/ NM	143,625,000	7,810	$20,526,000	18,390	$2,628
Small Industrial	ID/IG/IT	280,255,000	920	$39,026,000	304,625	$42,420
Large Industrial	HT/HG	280,749,000	60	$34,348,000	4,679,150	$572,467
Very Large Industrial	XT	145,163,000	5	$16,147,000	14,516,300	$1,614,700
Bulk Power	BP/BG	183,033,000	2	$18,794,000	91,516,500	$9,397,000
Farm	FE/FD/FG/ FT	233,063,000	3,220	$33,520,000	72,380	$10,410
Restricted Pumping	PI/PT	34,304,000	1,240	$4,746,000	27,665	$3,827
Municipal Energy	MC/MG	12,307,000	950	$1,736,000	12,955	$1,827
Municipal Demand	MD	132,992,000	300	$15,923,000	443,307	$53,077
Street Lighting – District Owned	LD/LO	3,299,000	N/A	$877,000	N/A	N/A
Street Lighting – Customer Owned	LC	4,466,000	N/A	$861,000	N/A	N/A
Total		**2,309,941,000**	**92,107**	**$322,763,000**	**N/A**	**N/A**

(1) Several subclasses are included within each rate class, as described in Section 4.
(2) Streetlights are not metered; therefore, they are excluded from the total customer count.
(3) Numbers may not add due to rounding.

Cost of Service and Rate Design Process Overview

Typically, the COS and rate design process includes five steps as follows:

1. *Determination of the Revenue Requirement* – This first step examines the District's financial needs and determines the amount of revenue that must be generated from rates. For publicly owned utilities such as the District, the revenue requirement is determined on a "cash basis." A cash basis analysis examines the cash obligations of the utility such as O&M expenses, debt service, cash funded capital projects, and other cash payments. Rates are set such that the utility can pay its bills on an annual basis going forward.

   In preparing our analysis of the electric rates and developing the revenue requirement, NewGen relied upon the District's financial plans, records of operation, customer billing data, and other detailed information and data compiled and provided by the District and its management and staff.

2. *Functionalization and Sub-functionalization of Costs* – The revenue requirement is then assigned to the particular function or sub-function of the utility. Utilities like the District typically have power supply/production, transmission, distribution, and customer services functions. Distribution sub-functions may include distribution infrastructure by voltage, metering, billing, collection, etc. Customer sub-functions include billing and collections, customer service, meter reading, etc.

3. *Classification of Costs* – Once costs are functionalized, they are classified based on their underlying nature. Of particular importance is the determination of fixed versus variable costs. Fixed costs remain a financial obligation of the District regardless of the amount of energy produced whereas variable costs fluctuate based on system energy requirements. Further, fixed and variable costs are associated with utility requirements to meet customer demand, energy, and customer service needs.

4. *Allocation of Costs* – Once costs are classified, they are then allocated to the various customer classes. Allocation factors align with cost classification. Therefore, demand-related costs are allocated on measures of class demand such as class contribution to the system coincident peak (CP). Energy allocation factors are based on energy consumed by customers. Customer allocation factors are based on the number of customers, which is sometimes weighted to reflect different cost causation associated with different customer types.

5. *Rate Design* – The fifth and final step is rate design, which translates COS results into rates for each customer class.

The first four steps describe the COS process and are depicted in the figure below.

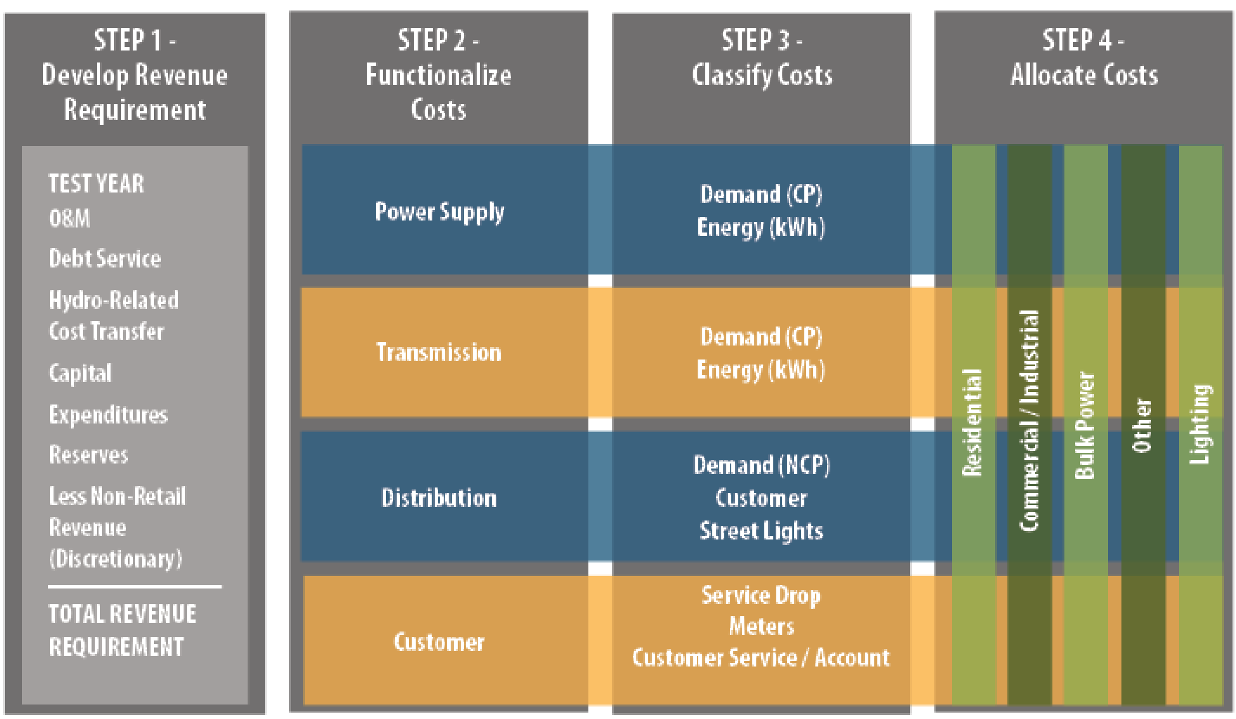

Figure 1-2. Typical Cost of Service Process

Cost of Service Results

Section 3 of the Electric Report describes the COS process. The results of the COS analysis provide a detailed assessment of the costs required to serve each customer class. These customer class costs are unbundled into functions and classified into demand, energy, and customer components. Customer class costs are compared to the projected revenues under current rates to determine if current rates are sufficient to meet costs. Once completed, the COS analysis can serve as the basis for rate design. A comparison of the projected TY revenue requirement by class and revenues collected under current tariffs is shown in Table 1-3.

Table 1-3
Comparison of Current Rate Revenues with Cost of Service Results (1,2)

Class/Service	TY Revenue Requirement ($)	Projected TY Revenues at Current Rates ($)	Projected Over/(Under) Recovery ($)	Difference (%)
Residential	$160,710,000	$136,259,000	($24,451,000)	17.9%
Small Commercial	$23,047,000	$20,526,000	($2,521,000)	12.3%
Small Industrial	$44,223,000	$39,026,000	($5,197,000)	13.3%
Large Industrial	$38,657,000	$34,348,000	($4,309,000)	12.5%
Very Large Industrial	$18,323,000	$16,147,000	($2,176,000)	13.5%
Bulk Power	$22,451,000	$18,794,000	($3,657,000)	19.5%
Farm	$34,768,000	$33,520,000	($1,248,000)	3.7%
Restricted Pumping	$6,229,000	$4,746,000	($1,483,000)	31.2%
Municipal Energy	$1,880,000	$1,736,000	($144,000)	8.3%
Municipal Demand	$20,527,000	$15,923,000	($4,604,000)	28.9%
Street Lighting – District Owned	$740,000	$877,000	$137,000	(15.6%)
Street Lighting – Customer Owned	$639,000	$861,000	$222,000	(25.8%)
Total	**$372,195,000**	**$322,763,000**	**($49,432,000)**	**15.3%**

(1) Numbers may not add due to rounding.

(2) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

The COS indicates that overall system rate revenues are insufficient to meet projected system costs by approximately 15.3%, as discussed herein. At the class level, all customer classes, except street lighting, are below their respective projected cost to serve.

Rate Design

Rate design is the culmination of a COS study as the rates and charges for each customer class are designed to equitably and fully recover the systemwide COS and customer class revenue requirements by the end of the rate period. Section 4 of the Electric Report describes proposed rate design for each customer class. The District's rates currently include the following components:

- Base rate (customer charge, energy charge, and demand charge). Base rates for some classes include a tiered charge and a summer/winter differentiated charge, as well as a Time of Use (TOU) charge, as discussed herein. Tiered energy charges send a pricing signal to the user to conserve energy. Many utilities, such as the District, have implemented tiered charges as a means to provide this conservation measure in their rates. Seasonal rates generally reflect higher prices for power supply seen by the District during the summer period.

- Environmental Charge (Surcharge).
- Power Supply Adjustment (PSA) (Surcharge).

Base rates are applied to the appropriate monthly billing determinants (e.g., number of customer months, kWh consumption, etc.) to project the new rate revenues by customer class. These projected revenues from the proposed rates are compared to the revenue requirements to ensure that rates generate sufficient revenue to recover the COS. The Environmental Charge is currently collected from every consumer based on energy usage. For the purposes of the retail rates developed in this Study, the District intends to remove the Environmental Charge as a line item on the customer's bill and collect the same revenue from base rates. As the District approaches the State's renewable timelines, a larger percentage of its power will be renewable; thus, eliminating the need for a separate Environmental Charge and simplifying customer billing.

Customers taking service under any of the District's electric rate schedules are assessed a PSA that takes into account variances in the District's net power supply cost. The PSA is applied to the customer's energy usage in kWh. The PSA is adjusted from time to time, generally twice a year to be effective on June 1 and December 1 of each year. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Based on a review of the existing rate structure, it was determined that some of the cost recovery components (i.e., customer, energy, and/or demand charges) of the current rates were not in alignment with the COS results. Proposed rates in the Study were designed to move each customer class closer to its respective COS while evaluating the impact of rate changes on customers' monthly bills. Additionally, certain rate components, such as the customer charge ($/month) and the demand charge ($/kW), were adjusted to increase the fixed cost recovery of the overall rate design.

It was determined that new electric rates would be implemented over a three-year period on an annual basis. The rate changes are proposed to be effective on January 1, 2025; January 1, 2026; and January 1, 2027. The intent of the proposed rate changes is for the District's electric rate revenue to meet its projected revenue requirement for the 2027 TY. Additional information and analyses for the District's proposed rates are included in Section 4 of the Electric Report.

Section 2
REVENUE REQUIREMENT

As part of the Study, NewGen developed a TY Revenue Requirement inclusive of all of the District's cash operating and capital expenses to be recovered from rates. The TY Revenue Requirement is based on projected TY operating and financial results which utilized the 2024 budget which were adjusted based on known and measurable changes for the projected 2027 period. Development of the TY Revenue Requirement was based on projected cost information provided by the District, which was studied and analyzed by NewGen, including its adopted budget, capital improvement project (CIP) plans, and financial metric needs. The TY Revenue Requirement represents projected expenses for the District for 2027 and is detailed in this section.

Test Year Revenue Requirement

To remain financially sound, the District's rates must produce sufficient revenues to recover the total costs of providing electric and water service to its customers. These costs imposed on the system by customers are commonly referred to as the utility's "revenue requirement" and consist of normal operating expenses, debt service, capital improvements and additions, non-operating expenses, reserve requirements, and other costs. These total revenue requirements are then compared to utility revenues to evaluate the need for rate changes. The revenue requirement acts as the foundation of a COS study.

The first step in the COS process involves separating the District's electric and water department costs. For the majority of the cost categories, this process is straightforward. For example, power purchases are within the power supply costs and are assigned to the electric operations. Similarly, water expenses are assigned to water operations. For the remainder of the costs, we relied on the District's internal cost allocation process, as well other cost allocators for this Study.

The District is required by Assembly Bill 1890 (1996) to impose a Public Benefits Surcharge of 2.85% on all customer electricity bills. The resulting Public Benefits Surcharge revenue is restricted for specific expenditures by the District. For the purpose of developing the TY revenue requirement, the expenses (and offsetting revenues) from the Public Benefits Surcharge are excluded. However, for the purpose of developing the effective rates for comparison purposes, as described herein in Section 4, the Public Benefits Surcharge is included in the analysis.

