PASADENA WATER AND POWER

MEMORANDUM

March 2, 2026

To: City Council

From: David M. Reyes
Interim General Manager

Subject: **Culmination of Comprehensive Electric Rate Study — Summary of Process, Findings, and Rate Strategy**

This memorandum summarizes the culmination of Pasadena Water and Power's (PWP) comprehensive Electric Rate Study, formally initiated in May 2024 with the selection of NewGen Strategies and Solutions, LLC ("NewGen") as the technical consultant. The study encompassed nearly two years of rigorous financial modeling, cost-of-service analysis, stakeholder engagement, and deliberative oversight by the Municipal Services Committee (MSC) and City Council.

This document is intended to serve as a concise executive record, for the benefit of the City Council, MSC, and key internal stakeholders, of how PWP arrived at the rate adjustment strategy, the legal and policy framework underpinning that strategy, and the protections embedded in the rate design for our most vulnerable customers.

BACKGROUND AND DRIVING NEED:

PWP last conducted a comprehensive electric rate study in 2014. In the twelve years since, the utility — and the California electric industry broadly — have been transformed by forces that have made the cost of delivering electricity fundamentally more expensive. The Electric Rate Study conducted by NewGen confirmed what internal financial analysis had been signaling: current rates are insufficient to meet projected revenue requirements, with a confirmed shortfall of approximately $67.9 million over the two-year study period (FY 2026–FY 2027).

Industry-Wide Cost Pressures: What Is Driving Costs Up Nation-wide

Four structural forces — drawn from independent third-party research — are driving up electricity costs across California and the nation. These are not PWP-specific problems; they affect every utility, public or private.

03/02/2026
Item 9
Supplemental Material

Cost Driver	What the Research Shows
Infrastructure & distribution investment	Distribution capital expenditures are now the single largest category of utility capital outlays, per CPUC. A 2024 Lawrence Berkeley National Laboratory report confirms sustained growth in distribution system capital investment is a primary driver of rising retail electricity rates nationally.
Wildfire mitigation & grid hardening	CPUC analyses confirm vegetation management, equipment upgrades, and system hardening have materially increased revenue requirements statewide, with wildfire mitigation accounting for a large share of above-inflation rate increases for California IOUs.
Rates rising faster than inflation	A January 2025 California LAO report found residential electricity rates statewide rose nearly 47% from 2019 to 2023 — far outpacing general price growth. PWP has not raised rates since 2019 and now faces accumulated pressure from this cost environment.
Fixed costs spread over flat usage	California's flat per-capita electricity consumption means utilities must recover high fixed infrastructure costs over a revenue base that is not growing proportionally. Flat or declining usage per customer pushes rates upward structurally.

What This Means for PWP

PWP serves approximately 68,000 electric accounts. The rate study confirmed specific cost pressures including: grid modernization, substation upgrades, Advanced Metering Infrastructure (AMI) deployment, and EV infrastructure support. The revenue plan also includes $50 million in debt financing to support the capital program. Operational costs, labor, materials, and technology, have escalated in line with broader market trends.

STUDY PROCESS AND GOVERNANCE TIMELINE:

The study was conducted through a rigorous multi-stage process with continuous MSC and City Council oversight. The table below summarizes key milestones from initiation through the public hearing process.

Date	Milestone / Action	Significance
May 2024	City Council approves contract with NewGen Strategies and Solutions, LLC	Formal launch of comprehensive rate study
Oct 2024	Electric Rate Study introduced to MSC — information only presentation	Informed elected officials of scope and process
Jan 2025	MSC approves removal of obsolete Direct Access ordinance provisions	Began modernizing rate ordinance framework
Mar 2025	Community engagement plan and strategy presented to MSC	Structured public outreach roadmap established
Jun 2025	MSC amends Stranded Investment Reserve provisions; establishes Working Capital Reserve Policy	Strengthened financial governance supporting rate study
Jun 2025	Power Fund revenue requirements projections and scenarios presented	Revenue gap confirmed; scenarios evaluated
Jul 2025	City Council directs PWP to proceed with two-year rate adjustment plan	Defined study period; endorsed phased approach
Oct–Dec 2025	NewGen draft reports on Financial Forecast and Cost of Service shared with MSC and public	Transparent release of technical findings
Dec 9, 2025	MSC directs staff to return with cost-of-service report and rate alternatives before recommending public hearing	MSC exercised deliberative oversight
Jan 13, 2026	MSC requests City Attorney guidance before setting public hearing date	Ensured legal compliance with California rate-setting law
Feb 10, 2026	MSC approves recommendation to set public hearing — forwarded to full City Council	Final committee approval; proceeding to public process

This timeline reflects a governance process that was iterative and responsive. Notably, the MSC exercised its oversight function at the December 2025 and January 2026 meetings by requesting additional analysis and legal guidance before endorsing the public hearing — ensuring that staff’s recommendation was thoroughly vetted before advancing to the City Council.

TECHNICAL FOUNDATION- COST OF SERVICE ANALYSIS AND RATE DESIGN:

The revenue requirement, cost-of-service analysis, and rate design are interdependent components of a single rate-setting framework and cannot be evaluated in isolation. The revenue requirement establishes the total funding needed. The COS analysis allocates that requirement to customer classes based on how they use the system and drive costs. Rate design translates those class-level cost responsibilities into specific charges on customer bills.

Revenue Requirement Determination

NewGen developed a four-year financial forecast (FY 2026–FY 2029), with the average of the first two years serving as the Test Year Revenue Requirement. The forecast incorporated FY 2026 budgeted expenses as the base year, projected O&M costs escalated using sector-specific factors, the adopted Capital Improvement Plan (CIP), existing debt amortization schedules, projected new debt issuances, City Transfer obligations under the Charter, and operating reserve targets established by the Council-adopted Working Capital Reserve Policy.

COS Study Key Findings: What It Actually Costs to Serve Each Class

- Production costs represent the largest share of total system costs at 49%; distribution accounts for 41%.
- 77% of system costs are fixed — they do not vary with electricity consumption (power purchase contracts, capital investments, system maintenance).
- It costs approximately $125/month to keep a residential customer connected to the grid, regardless of usage.
- Current rates under-recover for residential, small commercial, large commercial, and traffic signal customers. Street lighting and medium commercial classes are currently over-recovering.
- Residential customers (approximately 59,000 of 68,000 accounts) account for ~38% of load during the four highest peak months and drive the highest share of customer-related and distribution costs.

The residential gap is the largest of any class, requiring an estimated one-time increase of approximately 39% to reach full cost recovery immediately — a pace the recommended phased plan deliberately avoids.

Rate Alternatives Evaluated

PWP and NewGen modeled more than four rate strategies. Four were presented that met policy criteria, summarized as follows:

	Alt. 1	Alt. 2	Alt. 3	Alt. 4
# of phases	2	3 ★	3	3
Timeline	FY26–FY27	FY26–FY27	FY26–FY28	FY26–FY28+
Prop. 26 compliant	Yes	Yes	Yes	Yes
Reserve drawdown	$6M	$32M	$74M	High
Staff recommendation	Not recommended	✓ **Recommended**	Not recommended	Not recommended

Alternative 2 was recommended because it achieves full cost recovery before the next rate study period, aligns with MSC guidance for phased implementation, moderates bill impacts, and maintains reserves above policy minimums. Alternatives 3 and 4 were not recommended because they fail to close the revenue gap within the study period and require significantly greater reserve drawdowns ($74M+).

Proposition 26 Compliance

The recommended rate plan satisfies Proposition 26's requirement that charges do not exceed the reasonable cost of providing service. Rates are grounded in a formal COS study and move each customer class toward, not above, its cost-based level. Temporary under-recovery during a phased implementation does not violate Proposition 26.

PUBLIC ENGAGEMENT:

Public engagement was central to the rate study from the outset. PWP established a dedicated strategy through the EngagePWP.org platform that included:

- A community webinar explaining the rate study process and PWP's mission.
- Public open houses for face-to-face dialogue with utility staff.
- A dedicated rate study website publishing all technical reports and draft ordinance materials in real time.
- An online engagement hub to gather feedback from residential and commercial customers.
- Formal public presentation of draft COS and Financial Forecast reports to the MSC in multiple open sessions.

Customer feedback highlighted interest in clean energy options and EV incentives, and shaped rate design provisions including expanded EV rate schedules (EV-1, EV-2, EV-3) and the framework for Time-of-Use rates upon AMI deployment. The public hearing on March 2, 2026 is the capstone of this engagement process.

COMMITTEE RECOMMENDED RATE STRATEGY

PWP is adopting a 7% system-wide rate increase applied three times — March 2026, October 2026, and March 2027 — for a total cumulative revenue increase of approximately 22.5% (calculated as 1.07^3). Chair Jones's leadership through the Municipal Services Committee has directed that discretionary Light and Power Fund reserves (non-rate revenues) be used to moderate near-term rate impacts during the transition period.

The Rate Adjustments

The City Council has directed a 7% system-wide revenue increase per phase, applied across all customer classes on the following dates:

Customer Class	Phase 1 — March 2026	Phase 2 — October 2026	Phase 3 — March 2027
Residential	7%	7%	7%
Commercial — Small	7%	7%	7%
Medium Commercial	7%	7%	7%
Large Commercial	7%	7%	7%
Street Lighting	7%	7%	7%
Traffic Signals	7%	7%	7%
Total System	**7%**	**7%**	**7%**

Each 7% increase applies to the then-current rate — meaning the second increase compounds on the first, and the third compounds on both prior increases. The math is: 1.07 × 1.07 × 1.07 = 1.225, or a 22.5% cumulative system-wide revenue increase from today's rates over the full two-year cycle.

The City Council, as led by the Chair Jones of the Municipal Services Committee, exercising its authority as the policy-making and rate-setting body, directed a different approach: applying a uniform 7% system-wide increase across all classes while deploying discretionary Light and Power Fund reserves, non-rate revenues accumulated in the fund, to offset the imbalance between what the residential class currently pays and its actual cost to serve. This approach moderates the near-term impact on residential customers during the transition period. The Council's authority to make this determination is clear: while the cost-of-service study establishes what it costs to serve each class, the pace at which rates are adjusted toward those cost levels is a policy question, and rate strategy may appropriately deviate from technical recommendations when the governing body concludes that other considerations, including customer affordability and the availability of non-rate resources, warrant a different balance.

What This Means in Dollars: Actual Bill Impacts by Usage Level

The following table is derived directly from PWP's rate schedule (Rate Schedule R-1, flat-rate seasonal option, low season, February 2026 rate filing). These are not estimates or approximations — they are the computed bills at each usage level using the actual proposed rate components. Phase 2 and Phase 3 Power Cost Adjustment (PCA) values are designated TBD in the rate filing as the PCA is recalculated monthly based on actual power supply costs; those cells therefore exclude the PCA component and will be updated when the PCA is set.

500 kWh Residential Customer

Current

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 8.96	per month	$ 8.96
Grid Access Charge	1	$ 4.50	per month	$ 4.50
Distribution Charge	350	$ 0.02	kWh	$ 6.61
	150	$ 0.15	kWh	$ 22.01
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.13	kWh	$ 64.89
				$ 115.01

Phase 1

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 11.00	per month	$ 11.00
Grid Access Charge	1	$ 6.50	per month	$ 6.50
Distribution Charge	350	$ 0.04	kWh	$ 12.27
	150	$ 0.14	kWh	$ 21.03
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.10	kWh	$ 50.42
				$ 109.26

Phase 2

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 12.60	per month	$ 12.60
Grid Access Charge	1	$ 7.50	per month	$ 7.50
Distribution Charge	350	$ 0.04	kWh	$ 14.60
	150	$ 0.17	kWh	$ 25.02
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.11	kWh	$ 56.82
				$ 124.59

Phase 3

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 13.10	per month	$ 13.10
Grid Access Charge	1	$ 8.50	per month	$ 8.50
Distribution Charge	350	$ 0.05	kWh	$ 16.93
	150	$ 0.19	kWh	$ 29.02
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.11	kWh	$ 55.57
				$ 131.16

1,000 kWh Residential Customer

Current

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 8.96	per month	$ 8.96
Grid Access Charge	1	$ 4.50	per month	$ 4.50
Distribution Charge	350	$ 0.02	kWh	$ 6.61
	400	$ 0.15	kWh	$ 58.69
	250	$ 0.11	kWh	$ 26.77
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.13	kWh	$ 64.89
				$ 178.46

Phase 1

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 11.00	per month	$ 11.00
Grid Access Charge	1	$ 6.50	per month	$ 6.50
Distribution Charge	350	$ 0.04	kWh	$ 12.27
	400	$ 0.14	kWh	$ 56.07
	250	$ 0.25	kWh	$ 63.08
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.10	kWh	$ 50.42
				$ 207.39

Phase 2

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 12.60	per month	$ 12.60
Grid Access Charge	1	$ 7.50	per month	$ 7.50
Distribution Charge	350	$ 0.04	kWh	$ 14.60
	400	$ 0.17	kWh	$ 66.73
	250	$ 0.30	kWh	$ 75.07
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.11	kWh	$ 56.82
				$ 241.36

Phase 3

	Qty	Price	Unit of measure	Cost
Customer Charge	1	$ 13.10	per month	$ 13.10
Grid Access Charge	1	$ 8.50	per month	$ 8.50
Distribution Charge	350	$ 0.05	kWh	$ 16.93
	400	$ 0.19	kWh	$ 77.38
	250	$ 0.35	kWh	$ 87.05
Transmission Charge	500	$ 0.02	kWh	$ 8.05
Energy Services Charge	500	$ 0.11	kWh	$ 55.57
				$ 266.58

**Phase 2 and Phase 3 bills exclude the PCA ($0.0683/kWh current; $0.05165/kWh for Phase 1). All figures represent a winter month on the flat-rate seasonal option. Actual bills vary by season, rate option, and usage.*

Low-and-Typical-Usage Customers: Why Bills May Decrease Under Phase 1

The 7% system-wide figure describes total revenue increase, not individual bill impact. Low-to-typical users (250–750 kWh/month) may see bills decrease or hold flat under Phase 1, primarily because the Power Cost Adjustment drops from $0.0683 to $0.05165/kWh. High users (1,000+ kWh/month) will see meaningful increases, as the over-750 kWh distribution tier rises sharply — from $0.107/kWh currently to $0.252/kWh in Phase 1 and $0.348/kWh in Phase 3, reflecting cost-causation principles.

On Regional Rate Comparisons

PWP's staff materials reference comparisons to neighboring utilities for context — but any such comparison deserves an important caveat. A meaningful comparison requires knowing what other utilities' rates will be when PWP's rates take effect, and we do not know that. Southern California Edison, Glendale Water and Power, Burbank Water and Power, LADWP, and every regional utility face the same cost pressures documented above, each is running its own rate proceedings, and each will have adjusted rates by the time PWP's Phase 3 takes effect in March 2027. Comparing PWP's proposed 2027 rates to neighbors' current 2025–2026 schedules compares our future rates to their past rates. The Council should treat any such comparison in the public record with appropriate caution. The relevant question is not whether PWP's rates are lower than a neighbor's current rates — it is whether they are cost-justified and equitably structured, which the cost-of-service analysis confirms they are. PWP remains a not-for-profit municipal utility serving customers at cost, without investor returns embedded in the rate structure; that structural advantage does not disappear with the proposed increases.

Protection for Lower-Income and Lower-Usage Residential Customers

The rate design incorporates meaningful protections for PWP's most vulnerable customers, addressing equity concerns that were prominent in the public engagement process. First, the inclining block structure of the residential distribution charge ensures that lower-usage customers, who may be disproportionately lower or fixed income, face a lower effective per-kWh cost than high-usage customers. Because high-usage households tend to impose greater capacity and infrastructure costs on the grid (through higher peak demand, air conditioning loads, and greater draw on distribution assets), this design aligns cost recovery with cost causation. Academic research, including work published by Harvard Kennedy School's Mossavar-Rahmani Center, confirms that rate structures treating usage level as a reasonable proxy for income-related grid impact can improve distributional equity within a customer class.

Second, the Electric Utility Assistance Program (EUAP) is preserved and formalized in the restructured ordinance. The EUAP provides three targeted benefits:

- Basic Benefit: A monthly credit equal to the full fixed charge components (customer charge and grid access charge) for income-qualified households meeting City or CPUC eligibility thresholds — effectively eliminating the fixed cost burden for qualifying customers.
- Pasadena Cares: An additional credit equal to the public benefit charge for EUAP-eligible customers who are 62 or older, or who meet Social Security disability criteria.

- Medical Baseline: A Basic Benefit credit regardless of income for customers dependent on doctor-prescribed life-support equipment.

Third, the rate ordinance consolidates the EUAP provisions into a standalone section (proposed Section 13.04.046) applicable to all residential schedules, improving accessibility and clarity for customers seeking assistance. The combination of these features, an inclining block structure that shields low users from disproportionate cost burdens, a robust assistance program that eliminates fixed charges for qualifying customers, and a phased increase that avoids sudden bill shock, represents a rate strategy that is both financially responsible and equitable.

ORDINANCE MODERNIZATION (Chapter 13.04):

In addition to the rate adjustments, PWP is recommending an amendment of the Light and Power Rate Ordinance, Chapter 13.04, to modernize its structure, eliminate obsolete provisions, and align it with current industry standards. Key changes include:

- Moving all rate figures from the ordinance body into the Electric Utility Rate Resolution, a governance mechanism that allows Council to update specific pricing through resolution rather than requiring a full ordinance amendment, while preserving legislative oversight.
- Introducing a comprehensive definitions section incorporating modern utility terminology (e.g., Time-of-Use, Interval Read Capable Meter, Portfolio Content Category, Renewable Energy Credit, Net Surplus/Deficit Electricity).
- Establishing clear framework for Time-of-Use rate periods and seasonal pricing tied to AMI deployment milestones.
- Adding new EV charging rate schedules (EV-1, EV-2, EV-3) and City-owned retail charging station provisions to support Pasadena's electrification goals.
- Introducing a new Schedule L-3 (Extra-Large Commercial and Institutional Service) for customers with aggregate demand at or above 10 MW — addressing a gap in the existing rate structure.
- Consolidating and clarifying EUAP provisions into Section 13.04.046, applicable across all residential schedules.
- Retaining Net Energy Metering and local solar provisions for further stakeholder discussion, consistent with the MSC's direction.

The City Attorney's Office has been directed to prepare the ordinance amendment.

FISCAL IMPACT:

The three-phase rate strategy is projected to generate approximately $84 million in incremental annual revenue at full implementation. These revenues will fund increased operating costs (power supply, labor, materials), capital improvements (grid modernization, AMI deployment, substation upgrades, EV infrastructure), existing and projected debt obligations, and operating reserves at policy-target levels. In addition, the City Council has directed the use of discretionary Light and Power Fund reserves to offset a portion of the cost-to-serve imbalance during the transition period. Staff will provide updated reserve and financial performance analysis to the MSC and Council prior to Phase 3.

LEGAL COMPLIANCE:

The rate-setting process has been conducted in full compliance with California law. Key legal dimensions include: at the MSC's direction, the City Attorney's Office reviewed the proposed process prior to the public hearing date being set, confirming the legal framework for proceeding. Charter Compliance and the rate strategy and Electric Utility Rate Resolution framework are consistent with City Charter governing the Light and Power Fund transfer and rate-setting authority.

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CONCLUSION:

The resulting rate strategy is:

- Financially necessary — addressing a confirmed $67.9 million revenue shortfall that would otherwise impair the utility's ability to deliver safe and reliable service;
- Cost-based and equitable — grounded in a thorough cost-of-service analysis, with structural protections for lower-income and lower-usage residential customers;
- Graduated and affordable — phased over two years to minimize bill shock, supplemented by discretionary Light and Power Fund reserves;
- Legally compliant — conducted in accordance with California law and City Charter requirements; and
- Forward-looking — modernizing the rate ordinance to support Time-of-Use pricing, AMI deployment, EV adoption, and the City's 100% carbon-free electricity goal by 2030.

PWP is grateful for the engagement of residents and businesses throughout this process and the Municipal Services Committee, led by Chair Jones, who thoughtfully engaged in the process. The rate strategy reflected in the recommended ordinance and Electric Utility Rate Resolution is the product of collaboration between the utility, elected representatives, and the community. All prior staff reports are compiled in Appendix 1.

PASADENA WATER AND POWER

MEMORANDUM

March 2, 2026

To: City Council

From: David M. Reyes
Interim General Manager

Subject: **Appendix 1: Public Record Compilation for the Electric Rate Study**

This appendix is a compilation of the public record documents form the evidentiary basis for the recommendations summarized in this memorandum. All documents are available on the PWP website or City of Pasadena Website.

Date	Document / Action	Forum
May 6, 2024	Council approval of NewGen contract	City Council
Oct 22, 2024	Electric Rate Study Introduction	MSC
Jan 13, 2025	Removal of obsolete Direct Access ordinance provisions	MSC
Mar 11, 2025	Electric Rate Study Update — Customer Engagement Plan	MSC
Jun 2, 2025	Amendment of Stranded Investment Reserve / Working Capital Reserve Policy	MSC
Jun 24, 2025	Power Fund Revenue Requirements Projections and Scenarios	MSC
Jul 14, 2025	Direction to proceed with two-year rate adjustment plan	City Council
Oct 2025	Draft Financial Forecast and Revenue Requirements (Section 2)	MSC / Public Record
Dec 1, 2025	Draft Financial Forecast and Revenue Requirements — Final	MSC / Public Record

Date	Document / Action	Forum
Dec 16, 2025	Draft Cost of Service (Section 3)	MSC / Public Record
Dec 9, 2025	Electric Rate and Ordinance Adjustments presentation	MSC
Jan 13, 2026	City Attorney guidance requested re: public hearing	MSC
Feb 10, 2026	Recommendation to set public hearing — MSC approval	MSC
Feb 23, 2026	Agenda Report — Set Public Hearing Date; Ordinance Restatement	City Council

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Pasadena Water & Power

Authorization to Enter into a Contract with NewGen Strategies and Solutions, LLC for Electric Cost-of-Service Analysis and Rate Design Services ("Electric Rate Study") for an Amount Not-to-Exceed $258,042 for the Water and Power Department

Municipal Services Committee (MSC)

April 23, 2024

Item # 2

Purpose of the Electric Rate Study

Develop rates that ensure revenue adequacy and fair allocation of costs, while balancing customer satisfaction

Challenges

- Power Supply Cost Increase
- Integration of Customer Generation
- Prop 26 Constraints
- Financial Performance Targets

Trade-Offs

- Long-Term Infrastructure
- Power Supply Commitments
- Customer Satisfaction
- Data to Support Decision Making

Data-Informed Strategy

- Customer/Load Data Analysis
- Five-Year Revenue Requirement Projection
- Dynamic 10-Year Financial Forecast Model
- Rate Design
- Public Participation

Why Now?

- Best practice is to conduct an electric rate study every 5-10 years or with significant industry change; comprehensive electric rate study completed in 2014
- Many portions of Pasadena's electric rate ordinance untouched since "Deregulation" in the early 2000's
- Financial modeling has made significant improvements
  - Result will be a *dynamic financial planning* model with rates for 3-5 years that can be integrated with other studies and plans
- Updated policy goals (City Council Resolution 9977)

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Image from Vox.com.

Overview of Study Plan

Pasadena Water & Power

Where relevant and useful, the study plan will leverage findings and information from previous planning efforts (Integrated Resource Plan, Power Delivery Master Plan, Operating Budget, Capital Improvement Budget)

Preparatory Analysis

- Review of Prior Studies/ Reports
- Cost Allocation by Function
- Financial Model Core Assumptions and Budget Input
- Community Value Discussion

Rate Development

- Customer Class
- Cost Recovery by Rate Component (Fixed or Variable)
- Scenario Analysis
- Benchmarking/ Market Trend Analysis

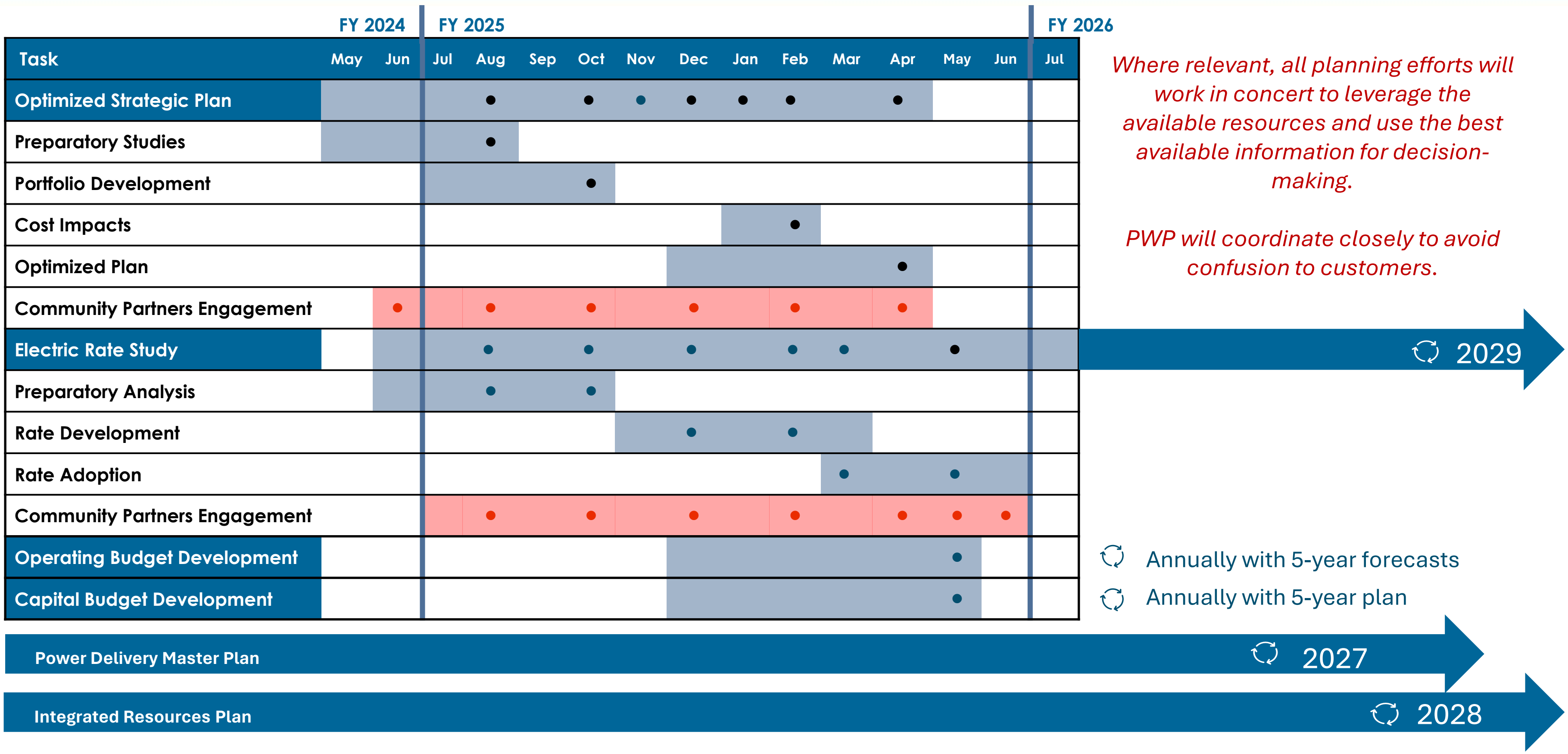
Rate Adoption

- Pricing Development
- Scenario Selection
- Customer Rate Impact Analysis
- Final Report

Community Partners Engagement

Plan Integrations and Dependencies

Pasadena Water & Power



PASADENA

About NewGen

NewGen is a nationally-recognized consulting firm

- Founded in 2012
- Over 60 Professionals and Support Staff
- 13 Offices Across the U.S.
- Utility Expertise
  - Electric
  - Water
  - Natural Gas
- Projects Include:
  - Load Forecasting
  - Appraisals
  - Feasibility Studies
  - Regulatory Matters
  - Utility Financial Planning
- Extensive Experience with California Publicly-Owned Utilities

NewGen Strategies & Solutions

Innovative Rate Design

Extensive COS & Rate Experience

Superior Modeling

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Competitive Selection Results

Firm Name	Location	Evaluated Score (Out of 100)
NewGen Strategies and Solutions, LLC	Lakewood, CO	85.2
1898 & Co., part of Burns & McDonnell	Kansas City, MO	76.4
MCR Corporate Services, Inc.	Deerfield, IL	59.6
AIP Capital Markets	Rolling Hills Estates, CA	50.5

- **NewGen obtained the highest average score**
  - Depth and range of cost-of-service analysis and rate design services
  - Solid expertise:
    - Proposition 26 and other California-specific policy issues
    - Hands-on work with recent rate design efforts in local markets

Fiscal Impact

Pasadena Water & Power

Two-year contract with two optional one-year extensions

Fiscal Impact Summary	
Contract	$ 215,035
Contingency for necessary change orders	$ 43,007
Total Fiscal Impact:	**$ 258,042**

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Staff Recommendations

Pasadena Water & Power

1. Find that the proposed action is not a project subject to the California Environmental Quality Act ("CEQA") pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3) and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project; and

2. Authorize the City Manager to enter a contract, as a result of a competitive selection process, as specified by Section 4.08.047 of the Pasadena Municipal Code, with NewGen Strategies and Solutions, LLC ("NewGen") for an amount not-to-exceed $258,042, which includes a base contract amount of $215,035 and a contingency of $43,007, to provide for any necessary change orders, for two years, with two optional one-year extensions.

Attachment A: Electric Cost-of-Service Analysis and Rate Design Evaluation Summary

Criteria	Proposed Solution	Experience (Including Company Staffing Assigned to Project) and References	Price Proposal	Local Pasadena Business	Small or Micro-Business	Total Score
Max Score	**40**	**35**	**15**	**5**	**5**	**100**
Vendor						
NewGen Strategies and Solutions, LLC	36.8	33.4	15	0	0	85.2
1898 & Co., part of Burns & McDonnell	35.4	30.2	10.8	0	0	76.4
MCR Corporate Services, Inc.	29.2	24.4	6	0	0	59.6
AIP Capital Markets	24.6	23	2.9	0	0	50.5

Agenda Report

September 30, 2024

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (9/24/2024)

FROM: Water and Power Department

SUBJECT: AN ORDINANCE AMENDING PASADENA MUNICIPAL CODE CHAPTER 13.04 TO INCREASE ELECTRIC UTILITY ASSISTANCE PROGRAM MONTHLY BENEFITS AND RELATED CHANGES

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the action proposed herein is statutorily exempt from the California Environmental Quality Act (CEQA) pursuant to State CEQA Guidelines Section 15273 (Rates, Tolls, Fares, and Charges); and

2) Direct the City Attorney to prepare an ordinance amending the Light and Power Rate Ordinance, Chapter 13.04, Sections 13.04.040 and 13.04.045 of the Pasadena Municipal Code implementing the changes to the Electric Utility Assistance Program as described herein.

EXECUTIVE SUMMARY:

PWP is recommending an enhancement to the Electric Utility Assistance Program ("EUAP") to increase the monthly basic benefit (bill credit) for income-qualified customers. The change would raise the $10 monthly basic benefit to be equal to the fixed charge components of the residential electric rates – the Customer Charge (currently $8.96) and Grid Access Charge (currently $4.50). If approved, the benefit would increase from $10 to $13.46 effective January 1, 2025, or as soon as practicable thereafter. Since the benefit would no longer be tied to a specific, static dollar amount, the bill credit would automatically increase in tandem with any rate increases to the Customer Charge and Grid Access Charge. This action would enhance rate equity by helping the City's most vulnerable households manage the fixed charges of their electric bill, which - unlike the variable charges - do not decrease with conservation. For the variable components, like the energy charge, customers can participate in PWP's numerous energy efficiency programs, which provide additional incentives for income-

qualified customers. Providing relief for the fixed components of the bill helps provide a holistic, nimble assistance program with minimal administrative turnaround time for implementation. The EUAP is funded through the Public Benefits Fund as one of four restricted uses for this revenue source.

BACKGROUND:

Customer Assistance Program

The EUAP provides monthly bill credits and certain waivers to PWP residential electric customers who meet established criteria relating to income, age, or certain health conditions or impairments. City Council first authorized the EUAP in March 2006, establishing a “basic benefit” (monthly bill credit) of $5 per month for income-qualified customers, or those with qualifying medical devices, plus a bill credit equal to the Public Benefit Charge (“PBC”) for income-qualified customers meeting age or disability requirements. The PBC was established pursuant to Section 385 of the California Public Utilities Code. EUAP funds are collected through the PBC, which is restricted to be used in a manner that includes “services provided for low-income electricity customers … including rate discounts” (PMC 13.04.23). The City Council has subsequently increased the monthly basic benefit to $7.50 in August 2009, and to $10 in July 2019.

Staff recommends increasing the $10 monthly basic benefit to be equal to the fixed charge components of the residential electric rates. These components are the Customer Charge (currently $8.96) and Grid Access Charge (currently $4.50). If the City Council approves the staff recommendation, the monthly basic benefit would increase from $10 to $13.46 effective January 1, 2025, or as soon as practicable thereafter.

Since the monthly basic benefit would no longer be tied to a specific, static dollar amount, the bill credit would automatically increase in tandem with any rate increases to the Customer Charge and Grid Access Charge. This action would provide enhanced rate equity by helping the City’s most vulnerable households manage the fixed components of their electric bill, which do not decrease even if a customer reduces their energy use or participates in energy efficiency programs.

Please Note: For the variable portions of the bill such as the energy charge, customers can help lower the cost by conserving energy and/or participating in PWP’s energy efficiency incentive programs, which include rebates and direct installations of efficiency measures. These programs also provide added incentives for income-qualified customers.

Providing relief for the fixed components of the bill helps provide a holistic assistance program that automatically grows in equal measure if the fixed charges increase. Additionally, automating this growth allows the program to be nimble and efficient with minimal administrative turnaround time for implementation.

Income Eligibility Criteria

The current Council-approved EUAP income eligibility criteria is established by the higher of the lowest income criteria used by the City's Housing and Community Development Division for the Rental Assistance Program stated in Section 17.80.020 of the City Zoning Code or the California Public Utilities Commission's ("CPUC") Low-Income Oversight Board. Table 1 lists the 2024 income thresholds.

Table 1: Comparison of Qualifying Annual Household Income Levels ($/year)

Household Size	1 person	2 people	3 people	4 people	5 people	6 people	7 people	8 people
Rental Assistance Program[1]	**$48,550**	**$55,450**	**$62,400**	**$69,350**	**$74,900**	$80,450	$86,000	$91,550
CPUC[2]	$40,880	$40,880	$51,640	$62,400	$73,160	**$83,920**	**$94,680**	**$105,440**
Proposed[3]	**$48,550**	**$55,450**	**$62,400**	**$69,350**	**$74,900**	**$83,920**	**$94,680**	**$105,440**

1 *Based on lowest income criteria used by the City's Housing and Community Development Division for the Rental Assistance Program stated in Section 17.80.020 of the City Zoning Code. Updated to 2024 values.*
2 *Income eligibility criteria updated annually by the California Public Utilities Commission ("CPUC") Low-Income Oversight Board. Updated to 2024 Values.*
3 *Greater of the two qualifying income levels.*

Nearly 5,000 customers are participating in the EUAP, all receiving the $10 per month basic benefit. Among them, more than 2,500 customers receive additional discounts under the EUAP Cares, EUAP Cares Plus, and Medical Assistance programs.

