EES Consulting
a GDS Associates Company

CITY OF CORONA

2024 Electric Greenfield Utility Rate Study

Final Report

September 23, 2024

CITY OF CORONA
2024 ELECTRIC GREENFIELD UTILITY RATE STUDY

FINAL REPORT

Prepared for:

City of Corona
400 South Vicentia Avenue
Corona, CA 92882

Prepared by:

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September 23, 2024

Mr. Tom Moody
Director of Utilities
City of Corona
400 South Vicentia Avenue
Corona, CA 92882

Subject: 2024 Electric Greenfield Utility Rate Study

Dear Mr. Moody:

EES Consulting (EES), a GDS Associates Company,. is pleased to provide this 2024 Electric Greenfield Utility Rate Study to the City of Corona (City). This rate study includes a financial plan to determine the revenue requirements for the next five years and a comprehensive review of the City's current rates based on the cost of service principles. This report outlines the approach, methodology, findings, and recommendations of the study. Each of the components of this study has enhanced the equitability of the rates we propose.

The proposed rates were developed utilizing the City's customer usage data, billing records, accounting, operating and management records, capital plans, and reserve policies. Based on the City-provided data, key assumptions were made for the study using appropriate resources and our econometric and financial expertise.

It has been an absolute pleasure and honor to work with your City. We thank you, Ms. Hockett, Ms. Kunkle, Ms. Betancourt, and Mr. Ma and all staff who helped complete this report.

Respectfully submitted,

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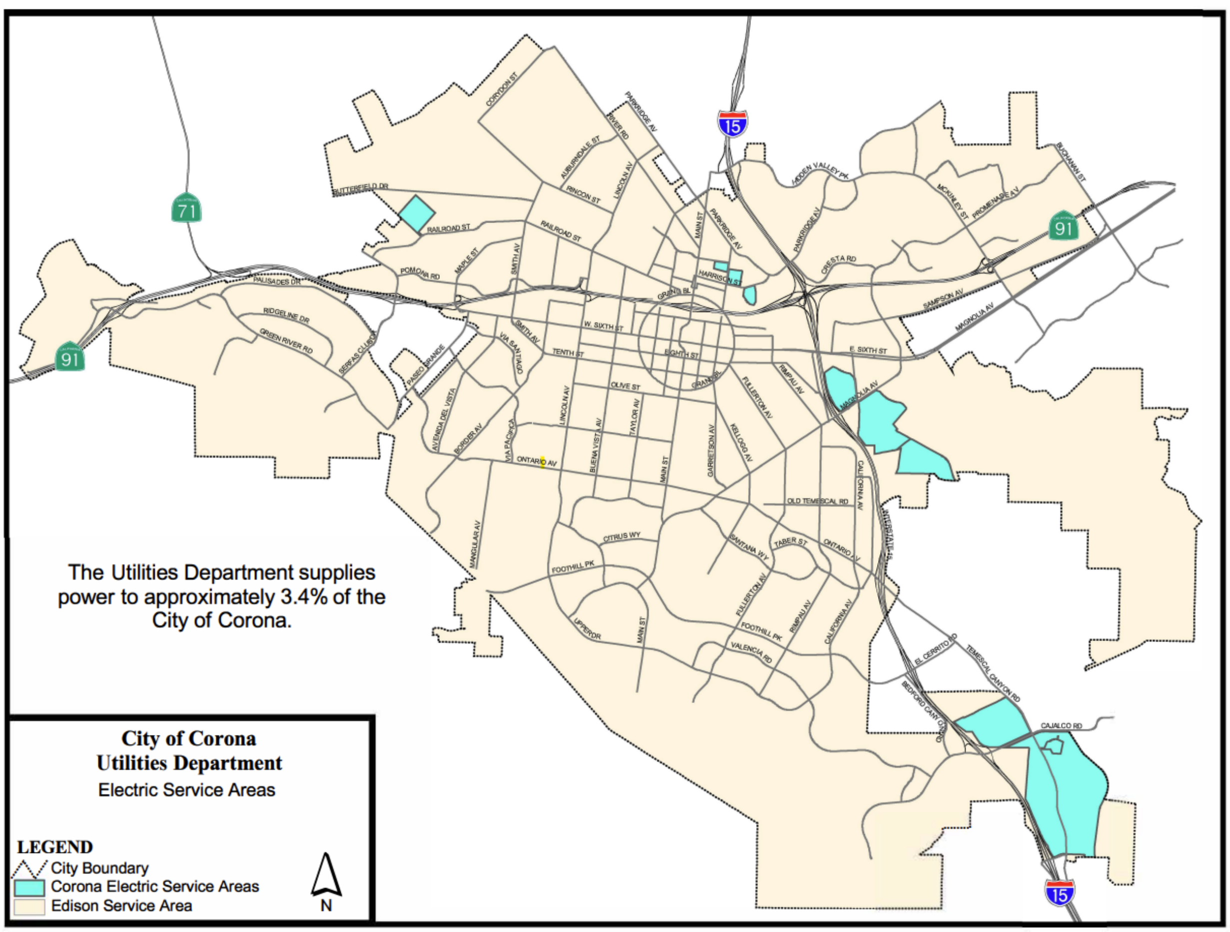
1 EXECUTIVE SUMMARY

1.1 Background

The Electric Utility of the City of Corona (City) was established on April 4, 2001 by City Council Resolution No. 2001-25 in response to state-wide rolling blackouts and electric price instability. The City provides fully-bundled “Greenfield” electric service to residents and businesses within the City’s electric service area. New developments will become customers of the Corona Greenfield electric utility (Greenfield System) if they are in the City’s service area and capacity is available. The Greenfield System currently provides bundled delivery and power supply services to approximately 1,800 customers in 5 different areas of the City. The City also provides Direct Access energy procurement or “generation” services through the Direct Access Program to municipal and commercial customers within the City. The Direct Access Program is not a part of this rate study.

Figure 1 illustrates the City’s electric utility service area.

Figure 1. City of Corona Electric Service Greenfield



1.2 Purpose of Study

The purpose of this analysis is to conduct a rate study which evaluates the City's current rates and financial data and propose new rates, if necessary, that meet the City's financial and strategic goals.

The primary objectives of this Study include:

- Projecting revenues and expenses for a ten-year study period
- Proposing five-year revenue adjustments to fund the City's projected financial needs
- Proposing rates which do not overly impact customers
- Producing an administrative record which effectively summarizes all findings

1.3 Rate Recommendations and Proposed Rates

Electric

- Adjusting rates annually by the recommended revenue adjustments of 4.0 percent per year.
- Adjust rate levels differently across customer classes to recover each class's unique cost of service. Effectively this realigns rates with cost of service.
- Increasing the fixed proportion of rate collection.
- Including a rate category for commercial electric vehicle charging stations.
- Separating the Public Benefits Charge from base rates.
- Remove seasonal energy rates for non-TOU commercial classes.
- Collect demand-related power supply costs throughout the year rather than just during summer peak periods.
- Increase demand rates for power supply and facilities charges based on cost of service.

1.4 Current and Proposed Electric Rates

The Greenfield System services customers are based on class of service and one or more of the 12 rate schedules as provided in the City's Electric Rates and Tariffs.[1] The cost of service analysis (COSA) combines similar rate schedules for the cost allocation analysis but then develops rates for each of the current rate schedules. **Table 1** describes the rate class and applicable rate schedules.

[1] https://www.coronaca.gov/home/showpublisheddocument/2238/638550797549230000

Table 1. Rate Class Definitions

Rate Class	Schedule	Notes
Residential	D (Domestic Service)	Applies to all single family and multifamily dwellings
Small General Service	GS-1	Non-demand metered, < 20 kW/month
Medium General Service	GS-2	Demand-metered, above 20 kW and below 200 kW
Large General Service	TOU-GS-3	Time of use and demand metered above 200 kW and below 500 kW
Industrial	TOU-8	Time of use and demand metered above 500 kW
Pumping and Agriculture	PA-2, TOU-PA	Demand metered service for pumping and agricultural usage (min of 70% total usage)
Lighting	AL-2, TC-1, LS-3	Street lighting, outdoor lighting, and traffic control

The City also provides net energy metering (NEM) and eligible renewable generation (ERG) service schedules. These services are considered in the rate study separately.

EES proposes the following rate and revenue adjustments to accomplish the City's goals of capital and reserve funding as well as maintaining debt service coverage ratios. To maintain the proposed financial plan, the City should raise electric revenues by 4.0 percent each year of the study period. **Table 2** shows the proposed revenue adjustments for the five-year rate study period.

Table 2. Proposed Revenue Adjustments FY 2024-25 to FY 2028-29

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Recommended Adjustment	4.0%	4.0%	4.0%	4.0%	4.0%

The City will implement the fiscal year rates in January of each fiscal year. **Tables 3 through 10** summarize the current and proposed electric rates based on the results of this study. Rates for FY 2025 through FY 2029 are shown in the Appendix.

Table 3. Current and Proposed Residential Rates (D)

<table>
<tr><th></th><th>Current Rates</th><th>Recommended FY 2025</th></tr>
<tr><td>Fixed Charge, $/month</td><td>Single Family: $0.88/day
Multi-Family: $0.67/day</td><td>$15.90</td></tr>
<tr><td>Energy, $/kWh</td><td></td><td></td></tr>
<tr><td>Tier 1 Baseline</td><td>$0.11808</td><td>$0.10100</td></tr>
<tr><td>Tier 2 101-130% Baseline</td><td>$0.13741</td><td>$0.11100</td></tr>
<tr><td>Tier 3 131-200% Baseline</td><td>$0.22696</td><td rowspan="2">$0.21000</td></tr>
<tr><td>Tier 4 over 200% Baseline</td><td>$0.32337</td></tr>
<tr><td>Public Benefits Charge $/kWh</td><td>Included in Energy Rate</td><td>$0.00378</td></tr>
</table>

Table 4. Current and Proposed Small General Service Rates (GS-1)

	Current Rates	Recommended FY 2025
Fixed Charge, $/month	Single Phase: $12.99 Three Phase: $3.16	Single Phase: $20.97 Three Phase: $3.16
Energy, $/kWh		
Summer	$0.17280	$0.15500
Winter	$0.16872	$0.15500
Public Benefits Charge, $/kWh	Included in Energy Rate	$0.00378
Total Variable Rate	**$0.17024**	**$0.15878**

Table 5. Current and Proposed Medium General Service Rates (GS-2)

	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$71.50	$35.13
Demand, $/kW		
Power Supply	Summer Peak:(1) $20.67	Peak: (2) $8.27
Distribution	Facilities: $7.35	Facilities: $15.74
Energy, $/kWh		
Summer	$0.09648	$0.05905
Winter	$0.08738	$0.05905
Public Benefits Charge	Included in Energy Rate	$0.00378
Total Variable Rate	**$0.09087**	**$0.06283**

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months
2. Peak is from 4 pm to 9 pm year-round

Table 6. Current and Proposed Large General Service Rates (TOU-GS-3)

	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$277.25	$49.30
Demand, $/kW		
Power Supply	Summer Peak:(1) $18.16 Mid-Peak:(2) $6.23	Peak:(3) $8.29
Distribution	Facilities: $7.62	Facilities: $17.51
Energy, $/kWh		
Summer On-Peak	$0.13561	$0.09620
Summer Mid-Peak	$0.11027	$0.07280
Summer Off-Peak	$0.07706	$0.05200
Winter Mid-Peak	$0.11282	$0.07986
Winter Off-Peak	$0.08052	$0.05200
Power Factor Adjustment, $/kVa	$0.18	$0.18
Public Benefits Charge, $/kWh	Included in Energy Rate	$0.00378