Table 2-1 provides a summary of the District's various operation accounts and the results of the allocation between the electric and water operations for TY 2027.

Table 2-1
Total District TY Revenue Requirement – Allocated to Electric and Water (1)

Account	Test Year (2027)	Electric	Water	% Electric	% Water
Power Supply	$295,692,000	$295,521,000	$171,000	100%	0%
Non-Power Supply O&M	$107,290,000	$82,480,000	$24,810,000	77%	23%
Total O&M	$402,982,000	$378,001,000	$24,981,000	94%	6%
Existing Debt Service	$30,091,000	$28,473,000	$1,618,000	95%	5%
New Debt Service	$10,597,000	$9,863,000	$734,000	93%	7%
Capital Funded by Cash	$29,111,000	$27,388,000	$1,723,000	94%	6%
Hydro-Related Cost Transfer (Water for Fuel)	$0	$8,496,000	($8,496,000)	0%	0%
Subtotal Revenue Requirement	$472,781,000	$452,221,000	$20,560,000	96%	4%
Deposit to Reserves for Metrics	$12,355,000	$11,367,000	$988,000	92%	8%
Discretionary Revenues	($102,222,000)	($91,394,000)	($10,828,000)	89%	11%
Total Revenue Requirement (2)	**$382,914,000**	**$372,195,000**	**$10,720,000**	**97%**	**3%**

(1) Numbers may not add due to rounding.

(2) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

The analysis suggests that approximately 97% of the District's costs are associated with its electric operations and 3% are associated with its water operations. This includes the recognition of the water for fuel cost transfer from electric to water, as described herein. The following provides additional detail on the various funds/accounts as utilized by the District.

Power Supply Expenses

The power supply expenses are primarily associated with the District's generation and purchased power expenses, including expenses related to their power production facilities, such as fuel expense. The TY power supply expense is approximately $295,692,000.

Total O&M Expenses

Total O&M consists of power supply and non-power supply O&M expenses. The non-power supply O&M expenses consist of the General Manager's office, the External Affairs office, the Financial Services Administration, Water Resources, Electric Engineering and Operations, and generation expenses in the Power Supply Administration. Power Supply Administration O&M expenses included non-power supply O&M and purchased power (Resource Management). Additionally, O&M expenses include those for the Don Pedro Joint Accounts (DPJA, which is shared between TID and MID) and the Don Pedro Recreational Agency (DPRA, which is shared between TID, MID, and the City and County of San Francisco), as provided in Table 2-2. These costs were allocated between electric and water based on the results of the District's internal cost allocation survey. The DPJA fund includes costs allocated to both electric and water. The DPRA fund is entirely allocated to the electric department. Overall, the TY O&M expenses, which include power supply and non-power supply costs, of approximately $403 million are allocated 94% to the electric department and 6% to the water department.

Table 2-2
O&M Funds – Allocated to Electric and Water (1)

Account	Test Year	Electric	Water	% Electric	% Water
Total General Manager	$10,108,000	$7,140,000	$2,968,000	71%	29%
Total Financial Services Administration	$27,768,000	$24,850,000	$2,918,000	89%	11%
Total Water Resources	$25,605,000	$7,975,000	$17,631,000	31%	69%
Total Electrical Engineering & Operations	$36,562,000	$35,370,000	$1,193,000	97%	3%
Total Power Supply Administration	$295,692,000	$295,521,000	$171,000	100%	0%
Subtotal O&M	$395,735,000	$370,856,000	$24,881,000	94%	6%
O&M Expenses – DPJA (2)	$5,181,000	$5,079,000	$102,000	98%	2%
O&M Expenses – DPRA (2)	$2,067,000	$2,067,000	$0	100%	0%
Total O&M Expenses	**$402,983,000**	**$378,001,000**	**$24,981,000**	**94%**	**6%**

(1) Numbers may not add due to rounding.

(2) DPJA – Don Pedro Joint Accounts; DPRA – Don Pedro Recreational Area (see text).

Total Debt Service

Total Debt Service includes the principal and interest payments due from the District's existing bond issues, which include the 2016 TID Bonds, 2019 TID Bonds, 2020 TID Bonds, and 2024 TID Bonds. This also includes refunding bond issues and interest associated with the District's issuance of Commercial Paper. Total Debt Service was allocated 94% to the electric department and 6% to the water department based on the need for the projected uses for the debt proceeds. Additional detail on this allocation of Total Debt Services is provided in Appendix A, Table A-1.

Total Debt Service is anticipated to be approximately $40.7 million during the TY. This value was determined by NewGen from existing debt service amortization schedules and anticipated debt service from the issuance of new debt to support capital investment over the three-year period ending in the TY. The new debt issued for the three-year period is anticipated to be approximately $247 million at an interest rate of 3.5% amortized over a period of 30 years, which results in a Test Year period increase of approximately $10.6 million. The new debt is assumed to be primarily for electric department investment (approximately 93%), as detailed in Appendix A, Table A-1.

Capital Funded by Cash

In addition to issuing debt, the District funds capital from its rate revenue. Capital Funded by Cash is allocated by project based on the function it is intended to serve. Overall, the Capital Funded by Cash is anticipated to be approximately $29 million in the TY. Approximately 94% of the total is allocated to electric and 6% is allocated to water. Additional detail on the allocation of Capital Funded by Cash is provided in Appendix A (Table A-2).

Value of Hydroelectric Power from Don Pedro (Water for Fuel)

TID owns 68.46% (139 megawatts [MW]) of the Don Pedro hydropower facility (Don Pedro) located on the Tuolumne River. The Modesto Irrigation District owns the rest of the Don Pedro hydropower facility. TID uses the power from this facility to serve a portion of its electric load.

The value of the hydropower provided by water to electric is based on (1) the value of forecasted energy associated with the hydropower generated by Don Pedro in the TY less (2) the costs related to Don Pedro that are already paid by electric customers through costs reflected elsewhere in electric's net revenue requirements. This Study relied on forward prices to determine the market value of energy from Don Pedro. For future energy prices, the District used Kiodex Market data published April 29, 2024.

In order to avoid double-counting as TID incurred Don Pedro-related expenses paid by electric that are already included in electric's cost of service, it is necessary to subtract those expenses from the gross value of energy and capacity provided to electric by water (irrigation). Those costs include TID's portion of:

- Electric's portion of certain water rights.
- Don Pedro generation O&M expenses.
- Various capital projects at Don Pedro.
- Relicensing costs for Don Pedro.

Customers of the electric business line receive this value from the water (irrigation) business line. Thus, to compensate the water business line for the value it provides to electric (or that is foregone by water by not selling the generation from Don Pedro on the open market), water's revenue requirements are reduced by approximately $8.5 million and electric's revenue requirements are increased by approximately $8.5 million. The approximate $8.5 million cost is indicated in Table 2-3.

Table 2-3
Hydro-Related Cost Transfer Detail

Year	Hydro Generation (MWH)	Energy Value	Hydro Costs Paid by Electric	Net Hydro Value Received by Electric
2027	392,000	$24,496,000	$16,000,000	$8,496,000

Deposits to Reserves for Metrics

The District's policy is to maintain compliance with two financial metrics: one relating to debt service coverage and one related to cash reserves.

- Debt Service Coverage Ratio: In any year, the District should maintain a Debt Service Coverage Ratio (DSCR) of at least 1.50.
- Days Cash on Hand: At the end of each Fiscal Year, the District should maintain a minimum of 225 days of annual Operating and Maintenance costs in cash reserves, also known as Days Cash On Hand (DCOH). The District may reserve a maximum of 275 days of annual Operating and Maintenance costs in cash reserves. Per its reserve policy, if the District falls below 225 DCOH, it has three years to increase cash levels to meet the minimum DCOH of 225 days.

NewGen's Study identified annual contributions to reserves necessary to meet the financial policies described above. In TY 2027, the contribution necessary to meet both the DSCR and DCOH policies is approximately $12.3 million, $11.4 million of which is assigned to the electric system.

Discretionary Revenue

The purpose of the COS analysis is to determine the revenue requirement associated with the retail operations of the District. Therefore, the revenue requirement is reduced to reflect non-retail revenues and expenses. For the District, these revenues include electric wholesale sales, wholesale gas sales, sales of its carbon credit allowances (CCA) to offset greenhouse gas emissions, wholesale water sales, penalties for late payments (water and electric), property taxes from Stanislaus County, and MID's share of the La Grange operating expenses. Some discretionary revenues, such as carbon credit allowances and some wholesale water sales, while discretionary, are limited in how they can be utilized. Discretionary revenues are anticipated to be approximately $102 million during the TY period and have been allocated approximately 89% to electric and 11% to water, based on the nature of the revenue items. Additional detail on the allocation of Discretionary Revenue is provided in Appendix A, Table A-3

The Board has complete discretion with regard to the use of these funds, including funding of cash reserves, advanced debt payment, capital investment, or other cash uses. For the purpose of this Study, discretionary revenues are applied to the system to reduce the revenue requirement for retail customers served by both the electric and water departments of the District.

Section 3
COST OF SERVICE

After determining the system revenue requirement, a COS analysis is developed to determine the specific costs to serve each class. Projected customer class revenues are compared to class revenue requirements to evaluate the current rates' ability to recover costs. NewGen analyzed the cost to serve each customer class based on the electric system revenue requirement developed in Section 2.

Once completed, the COS results indicate the degree to which existing rates recover the costs to serve customers. The COS results are then used to design electric rates.

The COS analyses relied on the following key supporting data and analysis:

- TY 2027 estimated revenue requirements and revenue projections based on current rates;
- Estimated total electric system and customer class demand and energy requirements at TY 2027;
- Actual and assumed customer service characteristics;
- Information obtained from customer accounts and records; and
- Discussions with TID regarding costs to provide services.

Electric Rate Functions

The District's electric rates were unbundled into four functions: power supply, transmission, distribution, and customer service. The assignment of costs by function falls into two general categories: 1) direct assignments and 2) derived allocations. Direct assignments are costs that are readily associated with a specific utility function and are directly assigned to that function. For example, the fuel expense is clearly an expense solely related to the power supply, so it is directly assigned to that function.

Derived allocators are allocation factors that are based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the following question: what underlying activities drive the cost of this item? For example, the General Manager expenses are included in O&M and are associated with the operations of all utility functions. Thus, General Manager expenses are allocated to each utility function using a derived allocator. Each of the four utility functions is described below.

Power Supply Function

The power supply function consists of costs associated with the operation of the power generation facilities, as well as the cost of purchased power. Additionally, costs associated with administering power supply contracts are included in the power supply function.

Transmission Function

For the purposes of this Study, we have identified the transmission function as costs associated with operating and maintaining the District's high-voltage transmission system and making capital investments, as necessary. The transmission facilities transmit electricity at high voltage from the generation stations to the distribution system. The District's costs include fixed costs associated with the debt, labor, and other items related to its transmission assets, as well as variable costs, a portion of which is included in the District's purchased power costs.

Distribution Function

The distribution function consists of costs associated with operating and maintaining the distribution portion of the electric grid and making capital investments, as necessary. The distribution facilities deliver power to most retail customers after it has been transmitted. This includes 12 kVa voltage distribution lines, distribution poles, underground lines, customer service connections, meters, and lighting-related assets.

Customer Service Function

The customer service function consists of costs associated with operating and maintaining the customer-related facilities to meet customer support needs. This includes, but is not limited to, customer service, billing and collection, and meter reading.

Unbundling of Revenue Requirement

Table 3-1 provides additional detail of the functionalization of the TY revenue by the District's account categories.