- EUAP Cares program waives the PBC for low-income seniors (ages 62 and up) and customers with permanent disabilities.
- EUAP Cares Plus program, designed for very low-income seniors, provides the same benefits as the Cares program, and additionally waives the Utility Users Tax.
- The Medical Assistance program offers the basic benefit to customers with qualifying electric-powered medical equipment, regardless of income.

Assuming no significant change in enrollment, the increased benefit will result in an additional annual cost of approximately $206,064 to the PBC Fund. The PBC fund has sufficient funds available to increase in customer benefit without compromising funding from existing programs.

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The proposed electric rate changes are statutorily exempt from CEQA pursuant to State CEQA Guidelines Section 15273 (Rates, Tolls, Fares, and Charges), which provides a statutory exemption for the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or other charges by public agencies, which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The changes would result in approximately $206,064 in FY25 in additional expenses to the Public Benefits Fund (410). If approved, the proposed EUAP change to increase benefit from $10.00 per month to match the Customer Charge and Grid Access Charge component of the bill, currently a total of $13.46 per month. There is no impact to the General Fund.

Respectfully submitted,

____

DAVID REYES
Interim General Manager
Water and Power Department

Prepared by:

Gordon Algermissen

Gordon Algermissen
Customer Program Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

Agenda Report

October 28, 2024

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (10/22/2024)

FROM: Water and Power Department

SUBJECT: **DIRECT THE CITY ATTORNEY TO PREPARE AN ORDINANCE AMENDING PASADENA MUNICIPAL CODE CHAPTER 13.04 TO REMOVE DIRECT ACCESS PROVISIONS AND RELATED TARIFFS, AND AMENDING LONG-TERM CONTRACT PROVISIONS**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed actions are exempt from the California Environmental Quality Act ("CEQA") pursuant to State CEQA Guidelines Section 15061(b)(3) (Common Sense Exemption); and

2) Direct the City Attorney to prepare an ordinance and return within 60 days, amending the Pasadena Municipal Code ("PMC") Chapter 13.04, the light and power rate ordinance to:

    a. Remove Sections 13.04.095 – Direct access service, 13.04.096 – Direct access transition charge, 13.04.097 – Direct access service charge; and

    b. Amend PMC Section 13.04.075 – Long-term contracts, to remove equity adjustments and associated provisions.

BACKGROUND:

In August 2024, Pasadena Water and Power ("PWP") initiated an electric rate study to review current rates and explore potential future designs. The goal is to ultimately provide recommendations to the City Council that will ensure revenue adequacy, fair and equitable allocation of costs, while balancing customer affordability and impacts to customers. The first step involved reviewing the current language in the rates ordinance.

As a result, multiple provisions within the PMC, Title 13, Utilities and Sewers, were identified to be outdated, obsolete or do not align with current industry best practice. These provisions include Sections 13.04.095, 13.04.096, and 13.04.097 – Direct Access Service, and Section 13.04.075 – Long-term contracts. Staff recommends removing or amending provisions to prevent confusion during future electric rate study phases and to simplify future ordinance changes during the rate study.

Direct Access Service (Sections 13.04.095, 13.04.096, and 13.04.097)

Direct access service allows retail customers to purchase their electricity directly from a third-party provider called an Electric Service Provider ("ESP"), instead of from a regulated electric utility, such as PWP. Under this service option, PWP would continue to deliver the electricity through its transmission and distribution network, regardless of which electric supplier the customer chooses.

In response to California's electricity sector deregulation starting in 1996, Section 13.04.095 – Direct Access Service and the associated Sections 13.04.096 – Direct Access transition charge and 13.04.097 – Direct Access Service charge were adopted and added to the PMC in early 2000. These provisions within the PMC outline the energy and service charges associated with the direct access service. Customers would receive a bill for energy from their chosen electric service provider and a bill for distribution services from PWP, including charges outlined in the rate tariff.

Since the code adoption in 2000, there have been several statutes that have affected Investor Owned Utilities ("IOUs"). While these changes in legislation impacted the IOUs, who are beholden to the rules of the California Public Utilities Commission ("CPUC"), PWP did not adjust or amend the direct access service during this time. Many Publicly Owned Utilities ("POUs") similar to PWP have since closed or removed direct access from their rate tariffs. Eliminating direct access service enables POUs to stabilize their customer base and ensure consistent recovery of power costs, reducing the risk of rate shocks caused by sales volatility and enhancing the utility's creditworthiness.

Although the option for direct access service is available under current regulations, PWP has not received any applications for enrollment. Additionally, offering direct access limits PWP's ability to control the type of energy resources used by electric service providers, which may not align with the City Council's policy goal of achieving 100% carbon-free energy for Pasadena. As a result, PWP staff recommends eliminating the direct access provision.

Long-term Contracts (Section 13.04.075)

When Section 13.04.075 – Long-term contracts was first codified it offered a contract between PWP and eligible customers served at 100 kW or higher for a minimum term of four years to receive a voltage discount, or equity adjustment, for maintaining either a minimum load or load factor for a minimum term of five years. PWP recommends retaining the beneficial aspects of the long-term contracts PMC, particularly the contract options for large, stable customers that provide system-wide benefits. However, PWP proposes removing sections of the ordinance with outdated or unclear tariff language that may lead to unintended subsidies.

PWP recommends keeping the general intent of the section, specifically related to remaining open to working directly with customers with high load factors. A high load factor profile is desirable to PWP because it makes a portion of energy demand predictable; minimizing some volatility in power supply planning. Load factor is a measure of the utilization rate or efficiency of electrical energy usage. Load factor is measured by the ratio of the highest actual kilowatt ("kW") demand during the billing period to the maximum theoretical kilowatt hour ("kWh") used if demand remained constant for the entire billing period. High load factor occurs when energy demand remains constant or nearly constant throughout the billing period.

However, PWP recommends eliminating prescriptive provisions related to equity adjustments and discounts that are no longer relevant. In 1999, following California's energy restructuring initiative, PWP completed an electric cost-of-service study and rate design and developed a restructured and unbundled electric rate structure. The rate restructure eliminated subsidies between customer groups allowing cost allocations to be based on cost to serve each customer group. As a result of the Long-term contract provision being superseded by the rate restructuring and current rates, equity adjustments may lead to inequities across existing customer classes and potential for direct customer subsidization, which is inconsistent with California Proposition 26. Currently, there are no PWP customers enrolled in this program.

It is recommended that the Long-term contract section of the PMC, be amended to provide flexible solutions to optimize electricity generation and demand volatility due to the rise of intermittent generation and the expected shutdown or repurposing of conventional generation assets. Potential Long-term contract arrangements may allow PWP to achieve sustainability goals and overcome future demand volatility with increased intermittent, distributed resource penetration by changing customer consumption behavior, such as shifting consumption away from peak periods or dispatching energy from battery storage when it is most valuable.

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The proposed amendments of the PMC have been determined to be exempt from the CEQA pursuant to State CEQA Guidelines Section 15061(b)(3), the common sense exemption (formerly the "general rule") that CEQA applies only to projects which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA. The proposed amendments of the PMC are limited to the provisions for agreements between PWP and customers for types of service and associated fees. Such PMC amendments would not result in any direct or indirect changes to the physical environment. Thus, these actions do not have the potential for causing a significant effect on the environment and are therefore exempt from CEQA per Section 15061(b)(3) (common sense exemption).

FISCAL IMPACT:

There is no fiscal impact for the action requested. There is no impact to the General Fund.

Respectfully submitted,

DAVID M. REYES
Interim General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistance General Manager
Water and Power Department

Approved by:

for MIGUEL MÁRQUEZ
City Manager

NICHOLAS G. RODRIGUEZ
Assistant City Manager

CITY OF PASADENA ★ INCORPORATED JUNE 1886 ★

Agenda Report

February 24, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (February 11, 2025)

FROM: Water and Power Department

SUBJECT: **AN ORDINANCE AMENDING PASADENA MUNICIPAL CODE CHAPTER 13.04 TO REMOVE STRANDED INVESTMENT CHARGE AND RESERVES AND AMEND TO INCLUDE A WORKING CAPITAL RESERVE TARGET**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the action proposed herein is not a "project" subject to the California Environmental Quality Act (CEQA) pursuant to California Public Resources Code Section 21065 and within the meaning of State CEQA Guidelines Section 15378(b); and

2) Direct the City Attorney to prepare an ordinance and return within 60 days, amending the Pasadena Municipal Code ("PMC") Chapter 13.04, the light and power rate ordinance to:

   a. Amend Section 13.04.173 – Power cost adjustment.
   b. Amend Section 13.04.175 – Reserve for stranded investment and change title to "Reserve for working capital"; and,
   c. Remove 13.04.176 – Stranded investment surcharge.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") recommends streamlining PMC code sections that impact the Light and Power Fund's reserves to adopt a working capital reserve target. The proposed target includes amounts to address liquidity needs and several types of risks within the utility. Established target amounts will ensure exceptional creditworthiness as well as resilience to unforeseen circumstances. The proposed PMC change also will include protocol for the use, replenishment, and monitoring of the target amounts. Furthermore, the recommendation is to dissolve the existing narrowly focused

Stranded Investment Reserve to address the current working capital needs to enable continuity of services and stability of customer rates.

BACKGROUND:

The Stranded Investment Reserve was established in 1996 as part of a strategy to address above-market energy costs anticipated from the Intermountain Power Project (IPP) and Magnolia projects, which, at the time, were projected to lose value due to industry restructuring. Funded through ratepayer contributions, this reserve was limited to covering stranded investment risks only. Since the establishment of the reserve, however, these assets have retained value, with much lower exposure to stranded costs than initially anticipated. As required by PMC 13.04.175, Council has approved the use of the Stranded Investment Reserve several times in the past, with uses such as the defeasance of $80 million in bonds and the most recent usage of $7 million per year from 2018- 2022 to mitigate future rate increases due to the increasing power supply costs.

In today's financial environment, Government Finance Officers' Association and other industry best practices recommend utility reserves focus on operational liquidity, cash flow stability, and risk mitigation for operational and capital needs. Adopting a working capital reserve will allow PWP to realign the stranded investment funds into reserve categories that better address modern utility risks, including unexpected cost fluctuations, seasonal revenue variances, and operational stability; all while considering a long-term perspective on funds management.

In light of the ongoing electric rate study, PWP is seeking policy direction on the amount of reserves deemed appropriate by Council in order to set rates that optimize for both affordability and rate stability.

Reserve Policy Target Components

The proposed Reserve Policy Target includes four main reserve categories, each tailored to mitigate specific risks and provide targeted financial stability:

1) **Liquidity Reserve**
   a) **Purpose**: Provides liquidity to meet routine operational expenses and cash flow during times of revenue variability.
   b) **Target Level**: Equivalent to the sum of 90 days of operating expenses, one-year principal payment for outstanding bonds, approved General Fund transfer amount, and one year capital improvement budget. This reserve helps PWP manage short-term financial disruptions, such as seasonal variations in revenue or unexpected operational expenses.
   c) **Risk Mitigation**: Protects against revenue volatility by ensuring sufficient funds are available to cover costs without needing immediate rate adjustments. This reserve level will also support debt service obligations, enhancing PWP's credit profile.
2) **Market Exposure Reserves**

   a) **Energy Services Charge Reserve**
      i) **Purpose**: Provides a buffer against fluctuations in energy costs and unexpected energy purchase needs. Energy markets can be volatile, impacting the cost of purchased power.
      ii) **Target Level**: Set at 90 days of projected energy costs.
      iii) **Risk Mitigation**: Enables PWP to manage unexpected energy price spikes or supply disruptions without impacting rate stability. The reserve also helps maintain rate stability by offsetting temporary increases in energy procurement costs.
   b) **Transmission Reserve**
      i) **Purpose**: Covers potential increases in transmission costs or investments needed for maintaining or upgrading transmission infrastructure. This reserve addresses cash needs arising from unforeseen transmission expenses that may arise from infrastructure wear, system expansion, or regulatory changes.
      ii) **Target Level**: Based on projected annual transmission costs amounting 90 days of PWP's annual transmission-related obligations.
      iii) **Risk Mitigation**: Supports the continuity of service by covering unanticipated transmission expenses without needing to increase customer rates or reduce service quality. A dedicated transmission reserve also ensures that PWP can meet short-term needs related to system upgrades or unexpected outages.
3) **Contingency Reserve**
   a) **Purpose**: Acts as a safeguard for extreme or unforeseen events that exceed standard operating and capital contingencies, including emergencies or regulatory changes requiring immediate capital outlays.
   b) **Target Level**: 90 days of annual operating expenses and capital workplan.
   c) **Risk Mitigation**: Enhances PWP's financial resilience to sudden disruptions that could impact service delivery, such as natural disasters or unexpected regulatory mandates requiring rapid response. The contingency reserve is an essential part of a strong reserve structure, ensuring operational continuity in critical times.

Proposed Policy Implementation

The conversion of the Stranded Investment Reserve into the Working Capital Reserve Target with established reserves will involve:

1) Reclassifying Funds: Allocating the existing balance from the Stranded Investment Reserve into the Working Capital Reserve based on PWP's needs and recommended reserve levels.
2) Establishing Utilization and Replenishment Policies: Defining criteria for withdrawals and required approvals to ensure that funds are used appropriately and replenished as needed to maintain established targets.
3) Annual Review and Adjustment: Regular assessment of reserve levels by the General Manager, reviewing as necessary to meet changing operational and market conditions.

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

CEQA excludes, from environmental review, actions that are not "projects" as defined by California Public Resources Code (PRC) CEQA Guidelines Section 21065 and within the meaning of CEQA Guidelines Section 15378(b). PRC Sections 21065 and CEQA Guidelines Section 15378(b) define a project as an action which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment. CEQA Guidelines Section 15378 excludes from the definition of "project" administrative activities of governments that will not result in direct or indirect physical changes in the environment. The actions proposed herein, amending the municipal code to establish a consolidated working capital reserve for the Light and Power Fund, is an administrative activity, and therefore is not a "project" as defined by CEQA. Since the action is not a project subject to CEQA, no environmental document is required.

FISCAL IMPACT:

This amendment requires no additional ratepayer contributions, as the funds are currently available within the Stranded Investment Reserve and Light and Power Fund Balance. By realigning these funds, PWP will improve financial stability, protect ratepayers from abrupt rate adjustments, and provide enhanced fiscal resilience for the utility. There is no impact to the General Fund.

Respectfully submitted,

DAVID M. REYES
Interim General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

PASADENA

Pasadena Water and Power

Electric Rate Study – Revenue Requirements Decision Points

Municipal Services Committee
June 24, 2025

Item #1

Recommendation

Provide guidance to staff on which Optimized Strategic Plan ("OSP") portfolio costs to proceed forward with for the revenue requirements in the Electric Rate Study ("ERS").

ROAD TO NEW ELECTRIC RATES

we are here

1

CLEAN UP

Modified legacy items such as direct access, long-term contracts and billing provisions that were created during a past era of deregulation that are incongruent with today's business model and regulatory framework

2

POLICY

Establish clear policies to serve as a foundation to set the bounds for future financial planning; restructured reserve-related code sections into consolidated working capital policy targets and minimums

3

TOOLS

Build out the financial models and tools with the established policy and parameters to forecast future revenue needs based on cost-of-service analysis and economic projections

4

DESIGN

Establish a future desired state and design a balanced rate structure to meet PWP's mission, based on realistic forecasts and established plans (i.e. budgets, PDMP, IRP, OSP)

5

SCENARIOS

Review multiple options based on Council and community inputs, feasible program implementations and future possible stressors, and establish a preferred scenario to develop rates and customer impacts

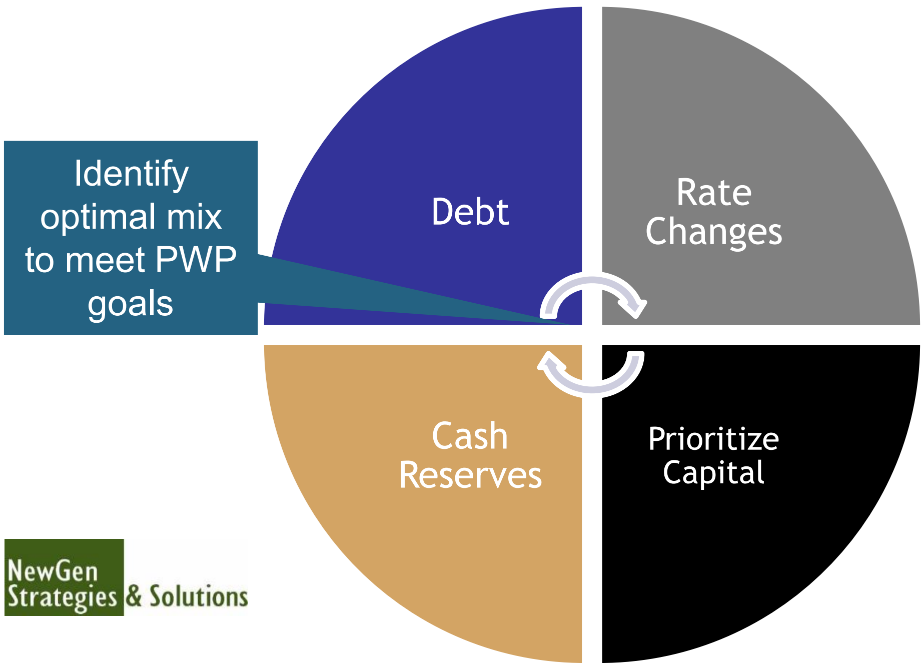
6

OUTCOME

Establish rate pricing and look at the customer impacts regarding the new rate design and pricing, and determine the timing of new rates and communicate through the customer base

PWP's Financial Modeling

Financial Forecast Optimization - Manage / Adjust the Following:



NewGen Strategies & Solutions

Monitor Key Financial Metrics

- Debt Service Coverage Ratio (PWP Targets and Bond Requirements)
- Days Cash on Hand (Cash Reserves)

PWP's Financial Metrics measure financial sustainability and health. These will directly impact the cost of debt, credit agencies ratings.

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Revenue Requirements are then Allocated to Set Rates

STEP 1	Determine the revenue requirements of the utility	Revenue Requirement (Financial Forecast)
STEP 2	Unbundle costs by functions and services (power supply, transmission, distribution, etc.)	Cost Allocation
STEP 3	Classify costs (demand, energy, customer costs, etc.)	Cost Allocation
STEP 4	Allocate cost among customer classes	Cost Allocation
STEP 5	Design rates	Rate Design

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Incorporating all costs into the Revenue Requirements

Pasadena Water and Power

Test Year Revenue Requirement:

Total costs to provide electric services to customers over the study period (for example: 2026–2030). Foundation of the COSA and based on forecast.

Base Year Financials

Budget Year 2026 Costs

→

Adjustments and Evaluations

Forecast 2026-2030 Debt/Rate/CIP Amounts Set

→

Test Year Revenue Requirement

(Avg. Costs for 2026-2030)

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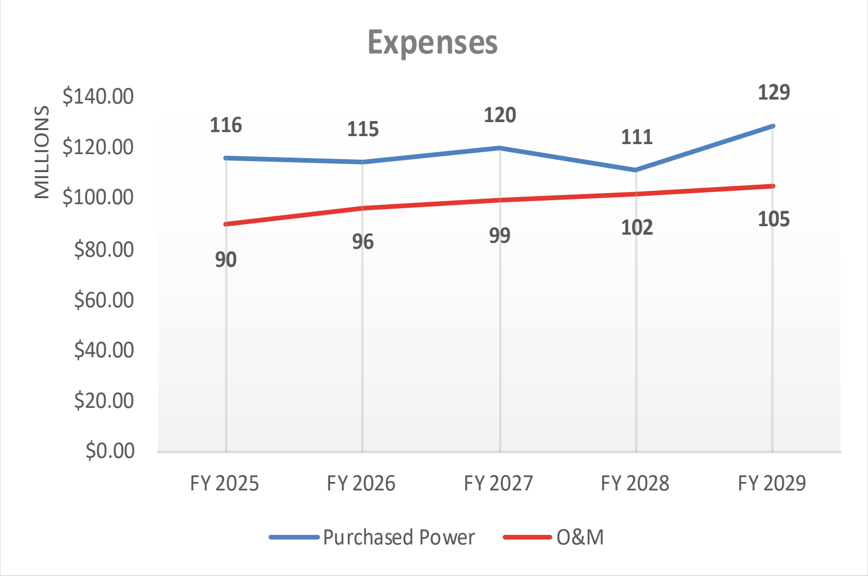
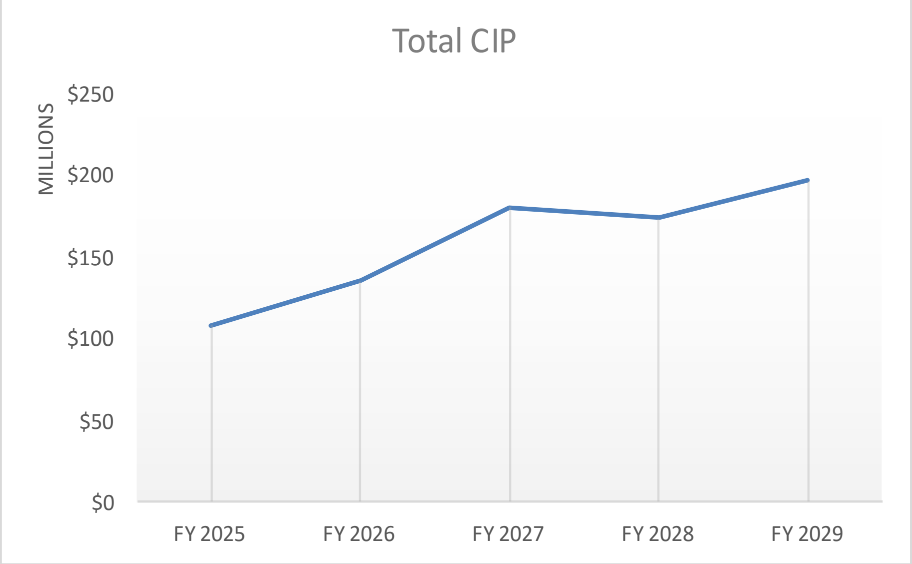
Projected Cost Trends Increasing

Pasadena Water and Power

Operating Expenses*



Capital Expenditures



*future year projections are draft subject to change

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Summary Results for 2031 Case Studies

Hourly Matching Accelerated | Hourly Matching Accelerated Plus | Annual Matching Accelerated | Annual Matching Accelerated Plus

	Portfolios Designed to Meet 100% of *Hourly* Needs *(No Market Purchases, Glenarm Replaced/Converted)*			Portfolios Designed to Meet 100% of *Hourly* Needs *(No Market Purchases, Glenarm Backup)*		Portfolios Designed to Meet 100% of *Annual* Needs *(Market Purchases, Glenarm Backup)*	
	Solar-Storage Replacement	**LDES Replacement**	**Hydrogen Conversion**	**Accel Local Resources**	**Accel Local Resources Plus**	**Accel Local Resources**	**Accel Local Resources Plus**
New Resource Needs by 2031							
New Renewables (MW)	600	568	165	363	417	123	151
New Storage (MW)	339	215	-	173	214	76	100
New DR & Load Flex (MW)	35	37	35	35	36	35	35
Clean Energy Metrics by 2031							
Metric 1 (%)	167%	183%	127%	170%	171%	108%	108%
Metric 2 (%)	100%	100%	100%	100%	100%	96%	96%
Metric 3 (%)	100%	100%	100%	100%	100%	94%	95%
Relative Costs in 2031							
Incremental Cost ($M/yr)	+$80-140	+$95-155	+$20-55	+$45-85	+$45-85	+$5-15	+$10-25
Other Considerations	Higher risk		Lower risk				
Local Resource Siting							
Technology Readiness							
Upstream H_2 Infrastructure							
Wholesale Market Exposure							
Resource Adequacy Risk							
Local Resilience							
Long-Term Optionality							

Note: Metric calculations are based on a single deterministic year of normal weather conditions and do not capture events where transmission or distribution contingencies would require Glenarm to operate to ensure local reliability. Actual outcomes may vary due to impacts of natural year-to-year weather variability, transmission and distribution contingencies, and dispatch instructions provided by CAISO.

DRAFT

OSP and Rate Study Data Flow

Optimized Strategic Plan
Relative Incremental Cost

Direct outputs from OSP modeling

- Procurement Cost for Generic Resources
- Incremental Market Revenues for Generic Resources
- Operating Costs for Existing Resources
- Market Revenues for Existing Resources
- Fixed O&M Costs for Existing Resources

Electric Rate Study – Financial Plan
Total Revenue Requirements

OSP outputs used directly in PWP financial plan

- $$$ Procurement Cost for Generic Resources
- $ Incremental Market Revenues for Generic Resources

Cost data developed specifically for financial plan (including operating and capital budget)

- $$ Operating Costs for Existing Resources
- $ Market Revenues for Existing Resources
- $$ Fixed O&M Costs for Existing Resources
- $$ PPA Costs for Existing Resources
- $$$$ All other system costs including distribution system costs, administration, customer service, facilities, external affairs, compliance, debt and indirect costs

Does not affect relative costs between case studies therefore not modeled in OSP

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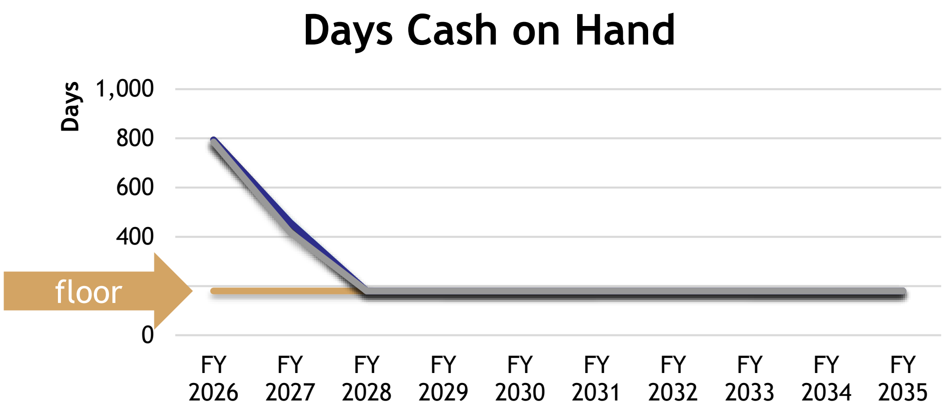
Scenario Levers

The general revenue requirements were derived from a total system wide needs including operations and capital. The System Wide Effective Rate is the quotient of total system revenue requirements and total system load. This does not account for different rates for different customer types or the fixed or variable charges on customer bills. Existing reserves were used to satisfy system requirements until they reached the floor for all scenarios.



Unchanged in scenario comparisons

1. No Debt Issuance
2. Days Cash on Hand Target (180) Days
3. No Rate Smoothing

Scenario Levers

4. Effective Rates (Total Rev. Req/ Total Sales in kWh)
5. Capital + or – for battery storage

For comparison purposes only

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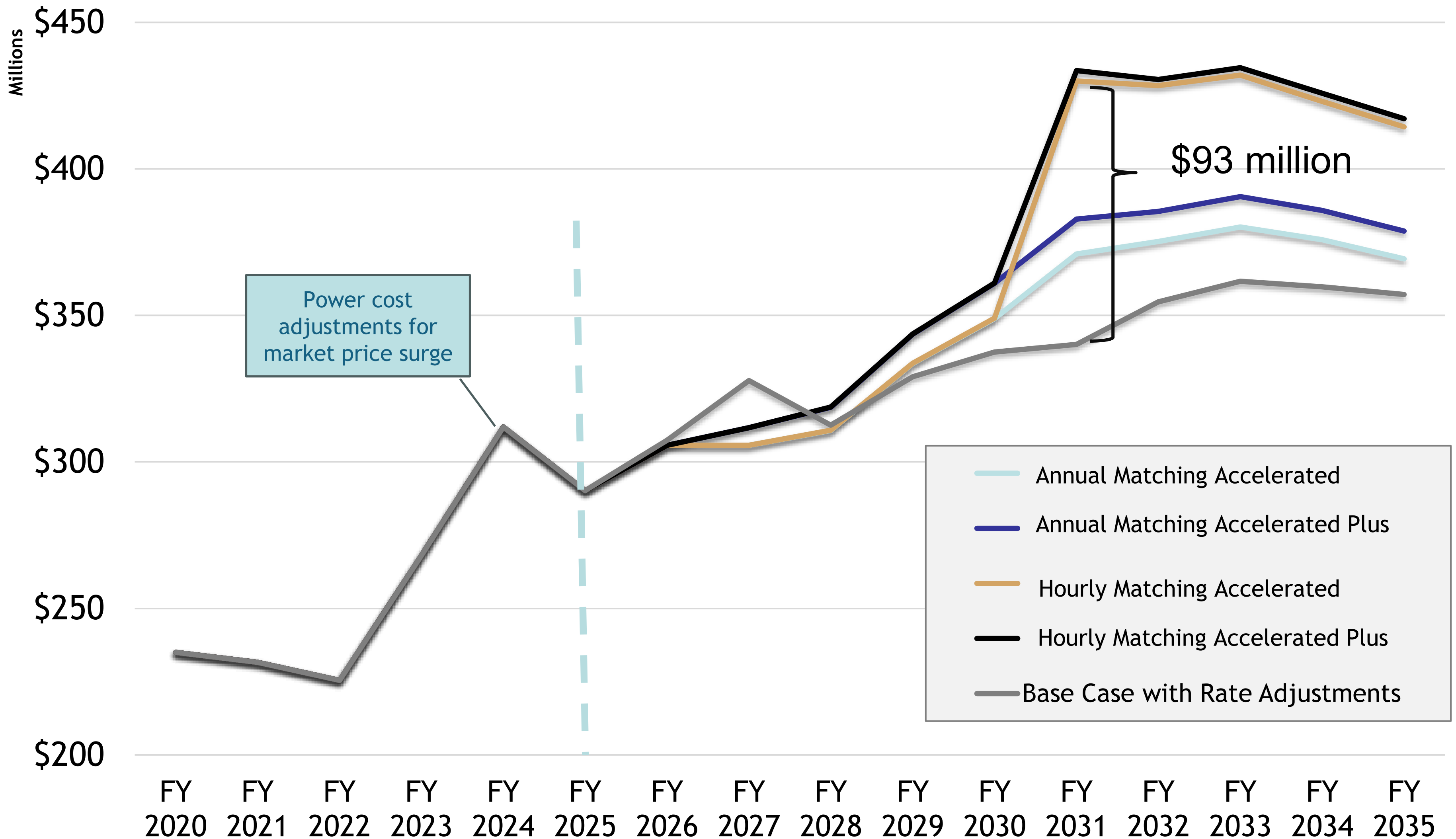
Revenue Requirements*

For comparison purposes only

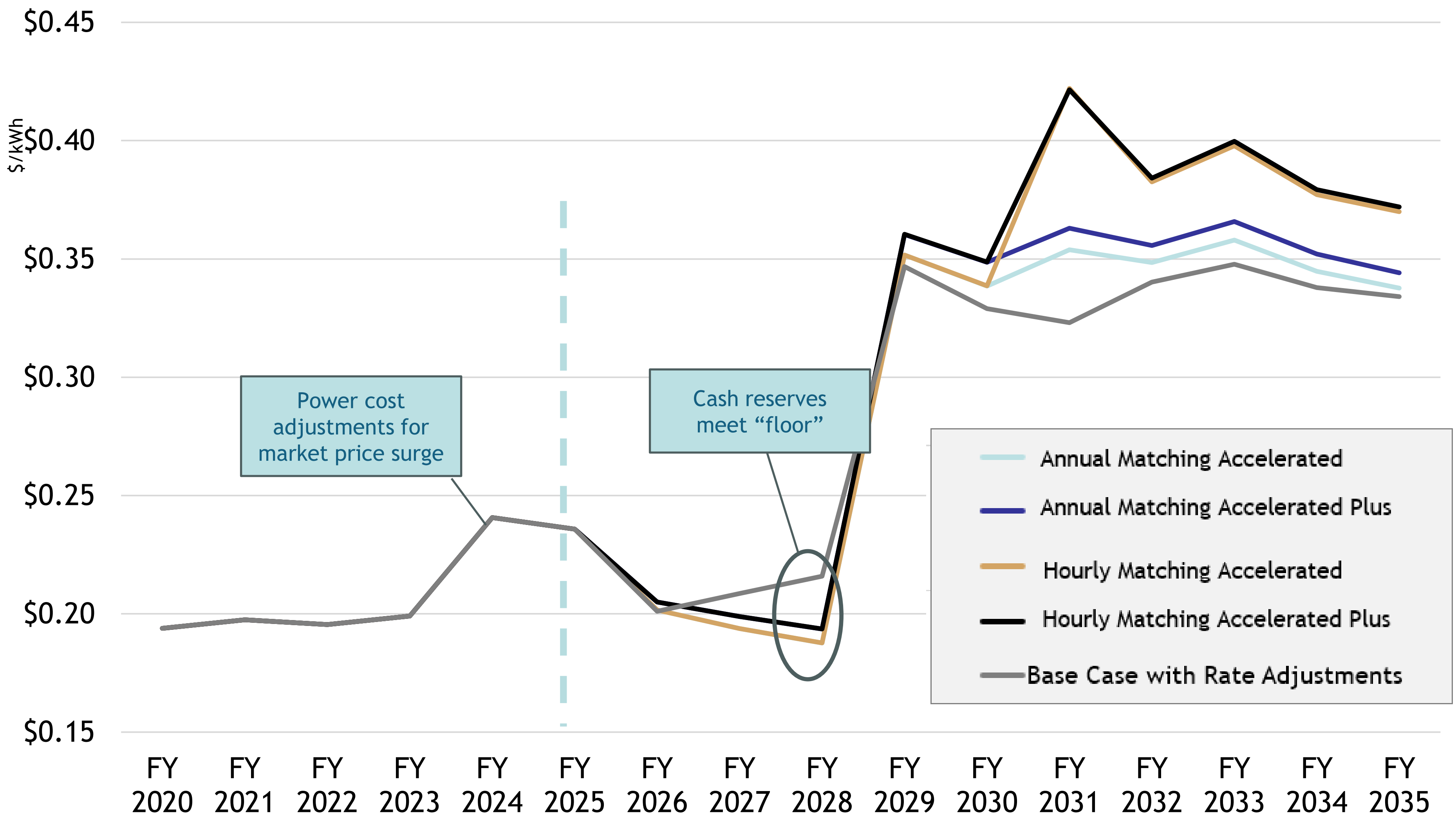
*DRAFT results final quality assurance is not yet complete



System Wide Effective Rate*

For comparison purposes only and does not include debt financing

*DRAFT results final quality assurance is not yet complete



Discussion and Next Steps

Provide guidance to staff on which Optimized Strategic Plan ("OSP") portfolio costs to proceed forward with for the revenue requirements in the Electric Rate Study ("ERS").