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months, except holidays
2. Mid-Peak is 4 pm to 9 pm on summer weekends except holidays
3. Peak is from 4 pm to 9 pm year-round

Table 7. Current and Proposed Industrial Rates (TOU-8)

	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$346.00	$76.97
Demand, $/kW		
Power Supply	Summer Peak: (1) $16.91 Mid-Peak: (2) $5.71	Peak: (3) $8.31
Distribution	Facilities: $8.31	Facilities: $15.06
Energy, $/kWh		
Summer On-Peak	$0.12675	$0.09630
Summer Mid-Peak	$0.10299	$0.07319
Summer Off-Peak	$0.07184	$0.05200
Winter Mid-Peak	$0.10538	$0.07986
Winter Off-Peak	$0.07509	$0.05200
Power Factor Adjustment, $/kVa	$0.18	$0.18
Public Benefits Charge, $/kWh	Included in Energy Rate	$0.00378

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months, except holidays
2. Mid-Peak is 4 pm to 9 pm on summer weekends except holidays
3. Peak is from 4 pm to 9 pm pm year-round

Table 8. Current and Proposed Pumping and Agriculture Service Rates (TOU-PA)

	Current Rates	January 2025 Proposed	July 2025 Proposed	January 2026 Proposed
Fixed Charge, $/month	$63.25	$19.14	$19.14	$20.86
Demand, $/kW				
Power Supply	Summer Peak:(1) $10.85	Peak: (2) $6.00	Peak: $12.00	Peak: $12.98
Distribution	Facilities: $3.85	Facilities: $8.00	Facilities: $10.00	Facilities: $21.55
Energy, $/kWh				
Summer On-Peak	$0.13064	$0.10361	$0.10361	$0.09444
Summer Mid-Peak	$0.10929	$0.07874	$0.07874	$0.07178
Summer Off-Peak	$0.05226	$0.05595	$0.05595	$0.05100
Winter Mid-Peak	$0.12255	$0.08592	$0.08592	$0.07832
Winter Off-Peak	$0.05226	$0.05595	$0.05595	$0.05100
Power Factor Adjustment, $/kVa	$0.18	$0.18	$0.18	$0.18720
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378	$0.00378	$0.00405

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months, except holidays
2. Peak is from 4 pm to 9 pm year-round

Table 9. Current and Proposed Lighting Rates

	Current Rates	Proposed FY 2025
Outdoor Area Lighting (AL-2)		
Energy Charge, $/kWh	$0.08224	$0.11678
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$7.00	$10.26
Street Lighting (LS-3)		
Energy Charge, $/kWh	$0.08224	$0.11678
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$7.00	$10.26
Traffic Control (TC-1)		
Energy Charge, $/kWh	$0.11407	$0.16345
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$9.49	$13.91
Three Phase, $/month	$3.16	$4.64

Table 10. Proposed Commercial Electric Vehicle Charging Rates

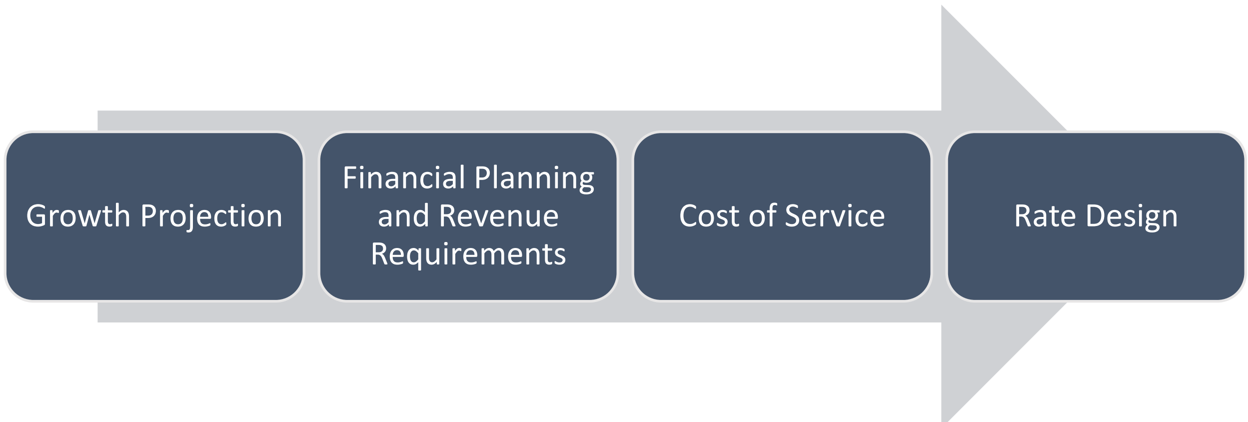
	Recommended FY 2025 Rates
Fixed Charge, $/month	$76.97
Demand (Facilities), $/kW	$15.06
Energy, $/kWh	
On-Peak 4-9 pm	$0.19710
Off-Peak All Other Hours	$0.06570
Power Factor Adjustment, $/kVa	$0.18
Public Benefits Charge $/kWh	$0.00378

2 METHODOLOGY

2.1 General Methodology

The Greenfield System cost of service analysis and rate design studies are based on industry best practices. **Figure 2** presents the steps taken to develop the City's proposed rates.

Figure 2. Electric Utility Greenfield Rate Study Process



- **Growth Projection:** Project customer growth for the ten-year study period, FY 2023-2024 through FY 2033-34, using the City's forecast growth data. Forecast revenues for the study period are based on the projected customer growth and current rate levels.
- **Financial Planning and Revenue Requirements:** Develop a ten-year financial plan based on the projected revenues and annual costs which include both operating and capital expenses. The City's target reserve level should also be considered as part of the financial planning. Based on the financial planning, revenue requirements are determined for each year of the study period.
- **Cost of Service:** Evaluate the customer classifications and allocate costs based on their service requirements.
- **Rate Design:** Design rates to equitably recover the rate revenue requirements from each customer.

2.2 Legal Considerations

This section describes the legal framework considered in the development of the recommended rates to ensure that the calculated cost of service rates provide a fair and equitable allocation of costs to each customer class.

California Constitution-Article XIII C (Proposition 26)

California voters approved Proposition 26 on November 2, 2010. Proposition 26 amended Article XIII C of the State Constitution to expand the definition of "tax" to include "any levy, charge, or exaction of any *kind imposed by a local government" with listed exceptions. By means of these exceptions, Article XIII C classifies several types of charges, in addition to property-related charges, that are not taxes, such as charges for specific services or benefits, regulatory charges and penalties.*

Article XIII C's definition of "tax" lists the following exceptions: (1) a charge imposed for a specific benefit conferred or privilege granted directly to the payer that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of conferring the benefit or granting the privilege; (2) a charge imposed for a specific government service or product provided directly to the payer that is not provided to those not charged, and which does not exceed the reasonable costs to the local government of providing the service or product; (3) a charge imposed for the reasonable regulatory costs to a local government for issuing licenses and permits, performing investigations, inspections, and audits, enforcing agricultural marketing orders, and the administrative enforcement and adjudication thereof; (4) a charge imposed for entrance to or use of local government property, or the purchase, rental, or lease of local government property; (5) a fine, penalty, or other monetary charge imposed by the judicial branch of government or a local government, as a result of a violation of law; (6) a charge imposed as a condition of property development; and (7) assessments and property-related fees imposed in accordance with the provisions of Article XIII D.

Proposition 26 also provides that the local government bears the burden of proving by a preponderance of the evidence that a levy, charge, or other exaction is not a tax, that the amount is no more than necessary to cover the reasonable costs of the governmental activity, and that the manner in which those costs are allocated to a payer bear a fair or reasonable relationship to the payer's burdens on, or benefits received from, the governmental activity. Like the proportionality requirements of Article XIII D, assessment of rates under these requirements, if applicable, would be supported by the cost of service approach.

2.3 Key Assumptions

A base year FY 2024-25 was selected for which budgetary costs are to be analyzed and rates to be established for this study. The financial plan was built for the next ten years, including the five-year study period FY 2025-26 through FY 2029-30 with a detailed revenue adjustment plan. The City's fiscal year starts on July 1 and ends on June 30.

Escalation Factors

The financial plan was built based on an assumption in the projected escalation of revenues and expenses associated with both operations and maintenance (O&M) and capital improvement projects (CIPs). Bureau of Labor Statistics (BLS) Los Angeles-Long Beach-Anaheim Consumer Price Index (CPI), Federal Reserve Bank of St. Louis (FRED) Economic Research Division, Quarterly Census of

Employment and Wages (QCEW), and Engineering News Record (ENR) Building Cost Index (BCI). Escalation factors used in this study are shown in **Table 11**. The Services and supplies escalator is based on the 3-year average of BLS CPI for all items through April 2024. This time period was selected to reflect the ongoing inflation observed in the electric utility industry. Cost drivers for electric utility operation and maintenance costs are largely based on the cost of distribution facilities. The Handy-Whitman Index (HWI)[2] is a cost index frequently used in the electric utility industry. The HWI for electric distribution plant has increased by an average of 25% between the two most recent years published (2022-2023). While inflationary pressures have eased broadly in the economy, electric utilities are still facing high costs and long-lead times for materials and stores.

The Payroll escalation factor was provided by City staff based on historical actual costs and unknown impacts of current employee bargaining unit negotiations. The Power Supply cost escalator was taken from power supply cost forecasts provided by the City's consultant.

Table 11. Expense Escalation Factors

Category	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Payroll	0.0%	8.0%	8.0%	4.0%	4.0%
Other Employee	0.0%	3.2%	3.2%	3.2%	3.2%
Services Supplies	0.0%	4.7%	4.7%	4.7%	4.7%
Power Supply	0.0%	5.0%	3.4%	3.4%	3.4%
CIP	0.0%	4.0%	4.0%	4.0%	4.0%

Customer and Sales Growth

Customer growth was forecast conservatively based on new service requests. It was assumed that per account electric use would remain stable over the study period with the exception of new large customers anticipated to begin taking service in 2024 and 2025. These large customers are a mix of electric vehicle (EV) charging stations, mixed commercial, multifamily dwellings, and a hotel. The City expects to add approximately 4.9 MW of load in the next 12-24 months as a result of these new customers.

There are currently approximately 1,936 electric meters connected to the Greenfield System. **Figure 3** shows the annual electric customer growth for the study period. **Table 12** shows the projected number of meters for all customer classes during the rate setting period.

[2] Whitman, Requardt, and Associates. The Handy-Whitman Index of Public Utility Construction Costs: Trends of Construction Costs. E-6 Pacific Region.