Table 3-1
2027 TY Total Electric Revenue Requirement – Functionalization

Item	Power Supply	Transmission	Distribution	Customer	Total
Total O&M and Water for Fuel Expense	$299,981,000	$24,125,000	$55,169,000	$7,223,000	$386,497,000
Total Debt Service	$25,322,000	$4,155,000	$8,858,000	$0	$38,336,000
Capital Funded by Cash	$11,517,000	$3,364,000	$12,046,000	$461,000	$27,388,000
Deposit to Reserves for Metrics	$8,466,000	$795,000	$1,912,000	$193,000	$11,367,000
Subtotal Revenue Requirement (1)	**$345,286,000**	**$32,439,000**	**$77,985,000**	**$7,877,000**	**$463,588,000**
% Function	74%	7%	17%	2%	100%
Less Discretionary Revenue					($91,394,000)
Net System Revenue Requirement (2)					**$372,195,000**

(1) Numbers may not add due to rounding.
(2) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

The power supply function represents approximately 74% of the TY Revenue Requirement. The distribution function is the second largest cost center, representing approximately 17% of the TY Revenue Requirement. The transmission function represents approximately 7% and the customer function represents the remaining 2% of the TY Revenue Requirement. For the purposes of this Study, estimated TY Discretionary Revenue was not functionalized, but is applied to the total TY revenue requirement as indicated above.

Classification of Costs

To provide a reasonable basis for the assignment of total revenue requirements (costs) to each customer class, costs for each function in the electric system have been analyzed and classified into four rate-making cost classifications, as described below.

1. **Demand Costs** – Capacity (fixed- or demand-related) costs are those costs incurred to maintain a utility system in a state of readiness to serve, enabling it to meet the total combined demands of its customers. Capacity costs include the portion of O&M expenses, debt service, capital expenditures, and other costs that are generally fixed and do not vary materially with the quantity of usage or that cannot be designated specifically as a customer or variable cost. For the purposes of this Study, we have further subclassified the power supply-related costs as either related to serving the "peak load" or the "base load" depending on the nature of the asset. Generally, the peaking assets include the combustion turbine facilities and other resources that are designed to meet peak load. Conversely, the base load assets are those that generate electricity on a consistent basis throughout the year. Demand costs include the fixed component of the transmission system and the non-customer component of the distribution system.
2. **Energy Costs** – Energy, or variable, costs are costs that vary directly with energy usage, including such items as fuel, energy-related purchased power, and a portion of O&M expenses.
3. **Customer Costs** – Customer costs are those costs directly related to the number and type of customers, such as customer accounting, billing, and meter related expenses. Customer costs include a portion of the distribution system (assets) designed to serve the customer, as well as the customer service-related costs.
4. **Direct Assignment Costs** – Direct assignment costs are those costs that are readily identifiable and applicable to a particular customer or customer class (e.g., Lighting).

Once the costs within each function are assigned to each service category, the demand, energy, customer, and direct assignment component of each service is calculated. As provided in Table 3-2, the power supply function has been allocated as demand-related – peak load, demand-related – base load, and energy related.

Table 3-2
Classified Power Supply Test Year Revenue Requirement

Classification	Demand-Related Peak Load	Demand-Related Base Load	Energy Related	Total
Power Supply				
Total Operation & Maintenance Expense	$40,567,000	$27,819,000	$231,595,000	$299,981,000
Total Debt Service	$158,000	$25,164,000	$0	$25,322,000
Total Capital	$93,000	$11,409,000	$14,000	$11,517,000
Deposits to Reserves for Financial Metrics	$1,026,000	$1,619,000	$5,822,000	$8,466,000
Total Revenue Requirement (1)	**$41,844,000**	**$66,011,000**	**$237,431,000**	**$345,286,000**

(1) Numbers may not add due to rounding.

Table 3-3 below provides the classification of the transmission, distribution, and customer functions into the three major cost categories (demand, energy, and customer). As indicated above, the transmission function includes demand- and energy-related costs. This breakdown of demand, energy, customer, and direct assignment costs is later applied to each customer class to facilitate rate design, as provided in Section 4.

Table 3-3
Classified Transmission, Distribution, and Customer Test Year Revenue Requirement

Cost Category	Transmission (Demand)	Transmission (Energy)	Distribution (Demand)	Distribution (Customer)	Distribution (Direct)	Customer
Total O&M	$22,502,000	$1,623,000	$47,156,000	$7,885,000	$128,000	$7,223,000
Total Debt Service	$4,155,000	$0	$7,087,000	$1,772,000	$0	$0
Total Capital	$3,363,000	$1,000	$7,000,000	$4,847,000	$200,000	$461,000
Deposits to Reserves for Financial Metrics	$755,000	$41,000	$1,546,000	$366,000	$0	$193,000
Total Revenue Requirement (1)	**$30,775,000**	**$1,665,000**	**$62,789,000**	**$14,870,000**	**$328,000**	**$7,877,000**

(1) Numbers may not add due to rounding.

Table 3-4 is a summary of the results of the classification on a total dollar (revenue requirement) basis.

Table 3-4
Classified Test Year Revenue Requirement

Classification	Revenue Requirement (1)	$/kWh (2)	% of Total
Power Supply			
Demand	$107,855,000	$0.0467	28.98%
Energy	$237,431,000	$0.1028	63.79%
Subtotal	$345,286,000	$0.1495	92.77%
Transmission			
Demand	$30,775,000	$0.0133	8.27%
Energy	$1,664,000	$0.0007	0.45%
Subtotal	$32,439,000	$0.0140	8.72%
Distribution			
Demand	$62,789,000	$0.0272	16.87%
Customer	$14,870,000	$0.0064	4.00%
Direct Assignment – Lighting	$328,000	$0.0001	0.09%
Subtotal	$77,985,000	$0.0338	20.95%
Customer	$7,877,000	$0.0022	2.12%
Discretionary Revenue	($91,394,000)		
Total (3)	$372,195,000	$0.1612	100.00%

(1) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.
(2) Based on Test Year energy sales of approximately 2,309,000,000 kWh.
(3) Numbers may not add due to rounding.

Allocation of Costs

Once costs are functionalized and classified, they are then allocated to the various customer classes. Customer classes represent aggregations of customers that have similar customer usage characteristics and use the system in a similar manner. These groups of customers have similar COS results which justify similar rates and rate changes. A summary of the allocation factors by class is provided in Appendix A (Table A-4).

Class Allocation Factors

Based upon actual and assumed customer service characteristics, NewGen developed various factors for use in allocating the adjusted revenue requirements to individual customer classes. These allocation factors reflect accepted ratemaking principles and were based upon embedded cost allocation procedures, as discussed in both the APPA and NARUC references cited earlier.

We have developed demand-related, energy-related, customer-related, and direct assignment allocation factors, as described below.

Demand Allocations

Demand allocators are derived based on the demand requirements of individual customers and classes of customers. Power supply-related demand costs are allocated to classes based on the class contribution to the electric system peak, or coincident peak allocators. This is a measure of each class's cost responsibility associated with the infrastructure required to meet the system peak demand. As you move from the generator to the meter, the measure of peak demand responsibility changes from a system perspective (coincident peak) to a class perspective (non-coincident peak). Demand contributions at these various points in the system are determined based on load data from the District's AMI and AMR systems. Demand cost allocators can be based on one peak month during a year, multiple months (such as the four summer months), or the 12 months of the year, depending on how the underlying costs are incurred (cost causation).

For this Study, the 12-month coincident peak (12CP), 12-month non-coincident peak (12NCP), and sum of max demands (SMD) methods were used to allocate demand-related power supply, transmission-, and distribution-related costs to individual customer classes.

The 12CP allocator was used to allocate costs of power supply demand based on the District's historical cost allocation (precedent). Transmission demand costs for the District's owned system were also allocated using the 12CP method, which recognizes the diversity in the use of the transmission system by individual customer classes over the year (often power supply and transmission demands are allocated similarly given the nature of power supply and delivery).

Distribution costs are designed to meet the maximum demands of the localized system or customers, so class demand allocation factors are used. Distribution demand-related costs were allocated to customer classes based on 12NCP for substations, transformers, and primary lines and SMD for secondary line costs.

The economic theory for the use of different allocation factors for the distribution system is that costs that drive portions of the distribution system are different. An NCP allocator is typically used to allocate distribution costs as these facilities are sized to meet localized peak demands rather than the system peak demand. As the distribution system moves closer to the customer, it is the customer demands (SMD) that drive costs.

Table 3-5 compares the various demand allocators utilized in the Study.

Table 3-5
Demand Allocators

Customer Class	12CP (%)	12NCP (%)	SMD (%)
Residential	48.00%	44.43%	52.45%
Small Commercial	5.52%	6.22%	5.55%
Small Industrial	10.66%	11.06%	12.96%
Large Industrial	9.53%	9.97%	10.10%
Very Large Industrial	4.45%	4.94%	0.00%
Bulk Power	5.92%	5.94%	0.00%
Farm	8.37%	9.06%	10.10%
Restricted Pumping	1.63%	2.17%	1.85%
Municipal Energy	0.47%	0.46%	0.53%
Municipal Demand	5.46%	5.41%	6.16%
Street Lighting – District Owned	0.001%	0.15%	0.13%
Street Lighting – Customer Owned	0.002%	0.20%	0.18%
Total	**100%**	**100%**	**100%**

Energy Allocations

Energy allocation factors are the basis for allocating costs or expenses classified as variable or energy related and are assumed to vary directly with kWh sales. Energy-related costs classified as variable were wholesale energy costs. Typically, net energy for load (NEFL), or the energy necessary to supply each customer class, is used to allocate these types of costs to individual customer classes. NEFL is also sometimes called adjusted metered load or energy at generation as it takes into consideration energy losses that occur on the transmission and distribution systems between the power supplier delivery point and the customer's meter. Energy losses provided by the District ranged from approximately 1.75% for the secondary distribution system, 1.75% for the primary distribution system, and 2.0% for the transmission system. NEFL was utilized to allocate the variable generation as well as the variable transmission costs to customer classes.

Table 3-6 lists the energy allocation factors (NEFL) utilized in the Study which incorporate the losses at the various levels of the system.

Table 3-6
NEFL (Energy) Allocators

Customer Class	Net Energy for Load
Residential	37.1%
Small Commercial	6.2%
Small Industrial	12.2%
Large Industrial	12.1%
Very Large Industrial	6.1%
Bulk Power	8.1%
Farm	10.1%
Restricted Pumping	1.5%
Municipal Energy	0.5%
Municipal Demand	5.8%
Street Lighting – District Owned	0.1%
Street Lighting – Customer Owned	0.2%
Total	**100.0%**

Customer Allocators

Customer costs are defined as those costs related to the number of customers and the type of service required. Included in the customer-related costs are the costs associated with meter reading, customer service, sales, billing, collection, and other customer-related activities. The customer allocation factors were largely based on the number of customers in each class.

In allocating certain customer-related costs to the various customer classifications, weighted customer allocation factors were utilized. Weighting reflects that servicing certain types of customers requires more effort and expenses than other types of customers. Weighting factors were developed based on discussions with District staff, as well as by applying industry knowledge and practices. Weighting factors derive relationships between the customer classes and the equipment or services needed to serve the class and the relative costs of those items. Weighting factors for customer-related costs are multiplied by the total number of customers in each class. The customer weighted allocation factors used in the Cost of Service Analysis are detailed below in Table 3-7. Additional detail on the development of the Customer Allocators is provided in Appendix A (Table A-5).

Table 3-7
Customer Weighted Allocators

Customer Class	Customer Service/Account Allocation (%)	Service Drop Allocation (%)	Meter Weighted Allocation (%)
Residential	66.2%	84.3%	71.5%
Small Commercial	6.7%	8.5%	11.8%
Small Industrial	4.7%	1.0%	4.3%
Large Industrial	1.0%	0.1%	0.2%
Very Large Industrial	0.7%	0.0%	0.0%
Bulk Power	0.3%	0.0%	0.0%
Farm	13.7%	3.5%	7.0%
Restricted Pumping	5.3%	1.3%	3.0%
Municipal Energy	0.8%	1.0%	1.4%
Municipal Demand	0.3%	0.3%	0.7%
Street Lighting – District Owned	0.4%	0.0%	0.0%
Street Lighting – Customer Owned	0.1%	0.0%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**

Discretionary Revenue Detail

Table 3-8 below details the TY Revenue Requirement, the revenue changes needed per year for the three-year Rate Plan period, and the Discretionary Revenues applied to each customer class, as directed by the District.