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WATER & POWER DEPARTMENT

Cost of Service Steps & Process

This is the current step

Revenue Requirements:

O&M
Debt Service
Transfers/Taxes
Capital Expenditures
Net Margin

Total Revenue Requirements

Production
Transmission
Distribution
Customer

Residential
Commercial
Large Commercial

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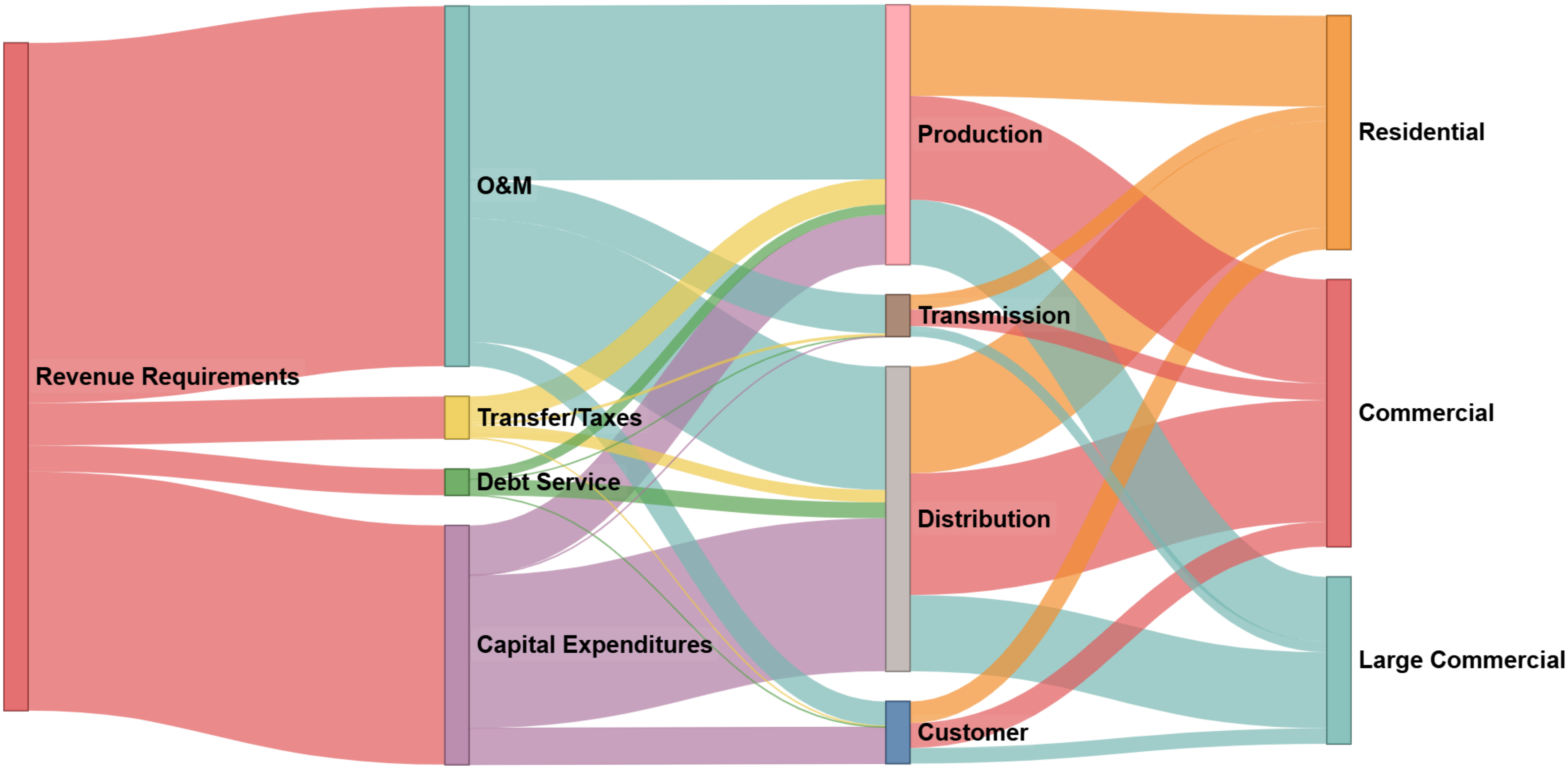
Flow of Revenue Requirements to Customer Prices



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Rate Strategy (Policy Decision)

Pasadena Water and Power

- COS is one step in rate making, rate making considers the COS, policy, and rate designs available
- If COS results show significant rate increases in some classes, we would propose gradualism or a "phased-in" approach to work towards the COS, but may not reach the final COS results
- Limit rate decreases, thus limiting rate increases

Rates Designed to Get to Rev. Requirements within Customer Groups

- Each rate design has a pricing tradeoff within each customer type based on individuality within each broadly defined customer class.
- Rate design is discussed to incentivize behavior we would like to see based on customer priorities and likelihood of adoption.

Next Steps

Pasadena Water and Power

Direct staff to return with proportion of solar and storage

Incorporate the proportion and type of solar and storage costs integrated into financial model

This will impact pricing by customer type(i.e. residential or commercial)

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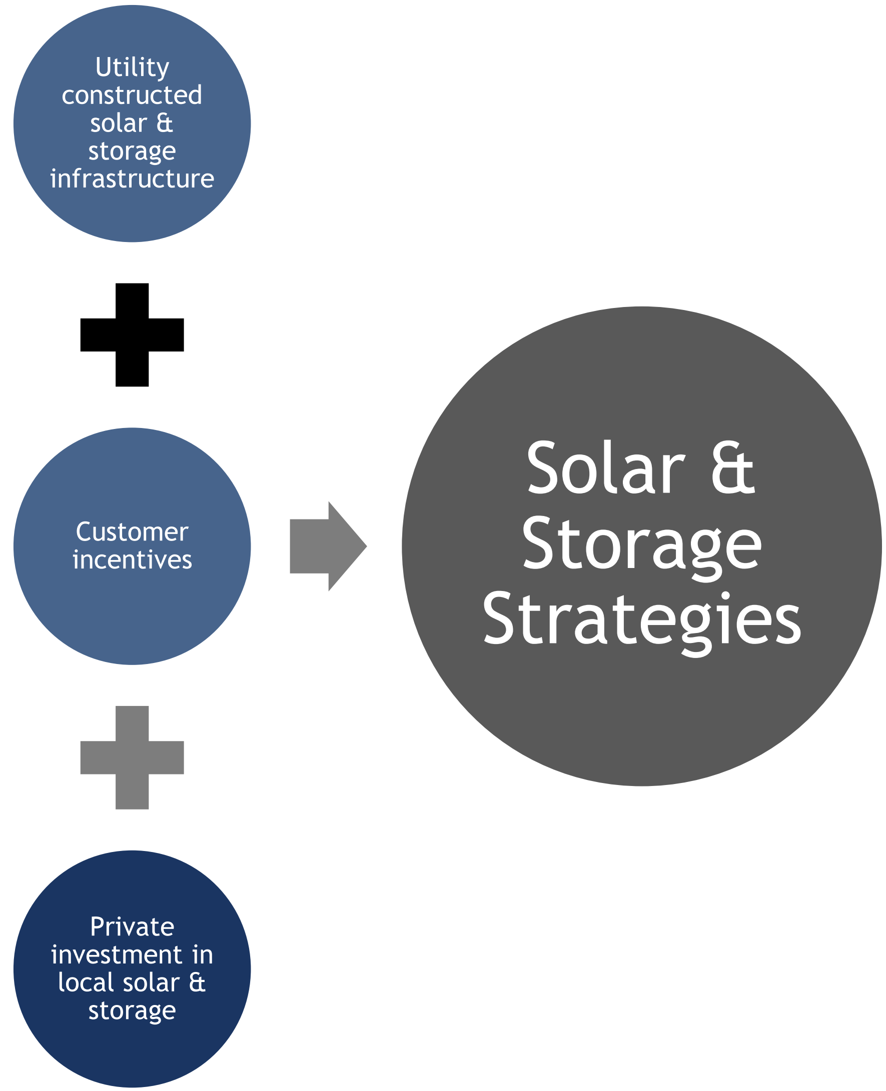
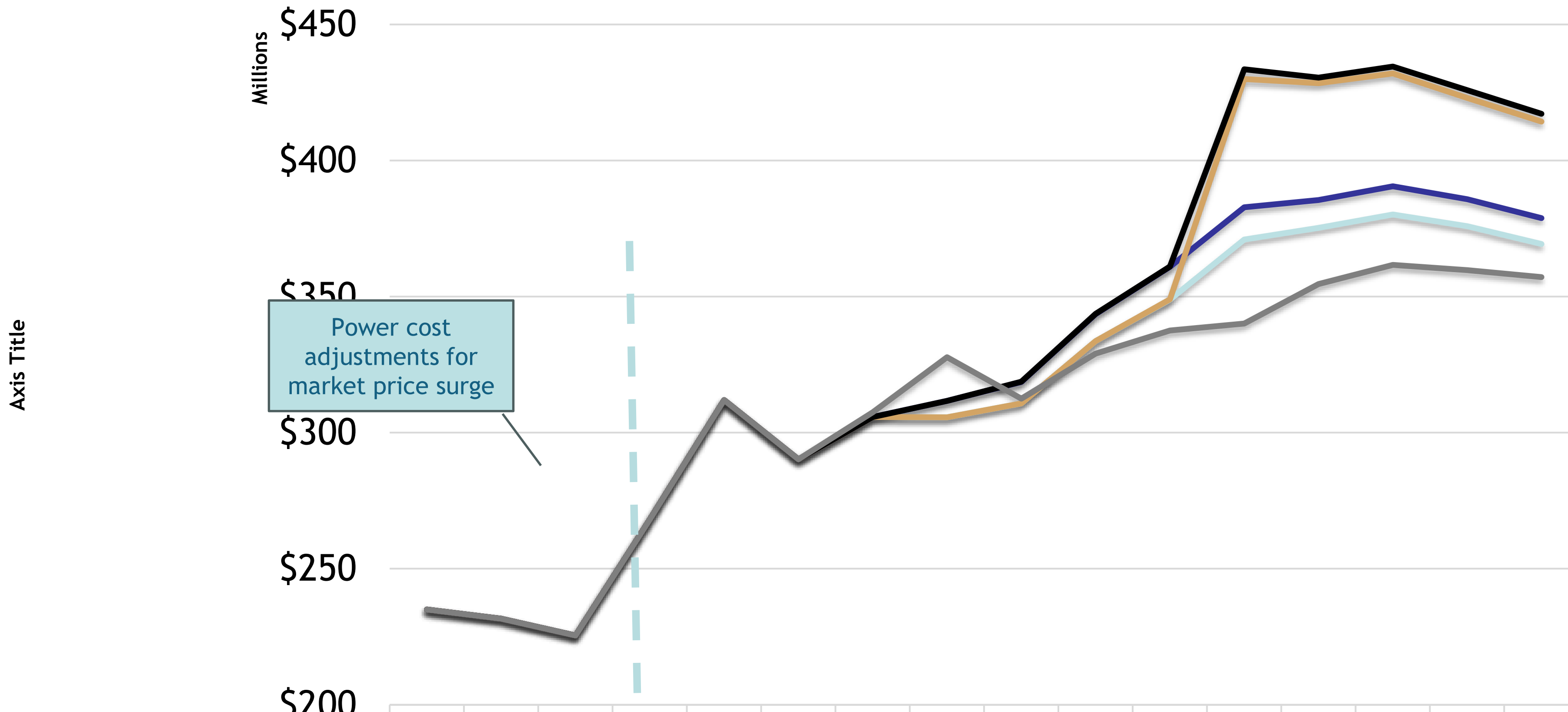
Direction on Proportional Investments

What strategy and in what proportion does the utility want to pursue to reach local solar and storage targets



Revenue Requirements*

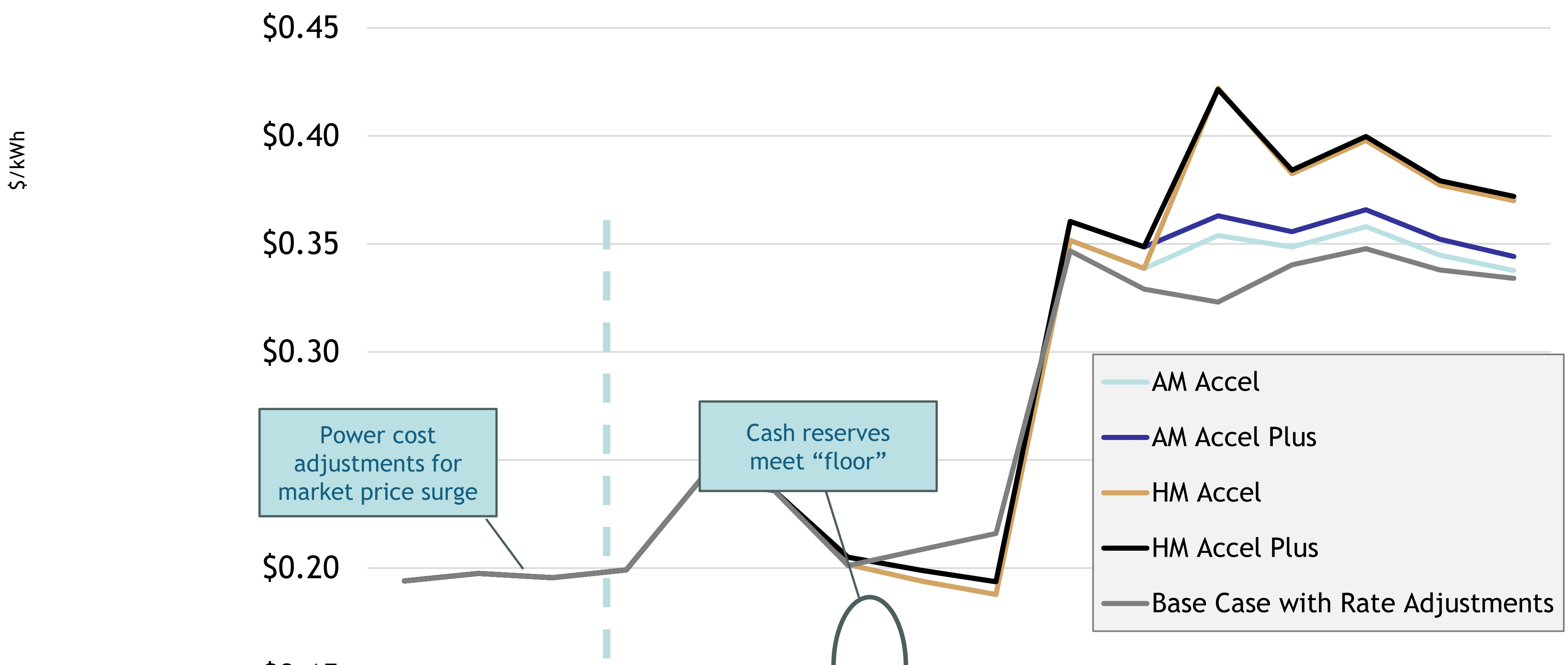
*DRAFT results final quality assurance is not yet complete



	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034	FY 2035
AM Accel	234,982	231,653	225,471	268,088	311,988	290,240	305,71	305,68	310,76	333,62	348,86	370,97	375,21	380,17	375,87	369,31
AM Accel Plus	234,982	231,653	225,471	268,088	311,988	290,240	305,71	311,71	318,66	343,62	360,93	382,88	385,48	390,53	385,83	378,82
HM Accel	234,982	231,653	225,471	268,088	311,988	290,240	305,71	305,68	310,78	333,64	349,03	429,96	428,42	432,00	423,01	414,33
HM Accel Plus	234,982	231,653	225,471	268,088	311,988	290,240	305,71	311,71	318,69	343,64	361,10	433,54	430,50	434,53	425,82	417,13
Base Case with Rate Adjustments	234,982	231,653	225,471	268,088	311,988	290,240	307,46	327,75	312,52	329,07	337,51	340,08	354,64	361,65	359,74	357,15

System Wide Effective Rate*

*DRAFT results final quality assurance is not yet complete

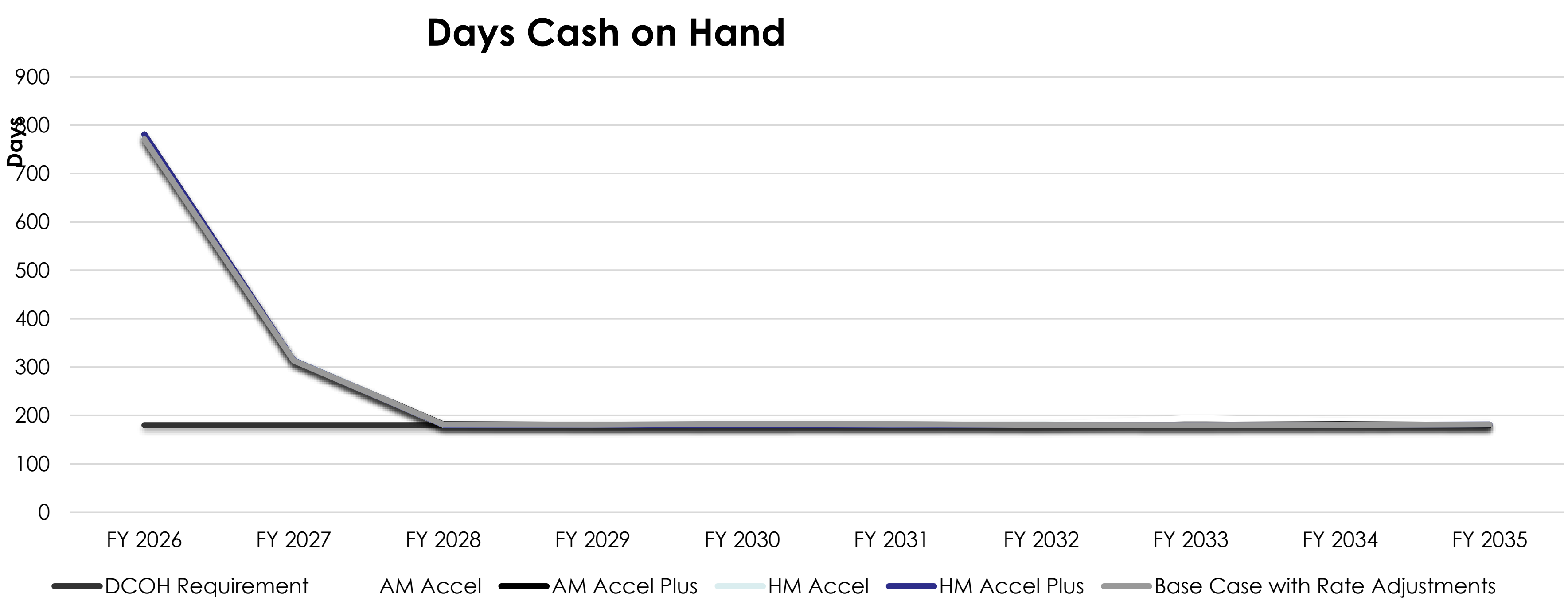


	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	FY 2032	FY 2033	FY 2034	FY 2035
AM Accel	0.1939	0.1975	0.1955	0.1991	0.2407	0.2358	0.20	0.19	0.19	0.35	0.34	0.35	0.35	0.36	0.34	0.34
AM Accel Plus	0.1939	0.1975	0.1955	0.1991	0.2407	0.2358	0.20	0.20	0.19	0.36	0.35	0.36	0.36	0.37	0.35	0.34
HM Accel	0.1939	0.1975	0.1955	0.1991	0.2407	0.2358	0.20	0.19	0.19	0.35	0.34	0.42	0.38	0.40	0.38	0.37
HM Accel Plus	0.1939	0.1975	0.1955	0.1991	0.2407	0.2358	0.20	0.20	0.19	0.36	0.35	0.42	0.38	0.40	0.38	0.37
Base Case with Rate Adjustments	0.1939	0.1975	0.1955	0.1991	0.2407	0.2358	0.20	0.21	0.22	0.35	0.33	0.32	0.34	0.35	0.34	0.33

Assumptions

Pasadena Water and Power

- "Just in time rates"
- No debt issuances
- No policy violations – i.e. drop below minimum



Agenda Report

July 14, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (June 24, 2025)

FROM: Water and Power Department

SUBJECT: **UPDATE ON THE ELECTRIC RATE STUDY AND THE ENERGY RESOURCE PORTFOLIO**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed actions are statutorily exempt from the California Environmental Quality Act ("CEQA") pursuant to CEQA Guidelines Section 15262, Feasibility and Planning Studies; and

2) Recommend that City Council direct staff to proceed with the rate study consistent with Municipal Services Committee ("MSC") guidance to prepare a two-year rate plan using the cost assumptions up to 2029.

MUNICIPAL SERVICES COMMITTEE RECOMMENDATION:

On June 24, 2025, the Municipal Services Committee provided guidance to prepare a two-year rate plan using the cost assumptions up to 2029. This consensus was based on discussion of draft financial results showing all the cost scenarios presented, until 2029, are not significantly different. MSC also reiterated that proposals would include rate increases as steadily as practical using all financial tools available, including the use of debt financing and cash balances.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") is conducting an Electric Rate Study ("ERS") to develop a cost-based, forward-looking rate plan aligned with the City's goals for affordability, reliability, and carbon-free electricity by 2030. The study includes a comprehensive cost of service analysis, financial modeling, and public engagement strategy tailored to customer profiles to enhance transparency and participation. In parallel with the ERS, several energy resource scenarios were evaluated as part of the Optimized Strategic Plan ("OSP") process, including options that accelerate local solar and storage development while preserving the Glenarm Power Plant as a limited-use backup. Revenue requirements and system-wide effective rate impact projections were developed for each scenario, showing annual systemwide revenue needs and average system wide effective rates. Once Council selects a preferred scenario, PWP will present the MSC and City Council with proposed approaches to advance local solar and storage initiatives and further refine forecasts to inform upcoming rate recommendations.

BACKGROUND:

The ERS's purpose is to evaluate and develop a recommended rate plan that aligns with established Council policies and legal constraints. The objective is to collect sufficient revenue while also supporting community and utility resiliency goals. This is achieved by sending price signals to customers that incentivize behaviors that are beneficial for both the community and the utility. With the use of empirical data and industry best practice, PWP will ultimately explore rate structures and pricing incentives that will accommodate evolving electric industry trends and customer practices. To achieve this purpose, there has been significant efforts and coordination with the OSP, specifically to integrate the power supply costs into the long-range forecast.

On October 8, 2024, PWP presented an update on the Electric Rate Study to MSC. The consultant, NewGen Strategies and Solutions, LLC ("NewGen"), had completed its initial phase, which included data collection, and was actively working on the cost of service analysis and development of the financial model. This model is designed to reflect the utility's cost to serve, establish revenue requirements, incorporate economic forecasts, and adhere to established policies and parameters. The ERS will also align with the Optimized Strategic Plan ("OSP"), which outlines key case studies to achieve the City's goal set forth in Resolution 9977 of sourcing 100% of its electricity from carbon-free sources by 2030.

On March 11, 2025, staff provided an update of the ERS public participation plan. PWP will implement a diverse and tailored approach to public engagement by segmenting participation based on customer profiles. Actively involving customers in the rate-setting process enhances transparency, builds trust, and fosters a deeper understanding of cost structures and service value. Public engagement efforts are underway.

On May 5, 2025, the City Council directed staff to complete the OSP final report, which includes four options with pathways that enable the Glenarm Power Plant to operate on a limited basis, and engage in market purchases to ensure electricity remains reliable and electric rates are optimized for affordability. The selected OSP options include annual and hourly methods of procuring clean energy where consumption is matched with production on an annual or hourly basis, ensuring every kilowatt-hour of electricity used is offset by carbon-free generation. In addition, each method includes options for accelerated local solar and storage energy resources.

Much of the data gathering and financial plan development has been completed and the analysis and options being presented to Council will enable movement of the ERS to the new phase of scenario refinement. The OSP cost data for resources has been integrated into the financial plan in order to show the proportional impact on revenue requirement and system-wide rates and is presented in this analysis.

Analysis

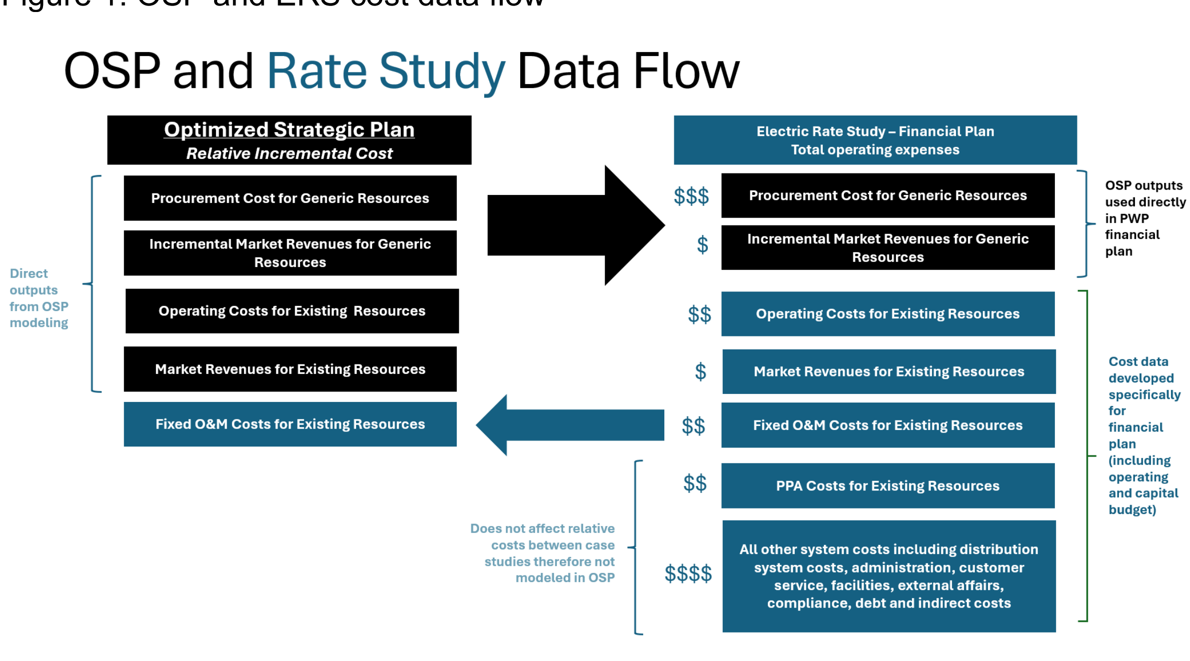
Financial Model and Revenue Requirements

The financial model determines whether the revenues from rates are sufficient to meet projected revenue requirements for the electric system. The developed model is based on the cost of service analysis utilizing fiscal year 2026 operating and capital budgets as the baseline and the utility's revenue requirements. Although the rates likely to be proposed are for a two- to three-year time period, the model provides a 10-year outlook aligned with economic forecasts and established policies and parameters to project future revenue needs. The long-term outlook enables the ability for stabilization of any proposed rate increases.

As a result of MSC's guidance, staff incorporated costs associated with the OSP scenarios to identify the revenue requirement impacts. Ultimately the model enables staff to evaluate the scenarios and provide the rough magnitude of customer rate impacts that may be proposed. All scenarios are also compared to the most recent forecasts as included in the Fiscal Year ("FY") 2026 proposed budgets, which is represented as "Base Case with Rate Adjustments". The selected portfolio balances the goal to source all power from carbon-free sources with affordability, rate equity, stability, and reliability to meet the goals of Resolution 9977.

Figure 1 below shows a conceptual diagram of how the costs presented from the OSP and the ERS are integrated and flow between model or study outputs.

Figure 1: OSP and ERS cost data flow



All scenarios are compared to a base case with rate adjustments. The base case with rate adjustments are reflective of the FY 2026 capital and operating budgets. All assumptions and projections are based on existing PWP forecasts and existing contracts for resources. Of note, the load forecasts for the base case with rate adjustments are based on PWP historical data and the resources required to meet those needs.

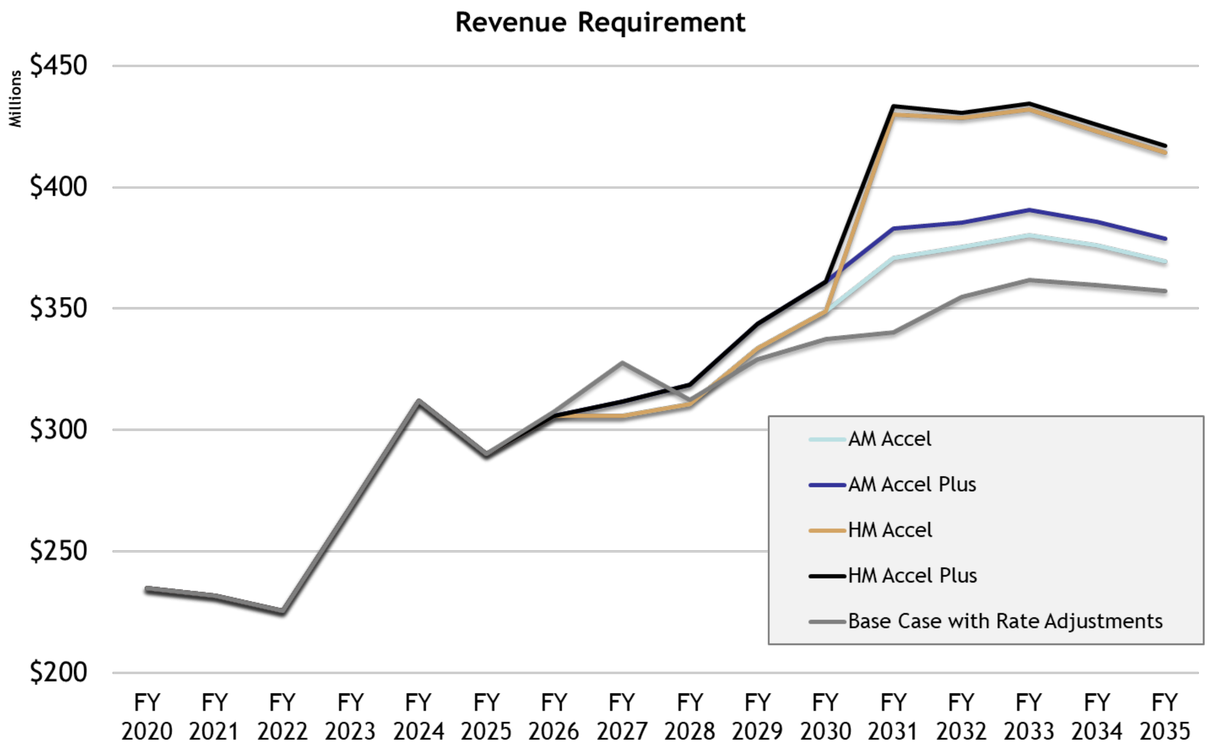
The portfolios approved at MSC are briefly described below.

a. Hourly Matching Accelerated Local Resources - Accelerated development of local solar and storage resources within the PWP service territory;
b. Hourly Matching Accelerated Local Resources Plus - Development of demand-side programs and rate structures to encourage load flexibility, managed electric vehicle charging, and other cost-effective demand response;
c. Annual Matching Accelerated Local Resources - Preservation of the Glenarm Power Plant as a “backup” resource for reliability that operates only under a narrow set of conditions; and
d. Annual Matching Accelerated Local Resources Plus - Pursuit of a balanced position in the California Independent System Operator (“CAISO”) wholesale energy market, allowing for limited sales and purchases to manage imbalances in supply and demand.

In order to show the proportional differences, there were several assumptions in the financial plan output from the ERS that were held constant, despite the utility’s ability to leverage those tools to stabilize rates. For all of the figures presented, there is the assumption that no debt will be issued. Debt being issued requires balancing several other financial metrics and is dependent on the type of investment being made. For example, if something being invested in does not have a useful life of 30 years, debt financing is not a tool that can likely be used. All scenarios also assumed that rate changes would not be made until cash reserve levels dropped below a pre-defined acceptable level. In all scenarios that did not increase revenues, the cash balance would become negative, which is not an option, so associated rates were adjusted when the reserves reached a pre-defined floor. PWP can also smooth out rates over time. Rate smoothing options will be presented with final staff recommendations. All figures presented are draft outputs that provide the best available information at this time, but they have not yet gone through the rigor that the final rate recommendations will have gone through.

As presented in Figure 2, to keep up with escalating costs and future investments, the system will have additional revenue requirements that increase from $306 million in FY2026 to the current forecast of the “base case with revenue adjustments” in FY2031 of $340 million. The OSP-generated case studies are also represented on the chart to show the varying levels of revenue requirements based on the selected pathway that PWP is directed to take. The scenarios all begin with the FY2026 budgeted revenue requirement and diverge from there. The greatest deviation is in FY2031, when the lowest annual revenue requirement is $340 million as compared to the highest annual revenue requirement of $434 million. These case studies slightly deviate from approved operating and capital budgets, which include moving BESS II, emerging/pilot project as they increase Distributed Energy Resources ("DER") and storage (in the OSP- increase purchased power costs).

Figure 2: Draft Revenue Requirements

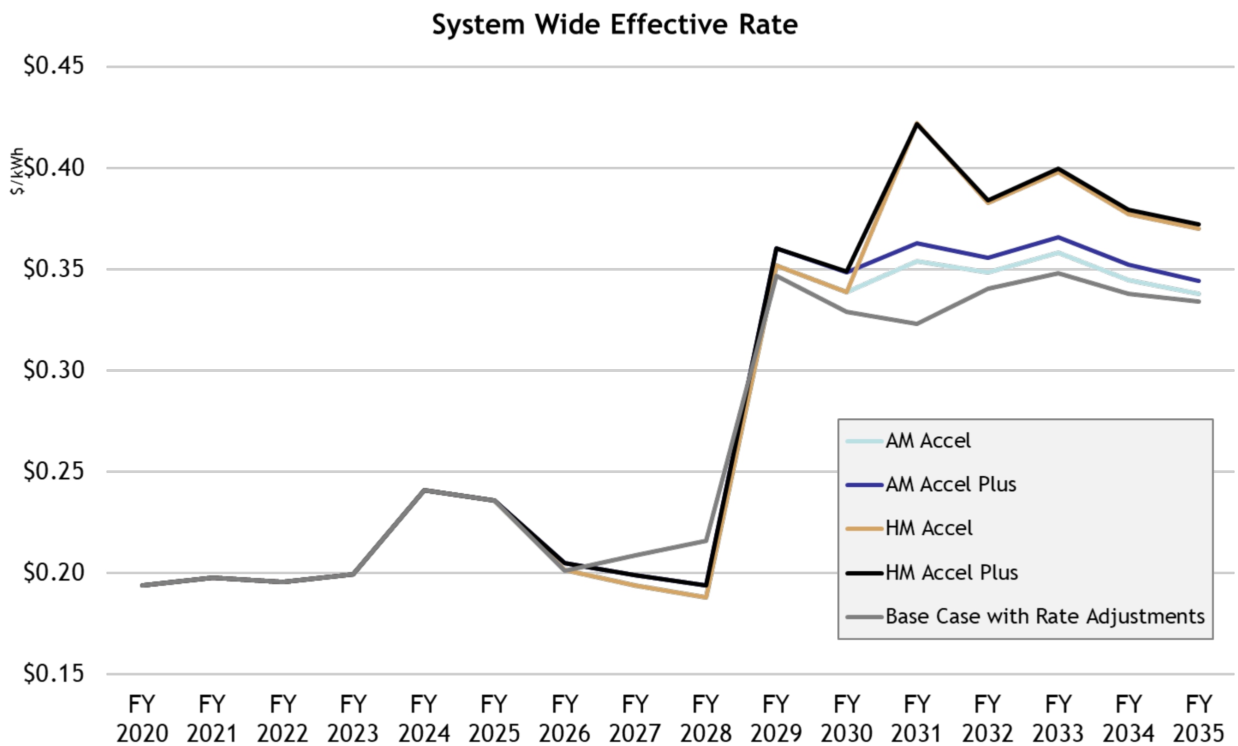


In order to present comparable data from a system wide effective rate perspective, rates were adjusted to keep the days cash-on-hand above 180 days. These rates are presented to exemplify differences in scenarios. This methodology is the simplest way to illustrate how various case studies may change rates if the utility were to adopt "just-in-time" rates. The utility can employ methods such as phasing-in rate increases and issuing debt in order to manage stable rates. The final recommendation, after receiving direction from the City Council, will be to propose steady increases as possible balancing debt issuances.