Figure 3. Electric Retail Sales (kWh) Forecast FY 2023-24 to FY 2033-34

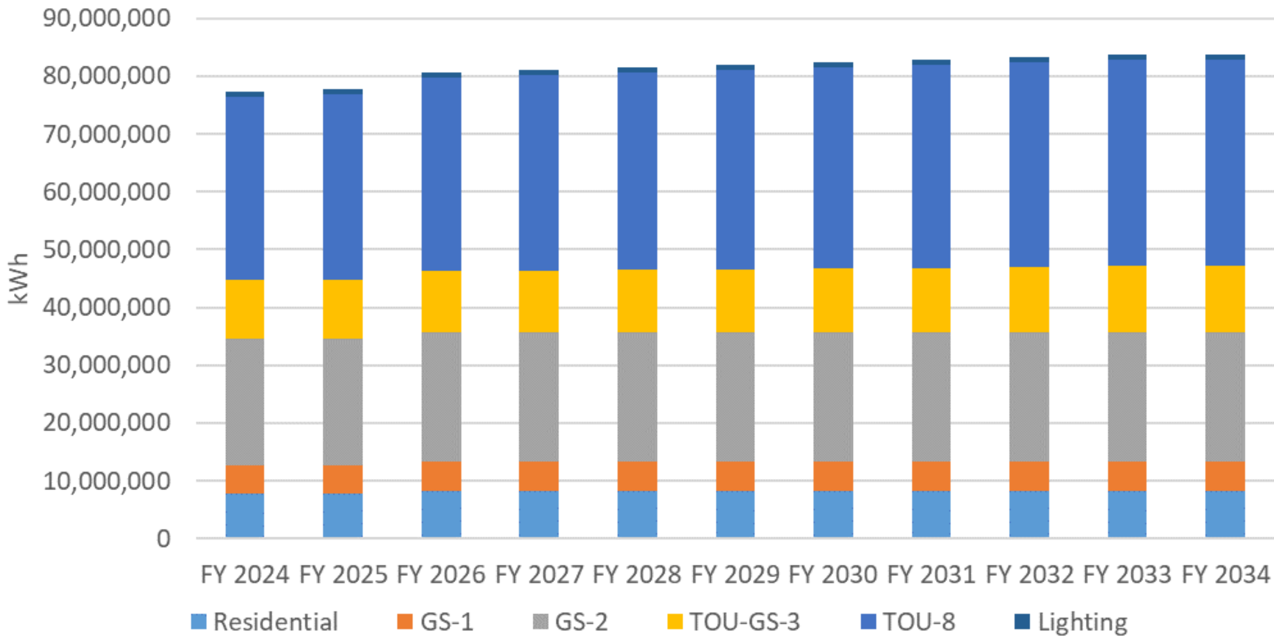


Table 12. Annual Meter Count FY 2023-24 to FY 2028-29

Rate Schedule	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Residential (D)	1,323	1,323	1,373	1,373	1,373	1,373
GS-1	372	373	373	373	373	373
GS-2	160	160	160	160	160	160
TOU-GS-3	8	11	11	11	11	11
TOU-8	10	13	13	13	13	13
Pumping and Agriculture	2	2	2	2	2	2
Lighting	61	61	61	61	61	61
Total	**1,936**	**1,943**	**1,993**	**1,993**	**1,993**	**1,993**

The above forecasts are used in both the financial plan and the cost of service analysis.

Debt Service Coverage Ratios

The City's debt covenants require a certain ratio of net revenue in excess of operating expenses. Debt service coverage ratios are one of the main financial plan drivers of the revenue adjustments. When calculating debt service coverage requirements, the City must maintain a net revenue of 125 percent, or a 1.25 debt service coverage ratio (DSCR) to avoid facing technical default.

3 FINANCIAL PLAN

EES prepared a 10-year financial model for the Greenfield System to meet the City's long-term financial goals. This section of the report details the financial forecast.

3.1 Revenues

Based on the account growth and demand projections as described in Section 3, EES forecasted retail rate revenues generated from customer rates using the current electric rates. Retail rate revenue is approximately $10.6 to $11.0 million annually. Other operating income and non-operating revenue are estimated to provide supplemental revenue each year as shown in **Table 13.** Surplus sales include the resale of excess power supply. AB32 revenues are the revenues earned by the utility for its allocation of carbon allowances through California's Cap-and-Trade program. Finally, daily damages include the estimated payments the utility receives for the delayed commercial operation date for a contracted wind resource.

Table 13. Annual Miscellaneous Revenue by Source, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Interest on Investments	$601,018	$762,323	$800,439	$800,439	$800,439	$800,439
Other Interest Income	$31,028	$36,627	$29,763	$24,186	$18,427	$12,481
Services to Other Funds	$4,620	$4,600	$4,600	$4,600	$4,600	$4,600
Misc. **Fees**	$132,774	$66,500	$66,500	$66,500	$66,500	$66,500
AB 32 Revenues	$580,000	$870,000	$870,000	$870,000	$870,000	$870,000
Surplus Sales	$774,300	$1,551,286	$2,144,126	$2,144,126	$2,144,126	$2,144,126
Daily Damages (Solar)	$101,376	$462,551	$0	$0	$0	$0
Rental/Lease Income	$109,000	$113,000	$118,000	$118,000	$118,000	$118,000
Total	**$2,334,116**	**$3,866,887**	**$4,033,428**	**$4,027,851**	**$4,022,092**	**$4,016,146**

The system's total revenue for the study period is estimated to be approximately $12.9 to $15.0 million annually under current rates. **Table 14** shows the projected revenue flow for the study period (FY 2023-24 – FY 2028-29) without any revenue adjustments. Projections are based on electric use and customer growth projections, as well as other operating and non-operating revenue estimates provided by City staff.

Table 14. Electric Utility Greenfield Operating Forecast, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Revenue from Rates	$10,590,000	$10,479,000	$10,956,112	$10,956,112	$10,956,112	$10,956,112
Other Operating Revenue	$1,579,870	$2,954,937	$3,085,226	$3,085,226	$3,085,226	$3,085,226
Non-Operation Revenues	$754,246	$911,950	$948,202	$942,625	$936,867	$930,920
Total	**$12,924,116**	**$14,345,887**	**$14,989,540**	**$14,983,963**	**$14,978,204**	**$14,972,257**

3.2 Operating and Maintenance (O&M) Expense

The majority of O&M expenses for the Greenfield System are in purchased power supply costs as shown in **Table 15**. These costs are increasing over time due to forecast market conditions and current contract arrangements. The systems power supply costs include all costs associated with serving retail customers including energy purchases, renewable energy, transmission and ancillary services, and capacity. Distribution O&M are the annual ongoing costs of maintaining the electric distribution system and does not include new capital investments. Customer service and account costs are the cost of maintaining the utility billing system, meter reading, customer programs, new service requests, and staffing to take customer calls. The administrative and general expense includes the overhead needed to run the electric utility such as property insurance and staffing.

Table 15. Operating Expenses by Expense Category, FY 2024 to FY 2029[3]

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Purchased Power Cost	$8,239,397	$10,801,225	$10,872,100	$11,172,908	$11,484,571	$11,807,506
Distribution O&M	$549,215	$505,074	$536,698	$570,438	$595,298	$621,248
Customer Accts & Svc	$505,902	$672,638	$469,204	$479,668	$488,404	$497,533
Administration & General	$1,658,408	$1,738,294	$1,815,816	$1,896,850	$1,981,506	$2,069,995
Total	**$10,952,922**	**$13,717,231**	**$13,693,818**	**$14,119,865**	**$14,549,778**	**$14,996,283**

3.3 Other Obligations

Other obligations included in the financial plan are capital improvement, franchise fee, debt service obligations, and reserve contributions made from rates. These are described below.

Capital Improvement Projects

The City plans to spend an average of $500,000 a year on electric related capital expenditures during the rate setting period. While the projects planned only total an average of $500,000 per year, the electric utility department anticipates major replacements will be needed during the 10-year planning period.

[3] District staff provided current year operating expenses by category, projections are based on individual line-item inflationary factors shown in Table 13.

These replacements include investments to improve reliability and resiliency of the electrical grid[4]. Therefore, in addition to the planned projects, the City's financial plan provides revenue to build a capital savings balance. In total, the City plans for $1.6 million per year to be either used directly for capital projects or to be saved for future replacements, as shown in **Table 16**. The 10-year savings target of $13.1 million for future capital projects is incorporated into the financial plan.

Table 16. Rate Study CIP Expenses and CIP Reserve, FY 2024 to FY 2029[5]

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total CIP Expense	$2,094,029	$1,600,000	$1,600,000	$1,600,000	$1,600,000	$1,600,000
CIP Projects Planned	$2,094,029	$810,000	$693,323	$231,000	$253,000	$545,000

More detail on reserve balances are provided below.

Reserves

The City must maintain an appropriate reserve balance to ensure the day-to-day operation will continue during emergencies and guarantee the future stability of the system. The City's financial goal is to build an appropriate level of cash reserves for the reserve fund included in the financial plan of this Study. Reserve target for the Greenfield System is described below:

- **Operating Reserve**: Three months of operating expenses plus annual depreciation.

The reserve target at the end of the 10-year study period reaches $4.9 million. **Table 17** shows the City's reserve targets for FY 2023-24 through FY 2028-29 based on the current reserve policy. **Figure 4** displays the resulting cash balances versus the reserve target under the current rates. Figure 4 demonstrates that the operating reserve is fully funded beginning FY2025.

Table 17. Electric Greenfield Reserve Target, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Operating Reserve	$3,213,509	$3,904,527	$3,906,793	$4,015,745	$4,125,747	$4,236,870

In addition to the operating reserve, the Greenfield electric utility tracks three other reserve accounts:

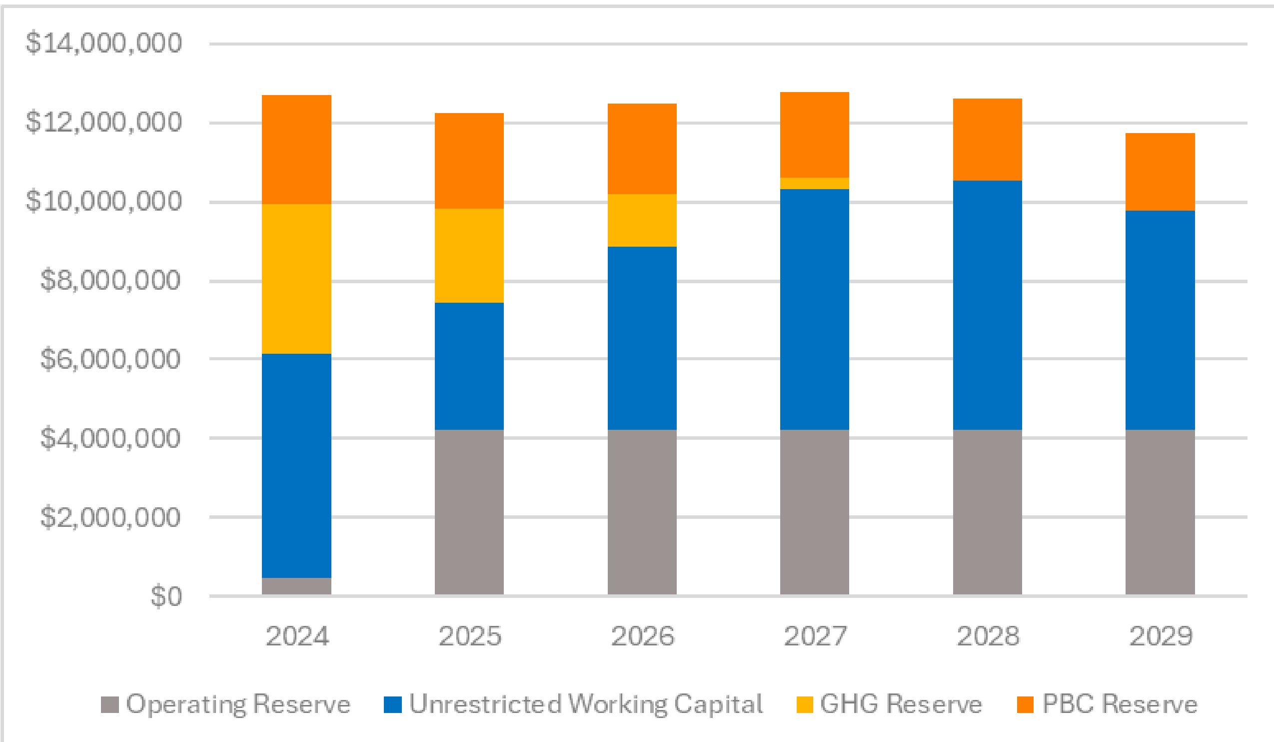
1. Unrestricted – Includes all unrestricted cash including contributions held for future CIP as discussed above.