Table 3-8
Summary of 2027 Revenue Requirement and Needed Class Revenue Increases (1)

	Gross Revenue Requirement [A]	Reduction for Discretionary Revenues [B]	Net Revenue Requirement [C] = [A]+[B]	Rate Revenue in 2027 (Current Rates) [D]	Rate Revenue Needed for 2027 Rev Req [E] = [C] - [D]	% Increase Needed for 2027 Rev Req [F] = [C]/[D] - 1
Residential	$201,561,000	($40,851,000)	$160,710,000	$136,259,000	$24,451,000	17.9%
Small Commercial	$28,292,000	($5,244,000)	$23,047,000	$20,526,000	$2,521,000	12.3%
Small Industrial	$52,067,000	($7,844,000)	$44,223,000	$39,026,000	$5,197,000	13.3%
Large Industrial	$48,450,000	($9,793,000)	$38,657,000	$34,348,000	$4,310,000	12.5%
Very Large Industrial	$22,927,000	($4,604,000)	$18,323,000	$16,147,000	$2,176,000	13.5%
Bulk Power	$30,185,000	($7,734,000)	$22,451,000	$18,794,000	$3,657,000	19.5%
Farm	$43,453,000	($8,686,000)	$34,768,000	$33,520,000	$1,248,000	3.7%
Restricted Pumping	$7,832,000	($1,603,000)	$6,229,000	$4,746,000	$1,484,000	31.2%
Municipal (combined)	$27,442,000	($5,035,000)	$22,407,000	$17,659,000	$4,748,000	26.9%
Streetlighting (combined)	$1,379,000	$0	$1,379,000	$1,738,000	($359,000)	(20.7%)
Total (2)	**$463,588,000**	**($91,394,000)**	**$372,195,000**	**$322,763,000**	**$49,432,000**	**15.3%**

(1) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

(2) Numbers may not add due to rounding.

Cost of Service Results

The unbundled COS results by customer class are shown in Table 3-9. Additional detail on allocation factors is provided in Appendix A, Table A-4.

Table 3-9
Unbundled Cost of Service Results by Class ($ 000s)

Classification	Allocator Used (1)	Residential DE/DT/DG	Sm. Comm. CE/CT/CG/ NM	Sm. Ind. ID/IG/IT	Lg. Ind. HT/HG	V. Lg. Ind. XT	Bulk Power BP/BG	Farm FE/FD/FT/ FG	Restricted. Pump PI/PT	Muni MC/MG	Muni – Demand MD	SL Dist. LD/LO	SL – Cust. LC	Total
Power Supply Costs														
Peak Load	12 CP	$20,084	$2,308	$4,461	$3,988	$1,863	$2,477	$3,501	$683	$195	$2,284	$1	$1	$41,846
Base Load	12 CP	$31,682	$3,641	$7,038	$6,291	$2,938	$3,908	$5,523	$1,077	$308	$3,603	$1	$1	$66,010
Energy Related	NEFL	$88,004	$14,767	$29,035	$28,663	$14,469	$19,263	$23,964	$3,527	$1,176	$13,764	$345	$454	$237,430
Total Power Supply		$139,770	$20,716	$40,534	$38,942	$19,270	$25,648	$32,988	$5,287	$1,679	$19,651	$347	$456	$345,286
Transmission														
Demand Related	12 CP	$14,771	$1,697	$3,281	$2,933	$1,370	$1,822	$2,575	$502	$143	$1,680	$0	$1	$30,775
Energy Related	NEFL	$617	$104	$204	$201	$101	$135	$168	$25	$8	$96	$2	$3	$1,665
Total Transmission		$15,388	$1,801	$3,485	$3,134	$1,471	$1,957	$2,743	$527	$151	$1,776	$2	$4	$32,440
Distribution														
Demand Related	12 NCP/ SMD	$29,480	$3,774	$7,320	$6,283	$2,126	$2,557	$5,894	$1,298	$303	$3,545	$89	$119	$62,789
Customer Related	Cust. Weightings	$11,712	$1,477	$360	$16	$1	$0	$748	$305	$178	$74	$0	$0	$14,870
Direct Assignment	Lighting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$273	$55	$328
Total Distribution		$41,192	$5,251	$7,680	$6,299	$2,127	$2,557	$6,642	$1,603	$481	$3,619	$362	$174	$77,987
Total Customer	Cust. Weightings	$5,211	$525	$369	$76	$58	$24	$1,081	$416	$64	$20	$28	$6	$7,877
Discretionary Revenue		($40,851)	($5,244)	($7,844)	($9,793)	($4,604)	($7,734)	($8,686)	($1,603)	($495)	($4,540)	$0	$0	($91,394)
Total COS (2)		**$160,710**	**$23,048**	**$44,223**	**$38,657**	**$18,323**	**$22,452**	**$34,768**	**$6,229**	**$1,880**	**$20,527**	**$739**	**$640**	**$372,195**

(1) Specific demand allocators described in text and show in Table 3-5. Specific customer weighting allocators described previously in Table 3-7. Numbers may not add due to rounding.

(2) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

Cost of Service Results Compared to Current Revenue

To evaluate the ability of current rates to adequately recover the COS, NewGen estimated revenues based on TY billing data and current rates, then compared the resulting revenues to the COS for each customer class. The results of the comparison are shown in Table 3-10.

The COS indicates that overall system rate revenues need to be increased by approximately 15% by 2027, as discussed herein. At the class level, all classes other than street lighting are below their respective cost to serve. Also shown in Table 3-10 is the approximate percentage increase/(decrease) in each customer class's revenues necessary to fully recover the identified COS for the TY (over the next three years).

Table 3-10
Comparison of Current TY Rate Revenues with TY Cost of Service Results (1)

Class/Service	Rate Code(s)	TY Revenue Requirement (2) ($)	Projected Revenues at Current Rates ($)	Projected Over/(Under) Recovery ($)	Difference (%)
Residential	DE/DT/DG	$160,710,000	$136,259,000	($24,451,000)	17.9%
Small Commercial	CE/CT/CG/NM	$23,047,000	$20,526,000	($2,521,000)	12.3%
Small Industrial	ID/IG/IT	$44,223,000	$39,026,000	($5,197,000)	13.3%
Large Industrial	HT/HG	$38,657,000	$34,348,000	($4,310,000)	12.5%
Very Large Industrial	XT	$18,323,000	$16,147,000	($2,176,000)	13.5%
Bulk Power	BP/BG	$22,451,000	$18,794,000	($3,657,000)	19.5%
Farm	FE/FD/FG/FT	$34,768,000	$33,520,000	($1,248,000)	3.7%
Restricted Pumping	PI/PT	$6,229,000	$4,746,000	($1,484,000)	31.2%
Municipal Energy	MC/MG	$1,880,000	$1,736,000	($144,000)	8.3%
Municipal Demand	MD	$20,527,000	$15,923,000	($4,604,000)	28.9%
Street Lighting – District Owned	LD/LO	$740,000	$877,000	$137,000	(15.6%)
Street Lighting – Customer Owned	LC	$639,000	$861,000	$222,000	(25.8%)
Total		**$372,195,000**	**$322,763,000**	**($49,432,000)**	**15.3%**

(1) Numbers may not add due to rounding.

(2) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

Table 3-11 provides a summary of the unit cost analysis by class from the COS for the 2027 TY. These values provide guidance for future rate design. The recommendations for new rate designs for this Study are presented in Section 4.

Table 3-11
Cost of Service Unit Costs by Rate Component by Class

Rate Component	Unit	Residential DE/DT/DG	Sm. Comm. CE/CT/CG/NM	Sm. Ind. ID/IG/IT	Lg. Ind. HT/HG	V. Lg. Ind. XT	Bulk Power BP/BG	Farm FE/FD/FG/ FT	Restricted. Pump PI/PT	Muni MC/MG	Muni – Demand MD	SL Dist. LD/LO	SL – Cust. LC
Customer Unit Cost	$/month	$14.49	$17.39	$56.34	$97.22	$794.53	$739.41	$37.88	$38.59	$16.78	$21.25	N/A	N/A
Demand Unit Cost	$/kW	$20.06	$23.02	$19.91	$21.17	$23.19	$24.36	$19.04	$21.08	$19.62	$20.29	$9.95	$9.54
Energy Unit Cost	$/kWh	$0.0826	$0.0843	$0.0879	$0.0826	$0.0828	$0.0770	$0.0828	$0.0824	$0.0820	$0.0848	$0.1035	$0.1035

Section 4
RATE DESIGN

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the utility will be recovered in the most equitable manner that is consistent, to the extent reasonable and practical, with the District's policies and applicable California regulations. Consideration was given to the recovery of fixed costs in the customer and demand charges, as well as to phasing in the proposed rate changes over the three-year rate plan period.

Rate Design Objectives

In general, proposed rate structures that are developed and submitted for adoption should meet the following objectives and best practices:

- Rates should be equitable among customer classes and individuals within classes, taking into consideration the costs incurred to serve each customer class.
- Rates may take into consideration other important factors, such as competitive concerns, policies, etc.
- Rates should be simple and understandable.

It is common that the foundation of rate design is the COS results tempered with policy considerations important to the community. Specific rate design goals for the District include:

- Improve fixed cost recovery within each class.
- Move toward COS results by class.

The rate plan calls for changes in rates and rate structures, as well as current rate offerings, over a three-year period. Rates are proposed to be effective January 1, 2025; January 1, 2026; and January 1, 2027.

2024 TID Rates and Rate Structures

The District currently provides a wide range of rate offerings for its customers. The following provides a summary of each of the various customer groups for which TID provides electrical service. For all customers, the current on-peak period is defined as 12:00 p.m. to 9:00 p.m., Monday through Friday (excluding holidays), and summer is defined as June through November bills. All demand and energy charges are differentiated by summer/winter, except for those noted below for horsepower charges. Some energy charges are further differentiated by on-/off-peak periods, as noted. Most of the larger customer classes with a demand charge (agriculture, industrial, and bulk power) have a power factor charge per kilovolt-ampere reactive (kVAR) which is not proposed to be changed as a result of this Study. All customers currently pay an Environmental Charge, which is charged on an energy basis, as well as a PSA charge or credit, which is a wholesale power cost adjustment mechanism also charged on an energy basis. As previously indicated, the Environmental Charge is anticipated to be removed as a line item on the customer bill and the same revenues to be collected in the base energy rate. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Residential

Residential rate offerings include Schedule DE (Domestic Energy), which has a monthly customer charge and a two-tiered energy charge; Schedule DG (Domestic Self-Generation), which has a customer charge, a demand charge, and an energy charge (differentiated by on-/off-peak); and Schedule DT, which has a customer charge and a seasonal energy charge (differentiated by on-/off-peak). There are provisions for a minimum bill and compensation for net generation (for DG) at the District's Short Run Marginal Cost of electricity at the time of delivery, as well as discount rates for customers with life-support systems and those in the California Alternative Rates for Energy (CARE) and Medical Rate Programs.

Commercial Rates

Commercial service is for commercial and industrial customers for general power use that is less than 35 kilowatt (kW) demand per month. These rate offerings include Schedule CE (Commercial Energy), which includes a monthly customer charge and an energy charge; Schedule CG (Commercial Self-Generation), which has a customer charge, a demand charge, and an energy charge (differentiated by on-/off-peak); and Schedule CT (Commercial Time of Use), which has a customer charge and an on-/off-peak energy charge. There are provisions in the tariff for a compensation for net generation for CG customers. Schedule NM (Flat Rate Service) is a seasonally differentiated fixed charge for small consistent non-metered incidental loads that varies by estimated kWh per month (not exceeding 265 kWh).

Industrial

Industrial rate offerings include small industrial (monthly demand between 35 to 499 kW) and large industrial (monthly demand between 500 and 6,999 kW). Rates include Schedule ID (Small Industrial – Demand), which has a customer charge, a demand charge, and an energy charge; and Schedule IG (Small Industrial – Self Generation) and Schedule IT (Small Industrial – Time of Use), both of which have a customer charge, a demand charge, and an energy charge (on-/off-peak).

Large industrial rates include Schedule HG (Large Industrial – Self Generation) and Schedule HT (Large Industrial – Demand Metered), both of which have a customer charge, a demand charge, and an energy charge (on-/off-peak).

Very Large Power Rates

Large power rate offerings include Schedule XT – Very Large Industrial Service – Demand Metered, for service between 3,000 and 6,999 kW per month, which includes a customer charge, a demand charge, and an on-/off-peak energy charge. Bulk power is provided to customers with a monthly demand of 7,000 kW or greater and is served by Schedule BG (Bulk Power – Self Generation) and Schedule BP (Bulk Power – Demand), both of which have a customer charge, a demand charge, and an energy charge (on-/off-peak).