Figure 3 shows the variations in systemwide effective rates from a different perspective using the same case studies. The systemwide effective rate, used for example purposes only, represents the total costs of the system divided by the kWh of sales. It is important to note that each customer class pays a different rate based on the cost to serve their demands on the system and other cost allocation factors that are discussed in the cost of service process.

As Figure 3 illustrates, each systemwide effective rate, as modeled for "just in time" increases, takes on different trajectories. For example, the base case with rate adjustments comes to a peak in FY2029, primarily due to the large capital spend for the installation for the 100 MW storage on the site of the Glenarm Power Plant and the funds required to construct the facility (even including offsetting grant projections). The base case with rate adjustments then slopes downward to plateau around 33 cents in FY2033. For the other side of the comparison, there is the Hourly Matching Case Studies (both Accelerated and Accelerated Plus have similar paths). The OSP costs peak in FY2031 as the models for capacity needs selected the latest possible execution time to optimize for costs. The Hourly Matching case studies peak at 42 cents and then slowly return to a flat growth trend around FY2033 to stay at 37 to 38 cents range.

Figure 3: Draft System Wide Effective Rate



Next Steps

To continue with the cost-of-service analysis and to appropriately collect revenue through rates, staff will return to MSC and the City Council with a presentation of solar and storage options for MSC's consideration and selection. Ultimately, staff will present final rate recommendations based on the selected options. The rate plan will cover actions for the next two to three years and will include an outlook on how rates may change in the future.

<u>COUNCIL POLICY CONSIDERATION</u>:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

These actions have been determined to be statutorily exempt from the California Environmental Quality Act (CEQA) pursuant to State CEQA Guidelines Section 15262. This Section states that a project involving only feasibility and planning studies for possible future actions which the agency has not approved, adopted, or funded are exempt from CEQA.

FISCAL IMPACT:

There is no fiscal impact from this action. Council may adopt proposed rate adjustments and fiscal impacts after several other decision points at a future meeting. There is no impact to the General Fund.

Respectfully submitted,

DAVID M. REYES
General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

Agenda Report

July 14, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (June 24, 2025)

FROM: Water and Power Department

SUBJECT: **UPDATE ON THE ELECTRIC RATE STUDY AND THE ENERGY RESOURCE PORTFOLIO**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed actions are statutorily exempt from the California Environmental Quality Act ("CEQA") pursuant to CEQA Guidelines Section 15262, Feasibility and Planning Studies; and

2) Provide guidance on which Optimized Strategic Plan ("OSP") portfolio costs to proceed forward with for the revenue requirements in the Electric Rate Study ("ERS").

MUNICIPAL SERVICES COMMITTEE ("MSC") RECOMMENDATION:

On June 24, 2025, the Municipal Services Committee recommended guidance to prepare a two-year rate plan using the cost assumptions up to 2029. This consensus based on the discussion that draft financial results show that all the cost scenarios presented, until 2029, are not significantly different. MSC also reiterated staff's assurance that rate proposals would include increases as steadily as practical using all financial tools available, including the use of debt financing and cash balances.

EXECUTIVE SUMMARY:

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BACKGROUND:

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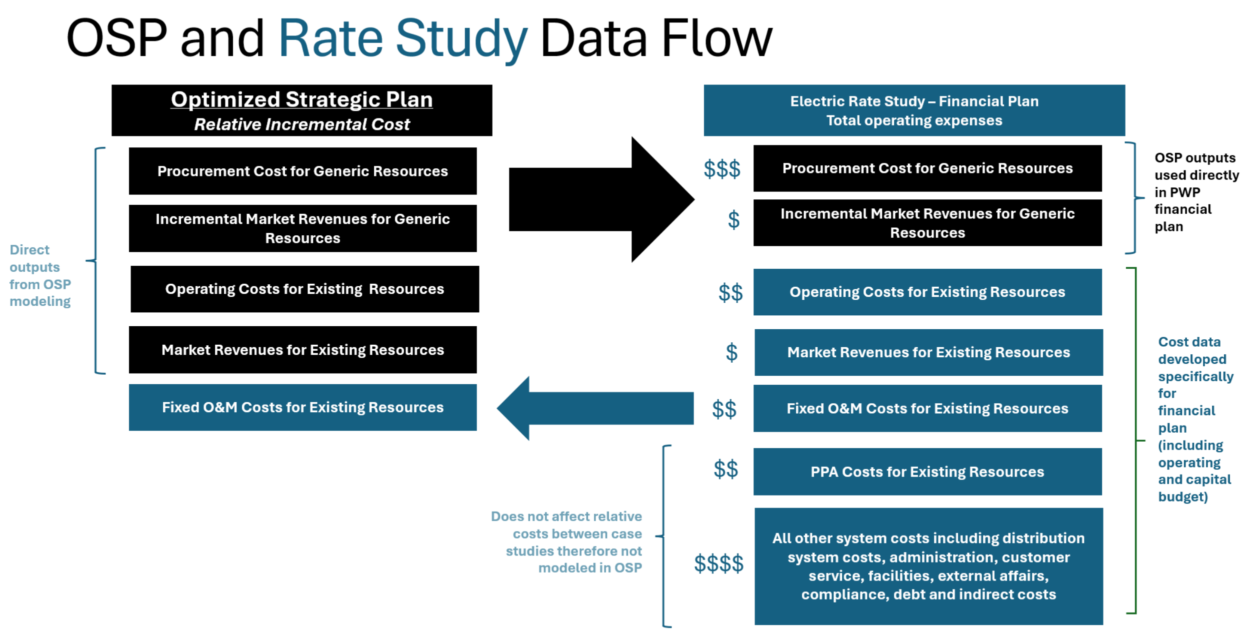

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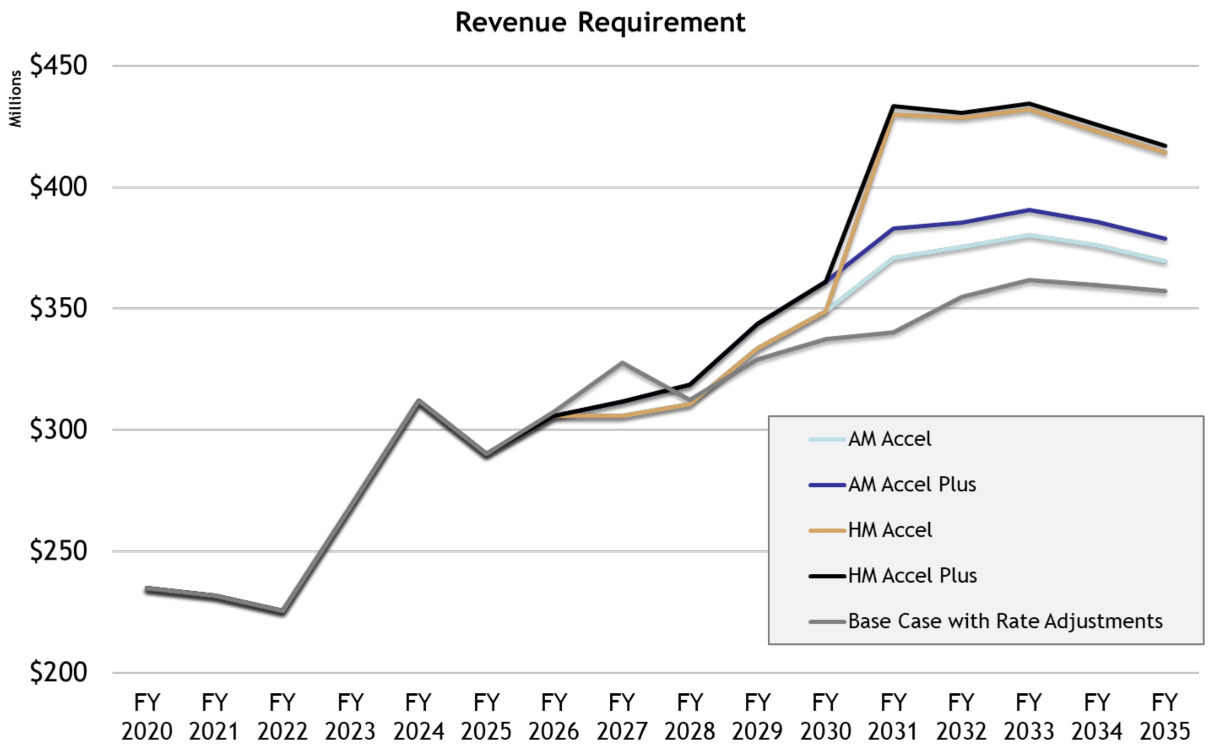

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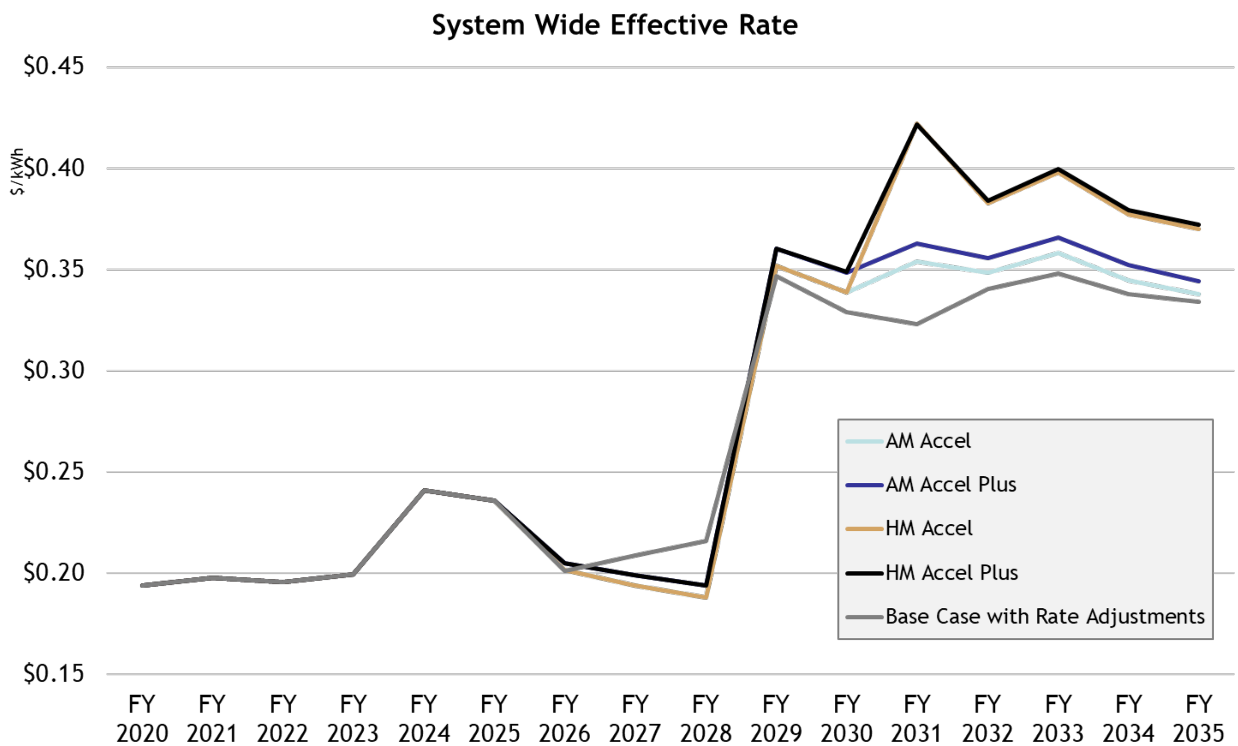


Next Steps

To continue with the cost-of-service analysis and to appropriately collect revenue through rates, staff will return to MSC and the City Council with a presentation of solar and storage options for MSC's consideration and selection. Ultimately, staff will present final rate recommendations based the selected options. The rate plan will cover actions for the next two to three years and will include an outlook on how rates may change in the future.

<u>COUNCIL POLICY CONSIDERATION</u>:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

These actions have been determined to be statutorily exempt from the California Environmental Quality Act (CEQA) pursuant to State CEQA Guidelines Section 15262. This Section states that a project involving only feasibility and planning studies for possible future actions which the agency has not approved, adopted, or funded are exempt from CEQA.

FISCAL IMPACT:

There is no fiscal impact from this action. Council may adopt proposed rate adjustments and fiscal impacts after several other decision points at a future meeting. There is no impact to the General Fund.

Respectfully submitted,

DAVID M. REYES
General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

CITY OF PASADENA INCORPORATED JUNE 1886

Agenda Report

December 15, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (December 9, 2025)

FROM: Water and Power Department

SUBJECT: **SET A DATE OF FEBRUARY 9, 2026, TO CONDUCT A PUBLIC HEARING FOR RECOMMENDED ELECTRIC RATE ADJUSTMENTS AND DIRECT CITY ATTORNEY'S OFFICE TO PREPARE AN AMENDMENT TO THE LIGHT AND POWER RATE ORDINANCE AND ADOPT THE UTILITY RATE RESOLUTION**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed action is not a project subject to the California Environmental Quality Act (CEQA) pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3), and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project;

2) Set a date of February 9, 2026, to conduct a public hearing for the recommended electric rate adjustments based on the findings of the recent electric rate study, with changes to take effect on March 1, 2026, or as soon thereafter as practicable;

3) Direct staff to prepare the Utility Rate Resolution using a two-year, three-phase rate adjustment (effective March 1, 2026, October 1, 2026, and March 1, 2027); and

4) Direct the City Attorney's Office to prepare a restatement of the Light and Power Rate Ordinance, Chapter 13.04 – Power Rates and Regulations, to reflect the proposed electric rate adjustments, eliminate outdated or obsolete provisions, and align the ordinance with current industry best practices.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") has completed a comprehensive Electric Rate Study to ensure that electric rates remain equitable, cost-based, and aligned with the City's long-term goals of fiscal responsibility, infrastructure modernization, and achieving 100% carbon-free electricity by 2030. Conducted in partnership with NewGen

MEETING OF ____________ AGENDA ITEM NO. ____________

Strategies and Solutions, LLC (“NewGen”), the study includes a full cost-of-service analysis, financial modeling, and extensive public engagement. The study confirms that current electric rates are insufficient to meet projected revenue needs, with a shortfall of approximately $67.9 million. To address this, PWP developed two rate adjustment alternatives. The recommended approach proposes a phased implementation over three steps allowing for gradual revenue recovery while maintaining reserve levels above policy minimums. This strategy balances financial sustainability with customer affordability and rate stability.

In addition to the rate adjustments, PWP recommends a full restatement of the Light and Power Rate Ordinance (Chapter 13.04). This restatement will modernize the ordinance by eliminating outdated provisions, aligning terminology with current industry standards, and streamlining governance by moving all rate figures to the Electric Utility Rate Resolution. The updated ordinance also anticipates future needs, including time-of-use pricing, advanced metering infrastructure, and expanded support for distributed energy resources such as electric vehicles and local solar generation.

PWP’s proposed rates remain among the most affordable in the region. The utility continues to prioritize equity by offsetting fixed charges for income-qualified customers and energy efficiency programs. Public engagement has been central to the process, with outreach efforts including webinars, open houses, and a dedicated website. Feedback from residential and commercial customers has informed the rate design and highlighted interest in clean energy options, electric vehicle incentives, and bill transparency tools. PWP recommends that the City Council set a public hearing for February 9, 2026, to present the proposed rate adjustments and ordinance restatement, and to gather community input. If approved, the new rates would take effect beginning March 1, 2026, or as soon thereafter as practicable.

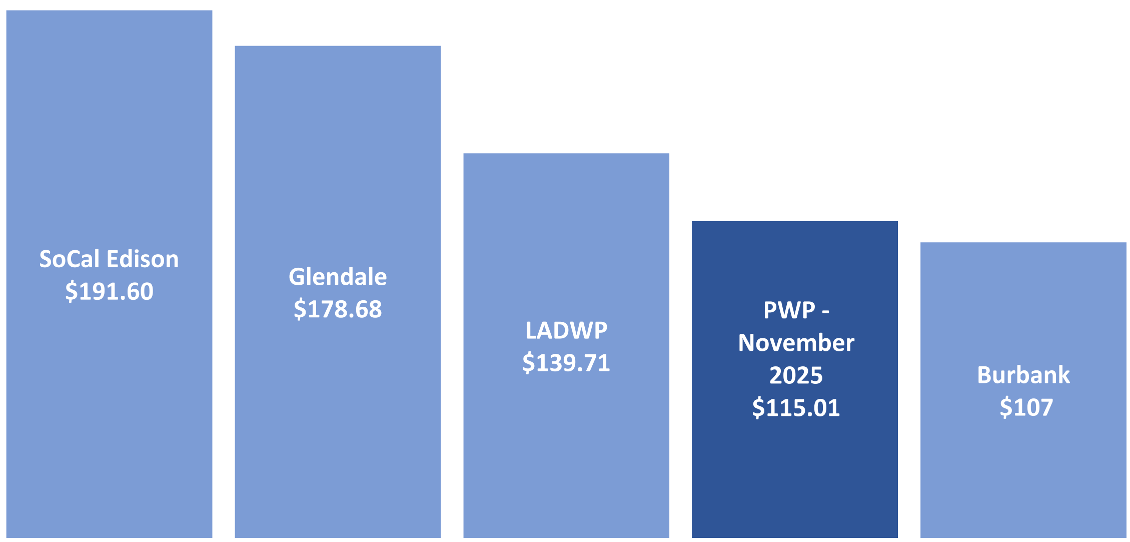
<u>BACKGROUND</u>:

State of the Industry

Across California and the nation, residential electricity rates continue to rise, driven by a combination of infrastructure investments, wildfire mitigation, regulatory mandates, and the growing demand for clean energy. California’s investor-owned utilities (“IOUs”) in particular—such as PG&E, Southern California Edison, and San Diego Gas & Electric—have implemented significant rate increases in recent years. These increases have pushed average residential rates in some territories to nearly 40 cents per kilowatt-hour, placing a growing burden on customers and raising concerns about long-term affordability.

In contrast, publicly owned utilities (“POUs”) like PWP have remained a more affordable and stable option for customers. PWP continues to offer some of the lowest residential electric rates in the region, thanks to its local governance, not-for-profit structure, and prudent financial planning. While PWP has implemented modest rate adjustments to support necessary investments in system reliability and clean energy commitment all within a challenging energy market, its rates remain well below those of neighboring utilities. This affordability is a direct reflection of the utility's commitment to balancing fiscal responsibility with customer value. The proposed rate increases are competitive with neighboring agencies. Figure 4 provides electric bill comparisons with neighboring agencies. It is important to note that rate structures differ between electric utilities based on operating costs, the level of infrastructure investment, and other factors. The comparisons are based on research of publicly available information on approved electric rate increases for the agencies shown.

Figure 1: Estimated Monthly Electric Bill Comparison*



*Amounts represent monthly total single family residential bill with the usage of 500 kWh for the month of November 2025. Amounts calculated using published rate schedules. Electric amounts calculated using published non-time of use rate schedules. Amounts also exclude taxes and non bypassable surcharges. Information has been sourced from publicly available information at the time generated.

It is important to note that all rate information represents a snapshot in time. As PWP adjusts its rates to meet evolving operational and regulatory needs, other utilities are doing the same, often at a much steeper pace. The utility sector as a whole is undergoing a period of transformation, with increasing capital requirements tied to grid modernization, electrification, and climate resilience. In this context, PWP's ability to maintain competitive rates while advancing its strategic goals is a testament to the strength of the public power model.

Why it is important to conduct the electric rate study now?

PWP manages the City's electric system, ensuring safe, reliable, and resilient service. To maintain operations, fund capital improvements, and preserve financial stability, the utility must generate sufficient revenue through rates that reflect the cost-of-service, in compliance with Proposition 26. Proposition 26 requires that charges must not exceed the reasonable cost of providing the service. These charges must also have a clear connection to the service received by the customer. As an enterprise fund, the Light and Power Fund is a self-sustaining, not-for-profit entity where all revenues are reinvested into the utility.

To avoid any perceived or actual misalignment of the costs to serve, PWP periodically conducts cost-of-service studies to assess operating expenses, capital requirements, customer usage patterns, and rate structures. These evaluations are typically performed every five to ten years, with the most recent review of the Power Fund completed in 2018. The Electric Rate Study was initiated in 2024 through a competitively awarded contract with NewGen. The scope of work included the development of a dynamic financial forecast model, a full cost-of-service analysis, rate design, ordinance review, and a public engagement strategy. The study builds on prior work, including the 2018 Power Integrated Resource Plan and the 2023 City Council Resolution 9977, which commits Pasadena to 100 percent carbon-free electricity by 2030.

As customer usage patterns evolve and the costs of providing electric service continue to shift, it is essential that PWP regularly conducts cost-of-service studies to ensure rates remain equitable, transparent, and aligned with actual service delivery. These studies help prevent disparities from growing unchecked, disparities that, if left unaddressed, could undermine financial stability and place the utility in a reactive position. By proactively evaluating and adjusting rate structures, PWP upholds its commitment to fiscal responsibility, regulatory compliance, and long-term sustainability, while continuing to provide safe, reliable, and resilient electric service to the Pasadena community.

Given the current and rapidly changing conditions, PWP as provided by guidance of Municipal Services Committee, intends to conduct a similar analysis in approximately two years. Thanks to the robust financial model developed for this study, PWP will be able to support a more condensed timeline for the next analysis.

Electric Rate Study Process Background

With the assistance of NewGen, PWP has recently finalized the first steps in the electric rate study, which are the accounting exercises of the development of the financial plan as well as the cost-of-service study (or cost allocation process). The study confirmed the need for rate adjustments to ensure the equitable recovery of increasing costs. Its primary objective is to develop a cost-based rate plan that supports the City’s goals of maintaining fiscal responsibility and stability, enhancing public infrastructure, and advancing sustainability initiatives. The study process included a full modernization of the financial planning model used by staff and a comprehensive review of cost accounting data to come up with billing determinants for which pricing and rates were developed.

On September 9, 2025, the Municipal Services Committee (“MSC”) directed staff to prepare a two-year electric rate plan with annual systemwide increases of 9.5% for Fiscal Year (“FY”) 2026 and 2027, and to finalize the cost-of-service analysis, rate design, and ordinance review. While the MSC provided guidance to develop a two-year rate plan, PWP also presented alternative multi-year scenarios based on different clean energy portfolios from the Optimized Strategic Plan (OSP). These scenarios were included to provide transparency and to illustrate the long-term financial implications of various clean energy strategies, including accelerated local solar and storage investments and hourly matching approaches. The alternatives are not proposed for adoption at this time but serve to inform future planning and demonstrate the potential range of outcomes.

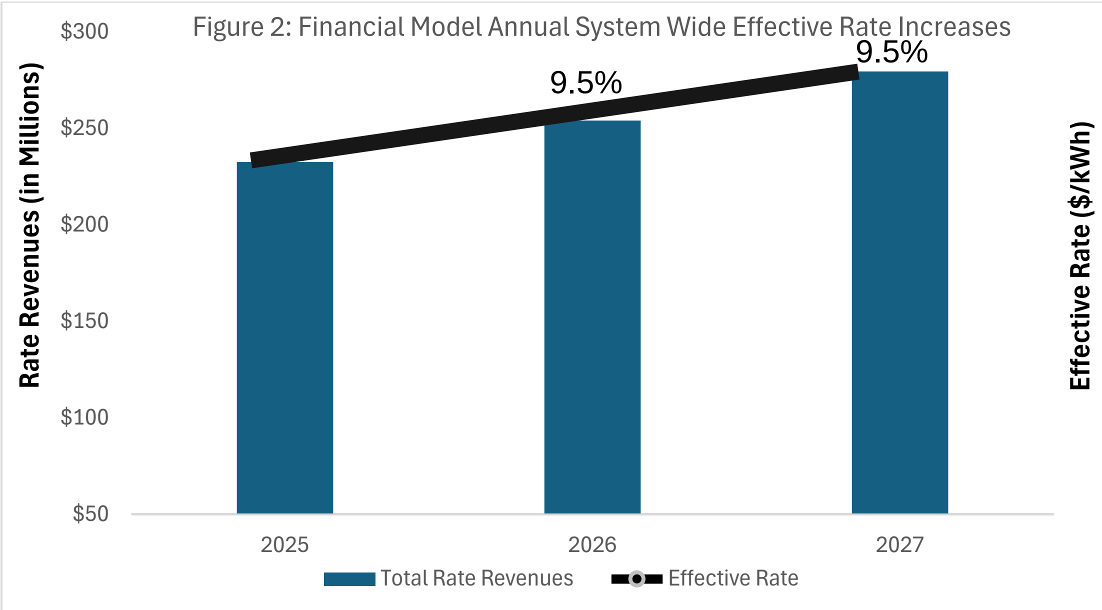
Earlier, on July 14, 2025 (following MSC review on June 24), City Council approved the development of a two-year rate plan using cost assumptions through 2029 and endorsed a strategy of steady, practical rate increases supported by financial tools such as debt and cash reserves. On March 11, 2025, staff introduced a customer-segmented public participation plan to enhance transparency and engagement. Previously, on October 22, 2024, PWP and NewGen presented an update to MSC, highlighting progress on the financial model.

PWP has updated the Municipal Services Committee and City Council along the way and taken on the following steps:

- On May 6, 2024, the City Council approved a contract with NewGen to perform an Electric Cost-of-Service Analysis and provide Rate Design Services.
- On October 22, 2024, staff presented an introduction to the Electric Rate Study to the MSC.
- On January 13, 2025, the City Council adopted Ordinance No. 7441, which amended Pasadena Municipal Code (“PMC”) Chapter 13.04 to remove Direct Access provisions and related tariffs, and to amend the long-term contract provisions.
- On March 11, 2025, staff provided an update to the MSC on the Electric Rate Study and introduced a customer engagement plan.
- On June 9, 2025, the City Council adopted Ordinance No. 7448, amending PMC Chapter 13.04 to eliminate the Stranded Investment Charge and Reserves, and to establish a Working Capital Reserve Policy.
- On June 24, 2025, staff sought direction from the MSC on which OSP portfolio costs should be included in the revenue requirements for the electric rate study.

Why are rate adjustments needed now?

Analysis shows that, using the current rates, the revenue generated is insufficient to meet the revenue requirements for the study period. As shown in Figure 2, the electric system financial model includes annual system wide effective rate increases of 9.5% in fiscal years 2026 and 2027 would collect sufficient revenue to meet the system need. When the rate increase is delayed, PWP is using funds out of cash reserves to fund to compensate for the under collection.



To address this gap, and in concert with the direction given by the Municipal Services Committee, the study recommends annual system wide effective rate increases of 9.5% in both FY 2026 and FY 2027. These rate changes are projected to generate approximately $21.5 million and $25.5 million in additional revenues in fiscal years 2026 and 2027, respectively. The revenue increases are necessitated by increasing costs to deliver power to customers and provide the excellent level of service in PWP's mission.

There are four key drivers behind the increasing need for electric rate adjustments. First, PWP is experiencing significant cost pressures due to rising prices for materials and equipment essential to maintaining the electric distribution grid, some of which, like cables and transformers, have seen cost increases of 75 to 100 percent since 2019. Secondly and concurrently, PWP is investing in critical infrastructure upgrades, including advanced metering systems, battery storage, and wildfire resilience projects, which are vital for long-term reliability and modernization. Third, the cost of energy procurement is rising as PWP is purchasing power supply resources to meet customer demand as a part of the larger California energy markets. Since committing in 2018 to purchasing only renewable resources, PWP has seen market-based prices for clean energy more than double over the past five years. Finally, PWP must ensure that the utility remains financially sound and resilient to serve customers for current and future generations. With these rate adjustments, PWP can ensure adequate funding for these essential initiatives while maintaining strong financial metrics and continuing to deliver reliable electric service that customers can count on.

There is meaning behind the metrics reflecting how PWP is actively working to ensure the financial health of the Light and Power Fund. Through strategic planning, PWP is identifying cost savings and operational efficiencies, issuing debt responsibly, and using a range of tools to manage the Fund's long-term sustainability.

To increase revenue and reduce costs, PWP has successfully pursued external funding, including nearly $10 million from the California Energy Commission for a battery energy storage system. To lower the cost of long-term renewable energy contracts, PWP is also working on a prepaid energy transaction expected to save approximately $1.4 million annually. This approach will be expanded as additional renewable resources come online in 2027 and 2028.

PWP continues to modernize its operations by implementing new technologies and improving supply chain strategies to drive efficiency. In 2024, PWP issued municipal electric revenue bonds to support capital investments in power delivery infrastructure. Approximately $34 million in bond proceeds are currently being used for existing capital projects, and a $50 million bond issuance is projected for fiscal year 2028. These actions help ensure intergenerational equity by spreading the cost of major system investments over time, rather than relying solely on cash funding.

Without these adjustments, PWP's cash balance—currently at $409 million—would decline by over $134 million by FY 2029, reducing the utility's financial flexibility and resilience. With the proposed rate plan, PWP has projected a use of $36 million at a minimum or more as discussed in the analysis portion.

Equity and Affordability

As part of the foundational work in the Electric Rate Study, PWP prioritized equity and affordability by ensuring that income-qualified customers would not bear the burden of fixed charges. One of the first policy decisions made was to structure the rate design so that 100% of fixed monthly fees, such as the customer charge and grid access charge, would be fully offset for qualifying low-income households using funds from the Public Benefits Charge. This ensures that our most vulnerable neighbors continue to receive essential electric service without undue financial strain. In addition to direct bill relief, PWP's energy efficiency programs, such as the Home Improvement Program and the Low-Income Energy Efficiency Under One Roof initiative, provide long-term affordability by reducing household energy consumption. These programs offer no-cost upgrades like LED lighting, smart thermostats, weatherization, and low-flow fixtures, which lower monthly bills and provide ongoing financial payback to customers. By embedding both immediate and sustained affordability measures into the rate structure and customer programs, the study reflects PWP's commitment to inclusive utility planning and reinforces the City's broader goals of equity, sustainability, and community resilience.

Public Engagement

Public engagement has been a cornerstone of the Electric Rate Study. In January 2025, PWP presented its Customer Engagement Plan to the MSC, outlining a two-phase strategy. Phase one focused on listening and gathering input from customers through webinars, open houses, and the launch of a dedicated website. Phase two, which will begin following Council action on the proposed rates, will focus on education and outreach. This includes the development of community outreach kits, targeted events, and digital tools to help customers understand the new rates and how to manage their energy use effectively.

PWP is actively engaging the community to raise awareness, gather input on customer priorities, and better understand the diverse needs of its customers. Transparency is a core value in this process, with a strong emphasis on clear, accessible communication to build trust and encourage meaningful public participation in rate-setting decisions.

Public engagement began in spring 2025 and has included a variety of outreach efforts, such as the Shaping Our Energy Future webinar, PWP's Open House, targeted events with residential and commercial customers, and the launch of https://engagepwp.org/, a dedicated platform for community input.

Through these engagement efforts, customers have expressed interest in more incentives and rate options for electric vehicle charging, solar with battery storage, and sustainable home upgrades. PWP's current solar program offers strong incentives, such as full retail-rate credits for exported energy. To further encourage clean energy adoption, PWP is recommending updates to time-of-use ("TOU") rates and net energy metering to better align with customer needs and support broader adoption of clean energy technologies.

PWP also has an active and engaged commercial and institutional customer base that is the backbone of the thriving local economy. As such, PWP met with commercial customers as well by presenting information and having a dialogue at the large-user breakfast as well as having open times available to discussion with commercial customers. As stated from one of the key accounts, Karl Zerrenner, Vice President of Volkswagon Pasadena said, "We appreciate PWP's engagement with their residential and commercial customers regarding future rate studies while working towards a 100% carbon-free energy future. Being invited to discuss these matters with the PWP finance team is a perfect example of the joint collaboration needed to help ease any concerns regarding future rates increases".

To further support transparency, PWP is preparing to launch an **electric bill estimator**, an online tool that will help customers estimate how proposed rate changes may affect their monthly bills based on actual or estimated usage. This tool is designed to empower customers with personalized insights and support informed participation.

PWP remains committed to delivering affordable, reliable, and sustainable service. Recognizing that affordability means different things to different households and businesses, PWP is using community feedback to shape future programs and ensure that rates remain equitable, competitive, and responsive to Pasadena's evolving energy landscape.

ANALYSIS

The analysis outlines the financial framework and cost-of-service considerations that guide PWP rate design and long-term financial planning. Central to this review is the development of the Test Year Revenue Requirement, which establishes the level of revenue necessary to recover all utility costs and maintain financial stability. The analysis evaluates revenue requirement methodologies, presents a four-year financial forecast, and examines how costs are allocated across customer classes to ensure fairness and transparency. By aligning rates with the actual cost of providing service, the study supports both operational needs and strategic objectives, while addressing challenges such as rising capital demands, evolving customer usage patterns, and the need to preserve adequate reserves. A draft report detailing full details of the revenue requirements and financial modeling can be found in Attachment A.

Revenue Requirements

There are two primary revenue requirement methodologies employed in the utility industry: the cash basis and the utility basis. The primary differences between the cash basis and the utility basis involve the treatment of depreciation, return on invested capital, and debt service. The cash basis, which is the most common method used by municipalities, includes debt service but excludes depreciation and return on invested capital in the revenue requirement determination. The cash basis focuses on meeting the cash demands of the utility. The utility basis, commonly used by private or for-profit utilities, includes depreciation and return on invested capital, but excludes debt service from the revenue requirement determination.

In this cost-of-service analysis, NewGen utilized the cash basis as it follows the traditional cash-oriented budgeting practices frequently used by government entities. Furthermore, the cash basis is generally easier to communicate to customers, as it aligns revenue with expenditures.

NewGen developed the Test Year Revenue Requirement for the two-year Study Period, including all costs required to operate the Utility and ensure its financial stability. The Test Year Revenue Requirement of $259.6 million is the two-year average of the annual revenue requirements, with the application of reserves of $36.3 million.

Financial Forecast

The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves over the four-year Study Period (FY 2026–FY 2029). PWP received guidance from City Council, on July 14, 2025, to establish the Study Period and set rates for a two-year period. To develop the financial forecast, NewGen utilized the Power fund’s FY 2026 budgeted expenses, load forecast documents, records of operations, customer billing data, and other detailed information and data compiled and provided by PWP. The forecast used the FY 2026 budgeted expenses as the base year in the financial forecast. Any projected non-recurring expenses or revenues were identified and incorporated in the financial forecast, as appropriate.