[4] Replacements include gas switches, breakers, and PME replacements as well as a portion of underground cable.
[5] District's 10-year CIP budget was used for project cost, project type, and funding source

2. Public Benefits Charge (PBC) Reserve – Contributions are made from the PBC revenues which is equal to 2.85% of retail revenues. Fund use is restricted to low-income or energy efficiency program expenditures.
3. Greenhouse Gas Reserve – Contributions are made from AB 32 auction proceeds. Fund use is restricted to renewable energy expenses.

At current rate levels and projected fund use, the aggregate reserve level decreases over the planning period. Total unrestricted cash decrease from $5.7 million to $5.5 million, of which, $5.5 million is needed to fund future CIP.

Figure 4. Electric Greenfield Cash Balances and Reserve Target with Current Rates, FY 2024 to FY 2029



Debt Service and Coverage Ratios

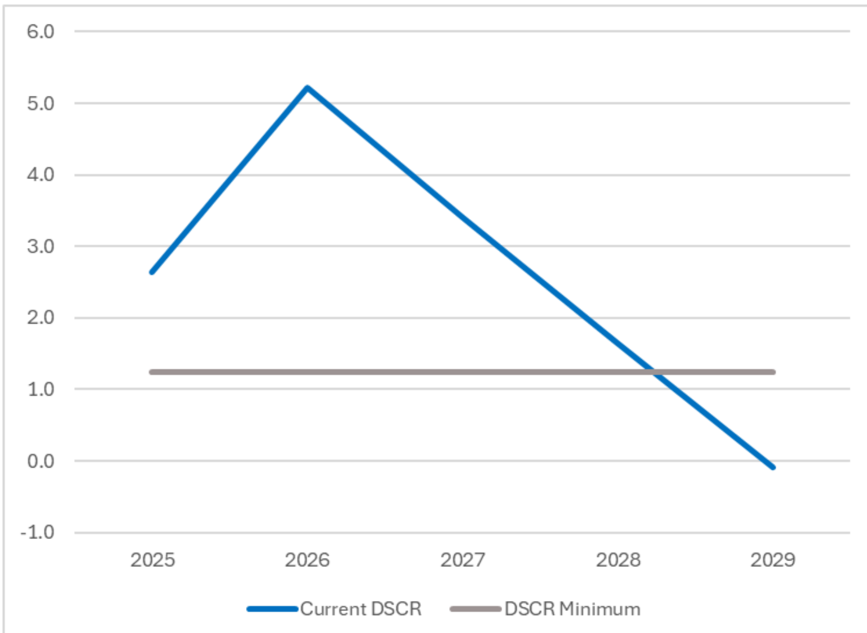
The City's Greenfield system does not carry any traditional debt, however, there is a pension obligation bonds (POB) payment. This obligation is approximately $250,000 a year during the study period. **Table 18** shows the DSCR under the current finances detailed in the previous tables. To derive the DSCR, net revenue is divided by the total debt service in each year.

Table 18. Electric Greenfield Utility Debt Service Coverage Ratio Calculation, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total Revenue	$12,910,916	$14,345,887	$14,989,540	$14,983,963	$14,978,204	$14,972,257
Total Operating Expense	$10,952,922	$13,717,231	$13,693,818	$14,119,865	$14,549,778	$14,996,283
Total Debt Service	$229,138	$238,897	$248,271	$254,605	$260,951	$254,857
DSCR	**8.55**	**2.63**	**5.22**	**3.39**	**1.64**	**-0.09**

Under the current rates, the City will be in technical default beginning in FY 2029 as net revenues are not 125 percent greater than debt service payments. **Figure 5** shows the projected debt service coverage ratios based on the current financial plan.

Figure 5. Debt Service Coverage Ratio Under Current Rates, FY 2024 to FY 2029



3.4 Financial Plan Summary

Based on the projected total revenue and necessary costs to be recovered during the study period, EES prepared a financial plan that will generate sufficient revenues for the day-to-day operation and annual CIP and make appropriate contributions to reserves. The City's Greenfield fund currently has a projected ending cash balance of $5.7 million in FY 2024. **Table 19** shows the status quo pro forma with no revenue adjustments and the resulting ending balances based on the revenues and expenses outlined in this section.

Table 19. Status Quo Financial Pro Forma for City of Corona Electric Greenfield, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Rate Increase		0%	0%	0%	0%	0%
Month Implemented		January	January	January	January	January
Cash Position Opening Balance	$13,071,906	$12,698,043	$12,228,235	$12,478,797	$12,748,593	$12,549,004
Revenues						
Retail Rate Revenue	$10,590,000	$10,479,000	$10,956,112	$10,956,112	$10,956,112	$10,956,112
Other Revenues	$2,334,116	$3,866,887	$4,033,428	$4,027,851	$4,022,092	$4,016,146
Transfers	$163,490	$164,205	$133,437	$137,787	$142,279	$146,917
Total Revenues	$13,087,606	$14,510,092	$15,122,976	$15,121,749	$15,120,482	$15,119,174
Operating Expenses	$11,187,897	$13,979,529	$13,977,194	$14,409,973	$14,846,195	$15,298,838
Net Operating Revenues	**$1,899,709**	**$530,564**	**$1,145,783**	**$711,776**	**$274,288**	**-$179,664**
Current Rate Funded Debt Service	$179,543	$190,371	$201,898	$210,980	$220,877	$218,898
New Debt Service	$0	$0	$0	$0	$0	$0
Total	$179,543	$190,371	$201,898	$210,980	$220,877	$218,898
Total Operating and Debt Service	**$11,367,439**	**$14,169,900**	**$14,179,092**	**$14,620,953**	**$15,067,072**	**$15,517,736**
Total Operating and Debt Net Revenues	**$1,720,166**	**$340,192**	**$943,885**	**$500,796**	**$53,411**	**-$398,562**
Capital Expenditure	$2,094,029	$810,000	$693,323	$231,000	$253,000	$545,000
Net Income	-$373,863	-$469,808	$250,562	$269,796	-$199,589	-$943,562
Cash Ending Balance	**$12,698,043**	**$12,228,235**	**$12,478,797**	**$12,748,593**	**$12,549,004**	**$11,605,442**
Restricted Funds Balance	$7,005,185	$9,048,639	$7,905,534	$6,775,938	$6,441,711	$6,394,984
Unrestricted Ending Balance	$5,692,858	$3,179,596	$4,573,263	$5,972,655	$6,107,293	$5,210,458

Restricted funds balance includes the PBC Reserve, Greenhouse Gas Reserve, and Operating Reserve. The unrestricted balance includes funds saved for future CIP and cash for working capital.

The transfers under Revenues of approximately $164,000 in FY 2025 is an interfund loan. This revenue is split between the Greenfield and Direct Access electric customers based on relative share of total energy.

Table 20 shows the proposed pro forma for the study period with the recommended revenue adjustments per year. All revenue adjustments will occur in January of the Fiscal Year.

Table 20. Proposed Financial Pro Forma for City of Corona Electric Greenfield System, FY 2024 to FY 2029

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Rate Increase		4%	4%	4%	4%	4%
Month Implemented		January	January	January	January	January
Cash Position Opening Balance	$13,071,906	$12,698,043	$12,437,815	$13,582,396	$15,220,216	$16,881,616
Revenues						
Retail Rate Revenue	$10,590,000	$10,688,580	$11,850,130	$12,324,136	$12,817,101	$13,329,785
Other Revenues	$2,334,116	$3,866,887	$4,033,428	$4,027,851	$4,022,092	$4,016,146
Transfers	$163,490	$164,205	$133,437	$137,787	$142,279	$146,917
Total Revenues	$13,087,606	$14,719,672	$16,016,995	$16,489,773	$16,981,472	$17,492,848
Operating Expenses	$11,187,897	$13,979,529	$13,977,194	$14,409,973	$14,846,195	$15,298,838
Net Operating Revenues	**$1,899,709**	**$740,144**	**$2,039,802**	**$2,079,800**	**$2,135,277**	**$2,194,009**
Current Rate Funded Debt Service	$179,543	$190,371	$201,898	$210,980	$220,877	$218,898
New Debt Service	$0	$0	$0	$0	$0	$0
Total	$179,543	$190,371	$201,898	$210,980	$220,877	$218,898
Total Operating and Debt Service	**$11,367,439**	**$14,169,900**	**$14,179,092**	**$14,620,953**	**$15,067,072**	**$15,517,736**
Total Operating and Debt Net Reven	**$1,720,166**	**$549,772**	**$1,837,903**	**$1,868,820**	**$1,914,400**	**$1,975,112**
Capital Expenditure	$2,094,029	$810,000	$693,323	$231,000	$253,000	$545,000
Net Income	-$373,863	-$260,228	$1,144,580	$1,637,820	$1,661,400	$1,430,112
Cash Ending Balance	**$12,698,043**	**$12,437,815**	**$13,582,396**	**$15,220,216**	**$16,881,616**	**$18,311,727**
Restricted Funds Balance	$7,005,185	$9,048,639	$7,905,534	$6,775,938	$6,441,711	$6,394,984
Unrestricted Ending Balance	$5,692,858	$3,389,176	$5,676,862	$8,444,278	$10,439,905	$11,916,743

3.5 Revenue Requirements

Table 21 displays the Greenfield Systems revenue requirements for FY 2024-25. The total expense is offset by other operating revenues and non-operating revenues to compute a pure portion of revenue requirements that need to be recovered from customers' rates. EES proposes annual revenue adjustments of 4.0 percent FY 2024-25 through FY 2028-29 to reach the financial goals set by the City.

Table 21. Revenue Requirements for City of Corona Electric Greenfield Utility, FY 2025

Revenue Requirement	FY 2025
O&M Expenses	$13,717,231
Franchise Fees	$213,772
Debt Service	$238,897
Capital Expenditures	$810,000
Other Operating Revenue	($2,954,937)
Non-Operating Revenue	($911,950)
Net Balance from Operations	($424,433)
Rate Revenue Requirement	**$10,688,580**

4 COST OF SERVICE ANALYSIS

The objective of the COSA is to analyze costs and equitably assign those costs to customers commensurate with the cost of serving those customers. The founding principal of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers. This section of the report will discuss the general approach used to apportion the utility's cost of service and provide a summary of the results.

4.1 COSA Definition and General Principles

A COSA study allocates the costs of providing utility service to the various customer classes served by the utility based upon the cost-causal relationship associated with specific expense items. This approach is taken to develop a fair and equitable designation of costs to each customer class, where customers pay for the costs that they incur. Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various classes using factors appropriate to each type of expense. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA then spreads the revenue requirement across the various customer classes, creating per unit costs by class. In the third step, rates are designed for each customer class, with per unit costs being one consideration in setting the appropriate rate levels.

A COSA study can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer and are based on costs of facilities and services, if incurred at the present time. While marginal costs can be valuable for designing rates in certain instances, marginal costs are generally higher than embedded costs. Therefore, the use of a marginal COSA study usually requires that all costs be scaled back to a level equal to the embedded cost revenue requirement established using actual or projected costs from an "accounting" perspective.

This study uses an embedded COSA as its standard methodology. Therefore, the City's electric utility embedded cost revenue requirement and existing rate base investment are used in developing the COSA results. Both the utility's revenue requirement (ongoing expenses) and the value of its fixed assets (plant) are spread across customer classes. The allocation of the fixed assets is then used to spread ongoing O&M costs according to how each class utilizes the utility investments.