Agricultural

Agricultural rates are applicable to Farm Service usage. Rate offerings include Schedule FD (Farm Demand), which includes a customer charge, a demand charge, and an energy charge; Schedule FE (Farm Energy), which includes a customer charge and an energy charge; and Schedule FG (Farm Self Generation), which includes a customer charge, a demand charge, and an energy charge (differentiated by on-/off-peak). Agricultural service can also be provided by Schedule FT (Farm – Time of Use), which has a customer charge, a demand charge, and an energy charge (on-/off-peak).

Municipal

Municipal rate offerings are for municipal uses and include Schedule MC (Municipal – Connected Load) (less than 35 kW), which has a customer charge, an energy charge, and a connected load charge per horsepower; Schedule MG (Municipal Self Generation), which has a customer charge, a demand charge, a power factor charge, and an on-/off-peak energy charge; and Schedule MD (Municipal – Demand) (greater than 35 kW), which has a customer charge, a demand charge, and an energy charge.

Lighting

Street and other lighting rates include Schedule LC (Street Lighting – Customer Owned), Schedule LD (Street Lighting – District Owned), and Schedule LO (Lighting – Outdoor Area). All lighting rates are unmetered and are a fixed monthly charge per lamp that is based on the lamp size and type of installation. These fixed lighting charges are not differentiated by season or on-/off-peak periods.

Agricultural Pumping Rates

Non-municipal agricultural pumping rates, which are limited to certain geographic areas within the District's service territory, include Schedule PI (Restricted Irrigation Pumping) and Schedule PT (Restricted Irrigation Pumping – Time of Use). These rates include an on-/off-season customer charge and energy charge, and an on-season connected load charge per horsepower during the on-season period.

Rate Design Results

Domestic Service

The domestic class is composed of residential customers served on a retail basis and includes the energy rate (Domestic Energy or DE), residential generation (on-site generation or DG), and residential time of use (TOU), or DT, designed for plug-in electric vehicles. Table 4-1 compares the current rates and the proposed rates for the DE subclass (which is approximately 98% of the total residential customer class by revenue).

Table 4-1
Residential Service (DE)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$17.00	$22.00	$26.00	$30.00
Energy Charges					
Winter: 0–700 kWh	$/kWh	$0.1016	$0.1289	$0.1338	$0.1388
Winter: Over 700 kWh	$/kWh	$0.1116	$0.1416	$0.1470	$0.1525
Summer: 0–700 kWh	$/kWh	$0.1070	$0.1358	$0.1410	$0.1463
Summer: 701–1100 kWh	$/kWh	$0.1305	$0.1656	$0.1719	$0.1783
Summer: Over 1100 kWh	$/kWh	$0.1436	$0.1822	$0.1891	$0.1962
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The proposed rate changes include increasing the customer charge to $22.00/month in 2025, $26.00/month in 2026, and $30.00/month in 2027 (approximately $4.00 a month each year). The current energy charge varies by season and by tier. The proposed changes include increasing the energy rate equitably among each of the seasons and tiers in each year of the rate plan.

As indicated, rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the proposed base rates and the line item to be removed from the customer's monthly bill. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Domestic Self-Gen (DG)

The District currently has a subclass within the Domestic service rate offering for residential customers with self-generation (domestic generation or DG). This rate includes a customer charge, a seasonal TOU energy charge, and seasonal demand charges. DG customers are identified as those customers that installed on-site generation (typically solar photovoltaic [PV] systems) after the District initiated its Net Energy Metering (NEM) 2.0 rate structures. NEM 2.0 refers to the California regulations that allow utilities to differentiate rates for customers with qualifying net metering systems (such as PV) after the utility has met certain requirements for distributed generation. Those systems that were installed prior to NEM 2.0 are included in the Domestic Energy service. Table 4-2 below provides a summary of the existing and proposed rates for the DG subclass.

Table 4-2
Residential Service (DG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer	$/Month	$17.00	$22.00	$26.00	$30.00
Energy Charges					
Winter: On-Peak kWh	$/kWh	$0.1044	$0.1198	$0.0994	$0.0835
Winter: Off-Peak kWh	$/kWh	$0.0653	$0.0749	$0.0622	$0.0522
Summer: On-Peak	$/kWh	$0.1359	$0.1559	$0.1294	$0.1087
Summer: Off-Peak	$/kWh	$0.0978	$0.1122	$0.0931	$0.0782
Demand Charges					
Winter	$/kW	$1.74	$2.55	$3.40	$4.25
Summer	$/kW	$2.00	$3.00	$4.00	$5.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The proposed rate changes for DG are similar to those proposed for DE and include increasing the customer charge to $22.00/month in 2025, $26.00/month in 2026, and $30.00/month in 2027. The current demand charges are differentiated by season and are projected to increase in each year of the rate plan period. The current energy charge varies by season and by TOU period. The proposed changes include increasing the energy rate equitably among each of the seasons and TOU periods for 2025, then decreasing the energy rates equitably as the seasonal demand rates increase.

As indicated, rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the proposed base rates and the line item to be removed from the customer's monthly bill. As noted above, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Domestic Plug-In EV (DT)

The District currently has a subclass within the Domestic service rate offering for residential customers with plug-in electric vehicle (EV) chargers (domestic plug in or DT). This rate includes a customer charge and a seasonal energy charge. The energy rate is differentiated by season and by TOU period.

The proposed rate changes include increasing the customer charge to $22.00/month in 2025, $26.00/month in 2026, and $30.00/month in 2027, similar to the DE rate. The proposed changes also include increasing the energy rate equitably among each of the seasons and TOU periods in each year of the rate plan. Similar to the DE rate, the Environmental Charge is proposed to be included in the proposed base rates, and the PSA is assumed to be neutral at $0.000/kWh.

Table 4-3
Domestic Service (DT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer	$/Month	$17.00	$22.00	$26.00	$30.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.1716	$0.2128	$0.2195	$0.2263
Winter: Off-Peak	$/kWh	$0.0772	$0.0957	$0.0987	$0.1018
Summer: On-Peak	$/kWh	$0.1863	$0.2310	$0.2383	$0.2457
Summer: Off-Peak	$/kWh	$0.0838	$0.1039	$0.1072	$0.1105
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Effective Rate Impacts – Residential Class

An effective rate is an "all-in" $/kWh representation of a class's rate structure and levels. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's COS effective rate by 2027. As previously indicated, the effective rate includes the Public Benefits surcharge of 2.85%.

Effective rates for the residential class are shown below in Table 4-4.

Table 4-4
Residential Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1641	$0.1733	$0.1830	$0.1929	$0.1929
% Change		5.6%	5.6%	5.5%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Commercial Service

The commercial service rate class is composed of commercial users served at secondary voltages with maximum monthly demand that does not exceed 35 kW. The District offers four types of rate offerings for Commercial service: Commercial Energy (CE), Commercial TOU (CT), Commercial Generation (CG), and a Flat Rate (NM). Table 4-5 provides a summary for the CE service, including current rates and proposed rates. Similar to the residential class, the CE represents approximately 98% of the revenue for the commercial service class as a whole.

Table 4-5
Commercial Service (CE)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$25.00	$30.00	$38.00	$45.00
Energy Charges					
Winter Energy	$/kWh	$0.0909	$0.1175	$0.1184	$0.1196
Summer Energy	$/kWh	$0.1065	$0.1377	$0.1387	$0.1402
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

As indicated, rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the proposed base rates and the line item to be removed from the customer's monthly bill. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Additional Commercial Service Rates (CT, CG, NM)

Similar to the residential customer class, the District has established subclasses for Commercial service, which include the CT, CG, and NM subclasses. The NM rate is a constant monthly charge based on the estimated utilized electricity that is seasonally differentiated. This is for commercial customers without meters who utilize up to 1,200 watts (1.2 kW) during a month; this rate offering is for timers, ancillary lighting (on customer premises, but not served by the primary meter), and other small electric uses where the costs to install a meter is prohibitive relative to the electricity utilized over a year.

Table 4-6 provides a summary of the existing and proposed rates for the CT subclass.

Table 4-6
Commercial Service (CT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$35.00	$40.00	$45.00	$50.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.1333	$0.1746	$0.1784	$0.1882
Winter: Off-Peak	$/kWh	$0.0848	$0.1111	$0.1135	$0.1197
Summer: On-Peak	$/kWh	$0.1599	$0.2095	$0.2140	$0.2258
Summer: Off-Peak	$/kWh	$0.0976	$0.1279	$0.1306	$0.1378
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

As indicated above, Commercial TOU customers currently pay a customer charge and a time-differentiated energy charge. Rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the proposed base rates and the line item to be removed from the customer's monthly bill. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Commercial customers with on-site generation (CG) are identified as those customers that installed on-site generation (typically PV systems) after the District implemented its NEM 2.0 rate changes (see discussion for residential generation customers above). Table 4-7 provides a summary of the existing and proposed rates for CG customers.

Table 4-7
Commercial Service (CG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$25.00	$30.00	$38.00	$45.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0866	$0.1195	$0.1159	$0.1124
Winter: Off-Peak	$/kWh	$0.0585	$0.0807	$0.0783	$0.0760
Summer: On-Peak	$/kWh	$0.1179	$0.1627	$0.1578	$0.1531
Summer: Off-Peak	$/kWh	$0.0848	$0.1170	$0.1135	$0.1101
Demand Charges					
Winter	$/kW	$2.61	$3.40	$4.25	$5.10
Summer	$/kW	$3.00	$4.00	$5.00	$6.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

As indicated above, CG customers currently pay a customer charge, a time and seasonally differentiated energy charge, and a seasonal demand charge. Proposed changes to this subclass include increases to the customer charge and increases to the seasonal demand charges over the three-year rate plan period. The energy charges are proposed to equitably increase in 2025 between the seasonal TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The energy charges are proposed to decrease in 2026 and 2027 as the revenue from the fixed charges (customer and demand charges) increases to meet the class COS. As mentioned above, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

NM Rate

Table 4-8 provides a summary of the existing and proposed rates for the NM subclass.

Table 4-8
NM Service
Current and Proposed Rates (1)

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
--Winter--					
0–200 watts	$/Month	$10.04	$11.37	$11.85	$12.36
201–300 watts	$/Month	$14.09	$15.95	$16.62	$17.33
301–500 watts	$/Month	$23.48	$26.58	$27.70	$28.89
501–800 watts	$/Month	$37.56	$42.52	$44.31	$46.22
801–1200 watts	$/Month	$54.76	$61.99	$64.59	$67.37
--Summer--					
0–200 watts	$/Month	$13.06	$14.78	$15.40	$16.06
201–300 watts	$/Month	$18.32	$20.74	$21.61	$22.54
301–500 watts	$/Month	$30.21	$34.20	$35.64	$37.17
501–800 watts	$/Month	$48.85	$55.30	$57.62	$60.10
801–1200 watts	$/Month	$73.27	$82.94	$86.42	$90.14

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in flat rates (see text).

As indicated above, NM customers currently pay a fixed monthly charge that varies by season and estimated service levels during a month. The Environmental Charge is proposed to be included in the flat rates (monthly charges) for these customers. These flat rates are anticipated to increase at the average rate revenue increase for the class as determined by the COS analysis.

Effective Rate Impacts – Commercial Class

An effective rate is an all-in $/kWh representation of customer class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's COS by 2027. As previously indicated, the effective rate includes the Public Benefits surcharge of 2.85%.

Effective rates for the commercial class are shown below in Table 4-9.

Table 4-9
Commercial Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1469	$0.1525	$0.1589	$0.1650	$0.1650
% Change		3.8%	4.2%	3.9%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Small Industrial

The small industrial class rate offerings include customers with a monthly demand between 35 to 499 kW and include Schedule ID (Small Industrial – Demand), which has a customer charge, a demand charge, and an energy charge; and Schedule IG (Small Industrial – Self Generation) and Schedule IT (Small Industrial – TOU), both of which have a customer charge, a demand charge, and an energy charge (on-/off-peak).

Table 4-10 provides a summary of the existing and proposed rates for the ID subclass.