To forecast expenses through FY 2029, NewGen used multiple escalation and forecast factors. The forecast applied specific inflation and customer growth rates to the baseline FY 2026 budget year data and reviewed each account or group of accounts to select an applicable escalation or inflation rate for the expenses. For Power Supply-related costs, NewGen relied on a detailed forecast and resource plan from PWP that

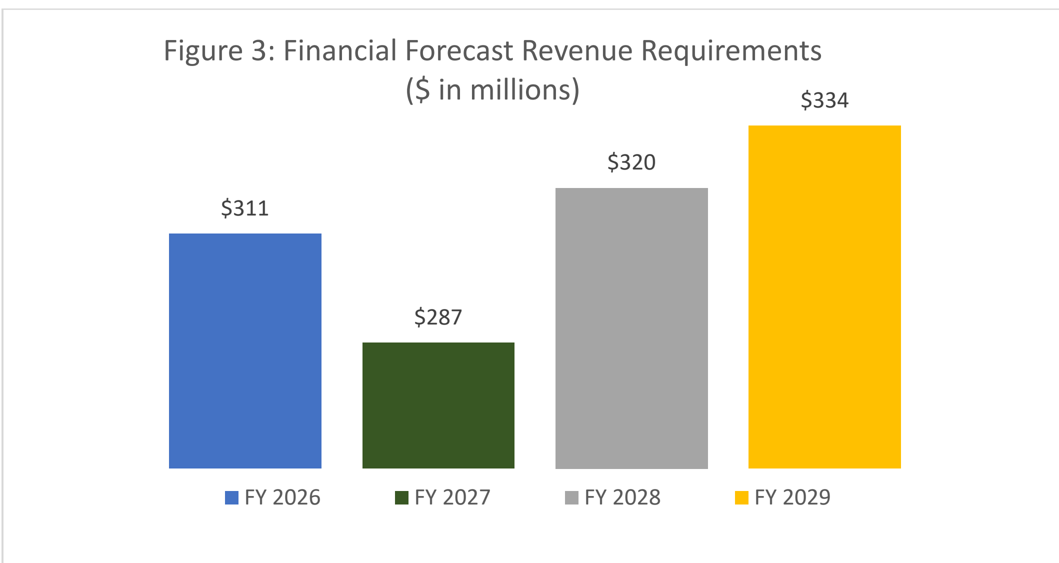
integrated long-term purchased power agreements, fuel price forecasts, renewable energy credit forecasts, and other proprietary energy market forecasts.
The financial model also provides the capability of evaluating scenarios for future financial performance by changing rates, issuing debt, and calculating key performance indicators ("KPIs"). These KPIs are based on the financial policies, bond covenants, and other financial performance targets set by the utility and/or City Council. Typically, as a utility best practice, PWP evaluates overall forecasted expenses, revenues, and the resulting KPIs such as the Debt Service Coverage Ratio ("DSCR") and level of cash reserves. PWP evaluates varying levels of debt issuance and changes in rates over time to fund the required capital investments, while ensuring it maintains the targeted financial KPIs. These rate and debt recommendations are primarily driven by PWPs increasing capital needs and to ensure established DSCR and cash reserve levels are maintained.

The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves. Key highlights include:

- Operations & Maintenance ("O&M"): $209.5 million average over FY 2026–2027
- Debt Service: $16.8 million average
- Capital Funded from Rates: $89.9 million average
- City Transfer: $29.2 million annually (12% of gross electric)
- Other Income/Offsets: $57.3 million in net non-operating revenues
- Use of Reserves: $36.3 million annually to reduce rate burden

Even with these investments, PWP maintains a DSCR of 6.4, far exceeding the industry benchmark of 1.5, ensuring continued financial strength.

Figure 3 represents revenue requirements. The forecasted revenue requirements in FY 2028 and 2029 may change based on progress, timing, fuel costs, power market prices, and execution of the Optimized Strategic Plan.

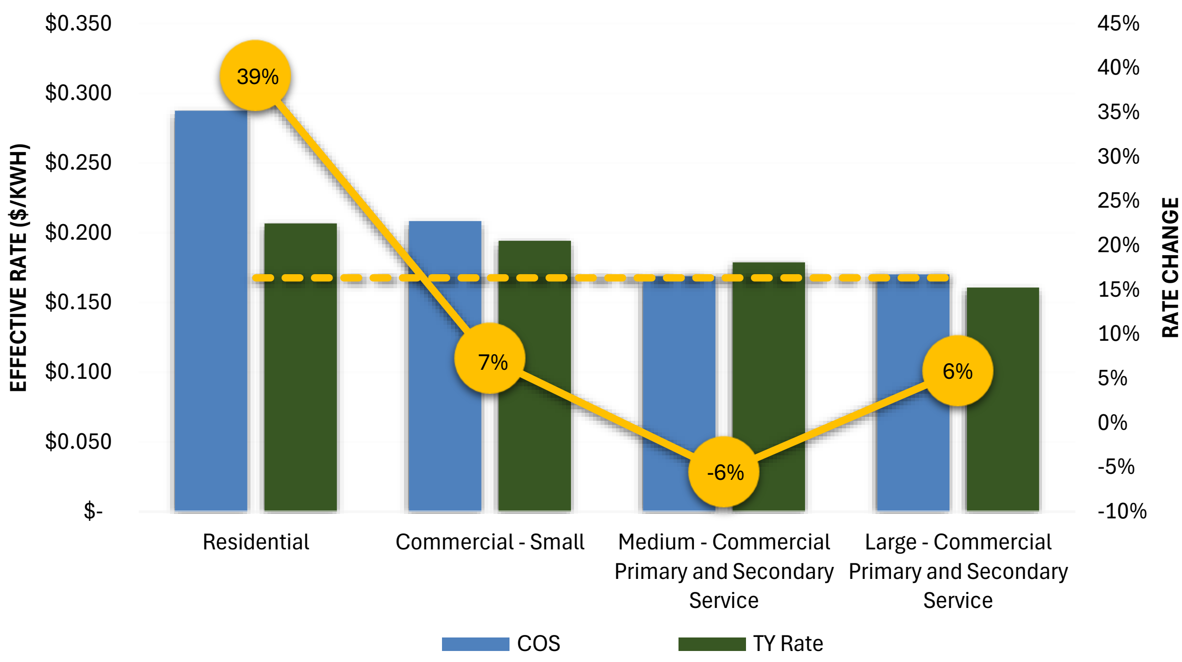


Cost of service – Aligning Cost and Pricing for Customer Types

A core objective of the Electric Rate Study is to ensure that electric rates are aligned with the actual cost of providing service. This means structuring rates so that each component—such as distribution, transmission, and power supply—is reflected in the appropriate charge. For example, the costs associated with maintaining and operating the distribution system are recovered through the distribution charge, while the costs of procuring and generating electricity are recovered through the energy services charge. In addition to aligning rates with functional costs, the study also ensures that costs are allocated to the customer classes that generate them. This principle of cost causation means that residential customers, who drive a significant portion of system demand and infrastructure needs, are responsible for covering the costs associated with their usage, rather than having those costs subsidized by other customer classes. This approach promotes fairness, transparency, and long-term financial sustainability for the utility.

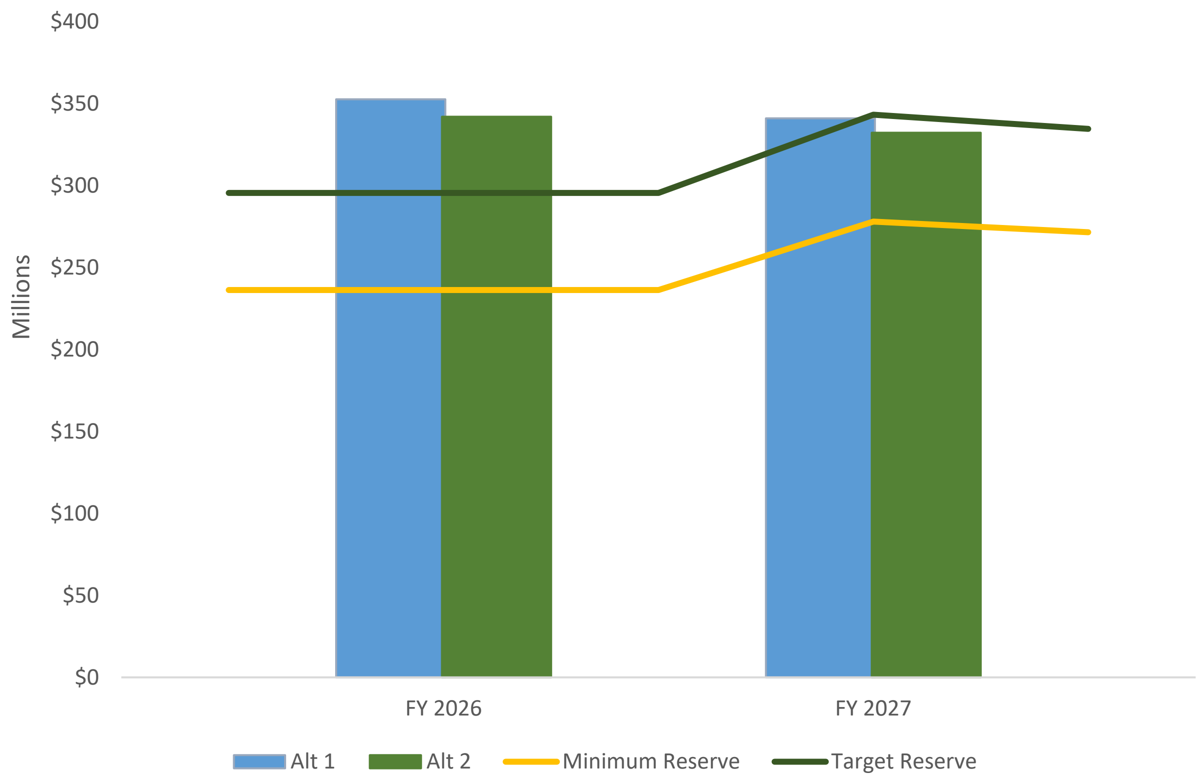
Among all customer groups, residential customers have seen the most significant reallocation of costs from the cost-to-serve. The residential sector has contributed to increased power peaks, particularly due to electrification trends and changing usage patterns. The study shows that the residential customer class is under-recovering by 39% as a customer base. Figure 4 below outlines the cost-of-service adjustments by customer class required to align the actual cost of providing service.

Figure 4: Cost-of-Service vs. Test Year Effective Rate



The cash reserve balances, resulting from the proposed systemwide rate adjustments, are consistent with industry standards and provide PWP flexibility and financial stability to support future operating and capital requirements. In addition, the reserves offer the ability to manage uncertainties related to construction timelines, project schedules, and financing costs, including interest rate fluctuations. Beyond these functions, the cash reserves serve multiple purposes, such as providing working capital, stabilizing rates to reduce volatility, and funding capital improvements. As depicted in the Figure 5 below, the rate plans maintain the power fund balance at the total minimum working capital reserves. The revenue plan also includes the issuance of $50 million dollars in debt financing.

Figure 5: Working Capital



Customer Classifications

Current customer classifications are single family residential, multifamily residential, small commercial, medium commercial, and large commercial. Each of these classifications have distinctive use patterns that enabled differentiation during the cost-of-service study. Since the last comprehensive rate study system usage has changed enough to warrant the introductions of several new customer classifications.

To continue to modernize, PWP proposes to introduce updated customer classifications that reflect the city's evolving energy priorities. These changes are grounded in a comprehensive cost-of-service analysis and support Pasadena's commitment to equity, sustainability, and grid reliability. The Electric Vehicle classification is designed to accommodate growing EV adoption while promoting efficient charging behavior. The Extra-Large Customer classification ensures that high-usage customers are billed more accurately based on their demand on the system. Additionally, the Standard Offer –

Local Clean Energy also known as Feed-in Tariff classification supports local renewable energy generation by compensating customers who export power back to the grid. Collectively, these updates position Pasadena to meet its long-term clean energy goals while maintaining fair and transparent electric rates.

Electric Vehicle: PWP proposes adding new rate schedules for electric vehicle charging to support transportation electrification and give customers pricing that matches how EVs use energy. These schedules apply to stand-alone EV meters and are based on charging demand levels, with separate options for variable capacity charging sites. Customers pay a standard set of charges that include customer, grid access, and time-of-use electric vehicle charging services. This structure encourages charging during lower-cost periods, supports reliable grid management, and helps customers plan charging costs with more certainty.

Extra-Large Commercial: A new extra-large commercial service category creates a distinct structure for customers with very high electricity demand. These customers now have rate schedules built around time-of-use pricing, defined billing demand, and standardized transmission and distribution treatment. The section sets a minimum demand threshold. This helps PWP match costs with usage more accurately and supports system planning for large facilities through increased options for potential collaboration to expedite common goals, through long-term contracting mechanisms and more integrated procurement planning.

Standard Offer – Local Clean Energy (Feed-in Tariff): The revised Feed-in Tariff section provides a clear framework for customers or developers who build local renewable generation and sell all of their output to PWP. The section defines eligibility, contract capacity, and program terms, and places all payment rates in the Electric Utility Rate Resolution for easier updates. It ensures generators meet interconnection and performance requirements and confirms that renewable attributes are transferred to the City. This approach promotes new local solar and other clean resources, while protecting reliability and providing consistent rules for long-term agreements.

Rate Design

Rate design is the final step of the electric rate study at which point PWP can establish recommendations and provide analysis on the impact to customers. After costs are aligned with customer classes, PWP develops the rate structure.

PWP's rate structure is made up of distinct charges, each tied to a specific cost function. These include:

- "Customer charge" is a fixed monthly charge regardless of energy use. It is generally associated with services such as billing, customer service, meter reading, and connection to the grid.

- "Distribution charge" is a usage-based charge generally associated with the cost of delivering electricity from the substations, including operation and maintenance costs, capital investment and debt service.
- "Energy services charge" (including power cost adjustment) is a usage-based charge generally associated with the solely variable cost of generating the actual amount of electricity consumed, measured in kilowatt-hours.
- "Grid access charge" is a fixed monthly charge generally associated with the fixed costs of connecting to and maintaining the electric grid, regardless of their energy consumption.
- "Public benefit charge" is a state-mandated nonbypassable, usage-based public benefit charge to fund assistance programs, energy efficiency and renewable energy projects.
- "Transmission services charge" is a usage-based charge generally associated with the cost of delivering electricity from the generating plants to our sub-stations.

After evaluation and analysis of the current rate structure, staff determined the unbundled methodology for calculation of customer bills provided a clear nexus with the cost-to-serve and enabled customers to receive price signals that align with controllable components of their bill. While analysis found that these charges can be more clearly defined, the fundamental structure is appropriate and aligns with best practice.

Each rate component was looked at with a critical eye and the energy services charge was one component that PWP recommends bringing into alignment with current best practice. For energy, TOU rates have been standard within electric utilities to encourage load shifting, support reliability, and align pricing with actual system costs throughout the day. The new proposed rate design introduces TOU rates as the default for all customers once advanced metering infrastructure is deployed. While PWP is unable to immediately implement TOU rates, the advanced metering infrastructure project is underway, and staff recommends building the capability into the rates so as soon as practical. Customers will retain the ability to opt out, ensuring flexibility while nudging participation in a rate structure that supports long-term sustainability and operational efficiency.

TOU pricing also introduces on peak, off peak, and a new critical peak, to reflect the increasing impact of increasing load peaks. While pricing is not yet suggested for critical peak, PWP included this to allow for options if current trends continue.

The updated residential rate structure introduces an inclining block design for distribution charges correcting a prior inversion where mid-tier usage was priced higher than high-tier usage. By assigning the lowest rate to usage between 0–350 kWh, a moderate rate for 351–750 kWh, and the highest rate for usage above 750 kWh, the rates promote conservation, improving fairness, and aligning rates with actual cost-of-service.

RECOMMENDATIONS

PWP recommendations reflect electric rates to ensure the utility recovers the full cost of providing safe, reliable, and sustainable electric service. Rate design began with establishing the revenue requirement. This is the total amount of revenue needed to fund annual operations, maintain and upgrade the electric grid, invest in capital improvements, meet regulatory mandates, and uphold financial performance targets.

For the current Electric Rate Study, the revenue requirement is based on the FY 2026–2027 test period and totals $259.6 million on a cash-basis methodology, after applying $36.3 million in reserves to reduce upward pressure on rates.

PWP then organized all utility costs into functional categories such as power supply, distribution, transmission, customer service, metering, and grid access. These functions represent the components of the electric system. They also form the basis for assigning costs to customer classes through a cost-of-service analysis. The recommendations ensures that each customer class, Residential, Small Commercial, Medium Commercial, Large Commercial, Extra-Large Commercial, Electric Vehicle Charging, and other specialized schedules pays its proportionate share based on how it uses the system. The current study confirms that the Residential class is significantly under-recovering its cost to serve, by roughly 39 percent, and the recommendation is to provide several strategies to gradually get to realignment.

Once the structure is set, PWP calculated recommended prices. Prices are developed by dividing the cost assigned to each rate component by forecasted billing determinants, such as the number of customers, kilowatt-hours sold, or kilowatts of billing demand.

Finally, PWP evaluated how the recommended rates achieve the revenue requirement and align with policy goals. This includes maintaining financial stability, supporting the transition to a carbon-free power supply by 2030, modernizing infrastructure, reducing long-term volatility, and providing equitable treatment across customer classes. It also includes assessing customer impacts.

Rate Design Alternatives

Given the policy direction to use all strategies available to gradually adjust rates, PWP created three alternatives for consideration and is requesting further guidance on which alternative is Council’s preference.

All rate design alternatives presented provide rates that are fair, transparent, compliant with Proposition 26, and able to support the utility’s operational and clean energy commitments.

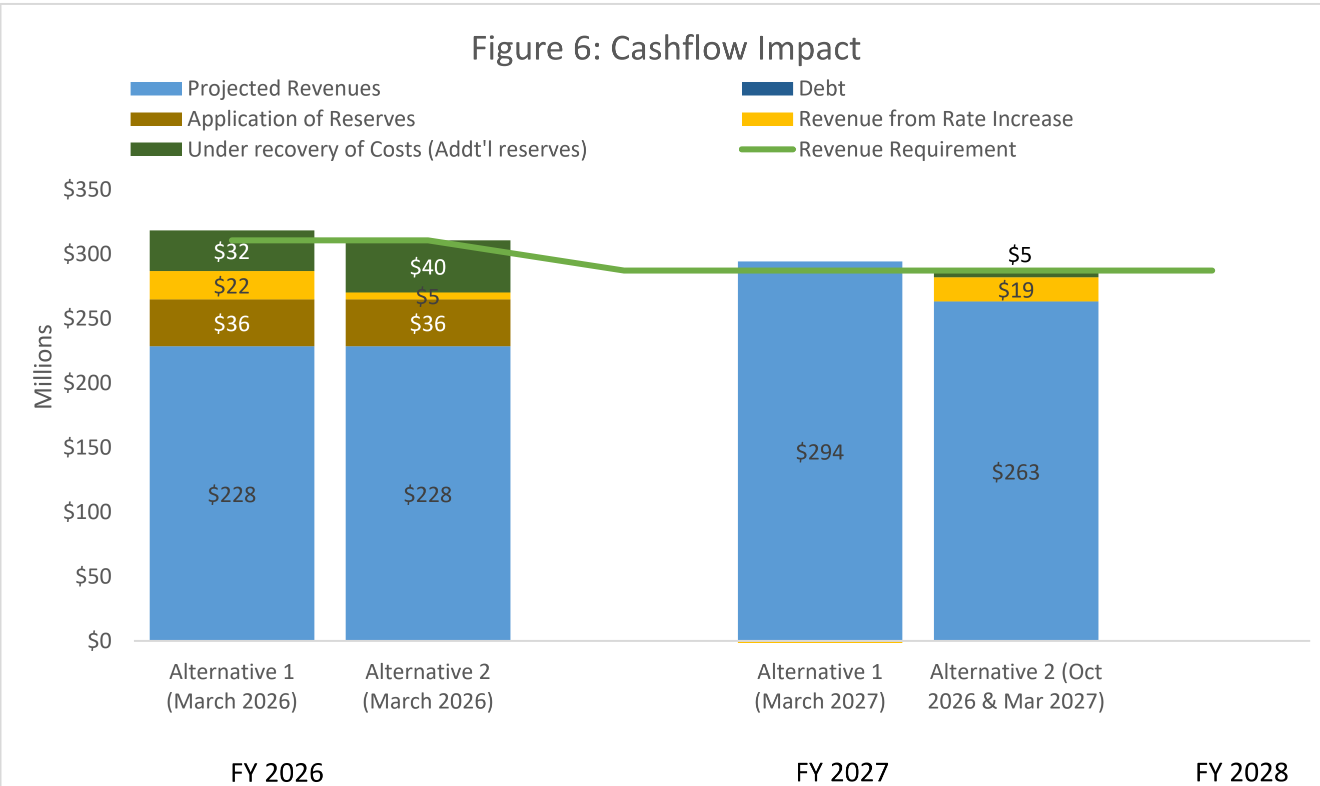
Alternative 1: Immediate Full Cost Recovery – Not Recommended

Alternative 1 establishes a rate plan that would, at the time of proposed adoption, achieve full-cost recovery by customer class with one adjustment. Given the drastic increase required and the implications for customer's and affordability, **staff does not recommend this alternative.**

Alternative 2: Gradual Full Cost Recovery with options for three adjustments over two Fiscal Years or over three Fiscal years.

Alternative 2 provides a strategy for three rate adjustments over two Fiscal Years, the changes recommended to take effect March 2026 (FY26), October 2026 (FY27) and the final adjustment March 2027 (FY27). This alternative is steady and is most aligned with Municipal Services Committee guidance. The revenue collection impact would be $40 million in FY26 and $5 million in FY27.

Each strategy has an impact on the timing for revenue collection. As shown in Figure 6 below.



Customer Bill Impacts

Individual customer bill impacts will vary depending on the customer class and the amount of electricity consumed. Because of the variability of rates, PWP will develop an estimator for customers to understand the impact once one rate plan is decided on. Below are some impacts using averages for consumption. For comparison purposes, above average usage is also presented for residential customers to give a bit more context on the variability in bill impact due to usage patterns. As shown in Figures 7 and 8, the proportional usage electricity by customer classification is significantly different.

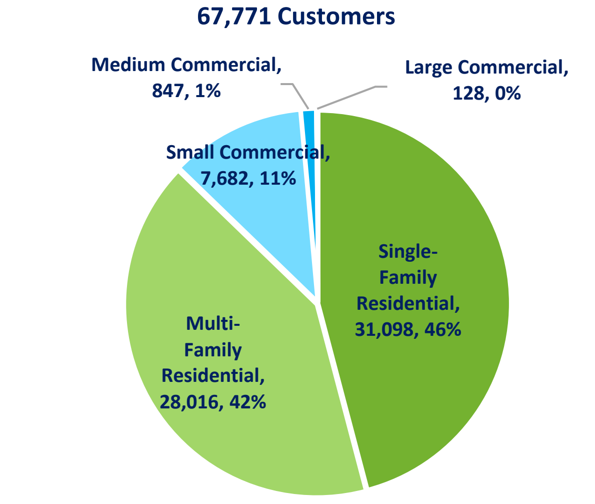


Figure 7: Customer Count FY24

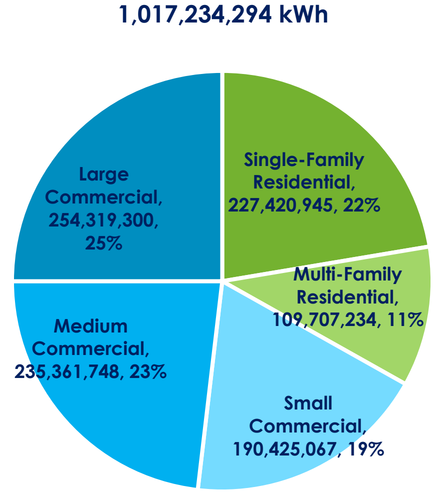


Figure 8: Customer Usage FY24

Residential Customer Bill Impacts

Single and multi-family residential customers represent nearly 88% of PWP's customer accounts, whereas they represent 22% of the total consumption for the utility. PWP ensures that the lights are on, and essential electrical services are provided reliably year-round. For comparison purposes, the bill impacts shown in Table 1 and Figure 9 below represent an approximation of the average customer, using 500 kWh monthly.

To demonstrate the different impact of the distribution charge structural change, the Tables 1 and 2 and Figures 9 and 10 below also show a residential customer with higher-than-average consumption at 1,000 kWh per month. The tables and figures below, show the impact based on the two alternative strategies to implement rate adjustments.

Table 1: Sample Electric Bills - Monthly (Residential @ 500 kWh)

		Approximate Bills			
	Current Bill	**March 2026**	**October 2026**	**March 2027**	**March 2028**
Alternative 1	$115.01	$150.24	$142.01	$142.01	$142.01
Alternative 2		$113.17	$123.17	$135.11	$135.11

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Figure 9: Residential - Average Use (500 kWh)

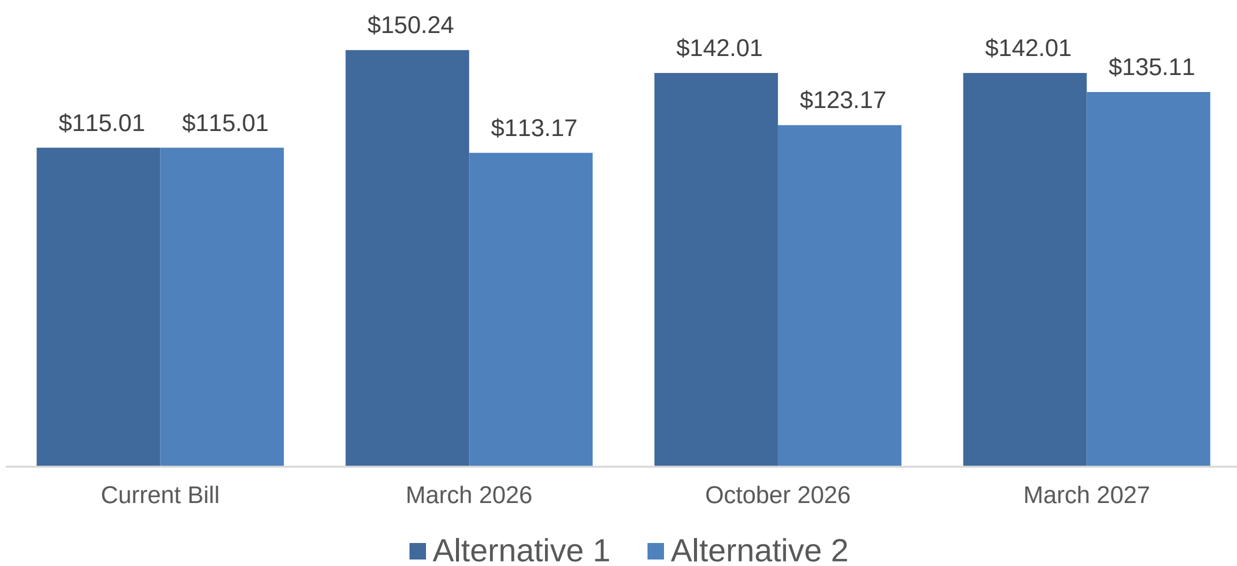
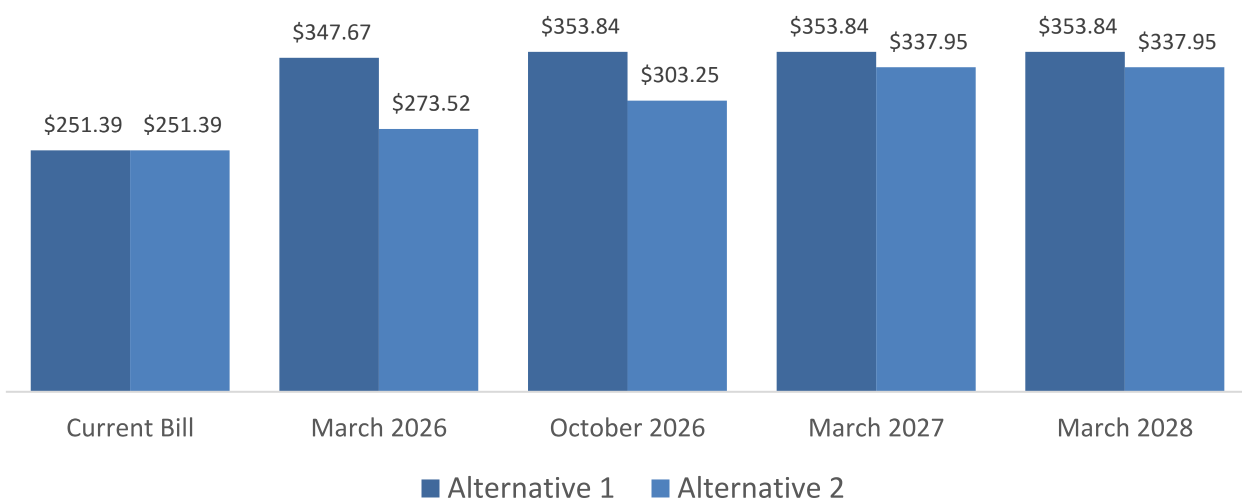


Table 2: Sample Electric Bills - Monthly (Residential @ 1,000 kWh)

		Approximate Bills			
	Current Bill	March 2026	October 2026	March 2027	March 2028
Alternative 1	$251.39	$347.67	$353.84	$353.84	$353.84
Alternative 2		$273.52	$303.25	$337.95	$337.95

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Figure 9: Residential - Above Average Use (1,000 kWh)



Small Commercial Rate Impacts:

Small commercial customers represent approximately 11% of PWP's customers and approximately 19% of the total retail power sales (in kWh) per year. Small commercial customers are the backbone of the community that includes establishments such as small retail and professional offices, cafes and small restaurants, and small dental or medical offices. An approximation of typical usage is estimated to be around 1,500 kWh per hour. The table 3 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 3: Sample Electric Bills - Monthly (Small Commercial @ 1,500 kWh)

	Current Bill	Approximate Bills: March 2026	October 2026	March 2027	March 2028
Alternative 1	$341.56	$419.88	$390.80	$390.80	$390.80
Alternative 2		$364.73	$385.44	$404.42	$404.42

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Medium Commercial Rate Impacts:

Medium commercial customers represent approximately 1% of PWP's customers and approximately 23% of the total retail power sales (in kWh) per year. Medium commercial customers include mid-size office buildings (20,000 – 30,000 sq ft), retail stores, groceries, urgent care facilities, veterinary hospitals, restaurants, fitness centers and warehouses. An approximation of typical usage is estimated to be around 15,000 kWh per hour, about ten times that of a small commercial customer. The table 4 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 4: Sample Electric Bills - Monthly (Medium Commercial Secondary @ 15,000 kWh)

	Current Bill	Approximate Bills: March 2026	October 2026	March 2027	March 2028
Alternative 1	$6,483.80	$7,384.29	$7,680.69	$7,680.69	$7,680.69
Alternative 2		$6,913.70	$7,353.40	$7,801.23	$7,801.23

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Large Commercial Rate Impacts:

Large commercial customers represent less than 1% or 130 of PWP's customers and comprise of approximately 25% of the total retail power sales (in kWh) per year. Large commercial customers include hospital, school campuses, supermarkets and departments stores. An approximation of typical usage is estimated to be around 175,000 kWh per hour, about ten times that of a small commercial customer. The table 5 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 5: Sample Electric Bills - Monthly (Large Commercial Secondary @ 175,000 kWh)

		Approximate Bills			
	Current Bill	March 2026	October 2026	March 2027	March 2028
Alternative 1	$37,227.41	$41,954.67	$38,695.51	$38,695.51	$38,695.51
Alternative 2		$38,791.99	$41,588.03	$39,987.64	$39,987.64

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Customer bill impacts will vary based on customer class and electricity usage. To help customers understand their specific impacts, PWP will provide an estimator once a final rate plan is selected. For residential customers bill impacts are shown for both average (500 kWh/month) and above-average (1,000 kWh/month) usage. Small commercial customers also see varying impacts depending on the rate adjustment strategy. Medium and large commercial customers, though fewer in number, account for a significant share of total energy use and will experience larger absolute bill changes. Across all customer classes, two alternative rate adjustment strategies are modeled, with impacts shown through 2028. PWP's proposed rates remain competitive with neighboring utilities, though comparisons are influenced by many factors such as differences in infrastructure needs and operating costs.

Comprehensive Light and Power Rate Ordinance Recommendations for Restatement and Modernization

The City recently updated several provisions of the Light and Power Rate Ordinance. These updates aimed to eliminate outdated or obsolete language and align with current industry best practices. Key changes included the removal of the Direct Access Service section and revisions to long-term contract provisions. In February 2025, the City Council approved amendments to the Pasadena Municipal Code to eliminate the outdated Stranded Investment Reserve and establish a Working Capital Reserve Policy. This policy includes targets for liquidity, energy market exposure, transmission, and contingency risks. These changes align with Government Finance Officers Association best practices and support long-term financial resilience. The reserve policy ensures that PWP maintains sufficient working capital to manage volatility in energy markets, unexpected capital needs, and other operational risks without abrupt rate changes.

Staff further reviewed the overall structure of the ordinance and recommends revisions that are aligned with current industry leading practices and provide a streamlined approach for future policy revisions and include the following guiding principles:

- Streamlined governance: Propose to move all rate figures to the *Electric Utility Rate Resolution* allows faster Council-approved adjustments.
- Future-readiness: The ordinance anticipates AMI deployment, time-of-use pricing, distributed generation (NEM/FIT), and renewable integration.
- Technical alignment: Definitions and schedules now match CPUC terminology, NERC standards, and CAISO market conventions.

Staff recommends a restatement because the current rates ordinance has become too unwieldy to manage through piecemeal amendments. Over time, layers of changes, cross-references, and outdated language have made it hard for staff, customers, and decision makers to read and understand. A restatement lets us reorganize the entire structure, integrate all prior amendments, remove inconsistencies, and modernize the policy in a clear and coherent format. This approach improves transparency, supports compliance, and gives the public a complete, readable ordinance instead of another round of patchwork edits.

Changes in the restated ordinance include:

1. Structural and Formatting Updates
   - The revised document (redline) retains the same section numbering but adds clearer formatting, headings, and spacing.
   - Cross-references to the Electric Utility Rate Resolution replace older inline rate tables or numeric rate references.
   - The term “Electric Utility Rate Resolution” now governs all fees, penalties, and charges across sections, providing flexibility for rate updates without ordinance amendments.
   - Several obsolete phrases and voltage configurations were modernized, and redundant phrases (e.g., “as herein used”) were removed for clarity.

2. Expanded and Updated Definitions (13.04.020)
   - New definitions added:
     - *Apparent Power*, *Distribution Charge*, *Energy Services Charge*, *Grid Access Charge*, *Interval Read Capable Meter*, *Portfolio Content Category One (PCC1)*, *Renewable Energy Credit (REC)*, *Reservation Charge*, *Time-of-Use (TOU)*, and *Electric Utility Rate Resolution*.
     - These definitions modernize terminology consistent with California Public Utilities Code and CPUC standards.
   - Terminology alignment: The definition of *Department*, *Customer Charge*, and *Transmission Services Charge* was standardized for consistent use in schedules
   - Environmental language: Added *Greenhouse Gas (GHG)* definition, reflecting PWP's decarbonization and carbon-free 2030 goals.
   - Measurement precision: Units like *kW*, *kWh*, *MW*, and *MWh* are now clearly defined, emphasizing technical accuracy and alignment with industry practice.

3. Modernization of Rate Design (13.04.031)
   - Introduced three-tiered TOU pricing: "on-peak," "off-peak," and "critical-peak."
   - Defined Seasonal Periods before and after *Interval Read Capable Meter* implementation, signaling a transition to AMI-based dynamic pricing.
   - Clarified that all rate elements (fees, charges, refunds) are governed by the *Electric Utility Rate Resolution* — a major administrative simplification

4. Residential Schedules (R-1 and R-2)
   - Structure and applicability updated: Now includes clearer descriptions of voltage types and service conditions.
   - Customer rates explicitly list six core charge components: customer, distribution, grid access, energy services, transmission, and public benefit charges.
   - Rate options: Adds clear choice between *seasonal flat* and *TOU* rates; specifies that Interval Read Capable Meters will automatically enroll customers into TOU rates once deployed
   - Lockout period of 12 months between rate option changes maintained but clarified.