There are three basic steps to follow in developing a COSA, or spreading expenses and fixed asset values across customers, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. Plant investment includes infrastructure such as control panels, switches, transformers, and wires and it includes other necessary investments to run the utility business such as software or property. The primary functional categories are production, transmission, distribution and general.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related or customer-related. Production costs are related to supplying and transporting power to customers on the system. Transmission costs are related to the bulk transfer of power throughout the system, which is designed to meet the peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Additionally, costs can be classified based on system revenues or directly assigned to a customer or group of customers.

Allocation of costs to specific customer classes is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand, whether coincident peak, non-coincident peak or some variation determined to be appropriate for the particular cost item. An analysis of customer requirement, loads and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data and special studies.

4.2 General Ratemaking Principles

While this section does not address the design of rates, it is important to note that the COSA results will be one of the considerations when the process of designing rates for various customer classes begins. The basic goals of rate design include:

- The utility has an ability to collect the appropriate revenue requirement
- Utility revenues and customer rates are stable and predictable
- Proper price signals are sent to create efficiency of resources

- Rates are fair and equitable among customers and avoid undue discrimination
- Rates are simple, easy to understand and feasible for the utility to implement

The COSA is generally used to assist in meeting the second and fourth goals of rate design. Price signals are best if they reflect the specific costs incurred. Rates are generally considered fair and equitable if customers are deemed to pay their share of the costs incurred by the utility. Additionally, the first goal is met as long as the COSA is based on the appropriate revenue requirement, and the use of a consistent COSA methodology contributes towards the second goal. Rates are more stable through time if the COSA methodology is not significantly changed every time a rate application is made.

4.3 Functionalization of Costs

The first step in the COSA process following finalization of the revenue requirement is to functionalize the revenue requirement and the rate base (plant). Functionalization is the separation of cost data into the functional activities performed in the operation of a utility system (i.e., power supply, transmission, distribution and customer service). Functionalization was accomplished using the City's system of accounts, which largely segregates costs in this manner.

In addition to the functionalized costs, certain joint costs are spread to each functional category based on the relationship of the joint cost to the business function. These joint costs include such items as administrative and general costs.

Standard Functionalization

Plant investment costs or rate base are generally functionalized into production, transmission, distribution and general cost categories. The functionalization of rate base typically is very straightforward as costs for the different functions are readily identifiable and rate base accounts are maintained by functional categories.

Expense accounts are also typically kept according to these basic functional categories, with expense items associated with certain types of plant being treated in the same manner as the corresponding plant account.

The two areas where there generally are differences in functionalization among utilities are in the treatment of general plant and administrative and general (A&G) expenses. Typically, general plant is considered a separate functional category. Some utilities, when their internal accounting systems can support such an assignment process, will record general plant investment by loading the costs into the other functional categories, much like an overhead assignment or a form of activity-based accounting.

On the expense side, A&G costs can be treated in much the same way. Generally, they are treated as a separate expense category that can be spread to functions based upon all other O&M expenses. However, they can also be spread to functions on the basis of total net plant, labor ratios or, in some cases, directly assigned as part of the activity-based accounting approach.

Table 22 displays the functionalization of the FY 2025 revenue requirement. Because the City does not own any transmission assets, only product (power supply) and distribution are shown.

Table 22. Functionalized Revenue Requirement FY 2025

Revenue Requirement Category	Total	Production	Distribution
Purchased Power	$10,801,225	$10,801,225	$0
Distribution O&M	$505,074	$0	$505,074
Customer Service, Accounts & Sales	$672,638	$185,000	$487,638
Admin & General	$1,738,294	$268,990	$1,469,304
Taxes (Franchise Fee)	$213,772	$0	$213,772
Interest & Debt Service	$238,897	$0	$238,897
Other Contributions	($424,433)	($1,743,483)	$1,319,051
Capital Projects Funded from Rates	$810,000	$0	$810,000
Other Revenues	($3,866,887)	($3,020,508)	($846,379)
Total	**$10,688,580**	**$6,491,223**	**$4,197,357**

Table 23 summarizes the functionalization of the City's fixed assets related to the electric utility. All fixed assets are functionalized as distribution.

Table 23. Functionalized Rate Base FY 2023

Description	FERC Cost Account(s)	Amount (millions)	Functionalized To:
Distribution	360-373	$15.0	100% Distribution
General Plant	389-399	$0.2	100% Distribution
Total Gross Plant		**$15.2**	

4.4 Classification of Costs

The second step in performing a cost of service analysis is to classify the functionalized expenses to traditional cost causation categories. These cost causation categories can be directly related to specific consumption behavior or system configuration measurements such as coincident peak (CP) or non-coincident peak (NCP) demand, energy or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

Functionalized power purchases, generation and transmission system costs are classified as demand-related and/or energy-related and in some instances directly assigned, while distribution costs are classified as demand- or customer-related, or directly assigned to specific customer classes of service.

Standard Classification

The three most general classification categories are demand-related, energy/commodity-related and customer-related. Within these three categories there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. For example, demand- and energy-related costs can be separated by seasonal distinctions as well as to reflect peak/off peak consumption periods. Customer-related costs could be separated by demand and customer categories, while customer categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where costs are not specifically classified to a particular category but rather in the same manner as an individual cost account or subtotal of specific cost accounts. For example, some of the overhead costs, like Administrative & General, are classified based on how all other O&M costs are classified which includes a classification to energy, demand, or customer.

Generally, power production and purchased power costs are classified by a combination of demand and energy. Transmission costs are generally classified as peak demand, while distribution costs are generally split between demand and customer. The City's electric utility purchases transmission service from the California Independent System Operator (CAISO). CAISO provides the load balancing services for much of the State. Because CAISO bills transmission based on energy, transmission costs for the City are classified as energy.

There are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built to meet the non-coincident peak. Therefore, distribution costs are classified as 100% demand-related. Specific distribution costs are sometimes split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 kWh of energy per year. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of electricity and that therefore, those costs should be treated as demand-related. Because the residential class tends to have a higher share of the number of customers as compared to the share of non-coincident peak, the minimum system methodology tends to allocate more costs to the residential customer class and customer charges tend to be higher than with the 100% demand methodology.

The process of cost classification is the area within the COSA that can create considerable cost variability between customer classes due to differences in system configurations, demand measurements and assignment philosophy. The complexity of the entire COSA process is further compounded since, in some cases, the classification category is clear, but the specific allocator is not. For example, a particular cost item may clearly be peak demand-related but that demand can be measured as either a single coincident peak for the year, a 2 coincident peak (CP) approach to reflect seasonal considerations, the sum of 12 monthly coincident peaks or through some other approach such as “Average & Excess.”

City of Corona Classification Method

The following describes the specific classifiers used in the City’s electric COSA within each of the four functions.

Power Supply

Classifying power supply costs to demand and energy (commodity) components requires the evaluation of a number of complex, interrelated factors. Consideration must be given to what or who caused the power supply purchase to be made, and to the uses to which it will be put (i.e., meeting demand and energy requirement). Within this study, power supply costs are classified to demand and energy based on the City’s power cost forecast for the test period. The specific classifiers used for the power supply function include Energy and Demand.

Energy-related costs are those that vary with the total amount of electricity consumed by a customer. Electricity usage measured in kWh is used in this portion of the analysis as well. Energy costs are the costs of consumption over a specified period of time, such as a month or year.

Demand-related costs are those that vary with the maximum demand or the maximum rates of power supply to customer classes. Customer and system demand for this analysis were measured in kW. Demand costs are generally related to the size of facilities needed to meet a customer’s maximum demand at any point in time.

All of the City’s power supply costs are purchases related to energy including most transmission purchases. Transmission purchases through CAISO or Southern California Edison (SCE) are included in this section of the revenue requirement. CAISO wheeling and the various facility charges are classified as demand-related since those costs are incurred by the utility based on demand readings.

Transmission (Utility-Owned)

The transmission function includes the utility's own transmission assets associated with providing power to the City's distribution system. Transmission services that the City purchases in order to facilitate the delivery of wholesale power purchases to the City's service area are included in power supply costs. The costs associated with the local utility's transmission service include only those costs for operating and maintaining the transmission lines, poles, towers, substations, etc. used to deliver power to the distribution network. The cost of providing transmission service to a customer is considered to be directly proportional to the demand that customer imposes on the system. The City does not own transmission equipment; therefore, these line items are not included in the analysis.

Distribution

Distribution services include all services required to get energy supply from the point of interconnection between the transmission system and the utility's service area to the end user of the power. Classifying distribution costs requires a special analysis of the nature of the costs. Because the City has collected billed demand data, the distribution system costs are classified as demand-related using the 100% demand approach described earlier.

Customer

Customer-related services include all services related to the presence of customers on the system, not to customer usage. These services include meter reading, billing, collections, advertising, etc. Customer-related costs vary with the number and type of customers. They do not vary with system supply levels. These costs are sometimes referred to as "readiness to serve" or "availability" charges. Customer costs are incurred by the utility to have electricity supply readily available for a customer whether it is utilized or not.

There are two types of customer-related cost classification categories—actual and weighted. Actual customer costs vary proportionally with the addition or deletion of a customer, regardless of the size or usage characteristics of the customer. An example of an actual customer-related cost is billing services needed to develop monthly customer bills. In contrast, a weighted customer cost reflects a disproportionate cost attributable to the addition or deletion of a customer. An example of weighted customer costs is meter-reading expenses. In some cases, it takes less time and effort to read a residential energy meter than it does to serve a large commercial customer that also has a demand meter. This type of difference is accounted for in the weighted customer allocation factors.

Direct Assignment

Some costs can be directly assigned to certain customer classes without being classified as demand-, energy-, or customer-related. These are generally costs associated with specific services, such as dedicated capital facilities, or with specific customer classes, such as lighting customers. Direct assignments include costs incurred to maintain and serve city-owned streetlights. The City of Corona does not have any expenses that are directly assignable.

Table 24 shows the functionalized and classified revenue requirement for FY 2025.

Table 24. Functionalized and Classified Revenue Requirement FY 2025

Function:	Production		Distribution		
Classification:	Demand	Energy	Demand	Energy	Customer
Purchased Power	$1,912,821	$8,888,404	$0	$0	$0
Distribution O&M	$0	$0	$505,074	$0	$0
Customer Service, Accounts & Sales	$0	$185,000	$331,145	$0	$156,493
Admin & General	$0	$268,990	$1,239,433	$0	$229,871
Taxes (Franchise Fee)	$0	$0	$194,537	$0	$19,235
Interest & Debt Service	$0	$0	$217,402	$0	$21,496
Other Contributions	$0	-$1,743,483	$1,262,743	$0	$56,308
Capital Projects Funded from Rates	$0	$0	$737,118	$0	$72,882
Other Revenues	$0	-$3,020,508	-$720,600	$0	-$125,779
Total	**$1,912,821**	**$4,578,402**	**$3,766,850**	**$0**	**$430,506**

Similar to the revenue requirement, **Table 25** shows the functionalized and classified rate base for FY 2023.

Table 25. Functionalized and Classified Rate Base FY 2023

	Distribution		
	Demand	Energy	Customer
Distribution Plant	$13,640,101	$0	$1,348,665
General Plant	$225,877	$0	$22,334
Accumulated Depreciation	$8,244,323	$0	$815,157
Total	**$5,621,655**	**$0**	**$555,841**

4.5 Allocation of Costs

The third step in performing a cost of service analysis is the allocation of the utility's total functionalized and classified revenue requirement to the customer classes of service. This is performed through the application of an appropriate allocation methodology.

City of Corona Allocation Methodology

The following are the specific allocation methods used in the City's electric COSA.