Table 4-10
Small Industrial Service (ID)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$82.00	$93.00	$98.00	$103.00
Energy Charges					
Winter	$/kWh	$0.0601	$0.0844	$0.0866	$0.0892
Summer	$/kWh	$0.0792	$0.1112	$0.1141	$0.1175
Demand Charges					
Winter	$/kWh	$10.66	$11.90	$12.75	$13.60
Summer	$/kWh	$12.67	$14.00	$15.00	$16.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

As indicated above, ID customers currently pay a customer charge, a seasonal energy charge, and a seasonal demand charge. Proposed changes to this subclass include increases to the customer charge and increases to the seasonal demand charges over the three-year rate plan period. The energy charges are proposed to equitably increase in 2025 between the seasonal periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The seasonal energy charges are proposed to increase in 2026 and 2027 to reflect the COS for this class. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Proposed Rates (IT, IG)

The IT rates currently have a seasonal TOU energy and seasonal demand rate structure (IT has TOU/seasonal demand and IG has on-site generation; however, the rates are the same for both subclasses).

Table 4-11
Small Industrial Service (IT/IG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$90.00	$93.00	$98.00	$103.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0797	$0.1132	$0.1185	$0.1226
Winter: Off-Peak	$/kWh	$0.0516	$0.0733	$0.0767	$0.0793
Summer: On-Peak	$/kWh	$0.1065	$0.1512	$0.1582	$0.1637
Summer: Off-Peak	$/kWh	$0.0674	$0.0957	$0.1002	$0.1037
Demand Charges					
Winter	$/kW	$11.50	$11.90	$12.75	$13.60
Summer	$/kW	$13.24	$14.00	$15.00	$16.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

As indicated above, IT/IG customers currently pay a customer charge, a seasonal and TOU energy charge, and a seasonal demand charge. Proposed changes to this subclass include increases to the customer charge and the seasonal demand charges to be consistent with the proposed changes to the ID customer subclass. The energy charges are proposed to equitably increase in 2025 between the seasonal and TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The seasonal energy charges are proposed to increase in 2026 and 2027 to reflect the class COS. As mentioned, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Effective Rate Impacts – Small Industrial Class

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed effective rate in 2027 will meet the TY COS effective rate. As previously indicated, the effective rate includes the Public Benefits surcharge of 2.85%.

Effective rates for the small industrial class are shown below in Table 4-12.

Table 4-12
Small Industrial Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1431	$0.1491	$0.1557	$0.1623	$0.1623
% Change		4.2%	4.4%	4.2%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Large Industrial

The large industrial class rate offerings include customers with a monthly demand between 500–2,999 kW for rate Schedule HT (Large Industrial – Demand Metered) and 500–6,999 kW for Schedule HG (Large Industrial – Self Generation), both of which have a customer charge, a seasonal demand charge, and a seasonal and TOU energy charge (on-/off-peak).

Table 4-13 provides a summary of the existing and proposed rates for the HT subclass.

Table 4-13
Large Industrial Service (HT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$250.00	$275.00	$300.00	$350.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0723	$0.0987	$0.1014	$0.1019
Winter: Off-Peak	$/kWh	$0.0459	$0.0627	$0.0644	$0.0647
Summer: On-Peak	$/kWh	$0.1044	$0.1425	$0.1464	$0.1471
Summer: Off-Peak	$/kWh	$0.0636	$0.0868	$0.0892	$0.0896
Demand Charges					
Winter	$/kW	$10.73	$13.50	$14.40	$16.20
Summer	$/kW	$11.88	$15.00	$16.00	$18.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Proposed changes to the HT subclass include increases to the customer charge and the seasonal demand charges. The energy charges are proposed to equitably increase in 2025 between the seasonal and TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The seasonal energy charges are proposed to increase in

2026 and 2027 to reflect the class COS. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-14 provides a summary of the existing and proposed rates for the HG subclass.

Table 4-14
Large Industrial Service (HG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$275.00	$350.00	$375.00	$400.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0689	$0.0978	$0.1004	$0.1004
Winter: Off-Peak	$/kWh	$0.0445	$0.0632	$0.0649	$0.0649
Summer: On-Peak	$/kWh	$0.0948	$0.1346	$0.1382	$0.1383
Summer: Off-Peak	$/kWh	$0.0597	$0.0847	$0.0870	$0.0870
Demand Charges					
Winter	$/kW	$11.79	$14.03	$15.30	$17.43
Summer	$/kW	$13.53	$16.50	$18.00	$20.50
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Proposed changes to the HG subclass include increases to the customer charge and the seasonal demand charges. The energy charges are proposed to equitably increase in 2025 between the seasonal and TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base energy rates, as discussed herein, and the class COS. The seasonal energy charges are proposed to increase in 2026 and 2027 to reflect the class COS. As noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Effective Rate Impacts – Large Industrial Class

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's COS by 2027. As previously indicated, the effective rate includes the Public Benefits surcharge of 2.85%.

Effective rates for the large industrial class are shown below in Table 4-15.

Table 4-15
Large Industrial Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1257	$0.1306	$0.1360	$0.1416	$0.1416
% Change		4.0%	4.1%	4.1%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Very Large Industrial Service

Large power rate offerings include Schedule XT – Very Large Industrial Service – Demand Metered for service between 3,000–6,999 kW per month, which includes a customer charge, a seasonal demand charge, and a seasonal TOU (on-/off-peak) energy charge.

Table 4-16 provides a summary of the existing proposed rates for the XT subclass.

Table 4-16
Very Large Industrial Service (XT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$500.00	$575.00	$625.00	$700.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0641	$0.0946	$0.0959	$0.0962
Winter: Off-Peak	$/kWh	$0.0428	$0.0632	$0.0641	$0.0643
Summer: On-Peak	$/kWh	$0.0909	$0.1341	$0.1359	$0.1364
Summer: Off-Peak	$/kWh	$0.0552	$0.0815	$0.0826	$0.0829
Demand Charges					
Winter	$/kW	$12.90	$14.72	$16.36	$18.81
Summer	$/kW	$15.25	$18.00	$20.00	$23.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Proposed changes to the XT subclass include an increase to the customer charge from the current rate of $500/month to $700/month in 2027. Seasonal demand charges are proposed to increase from $15.25/kW (current Summer) to $23.00/kW (proposed 2027 Summer). The relationship between the summer and winter demand rates is proposed to remain constant over the rate study period. The energy charges are proposed to equitably increase in 2025 between the seasonal and TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The seasonal energy charges are proposed to increase slightly in 2026 and 2027 to reflect the average rate increase for this class to meet its COS. As noted above, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Effective Rate Impacts – Very Large Industrial Service

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's COS by 2027.

Effective rates for the very large industrial class are shown below in Table 4-17.

Table 4-17
Very Large Industrial Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1144	$0.1193	$0.1241	$0.1298	$0.1298
% Change		4.3%	4.1%	4.6%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Bulk Power

Bulk power is provided to customers with a monthly demand of 7,000 kW or greater and is served by Schedule BG (Bulk Power – Demand), which has a customer charge, a seasonal demand charge, and a seasonal TOU energy charge (on-/off-peak).

Table 4-18 provides a summary of the existing and proposed rates for the BG subclass.

Table 4-18
Bulk Power (BG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$1,000.00	$1,000.00	$1,000.00	$1,000.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0513	$0.0821	$0.0858	$0.0882
Winter: Off-Peak	$/kWh	$0.0333	$0.0533	$0.0557	$0.0573
Summer: On-Peak	$/kWh	$0.0823	$0.1317	$0.1376	$0.1414
Summer: Off-Peak	$/kWh	$0.0466	$0.0746	$0.0779	$0.0801
Demand Charges					
Winter	$/kW	$15.15	$17.40	$19.14	$21.75
Summer	$/kW	$17.12	$20.00	$22.00	$25.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Table 4-19 provides a summary of the existing and proposed rates for the BP subclass.

Table 4-19
Bulk Power (BP)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$1,000.00	$1,000.00	$1,000.00	$1,000.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0513	$0.0821	$0.0858	$0.0882
Winter: Off-Peak	$/kWh	$0.0333	$0.0533	$0.0557	$0.0573
Summer: On-Peak	$/kWh	$0.0823	$0.1317	$0.1376	$0.1414
Summer: Off-Peak	$/kWh	$0.0466	$0.0746	$0.0779	$0.0801
Demand Charges					
Winter	$/kW	$15.15	$17.40	$19.14	$21.75
Summer	$/kW	$17.12	$20.00	$22.00	$25.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Proposed changes to the BP and BG subclasses include an increase in the seasonal demand charges from $17.12/kW (current Summer) to $25.00/kW (proposed 2027 Summer). The relationship between the summer and winter demand rates is proposed to remain constant over the rate study period. The energy charges are proposed to equitably increase in 2025 between the seasonal and TOU periods (the percent increase is the same) due to the inclusion of the Environmental Charge into the base rates, as discussed herein, and the class COS. The 2026 and 2027 energy rates are proposed to increase slightly to meet the class COS. The customer charge for the BP and BG subclasses is proposed to remain the same during the rate study period. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Effective Rate Impacts – Bulk Power Service

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's COS by 2027.

Effective rates for the bulk power class are shown below in Table 4-20.

Table 4-20
Bulk Power Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1056	$0.1119	$0.1188	$0.1262	$0.1262
% Change		6.0%	6.2%	6.2%	

(1) Excludes 2024 PSA Revenues.

(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Agricultural

Agricultural rates are applicable to farm service usage. Rate offerings include Schedule FD (Farm Demand), which includes a customer charge, a demand charge, and an energy charge; Schedule FE (Farm Energy), which includes a customer charge and an energy charge; and Schedule FG (Farm Self Generation), which includes a customer charge, a demand charge, and an energy charge (differentiated by on-/off-peak). Agricultural service can also be provided by Schedule FT (Farm – Time of Use), which has a customer charge, a demand charge, and an energy charge (on-/off-peak).

Table 4-21 provides a summary of the existing and proposed rates for the FE subclass.

Table 4-21
Farm Service – Energy (FE)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$28.00	$30.00	$34.00	$38.00
Energy Charges					
Winter Energy	$/kWh	$0.1057	$0.1305	$0.1308	$0.1311
Summer Energy	$/kWh	$0.1231	$0.1520	$0.1523	$0.1526
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Proposed changes to the Farm Service – Energy rate (FE) include increased customer service charges of $30/month (2025), $34/month (2026), and $38/month (2027), and increases in the seasonally differentiated energy rate for 2025, due to the inclusion of the Environmental Charge in the base rates and to meet the class COS. The seasonal energy rate for 2026 and 2027 is proposed to increase slightly to reflect the class COS. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-22 provides a summary of the existing and proposed rates for the FD subclass.

Table 4-22
Farm Service – Demand (FD)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$52.00	$54.00	$58.00	$62.00
Energy Charges					
Winter	$/kWh	$0.0663	$0.0890	$0.0871	$0.0854
Summer	$/kWh	$0.0798	$0.1071	$0.1049	$0.1028
Demand Charges					
Winter	$/kW	$8.63	$9.29	$10.14	$10.98
Summer	$/kW	$9.97	$11.00	$12.00	$13.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The current Farm Service Demand (FD) rate includes a customer charge and seasonally differentiated energy and demand charges. Proposed changes include increases in the customer service charge to $54/month (2025), $58/month (2026), and $62/month (2027), and increases to the seasonal demand charges (the relationship between the summer and winter demand charges is proposed to remain constant over the Study period). The seasonally differentiated energy rate is proposed to increase in 2025 with the inclusion of the Environmental Charge and to meet class COS, then to decrease in 2026 and 2027 to reflect the class COS. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-23 provides a summary of the existing and proposed rates for the FT subclass.

Table 4-23
Farm Service – TOU (FT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$82.00	$84.00	$88.00	$92.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0769	$0.1084	$0.1061	$0.1044
Winter: Off-Peak	$/kWh	$0.0505	$0.0712	$0.0697	$0.0686
Summer: On-Peak	$/kWh	$0.0985	$0.1389	$0.1360	$0.1338
Summer: Off-Peak	$/kWh	$0.0605	$0.0853	$0.0835	$0.0822
Demand Charges					
Winter	$/kW	$8.62	$9.29	$10.14	$10.98
Summer	$/kW	$9.84	$11.00	$12.00	$13.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Table 4-24 provides a summary of the existing and proposed rates for the FG subclass.