5. Commercial and Institutional Schedules (S-1 through L-3)
   - Standardization of applicability thresholds:
     - S-1 (<30 kW), M-2 (30–300 kW, secondary), M-1 (30–300 kW, primary), L-2 (>300 kW, secondary), L-1 (>300 kW, primary), and L-3 (≥10 MW).
   - Power Factor Penalty and Discount sections consolidated and made consistent across schedules.
     - Existing load correction thresholds (75%) and new load thresholds (85%) are standardized.
     - Discounts for >85% power factor capped at 5%.
   - Billing demand now includes detailed measurement interval (15 minutes, adjustable for intermittent load).
   - Minimum monthly charge language harmonized across classes to include customer, distribution, and grid access charges

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7. Load Management & Pilot Program Modernization (13.04.071)

- Expanded to authorize special experimental rates for:
  - Demand response,
  - Electric vehicle integration,
  - Load shifting incentives.
- Defines program caps: 3% of total system MWh and 10% per customer group, aligning with PWP's resource adequacy and innovation goals.

Section	Topic	Previous Version	Updated Version (Redline)	🆕 / 🔄
13.04.020	Definitions	Limited technical terms	Expanded to include TOU, PCC1, RECs, Net Energy terms, etc.	🆕 Major Expansion
13.04.031	Pricing & TOU	Two TOU periods (on/off-peak)	Adds "critical-peak"; TOU default after smart meter rollout	🔄 Enhanced
13.04.040 / 045	Residential Rates (R-1/R-2)	Seasonal flat rate mainly	Adds TOU option; auto-enroll post-meter upgrade	🔄 Modernized
13.04.046	EUAP (Assistance)	Embedded in R-1 and R-2	Created distinct section.	🔄 Clarified
13.04.050–060	Commercial Rates (S-1, M-1, M-2)	Basic rate structure	Unified charges, TOU options, power factor penalties/discounts	🔄 Standardized
13.04.067–069	Large Commercial (L-1, L-2)	No TOU or PF incentives	Adds TOU, PF penalties/discounts, demand thresholds	🔄 Updated
13.04.070	Extra-Large Commercial (L-3)	Not previously defined	New schedule for 10MW+ customers	🆕 New Customer Class
13.04.071	Load Management	Limited pilot language	Formalized optional rate for experimentation	🔄 Refined

Section	Topic	Previous Version	Updated Version (Redline)	🆕 / 🔄
13.04.074	EV Charging (EV-1 to EV-3)	Not included	New schedules by demand tier (<30kW, 30–300kW, >300kW)	🆕 Added
13.04.080	Standby Service	Basic contract language	Adds reservation charge, grid access, and safety provisions	🔄 Refined
13.04.085–087	Unmetered Rates (CE-1, CE-2)	Minimal detail	Adds billing formulas, audit rights, and load change rules	🔄 Strengthened
13.04.090	Street Lighting	Flat rate tables	Adjust in Electric Utility Rate Resolution	🔄 Modernized
13.04.100	Service Regulations	General manager authority	Adds 30-day notice to Council, website posting	🔄 Transparency
13.04.110	Meter Installation	Basic specs	Interval Read Meters become standard; opt-out fees added	🔄 Upgraded
13.04.150	Rate Schedule Changes	12-month lock-in	Adds TOU auto-enroll trigger with smart meters	🔄 Clarified
13.04.170	Transmission Services Charge	Basic formula	Minor changes to detailed formula	🔄 Refined
13.04.173	Power Cost Adjustment (PCA)	Basic adjustment	Clarify monthly recalculation, detailed forecast-based formula	🔄 Refined
13.04.176	Feed-in Tariff (FIT)	Not included	Standard Contract for Local Clean	🆕 New Program

Section	Topic	Previous Version	Updated Version (Redline)	🆕 / 🔄
			Energy Generation for developers (not customers)	
13.04.177	Net Energy Metering (NEM)	CPUC §2827-based	Adds post-2026 structure, surplus premium tie to pricing, re-establish eligibility rules	🔄 Transition Plan
13.04.178	Self-Generation (SG)	Basic crediting	Adds TOU-based billing, demand thresholds, credit carryover	🔄 Expanded
13.04.179	Green Power (GP)	Flat premium	Adds post-2026 premium flexibility, PCC1 REC valuation	🔄 Updated
13.04.230	Public Benefit Charge	Fixed minimum	Consistent language	🔄 Refined

Key Ordinance Enhancements Supporting Local Renewable Generation

The proposed updates to Chapter 13.04 of the Pasadena Municipal Code significantly enhance the City's support for local renewable energy generation. A key addition is the establishment of a Feed-in Tariff (FIT) program or a Standard Offer for Clean Energy, which enables eligible renewable energy generators (up to 3 MW) to enter into standardized long-term contracts with PWP to sell 100% of their output. The FIT rates are updated quarterly and reflect avoided energy costs, renewable energy credit (REC) values, greenhouse gas compliance savings, and avoided transmission losses, making local generation more financially viable.

The ordinance also modernizes the City's Net Energy Metering (NEM) program. While continuing to support customer-generators under the existing framework, the ordinance introduces a new post-2026 structure that provides monthly or bi-monthly credits for surplus energy, including a premium for renewable attributes. This ensures long-term program sustainability while aligning with evolving state regulations. The proposed program does not impact existing customers who have already invested in solar under annual net metering. It also does not modify existing monthly/bi-monthly net metering customers aside from removing one obsolete premium that was relevant prior to PWP's modernized customer information system and provides clarification that incentive amount for monthly/bi-monthly customers is for the energy portion of bills.

For larger customers, the updated Self-Generation (SG) schedule supports systems of 1 MW or more, offering credits for net energy delivered to PWP and incorporating TOU billing. Additionally, the Green Power Service schedule allows all customers to voluntarily support renewable energy procurement by opting into 100% green power or purchasing in 100 kWh blocks, with premiums reinvested into renewable energy resources.

These changes are supported by a recalibrated Public Benefit Charge, which continues to fund renewable energy incentives, energy efficiency programs, and low-income assistance. Collectively, these updates position Pasadena to meet its clean energy goals by expanding access to renewable generation, modernizing rate structures, and incentivizing sustainable energy practices across all customer classes.

Program / Section	Previous Policy	Updated Policy	Impact
Feed-in Tariff or Standard offer – Clean Energy Contract (13.04.176)	Not previously offered	New FIT program for ≤3 MW generators with standardized contracts and quarterly rate updates	Enables local renewable developers to sell power directly to PWP
Net Energy Metering (13.04.177)	Based on CPUC §2827; capped participation	Adds post-2026 structure with monthly/bi-monthly billing, surplus crediting, and renewable premium. **No impact to existing annual net metering customers**.	Sustains rooftop solar adoption and untethers policy from State adoption
Self-Generation (13.04.178)	Basic crediting for large systems	TOU billing, net delivery credits, and grid upgrade cost recovery	Encourages large-scale on-site renewable generation
Green Power Service (13.04.179)	Flat premium for 100% green power	Adds flexible block-based participation and post-2026 premium pricing	Expands voluntary support for renewable procurement

Implementation Timeline

PWP is recommending that a public hearing be set for February 9, 2026, to receive comments on the recommended adjustments to the electric rates. Following the City Council's action to set a date for the public hearing, a notice will be mailed to all electric system customers that includes the recommended rate adjustments and provides information regarding the public hearing. Table 6 outlines the approximate timeline and implementation schedule for the proposed rate actions.

Table 6: Timeline

Date	Action Item
December	Mail public hearing notice
December 2025-February 2026	Customer Outreach and Education
February 9, 2026	Electric Rates Public Hearing
February 23, 2026	First Reading of Updated Electric Rate Ordinance
March 2, 2026	Second Reading of Updated Electric Rate Ordinance
March 1, 2026 or as soon as practicable thereafter	Effective Date of First Rate Action

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The establishment of a date to conduct a public hearing for the consideration of electric rate adjustments and the drafting of related resolutions and ordinance amendments are administrative actions that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Therefore, the proposed actions do not constitute a "project" subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required. Furthermore, the recommended electric rate adjustments themselves would be statutorily exempt from CEQA. Section 15273 of the State CEQA Guidelines identifies a statutory exemption for "Rates, Tolls, Fares, and Charges" and states (in part) that:

a. CEQA does not apply to the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or their charges by public agencies which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The estimated cost to mail information about the public hearing and recommended rate increases to all City of Pasadena electric customers is approximately $30,000. Funds are available in the Light and Power Fund.

The rate increases are expected to generate incrementally between $17 million and $24 million depending on alternative enacted. The incremental revenues will be used to offset increased O&M and capital costs of the electric system.

Respectfully submitted,

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Approved by:

MIGUEL MÁRQUEZ
City Manager

Attachment A: Draft Financial Report and Revenue Requirements (NewGen Document)
Attachment B: Rate Schedule Alternative 1
Attachment C: Rate Schedule Alternative 2

Draft Report | November 18, 2025

Electric Rate Study

Pasadena Water and Power
Pasadena, California

Prepared by:

NewGen Strategies & Solutions

Section 2
REVENUE REQUIREMENTS

Developing the Test Year Revenue Requirement is the first step in the cost of service and rate design process, as shown in Figure 1-1. The Test Year Revenue Requirement for the City of Pasadena's Light and Power Fund was based on the average expenses for Fiscal Year ("FY") 2026 through FY 2027 with adjustments for unusual or one-time expenses, the adopted Capital Improvement Plan ("CIP"), existing debt amortization schedules, projected debt issuances, and forecasted escalation assumptions and factors. NewGen developed a four-year financial forecast for the Study Period. The average revenue requirement for the first two years was used as the test year revenue requirement and represents all costs that must be recovered through the electric rates. The Test Year Revenue Requirement serves as a basis for determining the overall level of revenue recovery and provides a foundation for the cost of service analysis.

Financial Forecast

The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves over the four-year Study Period (FY 2026–FY 2029). Pasadena Water and Power ("PWP" or "the Utility") received guidance from the ratemaking body, City Council, on July 14, 2025, to establish the Study Period and set rates for a two-year period. To develop the financial forecast, NewGen Strategies and Solutions, LLC (NewGen) utilized the Light and Power Fund's FY 2026 budgeted expenses, load forecast documents, records of operations, customer billing data, and other detailed information and data compiled and provided by PWP. The forecast used the FY 2026 budgeted expenses as the base year in the financial forecast. Any projected non-recurring expenses or revenues were identified and incorporated in the financial forecast, as appropriate.

To forecast expenses through FY 2029, NewGen used multiple escalation and forecast factors. The forecast applied specific inflation and customer growth rates to the baseline FY 2026 budget year data and reviewed each account or group of accounts to select an applicable escalation or inflation rate for the expenses. For Power Supply-related costs, NewGen relied on a detailed forecast and resource plan from PWP that integrated their long-term purchased power agreements, fuel price forecasts, renewable energy credit forecasts, and other proprietary energy market forecasts.

The financial model also provides PWP the capability of evaluating scenarios for future financial performance by changing rates, issuing debt, and calculating key performance indicators ("KPIs"). These KPIs for PWP are based on the financial policies, bond covenants, and other financial performance targets set by the Utility and/or City Council. Typically, as a utility best practice, PWP evaluates overall forecasted expenses, revenues, and the resulting KPIs such as the Debt Service Coverage Ratio ("DSCR") and level of cash reserves. PWP evaluates varying levels of debt issuance and changes in rates over time to fund the required capital investments, while ensuring it maintains the targeted financial KPIs. These rate and debt recommendations are primarily driven by the increasing capital needs of the Utility and the need to ensure PWP maintains established DSCR and cash reserve levels.

Projected Energy Requirements

The forecasted load demand was a key driver in projections of expenses and revenues in the financial forecast. PWP developed and supplied the load forecast. The forecasted retail electric consumption includes an annual average energy growth rate of 1.3% in the Study Period, which reflects sales to PWP's retail customers.

Table 2-1
Estimated Energy Requirements During Study Period

	FY 2026	FY 2027	FY 2028	FY 2029
PWP Retail Load (MWh)	1,037,516	1,042,651	1,054,593	1,078,494

Financial Forecast Results

The results of PWP's evaluation of the financial forecast are shown in Table 2-2. As discussed previously, PWP evaluated the overall financial performance to recommend balanced system-wide rate changes and debt issuances in the Study Period. Based on the forecast, the recommended total rate increase or total bill change for the Test Year period is 9.5% in FY 2026 and 9.5% in FY 2027. For the remaining years in the forecasted Study Period, PWP initially forecasts no total rate change or total change in bills for FY 2028 and 2029. Future rate changes in FY 2028 and 2029 are initial estimates based on guidance and may change based on progress, timing, fuel costs, power market prices, and execution of the Optimized Strategic Plan.

Table 2-2
Financial Forecast Results

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
O&M Expenses	$203,774,257	$215,204,439	$209,252,937	$229,852,057
Debt Service	$15,624,250	$18,000,250	$18,780,848	$18,779,473
Capital Paid from Current Earnings (1)	$106,015,456	$73,701,937	$99,636,557	$93,648,293
Capital Paid from Low Carbon Fuel Standard and Undergrounding Fund (2)	$8,052,160	$7,604,000	$8,392,000	$5,692,000
Capital Paid from Customers (3)	$5,574,406	$5,512,500	$5,512,500	$5,512,500
City Transfer	$28,500,000	$29,965,350	$33,036,361	$33,405,204
Other Expenses (Income)	($56,997,751)	($62,871,304)	($54,187,505)	($53,084,572)
Revenue Requirement	$310,542,778	$287,117,172	$320,423,697	$333,804,954
Debt Issuance Recommendations	$0	$50,000,000	$0	$0
Total Rate Change Recommendations (4)	9.5%	9.5%	0.0%	0.0%
Projected Revenues at Recommended Rates	$249,711,248	$275,303,011	$278,376,697	$314,120,676
Difference (5)	($60,831,530)	($11,814,162)	($42,047,000)	($19,684,277)

(1) Capital funded by grants nor grant revenue are included in the financial forecast results.
(2) Corresponding revenues for Low Carbon Fuel Standard ("LCFS") and Underground are included in Other Expenses (Income).
(3) Corresponding revenues for capital paid from customers are included in Other Expenses (Income).

Table 2-2
Financial Forecast Results

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029

(4) Rate changes represent rate changes implemented on January 1st, 2026, and 2027.

(5) The difference in the revenues and total expenses is managed by cash reserves. The results of the annual change in cash reserves are summarized later in this section.

The remainder of this section will summarize and describe the key components of the financial forecast results, in addition to quantifying the Test Year Revenue Requirement for FY 2026 and 2027 that will support the rate change recommendations for those years. As discussed previously, the Test Year and recommended rate plan do not include FY 2028 and 2029, as the operating and capital expenses for those years will change and are dependent on future decisions related to the implementation of the OSP.

Operations and Maintenance Expenses

The first step in developing the revenue requirement forecast was the creation of the base year operations and maintenance ("O&M") expenses. PWP'S historical data and FY 2026 budget provide the Light and Power Fund O&M expenses. In discussions with PWP management, NewGen selected the detailed FY 2026 budget as the base year in the financial forecast for projections of O&M expenses.

Based on the FY 2026 budget from PWP, NewGen forecasted the O&M costs for the Study Period. In addition to the projected other expenses/revenues (including interest income, capital contributions, miscellaneous revenues, and sales to other utilities), CIP, debt service projections, and City Transfer, these forecasted O&M expenses supported the eventual development of the Test Year Revenue Requirement. The Test Year Revenue Requirement includes all costs required to operate the Utility and ensure financial stability for the Electric Utility over the desired period of time the rates are in effect.

O&M Forecast Account Detail

Table 2-3 summarizes the forecasted O&M expenses for the Study Period. NewGen used the average two-year O&M expenses for FY 2026 and 2027 for the Test Year Revenue Requirement as seen in Table 2-4.

Table 2-3
Forecasted O&M Detailed Funds

Account	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Personnel				
General Manager	$539,001	$558,136	$577,949	$598,467
Public Benefit Charge	$1,491,644	$1,544,597	$1,599,431	$1,656,210
Finance and Administration	$3,949,226	$4,089,424	$4,234,598	$4,384,926
Customer Service and Administration	$7,337,358	$7,597,834	$7,867,557	$8,146,856
Power Delivery	$19,307,534	$19,992,951	$20,702,701	$21,437,647
Power Supply	$11,392,208	$11,796,631	$12,215,412	$12,649,059
External Affairs	$875,675	$893,189	$911,052	$929,273
Services & Supplies				
General Manager	$566,813	$578,149	$589,712	$601,506
Public Benefit Charge	$9,911,155	$10,109,378	$10,311,566	$10,517,797
Finance and Administration	$4,240,328	$4,325,135	$4,411,637	$4,499,870
Customer Service and Administration	$2,801,969	$2,858,008	$2,915,169	$2,973,472
Power Delivery	$9,801,632	$14,235,765	$14,435,718	$14,639,670
Power Supply	$119,848,203	$124,501,244	$115,928,569	$133,821,597
External Affairs	$793,902	$809,780	$825,976	$842,495
Internal Service Charge				
General Manager	$122,761	$127,671	$132,778	$138,089
Public Benefit Charge	$300,358	$312,372	$324,867	$337,862
Finance and Administration	$1,299,538	$1,351,520	$1,405,580	$1,461,804
Customer Service and Administration	$986,850	$1,026,324	$1,067,377	$1,110,072
Power Delivery	$4,778,438	$4,969,576	$5,168,359	$5,375,093
Power Supply	$1,261,922	$1,312,399	$1,364,895	$1,419,491
External Affairs	$162,992	$169,512	$176,292	$183,344
Other Operating Expenses				
General Manager	$0	$0	$0	$0
Public Benefit Charge	$0	$0	$0	$0
Finance and Administration	$36,415	$37,143	$37,886	$38,644
Customer Service and Administration	$72,835	$74,292	$75,778	$77,293
Power Delivery	$1,868,500	$1,905,870	$1,943,987	$1,982,867
Power Supply	$27,000	$27,540	$28,091	$28,653
External Affairs	$0	$0	$0	$0
Total	**$203,774,257**	**$215,204,439**	**$209,252,937**	**$229,852,057**

Table 2-4
O&M Revenue Requirement

Account	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Personnel	$44,892,646	$46,472,762	$45,682,704
Services & Supplies	$147,964,002	$157,417,459	$152,690,730
Internal Service Charge	$8,912,859	$9,269,373	$9,091,116
Other Operating Expenses	$2,004,750	$2,044,845	$2,024,798
Total	**$203,774,257**	**$215,204,439**	**$209,489,348**

A summary of the key elements of the O&M expenses in addition to other expenses, such as debt service and transfers, are included below.

Power Supply Expenses

Power Supply expenses are the largest portion of the total O&M expenses and are associated with take or pay contracts (i.e., Intermountain Power Plant, Magnolia Power Plant, Palo Verde Power Plant, and Hoover Hydro Power), purchased power agreements (i.e., numerous renewable energy contracts), resource adequacy costs, and all other purchases to meet system demand. PWP provided the projected power supply costs incorporated into the Study. Additional power supply expenses include PWP labor and other supporting O&M accounts for the power plant, wholesale operations, and power supply management and planning. The tables below summarize the total power supply expenses for the Study Period and the power supply expenses for the revenue requirement.

Table 2-5
Power Supply Expenses

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Power Supply				
Personnel	$11,392,208	$11,796,631	$12,215,412	$12,649,059
Fuel Cost	$5,513,608	$6,610,536	$6,651,127	$6,626,018
Purchased Power	$102,925,795	$105,078,270	$96,895,814	$114,226,684
Other Power Supply Expenses	$4,287,961	$3,580,699	$3,095,374	$3,709,607
Other Services & Supplies	$7,147,839	$9,259,278	$9,314,345	$9,287,940
Internal Service Charge	$1,261,922	$1,312,399	$1,364,895	$1,419,491
Total Power Supply O&M	**$132,529,333**	**$137,637,814**	**$129,536,966**	**$147,918,799**

Table 2-6
Power Supply Revenue Requirement

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Power Supply			
Personnel	$11,392,208	$11,796,631	$11,594,420
Fuel Cost	$5,513,608	$6,610,536	$6,062,072
Purchased Power	$102,925,795	$105,078,270	$104,002,033
Other Power Supply Expenses	$4,287,961	$3,580,699	$3,934,330
Other Services & Supplies	$7,147,839	$9,259,278	$8,203,558
Internal Service Charge	$1,261,922	$1,312,399	$1,287,160
Total Power Supply O&M	**$132,529,333**	**$137,637,814**	**$135,083,574**

Transfer to the City General Fund (City Transfer)

The annual contribution for any municipal purpose ("City Transfer") is defined in the Section 1408 stating, "each fiscal year, the City Council shall transfer from the Light and Power Fund an amount equal to twelve percent (12%) of the gross income of the electric works received during the immediately preceding fiscal year from the sale of electric energy at rates and charges." In the financial forecast and Test Year Revenue Requirement, the City Transfer forecast was calculated according to the City Charter.

Debt Service

The debt service represents existing and projected debt service. The existing debt service within the Study Period and the Test Year Revenue Requirement includes the three outstanding bond issuances and associated amortization schedules.

For the Study Period, one new debt issuance was forecasted. The new debt issue supports the large CIP plans over the Study Period and Test Year. Key capital projects funded through the debt issuance include major investments in power delivery modernization—such as sizing infrastructure for projected load growth from electrification, addressing aging infrastructure, and strengthening system resilience against risks like wildfires. Funding these projects are investments that will serve future generations of customers with substantial asset lives. PWP identified $50 million in total debt issuances within the Study Period would be sufficient with the expectation that rate revenues and cash reserves will fund all other anticipated CIP.

Table 2-7 summarizes the projected debt service for the Electric Utility, and Table 2-8 summarizes the debt service revenue requirement.

Table 2-7
Electric Debt Service (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Debt Service				
Existing Direct	$15,624,250	$15,625,250	$15,620,375	$15,619,000
Future	$0	$2,375,000	$3,160,473	$3,160,473
Total	**$15,624,250**	**$18,000,250**	**$18,780,848**	**$18,779,473**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

Table 2-8
Electric Debt Service Revenue Requirement (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Debt Service			
Existing Direct	$15,624,250	$15,625,250	$15,624,750
Future	$0	$2,375,000	$1,187,500
Total	**$15,624,250**	**$18,000,250**	**$16,812,250**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

As mentioned previously, PWP evaluates the financial forecast and possible rate and debt issuance actions by monitoring financial KPIs. By bond covenants, PWP must maintain a minimum 1.5 DSCR. Pasadena Municipal Code 13.04.17513 outlines the Light and Power Fund's working capital reserves, which includes maintaining a minimum and target reserve equivalent to one year of debt service payments for outstanding bond or credit obligations. Table 2-9 summarizes the DSCR for PWP at the recommended rate increases for FYs 2026 and 2027. The operating expenses shown in Table 2-9 do not include capital paid from rate revenues and cash reserves, which is explained later in this section.

Table 2-9
Electric Debt Service Coverage Ratio (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Operating Revenues (2)	$303,008,999	$336,542,314	$319,775,657
Operating Expenses	$203,774,257	$215,204,439	$209,489,348
Net Revenues Available	$99,234,742	$121,337,875	$110,286,308
Debt Service			
Existing Direct (3)	$15,624,250	$15,625,250	$15,624,750
Future	$0	$2,375,000	$1,187,500
Total	**$15,624,250**	**$18,000,250**	**$16,812,250**
Debt Service Coverage Ratio (4)	**6.4**	**6.7**	**6.6**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.
(2) Operating revenues include retail rate revenues, interest income, and other or miscellaneous revenues.
(3) DSCR equals the Net Revenues Available divided by the total Debt Service.

Capital Paid from Current Earnings

The Electric Utility's capital expenses are identified within the FY 2026 Budget four-year CIP. To finance these capital investments and system upgrades over the Study Period, the Utility plans to utilize a combination of debt, rate revenues, and cash reserves. These projects are most notably the implementation of the advanced metering infrastructure, a software and hardware investment, and the PWP battery energy storage system. These projects are critical modernization projects that have been delayed and are time-critical within the Study Period. However, in the absence of rate adjustments, a significant portion of the annual CIP would need to be funded through cash reserves. The average annual capital expenses funded through rate revenues or cash reserves—reflected in FY 2026, FY 2027, and the Test Year Revenue Requirement— totals $89.9 million. Table 2-10 presents the annual capital outlays funded through cash sources over the Study Period, while Table 2-11 summarizes the capital outlays attributed to cash sources in the Test Year.

Table 2-10
Electric Capital Funded with Cash Sources

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Cash-Funded Capital	$106,015,456	$73,701,937	$99,636,557	$93,648,293

Table 2-11
Electric Capital Funded with Cash Sources for Revenue Requirement

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Cash-Funded Capital	$106,015,456	$73,701,937	$89,858,696

Capital funded through grants and contributions in aid of construction ("CIAC") from customers are excluded from the revenue requirement and COS as they do not contribute to costs that must be recovered in PWP's rates. All expenses associated with construction in these two categories are independently funded and have no impact on revenue requirement. As such, CIAC is adjusted out of the revenue requirement as seen in Table 2-12.

Other Income and Expenses

Other income and expenses represent miscellaneous non-operating revenues or expenses that are a net $57.4 million in revenues in the Test Year. This amount reflects non-operating revenues, which include interest income, grants, charges for internal services, and miscellaneous revenues (e.g., late fees, connection fees, etc.). These net revenues act to reduce the overall revenue requirement and eventual rates paid by PWP customers. Adjustments have been made to other income to arrive at the Test year Revenue Requirement. Corresponding with the CIAC removal from capital expenses, the CIAC associated revenues are also removed from other income. Additionally, adjustments are made to the revenues associated with the public benefit charge and LCFS as these expenses and revenues be equal in practice. PWP targets annual public benefit charge and LCFS related expenses to be equal to the revenues generated. After adjustments, these net revenues reduce the overall Test Year Revenue Requirement by $57 million.

Revenue Requirement

There are two primary revenue requirement methodologies employed in the utility industry: the cash basis and the utility basis. The primary differences between the cash basis and the utility basis involve the treatment of depreciation, return on invested capital, and debt service. The cash basis, which is the most common method used by municipalities, includes debt service but excludes depreciation and return on invested capital in the revenue requirement determination. The cash basis focuses on meeting the cash demands of the utility. The utility basis, commonly used by private or for-profit utilities, includes depreciation and return on invested capital, but excludes debt service from the revenue requirement determination.

In this cost of service analysis, NewGen utilized the cash basis as it follows the traditional cash-oriented budgeting practices frequently used by government entities. Furthermore, the cash basis is generally easier to communicate to customers, as it aligns revenue with expenditures.

NewGen developed the Test Year Revenue Requirement for the two-year Study Period, including all costs required to operate the Utility and ensure its financial stability. The Test Year Revenue Requirement of $259,523,634 is the two-year average of the annual revenue requirements and is shown in Table 2-12.

The current rates are insufficient to fully recover the projected operating and capital costs by approximately $31.5 million.

Table 2-12
Test Year Revenue Requirement [1]

Account	2-Year Average	Adjustments	Test Year
O&M Expenses [2]	$209,489,348		$209,489,348
Debt Service [3]	$16,812,250		$16,812,250
Capital Paid from Rates	$89,858,696		$89,858,696
Capital Paid from Low Carbon Fuel Standard and Undergrounding Fund [4]	$7,828,080		$7,828,080
Capital Paid from Customers [5]	$5,543,453	($5,543,453)	$0
City Transfer	$29,232,675		$29,232,675
Other Expenses/(Income) [6]	($59,934,527)	$2,593,189	($57,341,338)
Application of Reserves	($36,322,846)		($36,322,846)
Revenue Requirement [7]	**$262,507,129**	**($2,950,264)**	**$259,556,865**
Test Year Projected Revenues [8]			**$227,990,390**
Over (Under) Recovery of Costs			**($31,566,475)**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.
(2) O&M Expenses exclude non-cash related items such as Depreciation.
(3) Debt service reflects the annual total principal and interest payments associated with current and expected new debt financing.
(4) Corresponding revenues for Low Carbon Fuel Standard (LCFS) and Underground are included in Other Income.
(5) Corresponding revenues to capital paid from customers are included in Other Income.
(6) Other Expenses/(Income) include interest income, non-operating expenses, miscellaneous revenues, and non-operating revenues.
(7) Please note the 2-year average revenue requirement shown here does not equal the revenue requirements shown in Table 2-2 as Table 2-12 applies the use of cash reserves to reduce the revenue requirement
(8) Test Year Projected Revenues assume the current Power Cost Adjustment.

NewGen has included the application of cash reserves to decrease the Test Year Revenue Requirement in Table 2-12. Existing reserves meet and exceed its financial policies and minimums and maintains them after the Test Year period and use of a portion of the reserves.

Reserves

Unrestricted cash reserves serve multiple purposes, including providing working capital, funding capital projects, mitigating market and price volatility risks to customers, and supporting the Utility's overall cash flow management. The annual balances and contributions to or use of reserves, assuming PWP does not adjust base rates, are shown in Table 2-13.

If PWP does not implement rate increases, the estimated annual shortfall of $31.5 million in the revenue requirement will further draw down the cash reserves beyond the levels already planned and shown in Table 2-12. The estimated reserve balance as of July 1, 2025, is $409 million or 741 days of cash on hand. Without any rate increases, PWP's cash reserve balance is projected to decline by $137 million over the Study Period, decreasing from $409 million to $271 million.

Table 2-13
Electric Cash Reserve Balances – No Rate Increases (1)

	Year 1 FY 2026	Year 2 FY 2027
Fund Balance – BOY	$408,829,565	$327,725,532
Deposits from Earnings (2)	$38,537,989	$30,928,969
Withdrawals (Capital & Operating)	($119,642,022)	($86,818,437)
Fund Balance – EOY	$327,725,532	$271,836,065
Days Cash on Hand BOY	741	564
Days Cash on Hand EOY	595	469

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

(2) Deposits from earnings represent the operating revenues less operating expenses, City Transfer, and debt service.

If the proposed total rate increases of 9.5% for both FY 2026 and FY 2027 are implemented, the projected ending balance in FY 2027 increases from $271 million to $336 million, equivalent to 578 days cash on hand. The cash reserve balances, resulting from the proposed systemwide rate adjustments, are consistent with industry standards and provide PWP flexibility and financial stability to support future operating and capital requirements. Additionally, the reserves offer the ability to manage uncertainties related to construction timelines, project schedules, and financing costs, including interest rate fluctuations. Beyond these functions, the cash reserves serve multiple purposes within the Utility, such as providing working capital, stabilizing rates to reduce volatility, and funding capital improvements.

PWP has a working capital policy reflected in Pasadena Municipal Code Chapter 13.04.175 which establishes the “Working Capital targets to be the sum of an Operational Reserve, a Debt Service Reserve, a Capital Expenditures Reserve, a General Fund Transfer Reserve, an Energy Services Charge Reserve, a Transmission Services Charge Reserve, and a Contingency Reserve.”

CITY OF PASADENA ★ INCORPORATED JUNE 1886 ★

Agenda Report

February 24, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (February 11, 2025)

FROM: Water and Power Department

SUBJECT: **DIRECTION TO CITY ATTORNEY TO PREPARE WITHIN 60 DAYS AN ORDINANCE AMENDING PASADENA MUNICIPAL CODE CHAPTER 13.04 TO REMOVE STRANDED INVESTMENT CHARGE AND RESERVES AND AMEND TO INCLUDE A WORKING CAPITAL RESERVE TARGET (Water & Power Depart.)**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the action proposed herein is not a "project" subject to the California Environmental Quality Act (CEQA) pursuant to California Public Resources Code Section 21065 and within the meaning of State CEQA Guidelines Section 15378(b); and

2) Direct the City Attorney to prepare an ordinance and return within 60 days, amending the Pasadena Municipal Code ("PMC") Chapter 13.04, the light and power rate ordinance to:

    a. Amend Section 13.04.173 – Power cost adjustment.
    b. Amend Section 13.04.175 – Reserve for stranded investment and change title to "Reserve for working capital"; and,
    c. Remove 13.04.176 – Stranded investment surcharge.

MUNICIPAL SERVICES COMMITTEE ("MSC") RECOMMENDATION:

On February 11, 2025, the MSC approved the staff recommendation to direct the City Attorney's Office to prepare an ordinance to amend PMC 13.04; the code change would create a working capital reserve target policy. Staff received guidance to also create a minimum level for reserves to establish the point at which reserve levels would be detrimental to the operations of the utility.

The basis for a minimum is recommended to be 60 days, as compared to 90 days for the target, for liquidity reserve for operating expenses (2) the market reserve category, and (3) the contingency risk category. Given that the current minimum reserve level within the City's Fund Balance Reserve Policy for the Light and Power Fund is 60 days of operating expenses, this recommendation is consistent with adopted policy. The revision to the code would also acknowledge that there are many other risks that the utility faces that require sufficient working capital in a rapidly changing industry and world.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") recommends streamlining PMC code sections that impact the Light and Power Fund's reserves to adopt a working capital reserve target. The proposed target includes amounts to address liquidity needs and several types of risks within the utility. Established target amounts will ensure exceptional creditworthiness as well as resilience to unforeseen circumstances. The proposed PMC change also will include protocol for the use, replenishment, and monitoring of the target amounts. Furthermore, the recommendation is to dissolve the existing narrowly focused Stranded Investment Reserve to address the current working capital needs to enable continuity of services and stability of customer rates.

BACKGROUND:

The Stranded Investment Reserve was established in 1996 as part of a strategy to address above-market energy costs anticipated from the Intermountain Power Project (IPP) and Magnolia projects, which, at the time, were projected to lose value due to industry restructuring. Funded through ratepayer contributions, this reserve was limited to covering stranded investment risks only. Since the establishment of the reserve, however, these assets have retained value, with much lower exposure to stranded costs than initially anticipated. As required by PMC 13.04.175, Council has approved the use of the Stranded Investment Reserve several times in the past, with uses such as the defeasance of $80 million in bonds and the most recent usage of $7 million per year from 2018- 2022 to mitigate future rate increases due to the increasing power supply costs.

In today's financial environment, Government Finance Officers' Association and other industry best practices recommend utility reserves focus on operational liquidity, cash flow stability, and risk mitigation for operational and capital needs. Adopting a working capital reserve will allow PWP to realign the stranded investment funds into reserve categories that better address modern utility risks, including unexpected cost fluctuations, seasonal revenue variances, and operational stability; all while considering a long-term perspective on funds management.

In light of the ongoing electric rate study, PWP is seeking policy direction on the amount of reserves deemed appropriate by Council in order to set rates that optimize for both affordability and rate stability.

Reserve Policy Target Components

The proposed Reserve Policy Target includes four main reserve categories, each tailored to mitigate specific risks and provide targeted financial stability:

1) **Liquidity Reserve**
   a) **Purpose**: Provides liquidity to meet routine operational expenses and cash flow during times of revenue variability.
   b) **Target Level**: Equivalent to the sum of 90 days of operating expenses, one-year principal payment for outstanding bonds, approved General Fund transfer amount, and one year capital improvement budget. This reserve helps PWP manage short-term financial disruptions, such as seasonal variations in revenue or unexpected operational expenses.
   c) **Risk Mitigation**: Protects against revenue volatility by ensuring sufficient funds are available to cover costs without needing immediate rate adjustments. This reserve level will also support debt service obligations, enhancing PWP's credit profile.
2) **Market Exposure Reserves**
   a) **Energy Services Charge Reserve**
      i) **Purpose**: Provides a buffer against fluctuations in energy costs and unexpected energy purchase needs. Energy markets can be volatile, impacting the cost of purchased power.
      ii) **Target Level**: Set at 90 days of projected energy costs.
      iii) **Risk Mitigation**: Enables PWP to manage unexpected energy price spikes or supply disruptions without impacting rate stability. The reserve also helps maintain rate stability by offsetting temporary increases in energy procurement costs.
   b) **Transmission Reserve**
      i) **Purpose**: Covers potential increases in transmission costs or investments needed for maintaining or upgrading transmission infrastructure. This reserve addresses cash needs arising from unforeseen transmission expenses that may arise from infrastructure wear, system expansion, or regulatory changes.
      ii) **Target Level**: Based on projected annual transmission costs amounting 90 days of PWP's annual transmission-related obligations.
      iii) **Risk Mitigation**: Supports the continuity of service by covering unanticipated transmission expenses without needing to increase customer rates or reduce service quality. A dedicated transmission reserve also ensures that PWP can meet short-term needs related to system upgrades or unexpected outages.
3) **Contingency Reserve**
   a) **Purpose**: Acts as a safeguard for extreme or unforeseen events that exceed standard operating and capital contingencies, including emergencies or regulatory changes requiring immediate capital outlays.
   b) **Target Level**: 90 days of annual operating expenses and capital workplan.
   c) **Risk Mitigation**: Enhances PWP's financial resilience to sudden disruptions that could impact service delivery, such as natural disasters or unexpected regulatory

mandates requiring rapid response. The contingency reserve is an essential part of a strong reserve structure, ensuring operational continuity in critical times.