- Demand Allocation Factors. For purposes of this study, two types of demand allocation factors were developed.
  - *Non-coincident peak demand allocation factor (NCP).* First, a non-coincident peak demand allocation factor was developed for each customer class. Expenses classified and allocated by the non-coincident peak demand allocation factor included those predicated on maximum demands such as distribution substations, and a portion of poles and lines, mains, meters and services. The NCP demand method allocates costs to each class of service based upon their highest individual non-coincident peak demand regardless of the time of occurrence. The NCP allocation factor is used to allocate distribution.
  - *Sum of monthly coincident peak (12 CP).* A contribution to monthly system coincident peaks was derived from the non-coincident peak by use of a coincidence factor. This coincident peak demand allocation method is referred to as the sum of the monthly coincident peak (12 CP) method. The 12 CP method allocates demand costs on the basis of demand value at the time of the system peak demand in each month by each class. As discussed previously, the 12 CP method is used for power supply costs and transmission costs.
- Energy Allocation Factors. Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon electricity sales for each class. Energy allocation factors were used to allocate power supply costs, green-energy related costs and revenues and surplus sales revenue.
- Customer Allocation Factors. Two basic types of customer costs were identified – actual and weighted. The allocation factor for actual customers was derived from the actual number of customers served in each class of service. Two weighted customer allocation factors were also developed. The first weighted customer allocation factor considered the relative differences among the various customer classes of meter costs. The second weighted customer allocation factor considered the cost of customer accounting and meter reading by each rate class. Customer allocation factors were used to allocate some distribution costs such as meters and meter installations, and costs associated with customer service, accounts and sales.
- Rate Base Allocation. The value of the City's electric system was estimated as of FY 2023 and is functionalized, classified and then allocated to customer classes. The resulting functionalized,

classified and allocated rate base is then used to develop rate base allocation factors. These allocation factors (i.e., general plant, net plant, distribution rate base, etc.) are then used to allocate revenue requirement expenses. For example, maintenance of station equipment can be allocated using station equipment rate base, or property taxes might be allocated using net plant.

- Other Cost Allocation. Other costs are allocated based on specific rate base items, O&M function totals, revenues, labor ratios and other allocation factors. These other allocation factors were used to allocate administrative and general expense items, as well as some other revenues such as dividend income or non-operating rental income.
- Administrative and General (A&G). All costs that are related to general overhead are classified to this area. Costs are allocated to customers based on their percentage of all other O&M expenses without power supply.
- Miscellaneous/Other Revenues. Miscellaneous/other revenues are generally allocated to customers based on allocation of all other O&M expenses.

The rate base allocation is shown in **Table 26**. The table summarizes how each rate class uses the distribution system based on their relative share of demand and size of services and meters.

Table 27 summarizes the load data used for customer class allocations.

Table 28 shows the allocated revenue requirement. Lastly, **Table 29** summarizes the COSA results and indicated rate adjustments. These rate adjustments are the basis for the recommended rebalancing proposal for the rate design provided in the next section.

Table 26. Functionalized, Classified, and Allocated Rate Base FY 2023

	Total	Residential (D)	GS-1	GS-2	TOU-GS-3	TOU-8	PA	Lighting
Distribution								
Demand	$5,621,655	$606,258	$462,142	$1,953,686	$693,333	$1,621,569	$218,063	$66,605
Energy	$0	$0	$0	$0	$0	$0	$0	$0
Customer	$555,841	$275,671	$155,571	$100,208	$6,550	$16,990	$850	$0
Direct Assignment	$0	$0	$0	$0	$0	$0	$0	$0
Total Cost / Classifier	**$6,177,496**	**$881,929**	**$617,713**	**$2,053,894**	**$699,883**	**$1,638,559**	**$218,913**	**$66,605**

Table 27. Summary of FY 2025 Load Data

	Total	Residential (D)	GS-1	GS-2	TOU-GS-3	TOU-8	PA	Lighting
Forecast Load Data								
Energy Sales (kWh)	80,579,364	7,799,088	4,947,100	21,917,230	10,143,439	32,132,199	2,815,310	824,999
Total Billing Capacity (kW)	189,895	0	0	78,309	26,422	78,770	6,394	0
Avg. Monthly Billing Capacity (kW)	15,825	0	0	6,526	2,202	6,564	533	0
Number of Customers	1,939	1,323	373	160	8	10	2	62
Ratio of NCP to Avg. Billing	375%	0%	0%	84%	90%	95%	106%	0%
Rate Classes NCP Demand at Meter	17,495	1,784	1,281	5,480	1,971	6,238	565	175
Forecast Based on Recorded and Forecast Data								
Annual NCP Load Factor	53%	50%	44%	46%	59%	59%	57%	54%
Rate Classes CP Demand at Input Voltage	15,993	1,636	1,281	4,912	1,970	5,460	565	168
Annual CP Load Factor	53%	54%	44%	51%	59%	67%	57%	56%

Table 28. Allocated Revenue Requirement FY 2025

Functional Cost Classification	Total Cost	Residential (D)	GS-1	GS-2	TOU-GS-3	TOU-8	PA	Lighting
Production								
Demand (PD)	$1,912,821	$159,868	$129,445	$647,349	$218,930	$654,270	$80,165	$22,794
Energy (PE)	$4,578,402	$447,415	$285,148	$1,254,070	$578,881	$1,806,893	$159,301	$46,695
Distribution								
Demand (DD)	$3,766,850	$412,438	$309,729	$1,232,601	$462,666	$1,186,613	$124,890	$37,912
Energy (DE)	$0	$0	$0	$0	$0	$0	$0	$0
Customer (DC)	$430,506	$252,492	$93,928	$67,587	$4,649	$9,415	$469	$1,968
Total	**$10,688,580**	**$1,272,213**	**$818,250**	**$3,201,607**	**$1,265,127**	**$3,657,192**	**$364,825**	**$109,368**

The retail rate increase of 2% would apply if the City were to increase rates on July 1, 2024. Since the City plans to adjust rates on January 1, 2025, the rate adjustment is 4%. This rate adjustment would collect revenues that meet forecasted FY 2025 costs.

Table 29. Total of Operating Functional Categories Allocated to Cost Components

	Total	Residential (D)	GS-1	GS-2	TOU-GS-3	TOU-8	PA	Lighting
Revenues - Present Rate	$10,479,000	$1,238,485	$905,310	$3,189,352	$1,341,516	$3,479,186	$250,567	$74,583
Less Allocated Revenue Requirement	$10,688,580	$1,272,213	$818,250	$3,201,607	$1,265,127	$3,657,192	$364,825	$109,368
Difference	-$209,580	-$33,727	$87,061	-$12,255	$76,389	-$178,006	-$114,258	-$34,785
Revenue To Cost Ratio	98.0%	97.3%	110.6%	99.6%	106.0%	95.1%	68.7%	68.2%
% Increase Retail Rates to Equal Allocated Cost	**2.00%**	**2.7%**	**-9.6%**	**0.4%**	**-5.7%**	**5.1%**	**45.6%**	**46.6%**

5 ELECTRIC RATE DESIGN

EES proposes the following adjustments to the Greenfield rate structures:

- Adjusting rates annually by the recommended revenue adjustments of 4.0 percent per year.
- Rebalance customer class rate levels to recover the rate class cost of service. These adjustments may result in rate adjustments that differ from the total 4.0 percent adjustment.
- Increasing the fixed proportion of rate collection to align with COSA results.
- Removing the highest cost tier to simplify the rate structure.
- Separate the PBC from base rates to improve transparency.
- Remove seasonal difference from energy rates.
- Implement a Specific rate for commercial electric vehicle charging stations.
- Recover power supply-related demand costs throughout the year rather than just summer peak periods.
- Rebalance customer class revenue collection based on COSA results.

The rebalancing proposal is provided in **Table 30** below. The proposed adjustment to the pumping and agriculture class is recommended to be implemented over an 18-month period. This longer period will allow existing customers to adjust their usage patterns to avoid large bill impacts.

Table 30. Recommended Rebalancing Proposal

	Total	Residential D	Small Commercial GS-1	Medium Commercial GS-2	Large Commercial GS-3	Industrial TOU-8	Pumping & Agriculture PA	Lighting
Rate Adjustment	4.0%	4.0%	-2.3%	1.6%	-2.9%	5.1%	57.9%	46.6%
Number of Meters	1,938	1,323	373	160	8	10	2	62

The electric rates have up to four components: 1) a fixed monthly service charge 2) volumetric rates, (3) demand charges, (4) Power Factor Adjustment, and (5) Public Benefits Charge. Customers must pay the fixed charge regardless of energy use or demand.

1. **Fixed monthly service charge**: The rates are established based on the size of the meter at the property receiving electric service and are calculated to recover a portion of the City's fixed costs, such as meter reading and customer service.

2. **Variable rates**: The rates are calculated based on the cost of wholesale electricity and transmission. The remaining fixed costs that are not recovered via fixed charges (fixed or demand charges) such as the cost of maintaining the electric distribution system, are also recovered from variable charges. The rates are billed per kWh.
3. **Demand Charge** For demand-metered customers, demand charges recover the cost of demand-related power supply expenses and the cost of maintaining the electric distribution system. These charges are billed each month based on maximum kW.
4. **Power Factor Adjustment:** The power factor adjustment recovers the cost of inefficient use of power on the customer side of the meter. The power factor is the ratio of real power to apparent power. The power factor adjustment is billed per kVa.
5. **Public Benefits Charge:** In 1996, the State of California required all publicly owned electric utilities to establish a charge for programs that would benefit the public such as low-income assistance, energy efficiency, and renewable resources. The Public Benefits Charge (PBC) is equal to 2.85% of the utility's annual revenue requirement.

Combining the rates and billing determinants for each customer results in monthly bills and annual revenue consistent with the cost of providing electric service. Each subsection below provides the unit COSA results, current rates, and proposed rates. The proposed rates are developed consistent with COSA unit costs to improve interclass equity.

5.1 Recommended Residential Rates

The proposed residential rates, as shown in **Table 31**, increase the fixed charge based on the COSA results (unit costs in column 1). The fixed charge is recommended for both single family and multifamily accounts as the cost of meter reading and billing is similar for both types of dwellings. The energy rate is reduced to account for the increase in fixed charge and the separation of the PBC (currently $0.00378/kWh based on 2.85% of the total revenue requirement). Additionally, the energy rate structure is simplified from 4 tiers down to 3 tiers. Most usage (64.2%) is in the Tier 1 baseline followed by 11.2% in Tier 2 and 24.6% in the new Tier 3. Maintaining the tiers encourages efficient use of electricity while not penalizing customers who adopt electric vehicles. Once the planned metering infrastructure is in place, it is recommended to re-evaluate the rate design to consider time-of-use rates which best represent the marginal cost of power supply for all customers.

Table 31. Residential: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	Cost of Service Unit Costs	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$15.90	Single Family: $0.88/day Multi-Family: $0.67/day	$15.90
Energy, $/kWh	$0.1273		
Tier 1 Baseline		$0.11808	$0.10100
Tier 2 101-130% Baseline		$0.13741	$0.11100
Tier 3 131-200% Baseline		$0.22696	$0.21000
Tier 4 over 200% Baseline		$0.32337	
Public Benefits Charge $/kWh		Included in energy rate.	$0.00378

5.2 Recommended Small Commercial (GS-1) Rates

The recommended small commercial rates increase the fixed charge based on the COSA results (unit costs in column 1) and shown in **Table 32**. The energy rate is reduced to account for the increase in fixed charge and the separation of the PBC (currently $0.00378/kWh). Additionally, the energy rate structure is simplified so that the rate is the same year-round instead of the differential between summer and winter. When reviewing seasonal power costs, we found that there was no significant difference in costs between summer and winter. The COSA unit costs separate demand and energy costs. Because this class is not demand-metered, the demand costs are recovered through the variable energy rate proposed.