Table 4-24
Farm Service – Self Generation (FG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$31.25	$36.00	$42.00	$50.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0839	$0.1133	$0.1020	$0.0923
Winter: Off-Peak	$/kWh	$0.0558	$0.0753	$0.0678	$0.0614
Summer: On-Peak	$/kWh	$0.1099	$0.1484	$0.1336	$0.1209
Summer: Off-Peak	$/kWh	$0.0647	$0.0873	$0.0786	$0.0711
Demand Charges					
Winter	$/kW	$8.19	$9.29	$10.14	$10.98
Summer	$/kW	$9.40	$11.00	$12.00	$13.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The FT and FG rates have identical rate structures (but slightly different rates) which include a customer charge, a seasonal TOU energy charge, and a seasonal demand charge. Proposed changes to FT subclass include increases in the customer service charge to $84/month (2025), $88/month (2026), and $92/month (2027), and increases to the seasonal demand charges (the relationship between the summer and winter demand charges is proposed to remain constant over the Study period). Proposed changes to the FG subclass include increases in the customer service charge to $36/month (2025), $42/month (2026), and $50/month (2027) and the same proposed changes to the demand charges as the FT subclass. The seasonally differentiated energy rate is proposed to increase in 2025 with the inclusion of the Environmental Charge and class COS, then decrease in 2026 and 2027 to reflect the class COS. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Rate Impacts by Customer Class

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. Since the proposed rates for each class are designed to meet the class's COS by 2027, the proposed effective rate in 2027 will approach or meet the COS effective rate.

Effective rates for the Agricultural class are shown below in Table 4-25.

Table 4-25
Agricultural Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1474	$0.1498	$0.1515	$0.1534	$0.1534
% Change		1.6%	1.2%	1.3%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Agricultural Pumping Rates (Restricted Pumping)

Non-municipal agricultural pumping rates, which are limited to certain geographic areas within the District's service territory, include Schedule PI (Restricted Irrigation Pumping) and Schedule PT (Restricted Irrigation Pumping – Time of Use). These rates include an on-/off-season customer charge and energy charge, and an on-season connected load charge per horsepower during the on-season period. As previously mentioned, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-26 provides a summary of the existing and proposed rates for the PT subclass.

Table 4-26
Restricted Irrigation Pumping TOU (PT)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$20.00	$20.00	$20.00	$20.00
Demand Charges					
Winter Connected Load, per HP	$/HP	$1.78	$1.93	$2.48	$3.03
Summer Connected Load, per HP	$/HP	$2.58	$3.50	$4.50	$5.50
Energy Charges					
Winter On-Peak	$/kWh	$0.0872	$0.1256	$0.1295	$0.1357
Winter Off-Peak	$/kWh	$0.0599	$0.0863	$0.0890	$0.0933
Summer On-Peak	$/kWh	$0.1103	$0.1588	$0.1637	$0.1716
Summer Off-Peak	$/kWh	$0.0488	$0.0703	$0.0725	$0.0760
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Table 4-27 provides a summary of the existing and proposed rates for the PI subclass.

Table 4-27
Restricted Irrigation Pumping (PI)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge					
On-Season	$/Month	$12.00	$13.50	$15.50	$17.00
Off-Season	$/Month	$12.00	$13.50	$15.50	$17.00
Demand Charges					
Connected Load, per HP	$/HP	$2.00	$3.00	$4.00	$5.00
Energy Charges					
On-Season	$/kWh	$0.0716	$0.0918	$0.0895	$0.0905
Off-Season	$/kWh	$0.1654	$0.1654	$0.1654	$0.1654
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

Effective Rate Impacts – Restricted Pumping Service

An effective rate is an all-in $/kWh representation of a class's rate structure. The effective rate is calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class. This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class are designed to meet the class's effective COS rate by 2027.

Effective rates for the restricted pumping class are shown below in Table 4-28.

Table 4-28
Restricted Pumping Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1396	$0.1510	$0.1672	$0.1868	$0.1868
% Change		8.1%	10.7%	11.8%	

(1) Excludes 2024 PSA Revenues.

(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Municipal

Municipal rate offerings are for municipal uses and include Schedule MC (Municipal – Connected Load – MC) (less than 35 kW), which has a customer charge, an energy charge, and a connected load charge per horsepower; Schedule MG (Municipal Self Generation), which has a customer charge, a demand charge, and an on-/off-peak energy charge; and Schedule MD (Municipal – Demand) (greater than 35 kW), which has a customer charge, a demand charge, and an energy charge.

Table 4-29 provides a summary of the existing and proposed rates for the MC subclass.

Table 4-29
Municipal Users – Connected Load (MC)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$13.00	$15.00	$15.00	$15.00
Demand Charges					
Connected Load, per HP	$/HP	$1.98	$3.75	$3.75	$4.00
Energy Charges					
Winter	$/kWh	$0.0670	$0.0710	$0.0731	$0.0716
Summer	$/kWh	$0.0779	$0.0826	$0.0851	$0.0834
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The current municipal connected (MC) rate includes a customer charge, a connected load charge, and a seasonally differentiated energy charge. Proposed changes for MC include an increase in the customer charge to $15.00/month and annual increases to the connected load charge (per HP). The seasonally differentiated energy rate is proposed to increase in 2025 and 2026 with the inclusion of the Environmental Charge and to reflect the class COS, then a slight decrease in 2027 to reflect the class COS. As previously noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-30 provides a summary of the existing and proposed rates for the MD subclass.

Table 4-30
Municipal Users – Demand (MD)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$29.00	$35.00	$35.00	$35.00
Energy Charges					
Winter	$/kWh	$0.0627	$0.0887	$0.0963	$0.1044
Summer	$/kWh	$0.0728	$0.1029	$0.1117	$0.1210
Demand Charges					
Winter	$/kW	$6.65	$9.31	$10.16	$11.01
Summer	$/kW	$7.67	$11.00	$12.00	$13.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The current Municipal Demand (MD) rate includes a customer charge and seasonally differentiated energy and demand charges. Proposed changes include an increase in the customer charge to $35/month and annual increases in the seasonal demand rate (the relationship between the summer and winter demand rates is proposed to remain constant over the rate plan period). The seasonally differentiated energy rate is proposed to increase with the inclusion of the Environmental Charge and the class COS. For the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-31 provides a summary of the existing and proposed rates for the MG subclass.

Table 4-31
Municipal Users – Self-Gen (MG)
Current and Proposed Rates

Item	Unit	Current	Proposed 2025	Proposed 2026	Proposed 2027
Customer Charge	$/Month	$17.00	$20.00	$20.00	$20.00
Energy Charges					
Winter: On-Peak	$/kWh	$0.0746	$0.0742	$0.0738	$0.0734
Winter: Off-Peak	$/kWh	$0.0574	$0.0571	$0.0568	$0.0565
Summer: On-Peak	$/kWh	$0.0954	$0.0949	$0.0944	$0.0939
Summer: Off-Peak	$/kWh	$0.0686	$0.0683	$0.0680	$0.0677
Demand Charges					
Winter	$/kW	$6.35	$9.31	$10.16	$11.01
Summer	$/kW	$6.93	$11.00	$12.00	$13.00
Adjustments (1)	$/kWh	$0.0269	$0.0000	$0.0000	$0.0000

(1) Current rate adjustments include the Environmental Charge. The Environmental Charge is proposed to be recovered in base rates (see text).

The current Municipal Demand Generation (MG) rate includes a customer charge, seasonally differentiated demand charges, and a seasonal and TOU differentiated energy charge. Proposed changes include an increase in the customer charge to $20/month, and annual increases in the seasonal demand rate (the relationship between the summer and winter demand rates is proposed to remain constant over the rate plan period). The monthly customer charge is proposed to increase in 2025 with the inclusion of the Environmental Charge and to reflect the class COS, then remain constant in 2026 and 2027 to reflect the class COS. As noted, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Effective Rate Impacts – Municipal Service

An effective rate is an all-in $/kWh representation of a class's rate structure. For Municipal Service, the subclasses MC and MG were combined for the purposes of the COS analysis, and the subclass MD was analyzed independently. The effective rates for these subclass groups are calculated by applying all class rate components to all the appropriate billing determinants to determine a total rate revenue for the class (or subclass). This total rate revenue is divided by the total kWh sold in that class, resulting in a $/kWh value. This value provides a simplified cost metric to a customer based on their kWh usage and is commonly used for total class rate comparisons. Effective rates are calculated for the current, proposed, and COS rates. The proposed rates for each class or groups are designed to be lower than or equal to each class or group's COS by 2027.

Effective rates for the municipal classes are shown below in Tables 4-32 and 4-33.

Table 4-32
Municipal (MC/MG) Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1459	$0.1519	$0.1538	$0.1555	$0.1571
% Change		4.1%	1.3%	1.1%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Table 4-33
Municipal (MD) Service
Current, Proposed, and Cost of Service Effective Rates

Item	Current (1)	Proposed 2025	Proposed 2026	Proposed 2027	COS
Effective Rate ($/kWh) (2)	$0.1231	$0.1348	$0.1466	$0.1587	$0.1587
% Change		9.5%	8.7%	8.3%	

(1) Excludes 2024 PSA Revenues.
(2) Effective Rate includes Public Benefit surcharge of 2.85%.

Street Lighting

Street and other lighting rates include Schedule LC (Street Lighting – Customer Owned), Schedule LD (Street Lighting – District Owned), and Schedule LO (Lighting – Outdoor Area). All lighting rates are unmetered and are a fixed monthly charge per lamp that is based on the lamp size and type of installation. These fixed lighting charges are not differentiated by season or on-/off-peak periods. Table 4-34 provides the existing and proposed rates for the LD/LO lights and Table 4-35 provides the existing and proposed rates for the LC lights.

Table 4-34
Lighting LD/LO
Current and Proposed Rates

Lamp Type	Current ($/Month)	Proposed 2025 ($/Month)	Proposed 2026 ($/Month)	Proposed 2027 ($/Month)
Street Lighting – District Owned				
175 W Mercury Vapor Lamp	$14.97	$14.30	$14.01	$13.76
400 W Mercury Vapor Lamp	$25.48	$24.33	$23.84	$23.42
100 W Sodium Vapor Lamp	$12.93	$12.35	$12.10	$11.89
200 W Sodium Vapor Lamp	$20.70	$19.77	$19.37	$19.03
Lighting – Outdoor Area				
175 W Mercury Vapor Lamp	$14.98	$14.31	$14.02	$13.77
400 W Mercury Vapor Lamp	$25.49	$24.34	$23.85	$23.43
100 W Sodium Vapor Lamp	$11.83	$11.30	$11.07	$10.88
200 W Sodium Vapor Lamp	$18.11	$17.30	$16.95	$16.65

The current Street Lighting – District Owned (LD) and Lighting – Outdoor Area (LO) rates are charged on a monthly rate that varies by lighting type and lamp size. Similar to the other customer classes, the lighting classes are charged for rate adjustments based on an assumed usage per lamp type (streetlights are not metered). As indicated, rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the monthly lamp charges and the line item to be removed from the customer's monthly bill. The monthly charges for the LD/LO subclasses are proposed to decrease over the rate study period to reflect the COS analysis. As previously stated, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Table 4-35
Lighting LC
Current and Proposed Rates

Lamp Type	Current ($/Month)	Proposed 2025 ($/Month)	Proposed 2026 ($/Month)	Proposed 2027 ($/Month)
Street Lighting – Customer Owned				
175 W Mercury Vapor Lamp	$8.65	$7.79	$7.17	$6.58
250 W Mercury Vapor Lamp	$11.63	$10.47	$9.63	$8.83
400 W Mercury Vapor Lamp	$18.30	$16.47	$15.15	$13.90
700 W Mercury Vapor Lamp	$31.14	$28.03	$25.79	$23.65
1,000 W Mercury Vapor Lamp	$35.34	$31.81	$29.27	$26.85
70 W Sodium Vapor Lamp	$5.69	$5.12	$4.71	$4.32
100 W Sodium Vapor Lamp	$6.03	$5.43	$5.00	$4.59
150 W Sodium Vapor Lamp	$8.24	$7.42	$6.83	$6.26
200 W Sodium Vapor Lamp	$9.90	$8.91	$8.20	$7.52
250 W Sodium Vapor Lamp	$12.45	$11.21	$10.31	$9.46
310 W Sodium Vapor Lamp	$15.23	$13.71	$12.61	$11.57
400 W Sodium Vapor Lamp	$19.33	$17.40	$16.01	$14.68

The current Street Lighting – Customer Owned (LC) rates are charged on a monthly rate that varies by lighting type and lamp size. The lighting classes are charged for rate adjustments based on an assumed usage per lamp type (streetlights are not metered). As indicated, rate adjustments (riders) include the Environmental Charge, which is proposed to be included in the monthly lamp charges, and the line item will be removed from the customer's monthly bill. The monthly charges for the LC subclasses are proposed to decrease over the rate study period to reflect the COS analysis. As previously stated, for the purposes of this Study, the PSA was assumed to be neutral at $0.000/kWh.