Proposed Policy Implementation

The conversion of the Stranded Investment Reserve into the Working Capital Reserve Target with established reserves will involve:

1) Reclassifying Funds: Allocating the existing balance from the Stranded Investment Reserve into the Working Capital Reserve based on PWP's needs and recommended reserve levels.
2) Establishing Utilization and Replenishment Policies: Defining criteria for withdrawals and required approvals to ensure that funds are used appropriately and replenished as needed to maintain established targets.
3) Annual Review and Adjustment: Regular assessment of reserve levels by the General Manager, reviewing as necessary to meet changing operational and market conditions.

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

CEQA excludes, from environmental review, actions that are not "projects" as defined by California Public Resources Code (PRC) CEQA Guidelines Section 21065 and within the meaning of CEQA Guidelines Section 15378(b). PRC Sections 21065 and CEQA Guidelines Section 15378(b) define a project as an action which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment. CEQA Guidelines Section 15378 excludes from the definition of "project" administrative activities of governments that will not result in direct or indirect physical changes in the environment. The actions proposed herein, amending the municipal code to establish a consolidated working capital reserve for the Light and Power Fund, is an administrative activity, and therefore is not a "project" as defined by CEQA. Since the action is not a project subject to CEQA, no environmental document is required.

FISCAL IMPACT:

This amendment requires no additional ratepayer contributions, as the funds are currently available within the Stranded Investment Reserve and Light and Power Fund Balance. By realigning these funds, PWP will improve financial stability, protect ratepayers from abrupt rate adjustments, and provide enhanced fiscal resilience for the utility. There is no impact to the General Fund.

Respectfully submitted,

DAVID M. REYES
Interim General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

for MIGUEL MÁRQUEZ
City Manager

PASADENA WATER AND POWER

MEMORANDUM

March 11, 2025

To: Municipal Services Committee

From: David M. Reyes
Interim General Manager

Subject: **Electric Rate Study Update – Customer Engagement Plan**

This memorandum is for information only.

BACKGROUND:

This report provides an informational update to the Municipal Services Committee ("MSC") about the status of the Pasadena Water and Power's ("PWP") Electric Rate Study ("ERS"), specifically the customer engagement plan. The ERS aims to evaluate and develop a recommended rate plan that aligns with City Council policies and legal constraints. The objective is to collect sufficient revenue while also supporting both community and utility goals. This goal is reached by sending price signals to customers that communicate key information and incentivize behaviors that benefit both the community and the utility. With the use of empirical data and professional expertise of industry best practice, PWP will explore rate structures and pricing incentives that will accommodate evolving electric industry trends and customer practices. The presentation will discuss planned customer engagement strategy for the study and provide a brief overview of activities since the most recent MSC update on October 22, 2024.

PROGRESS UPDATE:

The ERS, with the lead consultants from NewGen Strategies and Solutions, LLC ("NewGen"), has completed its first phase, including data gathering for the cost-of-service analysis and the development of a draft financial model. This model will serve as the primary tool for analysis and evaluating rate adjustments.

In parallel, several municipal code modifications have been approved or recommended, including the removal of direct access and related tariffs, amendments to long-term contract provisions, and restructuring reserve-related code sections into consolidated working capital policy targets and minimums. These foundational changes provide a strong starting point for aligning electric rates and tariffs with the utility's current operations and services.

Additionally, PWP continues to integrate its ERS with the Optimized Strategic Plan (“OSP”) to refine power cost projections and revenue requirements in alignment with Resolution 9977’s goal of achieving Carbon-Free electricity by 2030. Staff has collaborated closely to refine future load growth projections and ensure key financial and operational assumptions are aligned, supporting informed decision-making through the next waypoint in 2028.

NEXT STEPS:

PWP will implement a diverse and tailored approach to public engagement, recognizing that a one-size-fits-all strategy is insufficient. Customer engagement and segmented participation are essential for developing equitable and effective rates and pricing strategies. Actively involving customers in the rate-setting process enhances transparency, builds trust, and fosters a deeper understanding of cost structures and service value. By segmenting participation based on usage patterns and customer profiles, PWP can customize its outreach to better understand and implement incentives that promote conservation, efficiency, and sustainability. This approach not only supports policy goals, such as reducing peak demand and encouraging renewable energy adoption, but also ensures that costs are fairly distributed among customer classes, preventing undue burdens on any one group.

A key aspect of fostering engagement is increasing awareness of both the rate-setting process and the value that a publicly owned utility brings to the community’s quality of life. PWP will achieve this through digital advertising, content marketing, events, and webinars, ensuring that customers are well-informed and involved.

Recognizing the importance of customer insights, PWP will conduct targeted market research to listen and learn about customer expectations and priorities before making recommendations to the City Council. A variety of engagement strategies will be employed, ranging from digital outreach and online input tools to in-depth workshops and focus groups, ensuring broad and meaningful participation.

PWP’s engagement strategy is designed to empower customers with information while aligning pricing structures with community priorities and regulatory requirements. Sending clear pricing signals that encourage mutually beneficial behaviors is essential for Pasadena to achieve the policy objectives outlined in Resolution 9977—ensuring a carbon-free electricity future that is reliable, equitable, and affordable.

PASADENA

Pasadena Water and Power

Customer Engagement Plan for Electric Rate Study

Municipal Services Committee
March 11, 2025

Item #

CITY OF PASADENA
INCORPORATED JUNE 1886

ROAD TO NEW ELECTRIC RATES

we are here

1

CLEAN UP

Modified legacy items such as direct access, long-term contracts and billing provisions that were created during a past era of deregulation that are incongruent with today's business model and regulatory framework

2

POLICY

Establish clear policies to serve as a foundation to set the bounds for future financial planning; restructured reserve-related code sections into consolidated working capital policy targets and minimums

3

TOOLS

Build out the financial models and tools with the established policy and parameters to forecast future revenue needs based on cost-of-service analysis and economic projections

4

DESIGN

Establish a future desired state and design a balanced rate structure to meet PWP's mission, based on realistic forecasts and established plans (i.e. budgets, PDMP, IRP, OSP)

5

SCENARIOS

Review multiple options based on Council and community inputs, feasible program implementations and future possible stressors, and establish a preferred scenario to develop rates and customer impacts

6

OUTCOME

Establish rate pricing and look at the customer impacts regarding the new rate design and pricing, and determine the timing of new rates and communicate through the customer base

PASADENA
WATER & POWER DEPARTMENT

NOT A ONE SIZE FITS ALL PROPOSAL

PUBLIC ENGAGEMENT TRENDS

Identify a fully representative customer base and meet them where they are.

- Public engagement will be different for residential vs. commercial customers.
- Broad reaching community meetings are less effective than a targeted approach that engages customers at times and places where they can focus on discussing acceptable service levels and priorities for planning and managing electric services that are being provided.

STRATEGY

Employ diverse approaches that demonstrate transparency, foster meaningful conversations with customers, and gain insights into the perspectives of the different demographic groups and viewpoints.

PUBLIC PARTICIPATION OBJECTIVES

1. INCREASE AWARENESS

Achieve an increase in the recognition of the value proposition that a publicly owned utility brings to the quality of life in Pasadena.

2. EMPOWERING CUSTOMERS

Gather insights on customer priorities to gain a deeper understanding of their needs to differentiate among the expectations of various customer groups in service and rate design.

3. IMPROVING POLICY EFFECTIVENESS

Engage the public to ensure clear policies that guide future financial planning.

4. DEMONSTRATE TRANSPARENCY

Provide a high level of transparency to enhance public trust in the process and the careful consideration of all proposed changes.

PUBLIC PARTICIPATION STRATEGIES

DIGITAL AND IN-PERSON

DIGITAL ADVERTISING

Invest in social media campaigns to increase online visibility.

CONTENT MARKETING

Develop high-quality blog posts, videos, and infographics to attract and engage customers.

ONLINE INPUT

Use online platforms to engage customers such as bill-estimator and other tools to share information and customize the experience.

PUBLIC WORKSHOPS

Host workshops and events to have in-depth and meaningful conversations with customers.

PARTNERSHIPS

Collaborate with community-based organizations partners to expand reach and credibility.

EVENTS AND WEBINARS

Host online and in-person events to connect with residential customers. Connect with the business community through the Chamber of Commerce and Key Account meetings.

https://pwp.cityofpasadena.net/electric-rate-study-2024/

ENGAGEMENT PHASES

Rate Design Phase

- Invest time to hear feedback about Pasadena's service levels, value of services provided and priorities for rates.
- Focus on feasible solutions that align with City Council policies to present community-informed options.

Implementation Phase

- Customize information and events to customer segments.
- Flexibility to adapt to customers preferred way of receiving information: website, social media, in-person, bill inserts or other tools available.

ENGAGEMENT PHASES

Introduction	Launch rate design and explore rate considerations.
Listen	Develop tools to solicit customer feedback.
Broadcast	Widely share information on rate proposals and potential impact to future bills.

LET THE FUN BEGIN!

EDUCATION

Work with the PWP team to educate on the value of a publicly-owned utility.

MATERIALS DEVELOPMENT

Develop high-quality blog posts, videos, and infographics to attract and engage customers.

LISTENING

Host a community workshop with various ways to solicit feedback on priorities and have conversations with experts.

Shaping PWP's Energy Future:
How Safe, Reliable and Affordable Power Services are Provided to You
MARCH 26*

An introduction to all things about Pasadena Power. Why PWP was formed, how we get our power and deliver it to you, what programs are available to help you use electricity efficiently, and how you can save on your power bills with PWP programs.

Shaping PWP's Energy Future:
Clean Energy and Rates Forum
APRIL 24*

Host an event to hear from the community about their key issues and priorities surrounding power services with a cross-section of information ranging from upcoming projects, a rate design game and information about the energy future being developed in the Optimized Strategic Plan.

*Date subject to change, information will be distributed widely

PASADENA WATER & POWER DEPARTMENT

Agenda Report

January 26, 2026

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (January 13, 2026)

FROM: Water and Power Department

SUBJECT: **SET A DATE OF FEBRUARY 9, 2026, TO CONDUCT A PUBLIC HEARING FOR RECOMMENDED ELECTRIC RATE ADJUSTMENTS AND DIRECT THE CITY ATTORNEY'S OFFICE TO PREPARE AN ORDINANCE AMENDING THE LIGHT AND POWER RATE ORDINANCE AND ADOPT THE UTILITY RATE RESOLUTION**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed action is not a project subject to the California Environmental Quality Act (CEQA) pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3), and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project;
2) Set a date of February 9, 2026, to conduct a public hearing for the recommended electric rate adjustments based on the findings of the recent electric rate study, with changes to take effect on March 1, 2026, or as soon thereafter as practicable;
3) Direct staff to prepare the Utility Rate Resolution using a two-year, three-phase rate adjustment (effective March 1, 2026, October 1, 2026, and March 1, 2027); and
4) Direct the City Attorney's Office to prepare an ordinance within 60 days amending the Light and Power Rate Ordinance, Title 13, Chapter 13.04 – Power Rates and Regulations, to reflect the proposed electric rate adjustments, eliminate outdated or obsolete provisions, and align the ordinance with current industry best practices.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") has completed a comprehensive Electric Rate Study to ensure that electric rates remain equitable, cost-based, and aligned with the City's long-term goals of fiscal responsibility, infrastructure modernization, and achieving 100% carbon-free electricity by 2030. Conducted in partnership with NewGen

MEETING OF ________________ AGENDA ITEM NO. ____________

Strategies and Solutions, LLC ("NewGen"), the study includes a full cost-of-service ("COS") analysis, financial modeling, and extensive public engagement. The study confirms that current electric rates are insufficient to meet projected revenue needs, with a shortfall of approximately $67.9 million over 2 years. To address this, PWP developed three rate adjustment alternatives. The recommended approach proposes a phased implementation over three steps allowing for gradual revenue recovery while maintaining reserve levels above policy minimums. This strategy balances financial sustainability with customer affordability and rate stability.

In addition to the rate adjustments, PWP recommends a full restatement of the Light and Power Rate Ordinance (Chapter 13.04) except for items related to Net Energy Metering and any new provisions for local solar that will have further discussion. This restatement will modernize the ordinance by eliminating outdated provisions, aligning terminology with current industry standards, and streamlining governance by moving all rate figures to the Electric Utility Rate Resolution. The updated ordinance also anticipates future needs, including time-of-use pricing, advanced metering infrastructure, and expanded support for distributed energy resources such as electric vehicles.

PWP's proposed rates remain among the most affordable in the region. The utility continues to prioritize equity by offsetting fixed charges for income-qualified customers and energy efficiency programs. Public engagement has been central to the process, with outreach efforts including webinars, open houses, and a dedicated website. Feedback from residential and commercial customers has informed the rate design and highlighted interest in clean energy options, electric vehicle incentives, and bill transparency tools. PWP recommends that the City Council set a public hearing for February 9, 2026, to present the proposed rate adjustments and ordinance restatement, and to gather community input. If approved, the new rates would take effect beginning March 1, 2026, or as soon thereafter as practicable.

BACKGROUND:

On December 9, 2025, the Municipal Services Committee previously received a briefing on the state of the electric utility industry, regional rate trends, affordability considerations, public engagement efforts, and the policy and financial drivers behind the need for electric rate adjustments. That discussion, in Attachment A, addressed broader industry conditions, equity and affordability measures, public outreach, financial planning assumptions, and the multi-year rate strategy direction provided by the Committee.

This agenda item builds on that foundation and narrows the focus to two specific elements: the results of the Electric Cost-of-Service analysis and the introduction of new alternatives for consideration. The cost-of-service analysis provides the technical basis for aligning rates with the actual cost to deliver electric service in compliance with Proposition 26, while the alternatives offer additional context for evaluating rate design and implementation options. Together, these materials support informed decision-making without repeating prior background already reviewed by the Committee.

State of the Industry for the Cost-of-Service

Residential customers cost more to serve today than they did several decades ago for reasons that go beyond changes in how much electricity people use. Several independent analyses show structural and cost drivers that have increased the cost to serve residential customers:

- Infrastructure and distribution investments have grown significantly. Utilities across the state have raised spending on poles, wires, transformers, and other distribution system components to improve safety, reliability, and resilience. These costs have been recovered through customer rates and are a principal driver of higher retail prices. According to the California Public Utilities Commission, distribution capital expenditures have grown sharply in recent years, and distribution spending is now the largest category of utility capital outlays[1].
- Wildfire mitigation and grid hardening efforts have added new costs. Efforts to reduce wildfire risk—such as vegetation management, equipment upgrades, and other safety investments—have contributed materially to rising utility costs. One analysis of California investor-owned utilities found that wildfire mitigation spending accounted for a large share of above-inflation rate increases in recent years[2].
- Residential rates have risen faster than inflation. California's average residential electricity rates have grown significantly faster than inflation and now sit well above the national average. A Legislative Analyst's Office report shows that residential electricity rates in the state increased by nearly 47% from 2019 to 2023, outpacing general price growth and contributing to higher costs for customers[3].
- Fixed infrastructure costs are spread over lower per-customer usage. Independent research has noted that California's relatively flat per-capita electricity use means utilities must recover high fixed infrastructure costs (such as transmission and distribution) over less growth in energy sales. In other

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[1] Lawrence Berkeley National Laboratory, *Retail Electricity Price and Cost Trends: 2024 Update*, U.S. Department of Energy. The report identifies sustained growth in electric distribution system capital investments and concludes that increased spending on poles, wires, transformers, and grid modernization is a primary driver of rising retail electricity rates.

[2] California Public Utilities Commission, *Utility Wildfire Mitigation Cost Recovery and Grid Safety Reports*. CPUC analyses confirm that wildfire mitigation and system hardening requirements have materially increased electric utility revenue requirements statewide.

[3] California Legislative Analyst's Office, *Residential Electricity Rates in California*, January 2025. The report concludes that residential electricity rates in California have increased substantially faster than inflation over the past several years and are among the highest in the nation, driven largely by capital investment, safety, and regulatory compliance costs.

words, the same network of poles and wires must be paid for even if consumption per household doesn't grow[4].

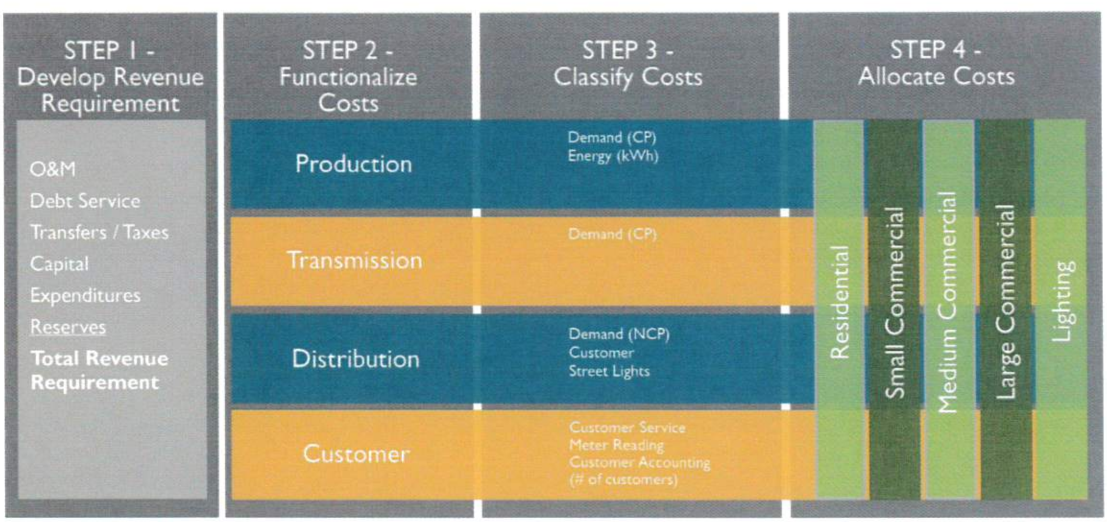
Taken together, these external analyses help explain why the cost to serve residential customers has increased so dramatically over time. The rise reflects long-term investments in grid modernization, safety improvements, and changing operational requirements, not simply changes in household energy usage.

ANALYSIS

The revenue requirement, cost-of-service analysis, and rate design are interdependent components of a single rate-setting framework and cannot be evaluated in isolation. The revenue requirement establishes the total amount of funding needed to operate, maintain, and invest in the electric system. The cost-of-service analysis then allocates that revenue requirement to customer classes based on how customers use the system and drive costs. Rate design translates those class-level cost responsibilities into specific rate structures and prices that appear on customer bills.

As illustrated in Figure 1, each element relies on the others. Changes to the revenue requirement affect cost allocations, and changes in cost allocations directly influence rate design outcomes. As a result, no single component can stand alone without losing context or accuracy.

Figure 1: Cost of service Process: Aligning Cost and Pricing for Customer Types



[4] Public Policy Institute of California, *A Closer Look at California's Surging Electricity Rates*. The analysis explains that relatively flat residential electricity consumption, combined with rising fixed infrastructure and reliability costs, increases the cost burden per residential customer.

The detailed financial forecast that supports the revenue requirement has already been reviewed and discussed with the MSC. That work established the overall system funding needs and long-term financial assumptions. Accordingly, this agenda item does not revisit the full financial forecast and analysis presented in Attachment A and in the report on the Financial Forecast and Revenue Requirements. Instead, it focuses on the cost-of-service results and associated rate design considerations, which explain how those previously established revenue needs are distributed across customer classes and translated into rates.

PWP Cost-of-Service Study Findings: Aligning Costs with Customer Classifications

PWP with NewGen's expertise used PWP accounting and demand data presented in the technical findings in the COS study, Attachment B. The technical findings of the cost-of-service study shows several customer classes are under-recovering costs, while others are above cost, leading to cross-subsidies. The study relied on customer data, PWP financials, system load profiles, and accepted industry methods.

PWP set out to evaluate the full cost of producing, transmitting, and delivering electricity. The study broke down the revenue requirement into production, transmission, distribution, and customer functions and then allocated these costs to each customer class based on how they use the system.

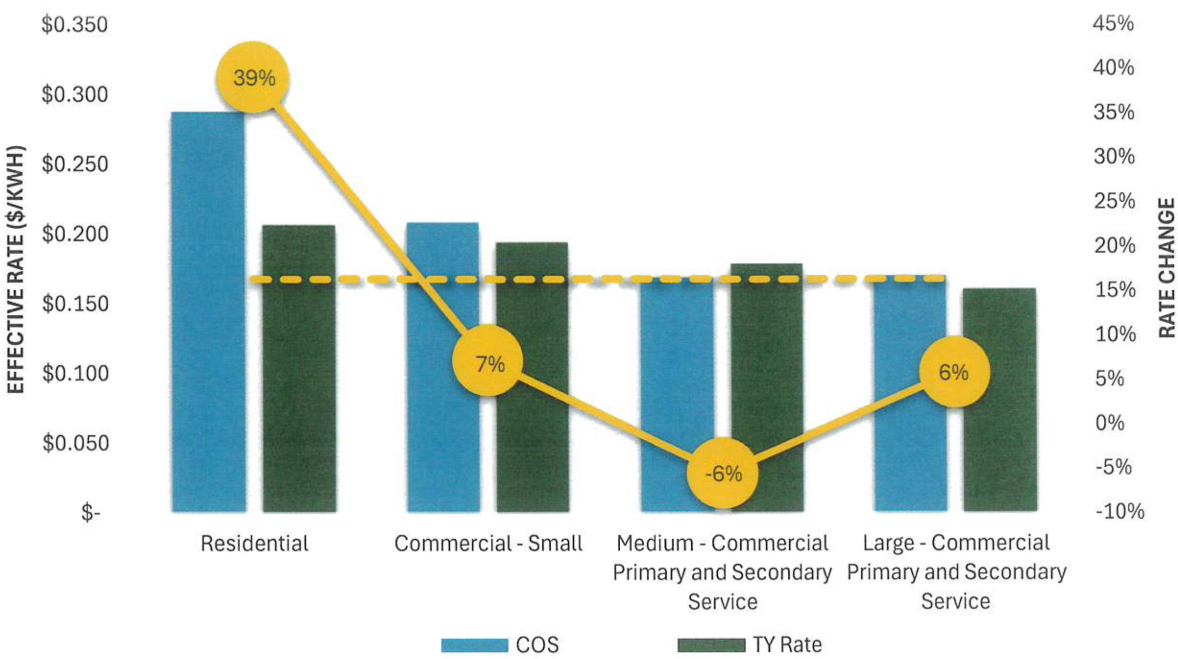
Key findings include:

- Production costs represent the largest share at 49%; distribution accounts for 41%.
- 77% of system costs are fixed.
- It costs about $125 per month to connect a residential customer to the system, regardless of usage.
- Current rates under-recover revenues for residential, small and large commercial, and traffic signal customers.
- Street lighting and medium commercial classes are above cost at present.

The COS analysis identifies the specific costs to serve each customer class using demand, energy, and customer allocation factors. These methods reflect customer contributions to peak load, energy use, and service requirements. PWP's system has pronounced summer peaks, which drive investment decisions. The study uses four-coincident peak and non-coincident peak allocation factors that fit PWP's load profile and operating conditions.

The COS results show that current rates do not match the actual cost to serve most customers. Residential customers face the largest gap, requiring an estimated one-time increase of about 39% to reach full cost recovery, compared to 7% for small commercial and 6% for large commercial. Medium commercial class is above cost and require adjustments downward to align with the COS Residential customers that fell out of alignment with their actual cost to serve for a few reasons that show up directly in the study data.

Figure 2: Cost-of-Service vs. Test Year Effective Rate



First, residential customers place the largest share of demand on the system. They make up about 38% of the load during the four highest peak months, which is the period that drives most of PWP's infrastructure costs. The system must be built and maintained to meet that peak, even though it only occurs a few hours per year. Residential demand during those hours pushes a large share of fixed production and distribution costs to this class.

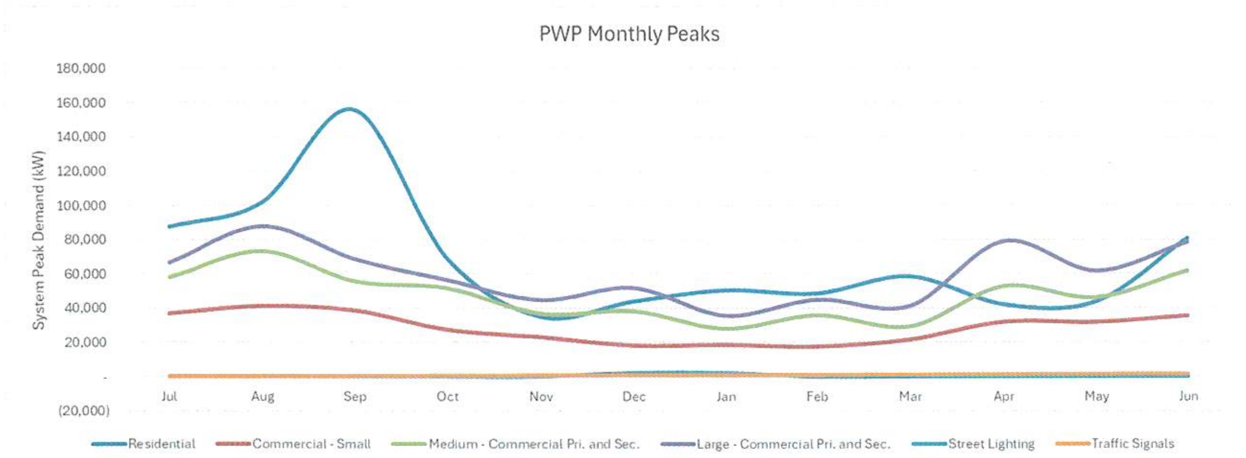
Second, residential customers create the highest number of customer-related costs. About 59,000 of PWP's 68,000 electric accounts are residential. Activities like billing, metering, and customer service scale with account count, not energy usage. When you spread customer-related costs across this many accounts, the cost per residential customer remains high. The study shows that it costs about $125 per month to keep a residential customer connected to the grid, regardless of how much energy they use.

Third, residential rates have not kept pace with rising fixed costs. The cost study shows that 77% of system costs are fixed. These include power purchase contracts, capital investments, and system maintenance. When rates place too much weight on per-kWh charges, they don't recover the actual fixed costs. Over time, this gap widens. Residential usage per customer has also flattened or declined, which makes it even harder for a variable-heavy rate to recover fixed costs.

Fourth, current residential rates don't reflect the cost characteristics of the class. The study found that residential revenue falling short of cost by about $30 million in the test year, requiring an increase of just over 39% to get back to actual cost. That's the largest gap of any class. Other classes, like medium and large commercial, already pay more than their cost-to-serve and would see lower increases match the cost study.

Finally, residential customers place more pressure on local distribution facilities. The study shows that residential customers make up over half of the sum of maximum demands, which is what drives local distribution costs, including transformers, local circuits, and service lines. The system data is presented in Figure 3. Because these assets are expensive to install and maintain, and because they serve many individual residential connections, this class picks up a large share of the distribution function costs.

Figure 3: PWP Monthly Demand Peaks by Customer Class



Put together, the data shows a simple story. Residential customers use a large share of the system at its most expensive hours, make up the majority of customer accounts, and depend heavily on local distribution assets. At the same time, residential rates haven't been adjusted to match these cost patterns. The result is a widening gap between what it costs to serve residential customers and what current rates collect.

Rate Making

The process of setting electric utility rates, commonly referred to as rate making, is a structured approach that translates the cost of providing electric service into the rates customers pay. It is both a technical and policy-driven exercise, designed to ensure that rates are equitable, cost-based, and aligned with the City's broader goals of fiscal responsibility, affordability, and sustainability.

Rate making begins with a COS analysis, where costs are allocated among customer classes. The next step is rate design, which converts those cost responsibilities into specific rate structures—such as fixed monthly charges, per-kWh energy rates, and demand charges. Rate design must balance several competing objectives: recovering costs, minimizing customer bill impacts, promoting fairness across customer classes, and supporting policy goals such as energy efficiency and clean energy adoption.

Importantly, rate making is not solely a financial exercise. It incorporates policy decisions that reflect community values and strategic priorities. These include:

- Affordability: Avoiding sudden or excessive bill increases by phasing in rate changes over time.
- Equity: Supporting income-qualified customers through targeted rate discounts.
- Sustainability: Encouraging behaviors that reduce peak demand, improve energy efficiency, and support carbon-free electricity.
- Transparency and predictability: Ensuring customers understand how rates are set and can anticipate future changes.

The structure of rates also influences customer behavior. For example, time-of-use pricing can encourage customers to shift consumption to off-peak hours, reducing strain on the grid. Similarly, clear and consistent rate signals can promote investment in energy-efficient appliances, electric vehicles, and distributed energy resources.

In Pasadena's case, the recommended rate adjustment strategy (Alternative 2) reflects a deliberate balance between cost recovery and customer impact. It phases in rate increases over three steps across two fiscal years, capping adjustments to avoid rate shock while maintaining a clear path to full cost recovery. This approach ensures compliance with Proposition 26, which requires that rates not exceed the reasonable cost of service and supports the City's long-term financial and environmental goals.

Rate Design Alternatives

The recommended rate plan is designed to move each customer class toward full cost of service in a gradual and measured manner. Rather than implementing the full cost-of-service adjustment in a single step, the rate design caps each class's rate adjustment at no more than 1.5 times the current rate change in any given adjustment period. This approach intentionally moderates bill impacts while maintaining a clear path to cost recovery.

Under this structure, customer classes that are currently under-recovering their cost of service will continue to under-recover during the transition period. That under-recovery is temporary and decreases with each adjustment as rates move closer to the cost-based level identified in the study. The cap prevents sudden or disruptive bill changes, particularly for residential, while still ensuring that rates progress in the correct direction.

This phased approach does not change the underlying cost responsibility of any customer class. The cost-of-service analysis establishes each class's full cost obligation. The rate design simply governs the pace at which rates are adjusted to reach that level. Each rate adjustment is applied proportionally and consistently, reducing cross-subsidies over time rather than perpetuating them.

The approach is compliant with Proposition 26. Proposition 26 requires that charges not exceed the reasonable cost of providing service and that there be a clear relationship between the charge and the service received. The proposed rates satisfy this requirement because they are grounded in a formal cost-of-service study and move each customer class toward its cost-based level once that information is known. Temporary under-recovery during a phased implementation does not violate Proposition 26, as rates are set below, not above, the cost of service and are structured to achieve full recovery over time.

By capping individual rate adjustments and phasing in cost recovery, PWP balances legal compliance, financial sustainability, and customer affordability. This method provides transparency, predictability, and fairness while allowing customers time to adjust and plan, and it ensures that the electric system remains financially sound as rates are aligned with actual costs.

At Council's direction, staff could also model additional lower caps ranging anywhere from 1.25 to 1.49. The cap works by limiting the increase by customer class as compared to the system average increase. The residential customer class cost of service results show that they need rate increases greater than the systemwide average, but the caps are a way to gradually phase in the increases. The caps are a ratio of the systemwide increase. For example, regardless of the increase needed for that customer class, a ratio of 1.25 would limit it to 11.9% per phase, because that is 1.25x the systemwide increase of 9.5% in that Fiscal Year. A ratio cap of 1.5 times is presented existing scenarios means that no customer class rate increase can increase by more than 14.3% per phase. This is common practice that moves toward cost recovery by class but gives time for adjustments and movements towards alignment for each customer class.

Since those options would require several weeks, which would also impact the implementation dates, for expediency, the presented alternatives are ones that have already been modeled. Staff has been advised that these are consistent with Proposition 26 defensibility, so other alternatives could be considered but would require advisement from the City Attorney's Office.

Given the policy direction to use all strategies available to gradually adjust rates, PWP modeled three alternatives for consideration and is requesting further guidance on which alternative is Council's preference and a summary of which is in Table 1 below.

Table 1: Key Differentiators Between Rate Strategy Alternatives

	Alternative 1	Alternative 2	Alternative 3	Alternative 4*
Cap on ratio of increases per phase	1.5	1.5	1.5	~ 1.25
# of adjustment phases	2	3	3	3
Fiscal Years Impacted	FY26 & FY27	FY26 & FY27	FY26, FY27 & FY28	FY26, FY27 & FY28+
Meets cost of service before next study period	Yes	Yes	No	No
Prop 26 Aligned	Yes	Yes	Yes	Yes
Use of reserves	Low	Medium	Medium/ High	High

Alternative 1: Immediate Full Cost Recovery – Not Recommended

Alternative 1 establishes a rate plan that would, at the time of proposed adoption, achieve full-cost recovery by customer class with one adjustment. Given the drastic increase required and the implications for customer's and affordability, staff does not recommend this alternative. Alternative 1 includes an additional $6 million draw down of cash reserves if implemented in March 2026.

Table 2: Percentage Bill Adjustments by Class for Alternative 1

Classes	Phase 1	Phase 2	Phase 3
Residential	10.5%	10.5%	10.5%
Commercial - Small	10.1%	6.2%	5.0%
Medium - Commercial	3.9%	5.0%	5.0%
Large - Commercial	3.9%	4.5%	5.0%
Street Lighting	3.9%	7.9%	5.0%
Traffic Signals	10.5%	10.5%	10.5%
Total System	7.0%	7.0%	7.0%
Maximum Rate Increase Multiple	1.5	1.5	1.5

Alternative 2: Gradual Full Cost Recovery with options for three adjustments over two Fiscal Years.

Alternative 2 provides a strategy for three rate adjustments over two Fiscal Years, the changes recommended to take effect March 2026 (FY26), October 2026 (FY27) and the final adjustment March 2027 (FY27). This alternative is steady and is most aligned with Municipal Services Committee guidance. Alternative 2 includes an additional $32 million draw down of cash reserves if implemented in March 2026, October 2026 and March 2027.

Table 3: Percentage Bill Adjustments by Class for Alternative 2

Classes	Phase 1	Phase 2	Phase 3*
Residential	10.5%	10.5%	10.5%
Commercial - Small	10.1%	6.2%	5.0%
Medium - Commercial	3.9%	5.0%	5.0%
Large - Commercial	3.9%	4.5%	5.0%
Street Lighting	3.9%	7.9%	5.0%
Traffic Signals	10.5%	10.5%	10.5%
Total System	7.0%	7.0%	7.0%
Maximum Rate Increase Multiple	1.5	1.5	1.5

*Phase 3 in March 2027 (FY 2027)

Alternative 3: Gradual Full Cost Recovery with options for three adjustments over three Fiscal Years

Alternative 3 provides a strategy for three rate adjustments over three Fiscal Years, the changes recommended to take effect March 2026 (FY26), March 2027 (FY27) and the final adjustment March 2028 (FY28). Alternative 3 includes an additional $74 million draw down of cash reserves if implemented in March 2026, March 2027 and March 2028. Staff does not recommend this alternative.