Table 32. GS-1: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	Cost of Service Unit Costs	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$20.97	Single Phase: $12.99 Three Phase: $3.16	Single Phase: $20.97 Three Phase: $3.16
Demand, $/kW	$27.82		
Energy, $/kWh	$0.058		
Summer		$0.17280	$0.15500
Winter		$0.16872	$0.15500
Public Benefits Charge, $/kWh		Included in energy rate.	$0.00378
Total Variable Rate		**$0.17024**	**$0.15878**

The removal of the seasonal energy rate increases bills during the winter but reduces summer bills for GS-1 customers. **Table 33** below shows examples of customer bill impacts including average seasonal use.

Table 33. GS-1: Bill Impact Example

Customer	Current Bill	Recommended FY 2025	$ Change
Average Summer Use, 1,100 kWh Summer	$203.10	$191.53	-$11.57
Average Winter Use, 700 kWh Winter	$131.14	$129.53	-$1.60
Dental Office, 400 kWh Winter	$80.51	$83.03	$2.52
Construction Retailer, 3,280 kWh Summer	$579.81	$529.43	-$50.35

5.3 Recommended Medium Commercial (GS-2) Rates

The recommended Medium Commercial rates decrease the fixed charge based on the COSA results (unit costs in column 1) and shown in **Table 34**. The energy rate is reduced to account for the separation of the PBC (currently $0.00378/kWh) and increase in demand rates. Additionally, the energy rate structure is simplified so that the rate is the same year-round instead of the differential between summer and winter. When reviewing seasonal power costs, we found that there was no significant difference in costs between summer and winter energy costs. The demand rate is adjusted so that power supply demand-related costs are collected year-round consistent with how the utility is billed for power supply. The facilities charge is increased to recover the fixed costs of the distribution. The power supply demand rate recovers the power supply related expenses incurred throughout the year.

Table 34. GS-2: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	Cost of Service Unit Costs	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$35.13	$71.50	$35.13
Demand, $/kW			
Power Supply	$8.27	Summer Peak:(1) $20.67	Peak: (2) $8.27
Distribution	$15.74	Facilities: $7.35	Facilities: $15.74
Energy, $/kWh	$0.057		
Summer		$0.09648	$0.05905
Winter		$0.08738	$0.05905
Public Benefits Charge		Included in energy rate.	$0.00378
Total Variable Rate		**$0.09087**	**$0.06283**

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months
2. Peak from 4 pm to 9 pm year-round

The removal of the seasonal energy rate increases bills during the winter but reduces summer bills for GS-2 customers. **Table 35** below shows examples of customer bill impacts from actual billing data.

Table 35. GS-2: Bill Impact Example

	kWh	kW	Current	Recommended FY 2025	Difference
Summer					
Medium/Large Retail	10,510	35.3	$1,930.56	$1,479.08	-$451.48
Hotel	58,800	197.6	$10,800.83	$8,274.94	-$2,525.89
Bank	6,700	23.7	$1,261.46	$970.36	-$291.10
Winter					
Medium/Large Retail	7,100	23.9	$795.75	$999.19	$203.43
Hotel	54,000	181.5	$6,052.19	$7,599.44	$1,547.25
Bank	4,800	18.4	$554.91	$728.92	$174.01

5.4 Recommended Large Commercial (TOU-GS-3) Rates

The recommended Large Commercial rates decrease the fixed charge based on the COSA results (unit costs in column 1), and shown in **Table 36**. The energy rate is reduced to account for the separation of the PBC (currently $0.00378/kWh) and increase in demand rates. Additionally, the energy rate structure is simplified so that the rate is the same year-round instead of the differential between summer and winter. When reviewing seasonal power costs, we found that there was no significant difference in costs between summer and winter energy costs. The demand rate is adjusted so that power supply demand-related costs are collected year-round consistent with how the utility is billed for power supply. The facilities charge is increased to recover the fixed costs of the distribution. The power supply demand rate recovers the power supply related expenses incurred throughout the year. The time of use energy rates reflect the actual power costs weighted according to the marginal cost of power supply during the respective billing periods.

Table 36. TOU-GS-3: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	Cost of Service Unit Costs	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$49.30	$277.25	$49.30
Demand, $/kW			
Power Supply	$8.29	Summer Peak:(1) $18.16 Mid-Peak:(2) $6.23	Peak:(3) $8.29
Distribution	$17.51	Facilities: $7.62	Facilities: $17.51
Energy, $/kWh	$0.057		
Summer On-Peak		$0.13561	$0.09620
Summer Mid-Peak		$0.11027	$0.07280
Summer Off-Peak		$0.07706	$0.05200
Winter Mid-Peak		$0.11282	$0.07986
Winter Off-Peak		$0.08052	$0.05200
Power Factor Adjustment, $/kVa		$0.18	$0.18
Public Benefits Charge, $/kWh		Included in energy rate.	$0.00378

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months
2. Mid-Peak is 4 pm to 9 pm on summer weekends except holidays and 4 pm to 9 pm winter weekdays, except holidays
3. Peak is from 4 pm to 9 pm year-round

The removal of the seasonal energy rate increases bills during the winter but reduces summer bills for GS-3 customers. **Table 37** below shows examples of customer bill impacts from actual billing data. Note that there are 8 winter months and 4 summer months.

Table 37. TOU-GS-3: Bill Impact Example

	kWh	kW	Current	Recommended FY 2025	Difference
Summer	58,953	181	$12,126.56	$9,165.12	-$2,961.44
Winter	41,967	96	$4,998.16	$5,392.00	$393.84

5.5 Recommended Industrial (TOU-8) Rates

The recommended Industrial rates decrease the fixed charge based on the COSA results (unit costs in column 1), as shown in **Tables 38 and 39**. The energy rate is reduced to account for the separation of the PBC (currently $0.00378/kWh) and increase in demand rates. The demand rate is adjusted so that power supply demand-related costs are collected year-round consistent with how the utility is billed for power supply. The facilities charge is increased to recover the fixed costs of the distribution. The power supply demand rate recovers the power supply related expenses incurred throughout the year. The time of use energy rates reflect the actual power costs weighted according to the marginal cost of power supply during the respective billing periods. This marginal cost pricing methodology is considered best practice in time of use rate-making for electric utilities.

Table 38. TOU-8: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	COSA Unit Costs	Current Rates	Recommended FY 2025
Fixed Charge, $/month	$76.97	$346	$76.97
Demand, $/kW			
Power Supply	$8.31	Summer Peak: (1) $16.91 Mid-Peak: (2) $5.71	Peak: (3) $8.31
Distribution	$15.06	Facilities: $8.31	Facilities: $15.06
Energy, $/kWh	$0.056		
Summer On-Peak		$0.12675	$0.09630
Summer Mid-Peak		$0.10299	$0.07319
Summer Off-Peak		$0.07184	$0.05200
Winter Mid-Peak		$0.10538	$0.07986
Winter Off-Peak		$0.07509	$0.05200
Power Factor Adjustment, $/kVa		$0.18	$0.18
Public Benefits Charge, $/kWh		Included in energy rate.	$0.00378

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months
2. Mid-Peak is 4 pm to 9 pm on summer weekends except holidays and 4 pm to 9 pm winter weekdays except holidays
3. Peak is from 4 pm to 9 pm year-round

Table 39. TOU-8: Bill Impact Example

Customer B	kWh	kW	Current	Recommended FY 2025	Difference
Summer	101,087	343	$19,889.12	$15,154.10	-$4,735.02
Winter	91,675	225	$9,986.80	$11,265.28	$1,278.48

5.6 Recommended Pumping and Agriculture (TOU-PA-2) Rates

The recommended pumping and agriculture rates decrease the fixed charge based on the COSA results (unit costs in column 1). The energy rate is reduced to account for the separation of the PBC (currently $0.00378/kWh) and increase in demand rates. The demand rate is adjusted so that power supply demand-related costs are collected year-round consistent with how the utility is billed for power supply. The facilities charge is increased to recover the fixed costs of the distribution. The power supply demand rate recovers the power supply related expenses incurred throughout the year. The time of use energy rates reflect the actual power costs weighted according to the marginal cost of power supply during the respective billing periods. **Table 40** below shows the rate adjustment planned over the 18-month phase-in period. The increase in the PBC in January of 2026 is due to the increase in revenue requirement in that year. Similarly, the fixed charge in January 2026 aligns with the fixed charge calculated by the COSA for FY 2026.

Table 40. TOU-PA-2: COSA Unit Costs, Current Rates, and Recommended FY 2025 Rates

	FY2025 COSA Unit Costs	Current Rates	January 2025 Proposed	July 2025 Proposed	January 2026 Proposed
Fixed Charge, $/month	$19.14	$63.25	$19.14	$19.14	$20.86
Demand, $/kW					
Power Supply	$12.54	Summer Peak:(1) $10.85	Peak: (2) $6.00	Peak: $12.00	Peak: $12.98
Distribution	$19.53	Facilities: $3.85	Facilities: $8.00	Facilities: $10.00	Facilities: $21.55
Energy, $/kWh	$0.057				
Summer On-Peak		$0.13064	$0.10361	$0.10361	$0.09444
Summer Mid-Peak		$0.10929	$0.07874	$0.07874	$0.07178
Summer Off-Peak		$0.05226	$0.05595	$0.05595	$0.05100
Winter Mid-Peak		$0.12255	$0.08592	$0.08592	$0.07832
Winter Off-Peak		$0.05226	$0.05595	$0.05595	$0.05100
Power Factor Adjustment, $/kVa		$0.18	$0.18	$0.18	$0.18720
Public Benefits Charge $/kWh		Included in energy rate.	$0.00378	$0.00378	$0.00405

1. Summer Peak is from 4 pm to 9 pm on weekdays during summer months
2. Peak is from 4 pm to 9 pm year-round

5.7 Recommended Lighting Rates

The current rate structure for each of the lighting schedules is updated based on the COSA results indicating a needed rate increase of approximately 47%. In order to develop new rate design for this class, a detailed lighting study would be needed as shown in **Table 41**.