Revenue Adequacy of Proposed Electric Rates

The proposed electric rates presented in this section recover revenues slightly lower (approximately $20,000) than the TY Revenue Requirement in the final year of the rate plan (2027) to incorporate the rate strategies enclosed herein. Rates were designed based on forecasted billing information provided by the District. To the extent that actual billing determinants vary from projections provided by the District, actual revenues may vary from the expected revenues as presented herein.

Table 4-36 shows the projected Test Year Revenue Requirement and the proposed rate revenue for the three years of the Study period.

Table 4-36
Projected Test Year Revenue Requirement

Customer Class	TY Revenue Requirement [1]	Projected Revenue FY 2025	Projected Revenue FY 2026	Projected Revenue FY 2027
Residential	$160,710,000	$139,428,000	$150,442,000	$160,710,000
Small Commercial	$23,047,000	$21,147,000	$22,110,000	$23,047,000
Small Industrial	$44,223,000	$40,042,000	$42,362,000	$44,224,000
Large Industrial	$38,657,000	$35,141,000	$37,065,000	$38,658,000
Very Large Industrial	$18,323,000	$16,590,000	$17,496,000	$18,324,000
Bulk Power	$22,451,000	$19,624,000	$21,116,000	$22,450,000
Farm	$34,768,000	$33,524,000	$34,117,000	$34,768,000
Restricted Pumping	$6,229,000	$5,140,000	$5,633,000	$6,231,000
Municipal Energy	$1,880,000	$1,807,000	$1,844,000	$1,879,000
Municipal Demand	$20,527,000	$17,152,000	$18,784,000	$20,508,000
Street Lighting – District Owned	$740,000	$751,000	$744,000	$739,000
Street Lighting – Customer Owned	$639,000	$704,000	$671,000	$639,000
Total System [2]	**$372,195,000**	**$331,050,000**	**$352,384,000**	**$372,175,000**

(1) The proposed three-year rate plan is designed to meet the 2027 Test Year Cost of Service.

(2) Numbers may not add due to rounding.

Section 5
CONCLUSIONS AND RECOMMENDATIONS

In reliance upon the data provided by the District and the analyses described herein, we conclude and recommend the following.

Conclusions

- Revenue Requirement:
  - Based on our development of the TY Revenue Requirement, current rates are not sufficient to recover projected costs. On a systemwide basis, current rate revenues require a 15.3% increase to meet the 2027 TY Revenue Requirement.
- Cost of Service:
  - All rate classes, with the exception of the street lighting classes, are below their respective COS.
- Rate Design:
  - The proposed changes to rates provided herein are designed to align each customer class with their respective effective COS rate.

Recommendations

Based on our conclusions and supporting analyses, NewGen recommends the following:

- The District should adopt the rate plan as proposed in this Electric Report.
- The District should continue to perform a comprehensive COS study every two to three years, or when aligned with a major change in operations such as changes in projected price for purchased power, a new large industrial customer, or significant change in system.

Appendix A
COST ALLOCATIONS UTILIZED FOR THIS STUDY

Table A-1
System Allocation of Debt Issuances

Debt Issuance	TY 2027 Amount ($)	Electric System Amount ($)	Water System Amount ($)	Electric System Allocation (%)	Water System Allocation (%)
Existing Debt Service					
Principal 2016 TID Rev Ref Bonds	$5,710,000	$5,527,000	$183,000	97%	3%
Principal 2019 TID Rev Ref Bonds	$5,374,000	$4,130,000	$1,244,000	77%	23%
Principal 2020 TID Rev Ref Bonds	$5,510,000	$5,510,000	$0	100%	0%
2016 TID Rev Refunding Bonds	$5,920,000	$5,729,000	$191,000	97%	3%
2020 TID Rev Refunding Interest	$5,399,000	$5,399,000	$0	100%	0%
2024 TID Rev Refunding Bonds	$2,103,000	$2,103,000	$0	100%	0%
Meter Deposit Interest Expenses	$75,000	$75,000	$0	100%	0%
Total Existing Debt Service	**$30,091,000**	**$28,473,000**	**$1,618,000**	**95%**	**5%**
Proposed Debt Service					
GM	$229,000	$229,000	$0	100%	0%
WRA	$2,024,000	$1,326,000	$698,000	66%	34%
EEOA	$5,425,000	$5,425,000	$0	100%	0%
PSA	$2,920,000	$2,884,000	$36,000	99%	1%
Total Proposed Debt Service	**$10,598,000**	**$9,864,000**	**$734,000**	**93%**	**7%**
Total	**$40,689,000**	**$38,337,000**	**$2,352,000**	**94%**	**6%**

Table A-1 details the allocation of existing and proposed debt between the electric system and water system. Allocation information was provided to NewGen by TID.

Table A-2
System Allocation of Cash Funded Capital Projects by Fund

Capital Project Fund	TY 2027 Amount ($)	Electric System Amount ($)	Water System Amount ($)	Electric System Allocation (%)	Water System Allocation (%)
Fund 01					
General Manager	$1,080,000	$985,000	$95,000	91%	9%
Financial Services Admin	$1,282,000	$1,158,000	$124,000	90%	10%
Water Services Admin	$4,765,000	$3,574,000	$1,191,000	75%	25%
Engineering and Ops. Admin	$11,988,000	$11,676,000	$313,000	97%	3%
Power Supply Admin	$9,415,000	$9,415,000	$0	100%	0%
Total Fund 01 Capital	$28,530,000	$26,808,000	$1,723,000	94%	6%
DPJA Capital (1)	$565,000	$565,000	$0	100%	0%
DPRA Capital (2)	$17,000	$17,000	$0	100%	0%
Total Capital	**$29,112,000**	**$27,390,000**	**$1,723,000**	**94%**	**6%**

(1) Don Pedro Joint Account.
(2) Don Pedro Recreation Agency.

Table A-2 details the allocation of cash capital projects to the electric and water systems. Allocations were assigned to each CIP project under the direction of TID. The summary of those allocated capital projects is shown above.

Table A-3
Allocation of Discretionary Revenue between Electric and Water

Discretionary Revenue	TY 2027 Amount ($)	Electric System Amount ($)	Water System Amount ($)	Electric System Allocation (%)	Water System Allocation (%)
Wholesale Gas Revenue	$2,148,000	$2,148,000	$0	100%	0%
Electric Wholesale Revenues	$67,369,000	$67,369,000	$0	100%	0%
Wind Revenue	$11,459,000	$11,459,000	$0	100%	0%
Electric Other	$3,447,000	$3,447,000	$0	100%	0%
CIAC (1)	$4,250,000	$4,250,000	$0	100%	0%
Water – Other Rev	$10,548,000	$0	$10,548,000	0%	100%
Interest Income – Net	$3,000,000	$2,720,000	$280,000	91%	9%
Total (2)	**$102,222,000**	**$91,394,000**	**$10,828,000**	**89%**	**11%**

(1) Contribution in Aid of Construction.
(2) Totals may not add due to rounding.

Table A-3 details the allocation of discretionary revenue to the electric and water systems. Allocations were assigned to discretionary revenue under the direction of TID.

Table A-4
Allocation Factors by Class

Allocation	Unit	Residential DE/DT/DG	Sm. Comm. CE/CG/CT/NM	Sm. Ind. ID/IG/IT	Lg. Ind. HG/HT	V. Lg. Ind. XT	Bulk Power BG/BP	Farm FE/FD/FG/FT	Restricted Pump PI/PT	Muni MC/MG	Muni – Demand MD	SL Dist. LD/LO	SL – Cust. LC
		79.8%	8.0%	0.9%	0.1%	0.0%	0.0%	3.3%	1.3%	1.0%	0.3%	4.4%	0.9%
No. of Meters	#	77,598	7,813	915	63	5	2	3,219	1,238	949	301	4,292	856
		48.0%	5.5%	10.7%	9.5%	4.5%	5.9%	8.4%	1.6%	0.5%	5.5%	0.0%	0.0%
12 CP	kW	2,257,191	259,393	501,391	448,174	209,341	278,396	393,459	76,740	21,927	256,700	69	90
		44.4%	6.2%	11.1%	10.0%	4.9%	5.9%	9.1%	2.2%	0.5%	5.4%	0.1%	0.2%
12 NCP	kW	2,279,961	319,165	567,702	511,336	253,330	304,656	464,843	111,237	23,711	277,584	7,667	10,082
		52.5%	5.6%	13.0%	10.1%	0.0%	0.0%	10.1%	1.8%	0.5%	6.2%	0.1%	0.2%
SMD @ Secondary	kW	3,816,850	404,135	942,783	734,799	-	-	735,244	134,327	38,291	448,570	9,170	12,783
		37.1%	6.2%	12.2%	12.1%	6.1%	8.1%	10.1%	1.5%	0.5%	5.8%	0.1%	0.2%
Net Energy for Load	kWh	903,822,758	151,658,120	298,198,834	294,374,232	148,601,418	197,831,520	246,117,361	36,225,098	12,074,869	141,362,558	3,541,969	4,657,732
		84.3%	8.5%	1.0%	0.1%	0.0%	0.0%	3.5%	1.3%	1.0%	0.3%	0.0%	0.0%
Service Drop Weighting	#	77,598	7,813	915	63	-	-	3,219	1,238	949	301	-	-
		71.5%	11.8%	4.3%	0.2%	0.0%	0.0%	7.0%	3.0%	1.4%	0.7%	0.0%	0.0%
Meter Weighting	#	77,598	12,832	4,656	172	13	5	7,644	3,235	1,532	775	-	-
		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.4%	16.6%
Streetlighting	#	-	-	-	-	-	-	-	-	-	-	4,198	838
		66.2%	6.7%	4.7%	1.0%	0.7%	0.3%	13.7%	5.3%	0.8%	0.3%	0.4%	0.1%
Customer Account Weighting	#	77,598	7,813	5,490	1,134	865	346	16,095	6,190	949	301	420	84
		66.2%	6.7%	4.7%	1.0%	0.7%	0.3%	13.7%	5.3%	0.8%	0.3%	0.4%	0.1%
Customer Service Weighting	#	77,598	7,813	5,490	1,134	865	346	16,095	6,190	949	301	420	84

Table A-4 details the allocation factors utilized for the electric system Study.

Table A-5
Weighting Factors by Class

Factor	Residential DE/DT/DG	Sm. Comm. CE/CT/CG/NM	Sm. Ind. ID/IG/IT	Lg. Ind. HG/HT	V. Lg. Ind. XT	Bulk Power BG/BP	Farm FE/FD/FG/FT	Restricted Pump PI/PT	Muni MC/MG	Muni – Demand MD	SL Dist. LD/LO	SL – Cust. LC
Customer Service	1.00	1.00	6.00	18.00	175.00	175.00	5.00	5.00	1.00	1.00	0.10	0.10
Customer Accounting	1.00	1.00	6.00	18.00	175.00	175.00	5.00	5.00	1.00	1.00	0.10	0.10
Meters	1.00	1.64	2.58	2.73	2.73	2.73	1.64	1.64	1.64	2.58	0.00	0.00
Services	1.00	1.00	1.00	1.00	0.00	0.00	1.00	1.00	1.00	1.00	0.10	0.10

Table A-5 details the customer weighting factors by class developed with TID staff and based on industry experience. Customer classes that require higher levels of customer service labor and customer accounting labor have higher weighting factors. Meter weighting factors are based on the cost of meters applied to various classes. Services weighting factors are based on a customer class's cost for service drops. These customer weighting factors are applied to the number of meters per class to create the weighted allocation factors for customer-related costs.

THANK YOU!

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