Table 41. Lighting: Current Rates and Recommended FY 2025 Rates

	Current Rates	Proposed FY 2025
Outdoor Area Lighting (AL-2)		
Energy Charge, $/kWh	$0.08224	$0.11678
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$7.00	$10.26
Street Lighting (LS-3)		
Energy Charge, $/kWh	$0.08224	$0.11678
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$7.00	$10.26
Traffic Control (TC-1)		
Energy Charge, $/kWh	$0.11407	$0.16345
Public Benefits Charge $/kWh	Included in Energy Rate	$0.00378
Customer Charge, $/month	$9.49	$13.91
Three Phase, $/month	$3.16	$4.64

5.8 Recommended Commercial Electric Vehicle Charging Rates

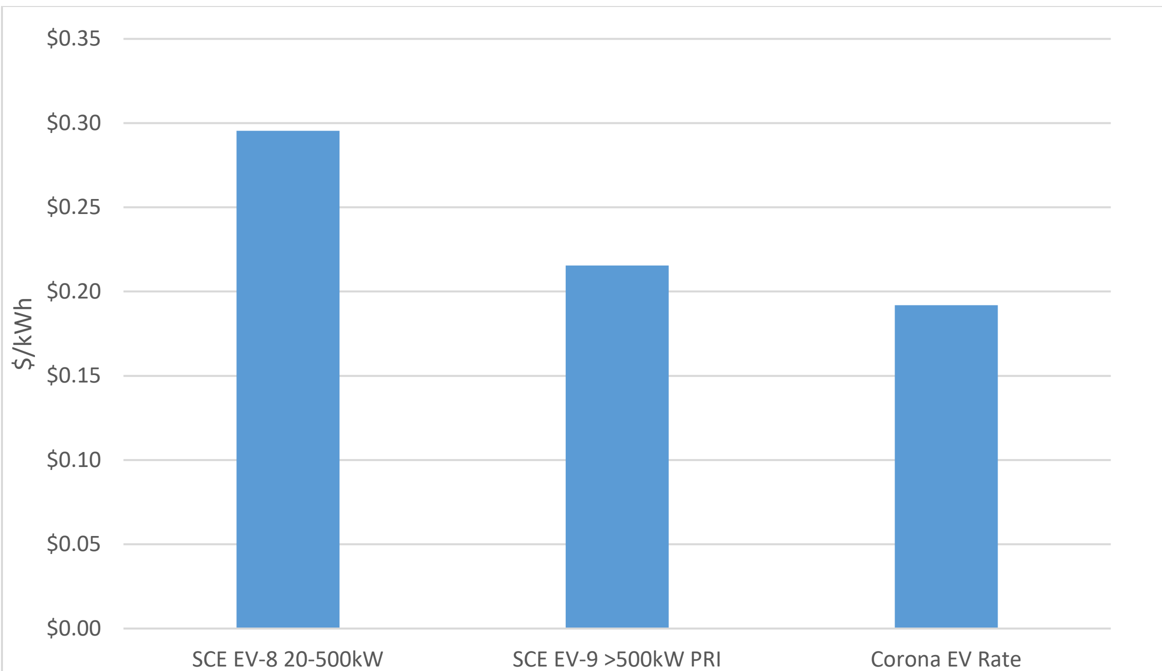
Current commercial EV charging stations are being served at the TOU-8 rate schedule, as shown in **Table 42**. The TOU-8 rate schedule more appropriately applies to services with high load factors, however, EV charging stations typically have very low load factors, often below 20%. These low load factors are associated with higher costs to serve. Therefore, it is recommended that a special EV charging rate be implemented so that the cost of service for these customers is not being shared with other rate classes. The recommended rate below takes the fixed charge and facilities charge from the TOU-8 rate schedule. Power-supply related demand costs are recovered through the recommended energy rates. The on-peak and off-peak period energy rates provide incentives to customers to use the charging stations during off-peak periods.

Table 42. EV Charging: Recommended FY 2025 Rates

	Recommended FY 2025 Rates
Fixed Charge, $/month	$76.97
Demand (Facilities), $/kW	$15.06
Energy, $/kWh	
On-Peak 4-9 pm	$0.19710
Off-Peak All Other Hours	$0.06570
Power Factor Adjustment, $/kVa	$0.18
Public Benefits Charge $/kWh	$0.00378

Figure 6 compares the recommended EV Charging rate for the City with current EV charging rates offered by SCE.

Figure 6. EV Charging Rate Comparison with SCE



Once the utility has collected usage data for this new class, it is recommended that the rate analysis be updated for the specific usage patterns at city-served charging stations.

APPENDIX

Rate	Current Rate	FY25 Proposed	FY26 Proposed	FY27 Proposed	FY28 Proposed	FY29 Proposed
Residential						
Fixed Charge, $/month	Single Family $0.88 Multi-Family $0.67	$15.90	$16.54	$17.20	$17.89	$18.61
Energy $/kWh Tier 1 Baseline	$0.11808	$0.10100	$0.10504	$0.10924	$0.11361	$0.11815
Energy $/kWh Tier 2 101-130% Baseline	$0.13741	$0.11100	$0.11544	$0.12006	$0.12486	$0.12985
Energy $/kWh Tier 3 131-200% Baseline	$0.22696	$0.21000	$0.21840	$0.22714	$0.23623	$0.24568
Energy $/kWh Tier 4 over 200% Baseline	$0.32337					
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
Small Commercial GS-1						
Fixed Charge, $/month Single Phase	$12.99	$20.97	$21.81	$22.68	$23.59	$24.53
Fixed Charge, $/month Three Phase*	$3.16	$3.16	$3.29	$3.42	$3.56	$3.70
Energy $/kWh Summer	$0.17280	$0.155000	$0.161200	$0.167650	$0.174360	$0.181330
Energy $/kWh Winter	$0.16872					
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
**Note: total cost for Three Phase customer will include Single Phase rate plus Three Phase rate.*						
Medium Commercial GS-2						
Fixed Charge, $/month	$71.50	$35.13	$36.54	$38.00	$39.52	$41.10
Demand $/kW Power Supply (Peak)**	Summer Peak $20.67	$8.27	$8.60	$8.94	$9.30	$9.67
Demand $/kW Distribution (Facilities)	$7.35	$15.74	$16.37	$17.02	$17.70	$18.41
Energy $/kWh Summer	$0.09648	$0.05905	$0.06141	$0.06387	$0.06642	$0.06908
Energy $/kWh Winter	$0.08738					
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
***Summer Peak is used for current rates: 4-9 pm during summer months. Peak will be used for proposed rates: 4-9 pm year-round.*						
Large Commercial TOU-GS-3						
Fixed Charge, $/month	$277.25	$49.30	$51.27	$53.32	$55.45	$57.67

Rate	Current Rate	FY25 Proposed	FY26 Proposed	FY27 Proposed	FY28 Proposed	FY29 Proposed
Demand $/kW Power Supply (Peak)***	Summer Peak $18.16 Summer Mid Peak $6.23	$8.29	$8.62	$8.96	$9.32	$9.69
Demand $/kW Distribution (Facilities)	$7.62	$17.51	$18.21	$18.94	$19.70	$20.49
Energy $/kWh Summer On-Peak	$0.13561	$0.09620	$0.10005	$0.10405	$0.10821	$0.11254
Energy $/kWh Summer Mid-Peak	$0.11027	$0.07280	$0.07571	$0.07874	$0.08189	$0.08517
Energy $/kWh Summer Off-Peak	$0.07706	$0.05200	$0.05408	$0.05624	$0.05849	$0.06083
Energy $/kWh Winter Mid-Peak	$0.11282	$0.07986	$0.08305	$0.08637	$0.08982	$0.09341
Energy $/kWh Winter Off-Peak	$0.08052	$0.05200	$0.05408	$0.05624	$0.05849	$0.06083
Power Factor Adjustment $/kVa	$0.18000	$0.18000	$0.18720	$0.19469	$0.20248	$0.21058
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
****Summer Peak and Summer Mid-Peak are used for current rates. Peak will be used for proposed rates and apply for the period 4 pm to 9 pm year-round.*						
Industrial TOU-8						
Fixed Charge, $/month	$346.00	$76.97	$80.05	$83.25	$86.58	$90.04
Demand $/kW Power Supply (Peak)***	Summer Peak $16.91 Summer Mid Peak $5.71	$8.31	$8.64	$8.99	$9.35	$9.72
Demand $/kW Distribution (Facilities)	$8.31	$15.06	$15.66	$16.29	$16.94	$17.62
Energy $/kWh Summer On-Peak	$0.12675	$0.09630	$0.10015	$0.10416	$0.10833	$0.11266
Energy $/kWh Summer Mid-Peak	$0.10299	$0.07319	$0.07611	$0.07915	$0.08232	$0.08561
Energy $/kWh Summer Off-Peak	$0.07184	$0.05200	$0.05408	$0.05624	$0.05849	$0.06083
Energy $/kWh Winter Mid-Peak	$0.10538	$0.07986	$0.08305	$0.08637	$0.08982	$0.09341
Energy $/kWh Winter Off-Peak	$0.07509	$0.05200	$0.05408	$0.05624	$0.05849	$0.06083
Power Factor Adjustment $/kVa	$0.18000	$0.18000	$0.18720	$0.19469	$0.20248	$0.21058
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
****Summer Peak and Summer Mid-Peak are used for current rates. Peak will be used for proposed rates and apply for the period 4 pm to 9 pm year-round.*						
Outdoor Area Lighting (AL-2)						
Fixed Charge, $/month	$7.00	$10.26	$10.67	$11.10	$11.54	$12.01
Energy $/kWh	$0.08224	$0.11678	$0.12145	$0.12631	$0.13136	$0.13661
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
Street Lighting (LS-3)						
Fixed Charge, $/month	$7.00	$10.26	$10.67	$11.10	$11.54	$12.01

Rate	Current Rate	FY25 Proposed	FY26 Proposed	FY27 Proposed	FY28 Proposed	FY29 Proposed
Energy $/kWh	$0.08224	$0.11678	$0.12145	$0.12631	$0.13136	$0.13661
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
Traffic Control (TC-1)						
Fixed Charge, $/month Single Phase	$9.49	$13.91	$14.47	$15.05	$15.65	$16.28
Fixed Charge, $/month Three Phase*	$3.16	$4.64	$4.82	$5.02	$5.22	$5.43
Energy $/kWh	$0.11407	$0.16345	$0.17598	$0.18994	$0.20852	$0.23192
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448
**Note: total cost for Three Phase customer will include Single Phase rate plus Three Phase rate.*						
EV Charging Rate: Commercial						
Fixed Charge, $/month		$76.97	$80.05	$83.25	$86.58	$90.04
Demand $/kW		$15.06	$15.66	$16.29	$16.94	$17.62
Energy $/kWh On-Peak 4-9 pm		$0.19710	$0.20498	$0.21318	$0.22171	$0.23058
Energy $/kWh Off-Peak All Other Hours		$0.06570	$0.06833	$0.07106	$0.07390	$0.07686
Power Factor Adjustment $/kVa		$0.18000	$0.18720	$0.19469	$0.20248	$0.21058
Public Benefits Charge $/kWh		$0.00378	$0.00405	$0.00419	$0.00433	$0.00448

	Current Rate	January 25 Proposed	July 25 Proposed	FY26 Proposed	FY27 Proposed	FY28 Proposed	FY29 Proposed
Pumping & Agriculture							
Fixed Charge, $/month	$63.25	$19.14	$19.14	$20.86	$21.69	$22.56	$23.46
Demand $/kW Power Supply (Peak)***	Summer Peak $10.85	$6.00	$12.00	$12.98	$13.50	$14.04	$14.60
Demand $/kW Distribution (Facilities)	$3.85	$8.00	$10.00	$21.55	$22.41	$23.31	$24.24
Energy $/kWh Summer On-Peak	$0.13064	$0.10361	$0.10361	$0.09444	$0.09822	$0.10215	$0.10624
Energy $/kWh Summer Mid-Peak	$0.10929	$0.07874	$0.07874	$0.07178	$0.07465	$0.07764	$0.08075
Energy $/kWh Summer Off-Peak	$0.05226	$0.05595	$0.05595	$0.05100	$0.05304	$0.05516	$0.05737
Energy $/kWh Winter Mid-Peak	$0.12255	$0.08592	$0.08592	$0.07832	$0.08145	$0.08471	$0.08810
Energy $/kWh Winter Off-Peak	$0.05226	$0.05595	$0.05595	$0.05100	$0.05304	$0.05516	$0.05737
Power Factor Adjustment $/kVa	$0.18000	$0.18000	$0.18000	$0.18720	$0.19469	$0.20248	$0.21058
Public Benefits Charge $/kWh	Incl. in rates	$0.00378	$0.00378	$0.00405	$0.00419	$0.00433	$0.00448

****Summer Peak and Summer Mid-Peak are used for current rates. Peak will be used for proposed rates and apply for the period 4 pm to 9 pm year-round.*