Table 4: Percentage Bill Adjustments by Class for Alternative 3

Classes	Phase 1	Phase 2	Phase 3*
Residential	10.5%	10.5%	10.5%
Commercial - Small	10.1%	6.2%	5.0%
Medium - Commercial	3.9%	5.0%	5.0%
Large - Commercial	3.9%	4.5%	5.0%
Street Lighting	3.9%	7.9%	5.0%
Traffic Signals	10.5%	10.5%	10.5%
Total System	7.0%	7.0%	7.0%
Maximum Rate Increase Multiple	1.5	1.5	1.5

*Phase 3 in March 2028 (FY 2028)

Alternative 4: Gradual Full Cost Recovery Extending Beyond Study Period, Capping ratio to 1.25 for Residential Customers per phase

This option suggests implementing changes in three steps over three phases (timing is to be determined and has not yet been modeled), allowing customers to adjust gradually while addressing revenue needs more sustainably without shock increases. The cap of rate increases is set to 1.25 for the Residential customer class but does not reach cost-of-service by the end of FY2027. Future rate increases will be studied and rate impacts may be steeper. This alternative utilizes reserves for delay in revenue collection. Staff does not recommend this alternative.

Table5: Percentage Rate Adjustments by Class for Alternative 4

Classes	Phase 1	Phase 2	Phase 3
Residential	8.7%	8.7%	8.7%
Commercial - Small	8.7%	7.0%	6.0%
Medium - Commercial	4.8%	6.0%	6.0%
Large - Commercial	4.8%	5.5%	6.0%
Street Lighting	4.8%	8.7%	6.0%
Traffic Signals	8.7%	8.7%	8.7%
Total System	7.0%	7.0%	7.0%
Maximum Rate Increase Multiple	1.25	1.25	1.25

Customer Bill Impacts

Individual customer bill impacts will vary depending on the customer class and the amount of electricity consumed. Because of the variability of rates, PWP will develop an estimator for customers to understand the impact once one rate plan is decided on. Below are some impacts using averages for consumption. For comparison purposes, above average usage is also presented for residential customers to give a bit more context on the variability in bill impact due to usage patterns. Timing prohibited PWP with the full pricing development for Alternative 4, and as such, the impact examples are limited to Alternatives 1, 2 and 3.

Residential Customer Bill Impacts

Single and multi-family residential customers represent nearly 88% of PWP's customer accounts, whereas they represent 22% of the total consumption for the utility. PWP ensures that the lights are on, and essential electrical services are provided reliably year-round. For comparison purposes, the bill impacts shown in Table 5 below represent an approximation of the average customer, using 500 kWh monthly.

To demonstrate the different impact of the distribution charge structural change, the Tables 5 and 6 below also show a residential customer with approximately "average" monthly consumption with 500 kWh per month and higher-than-average consumption at 1,000 kWh per month. The tables show the impact based on the three alternative strategies to implement rate adjustments.

Table 6: Sample Electric Bills - Monthly (Residential @ 500 kWh)

		Approximate Bills			
	Current Bill	**March 2026**	**October 2026**	**March 2027**	**March 2028**
Alternative 1		$150.24	$144.10	$144.10	$144.10
Alternative 2	$115.01	$113.17	$123.17	$135.11	$135.11
Alternative 3		$113.17	$113.17	$123.17	$135.11

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Table 7: Sample Electric Bills - Monthly (Residential @ 1,000 kWh)

		Approximate Bills			
	Current Bill	**March 2026**	**October 2026**	**March 2027**	**March 2028**
Alternative 1		$347.67	$355.94	$355.94	$355.94
Alternative 2	$251.39	$273.52	$303.25	$337.95	$337.95
Alternative 3		$273.52	$273.52	$303.25	$337.95

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Small Commercial Rate Impacts:

Small commercial customers represent approximately 11% of PWP's customers and approximately 19% of the total retail power sales (in kWh) per year. Small commercial customers are the backbone of the community that includes establishments such as small retail and professional offices, cafes and small restaurants, and small dental or medical offices. An approximation of typical usage is estimated to be around 1,500 kWh per hour. The table 7 below, shows the impact based on the three alternative strategies to implement rate adjustments.

Table 8: Sample Electric Bills - Monthly (Small Commercial @ 1,500 kWh)

	Current Bill	Approximate Bills			
		March 2026	**October 2026**	**March 2027**	**March 2028**
Alternative 1		$419.88	$390.80	$390.80	$390.80
Alternative 2	$341.56	$364.73	$385.44	$404.42	$404.42
Alternative 3		$364.73	$364.73	$385.44	$404.42

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Medium Commercial Rate Impacts:

Medium commercial customers represent approximately 1% of PWP's customers and approximately 23% of the total retail power sales (in kWh) per year. Medium commercial customers include mid-size office buildings (20,000 – 30,000 sq ft), retail stores, groceries, urgent care facilities, veterinary hospitals, restaurants, fitness centers and warehouses. An approximation of typical usage is estimated to be around 15,000 kWh per hour, about ten times that of a small commercial customer. The table 8 below, shows the impact based on the three alternative strategies to implement rate adjustments.

Table 9: Sample Electric Bills - Monthly (Medium Commercial Secondary @ 15,000 kWh)

	Current Bill	Approximate Bills			
		March 2026	**October 2026**	**March 2027**	**March 2028**
Alternative 1		$7,384.29	$7,680.69	$7,680.69	$7,680.69
Alternative 2	$6,483.80	$6,913.70	$7,353.40	$7,801.23	$7,801.23
Alternative 3		$6,913.70	$6,913.70	$7,353.40	$7,801.23

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Large Commercial Rate Impacts:

Large commercial customers represent less than 1% or 130 of PWP's customers and comprise of approximately 25% of the total retail power sales (in kWh) per year. Large commercial customers include hospital, school campuses, supermarkets and departments stores. An approximation of typical usage is estimated to be around 175,000 kWh per hour, about ten times that of a small commercial customer. The table 5 below, shows the impact based on the three alternative strategies to implement rate adjustments.

Table 10: Sample Electric Bills - Monthly (Large Commercial Secondary @ 175,000 kWh)

		Approximate Bills			
	Current Bill	**March 2026**	**October 2026**	**March 2027**	**March 2028**
Alternative 1		$41,954.67	$38,695.51	$38,695.51	$38,695.51
Alternative 2	$37,227.41	$38,791.99	$41,588.03	$39,987.64	$39,987.64
Alternative 3		$38,791.99	$38,791.99	$41,588.03	$39,987.64

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

To reiterate, customer bill impacts will vary based on customer class and electricity usage as well as seasonally for the residential customers on seasonal flat rates which are variable in the summer vs. winter. PWP's proposed rates remain competitive with neighboring utilities, though comparisons are influenced by many factors such as differences in infrastructure needs and operating costs.

Alternatives Impacts on Cash or Working Capital Reserves

The cash reserve balances, resulting from the proposed systemwide rate adjustments, are consistent with industry standards and provide PWP flexibility and financial stability to support future operating and capital requirements. In addition, the reserves offer the ability to manage uncertainties related to construction timelines, project schedules, and financing costs, including interest rate fluctuations. Beyond these functions, the cash reserves serve multiple purposes, such as providing working capital, stabilizing rates to reduce volatility, and funding capital improvements. As depicted in the Figure 4 below, the rate plans maintain the power fund balance at the total minimum working capital reserves. The revenue plan also includes the issuance of $50 million dollars in debt financing.

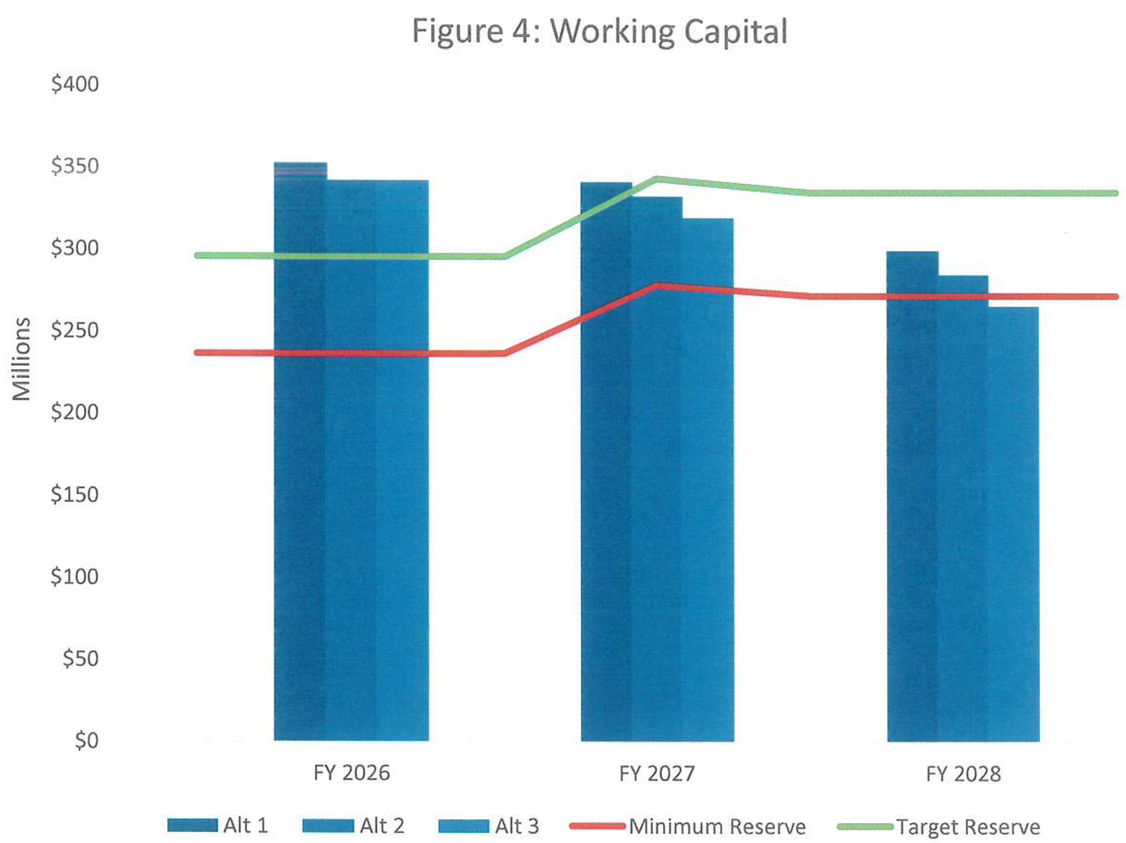


Figure 4: Working Capital
$400
$350
$300
$250
$200
$150
$100
$50
$0
Millions
FY 2026
FY 2027
FY 2028
Alt 1
Alt 2
Alt 3
Minimum Reserve
Target Reserve

RECOMMENDATIONS:

The recommended rate adjustment alternative was selected through a comprehensive evaluation, financial modeling, and policy guidance from MSC. The COS Study, conducted in partnership with NewGen, identified a projected revenue shortfall of approximately $67.9 million over two years and revealed significant disparities between current rates and the actual cost to serve various customer classes.

The COS analysis showed that residential, small commercial, large commercial, and traffic signal customers are under-recovering costs, while medium commercial customers are over-recovering. Specifically, residential customers require a 39% increase to reach full cost recovery, driven by high fixed infrastructure costs, peak demand contributions, and customer-related service expenses. These findings underscore the need for rate adjustments that realign revenues with cost responsibilities in compliance with Proposition 26.

To address this, PWP developed and modeled four rate design alternatives, each balancing cost recovery, customer affordability, reserve impacts, and legal compliance. The alternatives varied in the number of adjustment phases, the cap on rate increases, and the timeline for achieving full cost recovery.

Alternative 2 was selected as the recommended approach because it:

- Aligns with MSC guidance for a steady, phased implementation over two fiscal years (FY26 and FY27).
- Achieves full cost recovery before the next rate study period, ensuring financial sustainability.
- Moderates customer bill impacts by capping rate increases at 1.5 times the current rate change per phase.
- Maintains reserve levels above policy minimums, supporting operational and capital needs without excessive reliance on reserves.
- Complies with Proposition 26, ensuring rates are based on actual costs and structured to achieve full recovery over time.

Staff believes this approach provides a balanced path forward, reducing cross-subsidies while allowing customers time to adjust. It supports the City's goals of fiscal responsibility, infrastructure modernization, and clean energy transition, and reflects community input gathered through extensive public engagement.

Comprehensive Light and Power Rate Ordinance Recommendations for Restatement and Modernization

Staff recommends a restatement because the current rates ordinance has become too unwieldy to manage through piecemeal amendments. Over time, layers of changes, cross-references, and outdated language have made it hard for staff, customers, and decision makers to read and understand. A restatement lets us reorganize the entire structure, integrate all prior amendments, remove inconsistencies, and modernize the policy in a clear and coherent format. This approach improves transparency, supports compliance, and gives the public a complete, readable ordinance instead of another round of patchwork edits.

Details were summarized and stated as in Attachment A. Attachment C is the redlined version of the proposed edits published for transparency and for policy guidance.

Implementation Timeline

PWP is recommending that a public hearing be set for February 9, 2026, to receive comments on the recommended adjustments to the electric rates. Following the City Council's action to set a date for the public hearing, a notice will be mailed to all electric system customers that includes the recommended rate adjustments and provides information regarding the public hearing. Table 6 outlines the approximate timeline and implementation schedule for the proposed rate actions.

Table 11: Timeline

Date	Action Item
January 2026	Mail public hearing notice
January 2026-February 2026	Customer Outreach and Education
February 9, 2026	Electric Rates Public Hearing
February 23, 2026	First Reading of Updated Electric Rate Ordinance
March 2, 2026	Second Reading of Updated Electric Rate Ordinance
March 1, 2026 or as soon as practicable thereafter	Effective Date of First Rate Action

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The establishment of a date to conduct a public hearing for the consideration of electric rate adjustments and the drafting of related resolutions and ordinance amendments are administrative actions that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Therefore, the proposed actions do not constitute a "project" subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required. Furthermore, the recommended electric rate adjustments themselves would be statutorily exempt from CEQA. Section 15273 of the State CEQA Guidelines identifies a statutory exemption for "Rates, Tolls, Fares, and Charges" and states (in part) that:

a. CEQA does not apply to the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or their charges by public agencies which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The estimated cost to mail information about the public hearing and recommended rate increases to all City of Pasadena electric customers is approximately $30,000. Funds are available in the Light and Power Fund.

The rate increases are expected to generate revenue of approximately $84 million annually. Depending on the alternative, additional reserves would be used up to $74 million through FY28. The incremental revenues will be used to offset increased O&M and capital costs of the electric system.

Respectfully submitted,

DAVID M. REYES
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Water and Power Department

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Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

Attachment A: December 9,2025 Municipal Services Committee Agenda Report and attachments.
Attachment B: Draft Cost-of-Service Report
Attachment C: Redline of Light and Power Rate Ordinance Chapter 13.04
Attachment D: Rate Schedule Alternative 3
Attachment E: Revised Rate Schedule Alternatives 1 and 2

Agenda Report

December 15, 2025

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (December 9, 2025)

FROM: Water and Power Department

SUBJECT: **SET A DATE OF FEBRUARY 9, 2026, TO CONDUCT A PUBLIC HEARING FOR RECOMMENDED ELECTRIC RATE ADJUSTMENTS AND DIRECT THE CITY ATTORNEY'S OFFICE TO PREPARE AN ORDINANCE AMENDING THE LIGHT AND POWER RATE ORDINANCE AND ADOPT THE UTILITY RATE RESOLUTION**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed action is not a project subject to the California Environmental Quality Act (CEQA) pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3), and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project;

2) Set a date of February 9, 2026, to conduct a public hearing for the recommended electric rate adjustments based on the findings of the recent electric rate study, with changes to take effect on March 1, 2026, or as soon thereafter as practicable;

3) Direct staff to prepare the Utility Rate Resolution using a two-year, three-phase rate adjustment (effective March 1, 2026, October 1, 2026, and March 1, 2027); and

4) Direct the City Attorney's Office to prepare an ordinance within 60 days amending the Light and Power Rate Ordinance, Title 13, Chapter 13.04 – Power Rates and Regulations, to reflect the proposed electric rate adjustments, eliminate outdated or obsolete provisions, and align the ordinance with current industry best practices.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") has completed a comprehensive Electric Rate Study to ensure that electric rates remain equitable, cost-based, and aligned with the City's long-term goals of fiscal responsibility, infrastructure modernization, and achieving 100% carbon-free electricity by 2030. Conducted in partnership with NewGen

Strategies and Solutions, LLC ("NewGen"), the study includes a full cost-of-service analysis, financial modeling, and extensive public engagement. The study confirms that current electric rates are insufficient to meet projected revenue needs, with a shortfall of approximately $67.9 million over 2 years. To address this, PWP developed two rate adjustment alternatives. The recommended approach proposes a phased implementation over three steps allowing for gradual revenue recovery while maintaining reserve levels above policy minimums. This strategy balances financial sustainability with customer affordability and rate stability.

In addition to the rate adjustments, PWP recommends a full restatement of the Light and Power Rate Ordinance (Chapter 13.04). This restatement will modernize the ordinance by eliminating outdated provisions, aligning terminology with current industry standards, and streamlining governance by moving all rate figures to the Electric Utility Rate Resolution. The updated ordinance also anticipates future needs, including time-of-use pricing, advanced metering infrastructure, and expanded support for distributed energy resources such as electric vehicles and local solar generation.

PWP's proposed rates remain among the most affordable in the region. The utility continues to prioritize equity by offsetting fixed charges for income-qualified customers and energy efficiency programs. Public engagement has been central to the process, with outreach efforts including webinars, open houses, and a dedicated website. Feedback from residential and commercial customers has informed the rate design and highlighted interest in clean energy options, electric vehicle incentives, and bill transparency tools. PWP recommends that the City Council set a public hearing for February 9, 2026, to present the proposed rate adjustments and ordinance restatement, and to gather community input. If approved, the new rates would take effect beginning March 1, 2026, or as soon thereafter as practicable.

BACKGROUND:

State of the Industry

Across California and the nation, residential electricity rates continue to rise, driven by a combination of infrastructure investments, wildfire mitigation, regulatory mandates, and the growing demand for clean energy. California's investor-owned utilities ("IOUs") in particular—such as PG&E, Southern California Edison, and San Diego Gas & Electric—have implemented significant rate increases in recent years. These increases have pushed average residential rates in some territories to nearly 40 cents per kilowatt-hour, placing a growing burden on customers and raising concerns about long-term affordability.

In contrast, publicly owned utilities ("POUs") like PWP have remained a more affordable and stable option for customers. PWP continues to offer some of the lowest residential electric rates in the region, thanks to its local governance, not-for-profit structure, and prudent financial planning. While PWP has implemented modest rate adjustments to support necessary investments in system reliability and clean energy commitment all within a challenging energy market, its rates remain well below those of neighboring utilities. This affordability is a direct reflection of the utility's commitment to balancing fiscal responsibility with customer value. The proposed rate increases are competitive with neighboring agencies. Figure 1 provides electric bill comparisons with neighboring agencies. It is important to note that rate structures differ between electric utilities based on operating costs, the level of infrastructure investment, and other factors. The comparisons are based on research of publicly available information on approved electric rate increases for the agencies shown.

Figure 1: Estimated Monthly Electric Bill Comparison*

*Amounts represent monthly total single family residential bill with the usage of 500 kWh for the month of November 2025. Amounts calculated using published rate schedules. Electric amounts calculated using published non-time of use rate schedules. Amounts also exclude taxes and non bypassable surcharges. Information has been sourced from publicly available information at the time generated.

It is important to note that all rate information represents a snapshot in time. As PWP adjusts its rates to meet evolving operational and regulatory needs, other utilities are doing the same, often at a much steeper pace. The utility sector as a whole is undergoing a period of transformation, with increasing capital requirements tied to grid modernization, electrification, and climate resilience. In this context, PWP's ability to maintain competitive rates while advancing its strategic goals is a testament to the strength of the public power model.

Why it is important to conduct the electric rate study now?

PWP manages the City's electric system, ensuring safe, reliable, and resilient service. To maintain operations, fund capital improvements, and preserve financial stability, the utility must generate sufficient revenue through rates that reflect the cost-of-service, in compliance with Proposition 26. Proposition 26 requires that charges must not exceed the reasonable cost of providing the service. These charges must also have a clear connection to the service received by the customer. As an enterprise fund, the Light and Power Fund is a self-sustaining, not-for-profit entity where all revenues are reinvested into the utility.

To avoid any perceived or actual misalignment of the costs to serve, PWP periodically conducts cost-of-service studies to assess operating expenses, capital requirements, customer usage patterns, and rate structures. These evaluations are typically performed every five to ten years, with the most recent review of the Power Fund completed in 2018. The Electric Rate Study was initiated in 2024 through a competitively awarded contract with NewGen. The scope of work included the development of a dynamic financial forecast model, a full cost-of-service analysis, rate design, ordinance review, and a public engagement strategy. The study builds on prior work, including the 2018 Power Integrated Resource Plan and the 2023 City Council Resolution 9977, which commits Pasadena to 100 percent carbon-free electricity by 2030.

As customer usage patterns evolve and the costs of providing electric service continue to shift, it is essential that PWP regularly conducts cost-of-service studies to ensure rates remain equitable, transparent, and aligned with actual service delivery. These studies help prevent disparities from growing unchecked, disparities that, if left unaddressed, could undermine financial stability and place the utility in a reactive position. By proactively evaluating and adjusting rate structures, PWP upholds its commitment to fiscal responsibility, regulatory compliance, and long-term sustainability, while continuing to provide safe, reliable, and resilient electric service to the Pasadena community.

Given the current and rapidly changing conditions, PWP with guidance from Municipal Services Committee, intends to conduct a similar analysis in approximately two years. Thanks to the robust financial model developed for this study, PWP will be able to support a more condensed timeline for the next analysis.

Electric Rate Study Process

With the assistance of NewGen, PWP has finalized the first steps in the electric rate study, which are the accounting exercises of the development of the financial plan as well as the cost-of-service study (or cost allocation process). The study confirmed the need for rate adjustments to ensure the equitable recovery of increasing costs. Its primary objective is to develop a cost-based rate plan that supports the City's goals of maintaining fiscal responsibility and stability, enhancing public infrastructure, and advancing sustainability initiatives. The study process included a full modernization of the financial planning model used by staff and a comprehensive review of cost accounting data to come up with billing determinants for which pricing and rates were developed.

On September 9, 2025, the Municipal Services Committee ("MSC") directed staff to prepare a two-year electric rate plan with annual systemwide increases of 9.5% for Fiscal Year ("FY") 2026 and 2027, based on projected budget needs, and to finalize the cost-of-service analysis, rate design, and ordinance review. While the MSC provided guidance to develop a two-year rate plan, PWP also developed alternative multi-year scenarios based on different clean energy portfolios from the Optimized Strategic Plan ("OSP"). These scenarios were included to provide transparency and to illustrate the long-term financial implications of various clean energy strategies, including accelerated local solar and storage investments and hourly matching approaches. The alternatives are not proposed for adoption at this time but serve to inform future planning and demonstrate the potential range of outcomes.

Earlier, on July 14, 2025 (following MSC review on June 24), City Council approved the development of a two-year rate plan using cost assumptions through 2029 and endorsed a strategy of steady, practical rate increases supported by financial tools such as debt and cash reserves. On March 11, 2025, staff introduced a customer-segmented public participation plan to enhance transparency and engagement. Previously, on October 22, 2024, PWP and NewGen presented an update to MSC, highlighting progress on the financial model.

PWP has updated the Municipal Services Committee and City Council along the way and taken on the following steps:

- On May 6, 2024, the City Council approved a contract with NewGen to perform an Electric Cost-of-Service Analysis and provide Rate Design Services.
- On October 22, 2024, staff presented an introduction to the Electric Rate Study to the MSC.
- On January 13, 2025, the City Council adopted Ordinance No. 7441, which amended Pasadena Municipal Code ("PMC") Chapter 13.04 to remove Direct Access provisions and related tariffs, and to amend the long-term contract provisions.
- On March 11, 2025, staff provided an update to the MSC on the Electric Rate Study and introduced a customer engagement plan.
- On June 9, 2025, the City Council adopted Ordinance No. 7448, amending PMC Chapter 13.04 to eliminate the Stranded Investment Charge and Reserves, and to establish a Working Capital Reserve Policy.
- On June 24, 2025, staff sought direction from the MSC on which OSP portfolio costs should be included in the revenue requirements for the electric rate study.

Why are rate adjustments needed now?

Analysis shows that, using the current rates, the revenue generated is insufficient to meet the revenue requirements for the study period. The electric system financial model includes annual system wide effective rate increases of 9.5% in fiscal years 2026 and 2027 would collect sufficient revenue to meet the system need. When the rate increase is delayed, PWP is using funds out of cash reserves to compensate for the under collection.

To address this gap, and in concert with the direction given by the Municipal Services Committee, the study recommends annual system wide effective rate increases of 9.5% in both FY 2026 and FY 2027. These rate changes are projected to generate approximately $21.5 million and $25.5 million in additional revenues in fiscal years 2026 and 2027, respectively. The revenue increases are necessitated by increasing costs to deliver power to customers and provide the excellent level of service in PWP's mission.

There are four key drivers behind the increasing need for electric rate adjustments. First, PWP is experiencing significant cost pressures due to rising prices for materials and equipment essential to maintaining the electric distribution grid, some of which, like cables and transformers, have seen cost increases of 75 to 100 percent since 2019. Secondly and concurrently, PWP is investing in critical infrastructure upgrades, including advanced metering systems, battery storage, and wildfire resilience projects, which are vital for long-term reliability and modernization. Third, the cost of energy procurement is rising as PWP is purchasing power supply resources to meet customer demand as a part of the larger California energy markets. Since committing in 2018 to purchasing only renewable resources, PWP has seen market-based prices for clean energy more than double over the past five years. Finally, PWP must ensure that the utility remains financially sound and resilient to serve customers for current and future generations. With these rate adjustments, PWP can ensure adequate funding for these essential initiatives while maintaining strong financial metrics and continuing to deliver reliable electric service that customers can count on.

Through strategic planning, PWP is identifying cost savings and operational efficiencies, issuing debt responsibly, and using a range of tools to manage the Fund's long-term sustainability.

To increase revenue and reduce costs, PWP has successfully pursued external funding, including nearly $10 million from the California Energy Commission for a battery energy storage system. To lower the cost of long-term renewable energy contracts, PWP is also working on a prepaid energy transaction expected to save approximately $1.4 million annually. This approach will be expanded as additional renewable resources come online in 2027 and 2028.

PWP continues to modernize its operations by implementing new technologies and improving supply chain strategies to drive efficiency. In 2024, PWP issued municipal electric revenue bonds to support capital investments in power delivery infrastructure. Approximately $34 million in bond proceeds are currently being used for existing capital projects, and a $50 million bond issuance is projected for fiscal year 2028. These actions help ensure intergenerational equity by spreading the cost of major system investments over time, rather than relying solely on cash funding.

Without these adjustments, PWP's cash balance—currently at $409 million—would decline by over $134 million by FY 2029, reducing the utility's financial flexibility and resilience. With the proposed rate plan, PWP has projected a use of $36 million at a minimum or more as discussed in the analysis portion.

Equity and Affordability

As part of the foundational work in the Electric Rate Study, PWP prioritized equity and affordability by ensuring that income-qualified customers would not bear the burden of fixed charges. One of the first policy decisions made was to structure the rate design so that 100% of fixed monthly fees, such as the customer charge and grid access charge, would be fully offset for qualifying low-income households using funds from the Public Benefits Charge. This ensures that our most vulnerable neighbors continue to receive essential electric service without undue financial strain. In addition to direct bill relief, PWP's energy efficiency programs, such as the Home Improvement Program and the Low-Income Energy Efficiency Under One Roof initiative, provide long-term affordability by reducing household energy consumption. These programs offer no-cost upgrades like LED lighting, smart thermostats, weatherization, and low-flow fixtures, which lower monthly bills and provide ongoing financial payback to customers. By embedding both immediate and sustained affordability measures into the rate structure and customer programs, the study reflects PWP's commitment to inclusive utility planning and reinforces the City's broader goals of equity, sustainability, and community resilience.

Public Engagement

Public engagement has been a cornerstone of the Electric Rate Study. In January 2025, PWP presented its Customer Engagement Plan to the MSC, outlining a two-phase strategy. Phase one focused on listening and gathering input from customers through webinars, open houses, and the launch of a dedicated website. Phase two, which will begin following Council action on the proposed rates, will focus on education and outreach. This includes the development of community outreach kits, targeted events, and digital tools to help customers understand the new rates and how to manage their energy use effectively.
PWP is actively engaging the community to raise awareness, gather input on customer priorities, and better understand the diverse needs of its customers. Transparency is a core value in this process, with a strong emphasis on clear, accessible communication to build trust and encourage meaningful public participation in rate-setting decisions.

Public engagement began in spring 2025 and has included a variety of outreach efforts, such as the Shaping Our Energy Future webinar, PWP's Open House, targeted events with residential and commercial customers, and the launch of https://engagepwp.org/, a dedicated platform for community input.

Through these engagement efforts, customers have expressed interest in more incentives and rate options for electric vehicle charging, solar with battery storage, and sustainable home upgrades. PWP's current solar program offers strong incentives, such as full retail-rate credits for exported energy. To further encourage clean energy adoption, PWP is recommending updates to time-of-use ("TOU") rates and net energy metering to better align with customer needs and support broader adoption of clean energy technologies.

PWP also has an active and engaged commercial and institutional customer base that is the backbone of the thriving local economy. As such, PWP met with commercial customers as well by presenting information and having a dialogue at the large-user breakfast as well as having open times available to have discussions with commercial customers. As stated from one of the key accounts, Karl Zerrenner, Vice President of Volkswagon Pasadena said, "We appreciate PWP's engagement with their residential and commercial customers regarding future rate studies while working towards a 100% carbon-free energy future. Being invited to discuss these matters with the PWP finance team is a perfect example of the joint collaboration needed to help ease any concerns regarding future rates increases".

To further support transparency, PWP is preparing to launch an electric bill estimator, an online tool that will help customers estimate how proposed rate changes may affect their monthly bills based on actual or estimated usage. This tool is designed to empower customers with personalized insights and support informed participation.

PWP remains committed to delivering affordable, reliable, and sustainable service. Recognizing that affordability means different things to different households and businesses, PWP is using community feedback to shape future programs and ensure that rates remain equitable, competitive, and responsive to Pasadena's evolving energy landscape.

ANALYSIS

The analysis outlines the financial framework and cost-of-service considerations that guide PWP rate design and long-term financial planning. Central to this review is the development of the Test Year Revenue Requirement, which establishes the level of revenue necessary to recover all utility costs and maintain financial stability. The analysis evaluates revenue requirement methodologies, presents a four-year financial forecast, and examines how costs are allocated across customer classes to ensure fairness and transparency. By aligning rates with the actual cost of providing service, the study supports both operational needs and strategic objectives, while addressing challenges such as rising capital demands, evolving customer usage patterns, and the need to preserve adequate reserves. A draft report detailing full details of the revenue requirements and financial modeling can be found in Attachment A.

Revenue Requirements

There are two primary revenue requirement methodologies employed in the utility industry: the cash basis and the utility basis. The primary differences between the cash basis and the utility basis involve the treatment of depreciation, return on invested capital, and debt service. The cash basis, which is the most common method used by municipalities, includes debt service but excludes depreciation and return on invested capital in the revenue requirement determination. The cash basis focuses on meeting the cash demands of the utility. The utility basis, commonly used by private or for-profit utilities, includes depreciation and return on invested capital, but excludes debt service from the revenue requirement determination.

In this cost-of-service analysis, NewGen utilized the cash basis as it follows the traditional cash-oriented budgeting practices frequently used by government entities. Furthermore, the cash basis is generally easier to communicate to customers, as it aligns revenue with expenditures.

NewGen developed the Test Year Revenue Requirement for the two-year Study Period, including all costs required to operate the Utility and ensure its financial stability. The Test Year Revenue Requirement of $259.6 million is the two-year average of the annual revenue requirements, with the application of reserves of $36.3 million.

Financial Forecast

The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves over the four-year Study Period (FY 2026–FY 2029). PWP received guidance from City Council, on July 14, 2025, to establish the Study Period and set rates for a two-year period. To develop the financial forecast, NewGen utilized the Power fund's FY 2026 budgeted expenses, load forecast documents, records of operations, customer billing data, and other detailed information and data compiled and provided by PWP. The forecast used the FY 2026 budgeted expenses as the base year in the financial forecast. Any projected non-recurring expenses or revenues were identified and incorporated in the financial forecast, as appropriate.

To forecast expenses through FY 2029, NewGen used multiple escalation and forecast factors. The forecast applied specific inflation and customer growth rates to the baseline FY 2026 budget year data and reviewed each account or group of accounts to select an applicable escalation or inflation rate for the expenses. For Power Supply-related costs, NewGen relied on a detailed forecast and resource plan from PWP that integrated long-term purchased power agreements, fuel price forecasts, renewable energy credit forecasts, and other proprietary energy market forecasts.
The financial model also provides the capability of evaluating scenarios for future financial performance by changing rates, issuing debt, and calculating key performance indicators ("KPIs"). These KPIs are based on the financial policies, bond covenants, and other financial performance targets set by the utility and/or City Council. Typically, as a utility best practice, PWP evaluates overall forecasted expenses, revenues, and the resulting KPIs such as the Debt Service Coverage Ratio ("DSCR") and level of cash reserves. PWP evaluates varying levels of debt issuance and changes in rates over time to fund the required capital investments, while ensuring it maintains the targeted financial KPIs. These rate and debt recommendations are primarily driven by PWPs increasing capital needs and to ensure established DSCR and cash reserve levels are maintained.

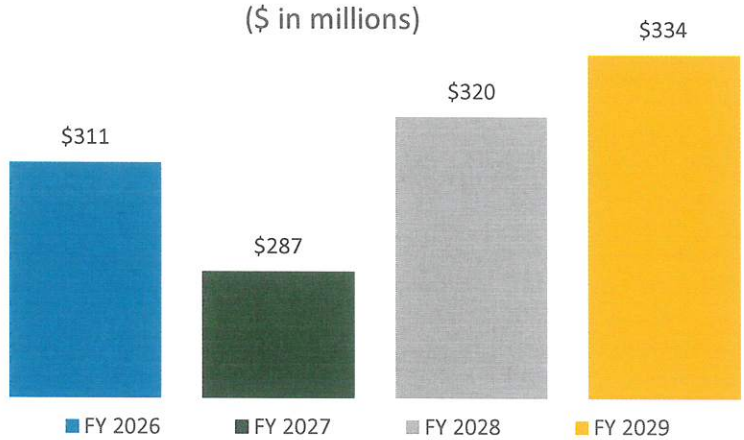
The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves. A comprehensive financial report is included as Attachment A, Draft Financial Report and Revenue Requirements. Key highlights include:

- Operations & Maintenance ("O&M"): $209.5 million average over FY 2026–2027
- Debt Service: $16.8 million average
- Capital Funded from Rates: $89.9 million average
- City Transfer: $29.2 million annually (12% of gross electric)
- Other Income/Offsets: $57.3 million in net non-operating revenues
- Use of Reserves: $36.3 million annually to reduce rate burden

Even with these investments, PWP maintains a DSCR of 6.4, far exceeding the industry benchmark of 1.5, ensuring continued financial strength.

Figure 2 represents revenue requirements. The forecasted revenue requirements in FY 2028 and 2029 may change based on progress, timing, fuel costs, power market prices, and execution of the Optimized Strategic Plan.

Figure 2: Financial Forecast Revenue Requirements
($ in millions)

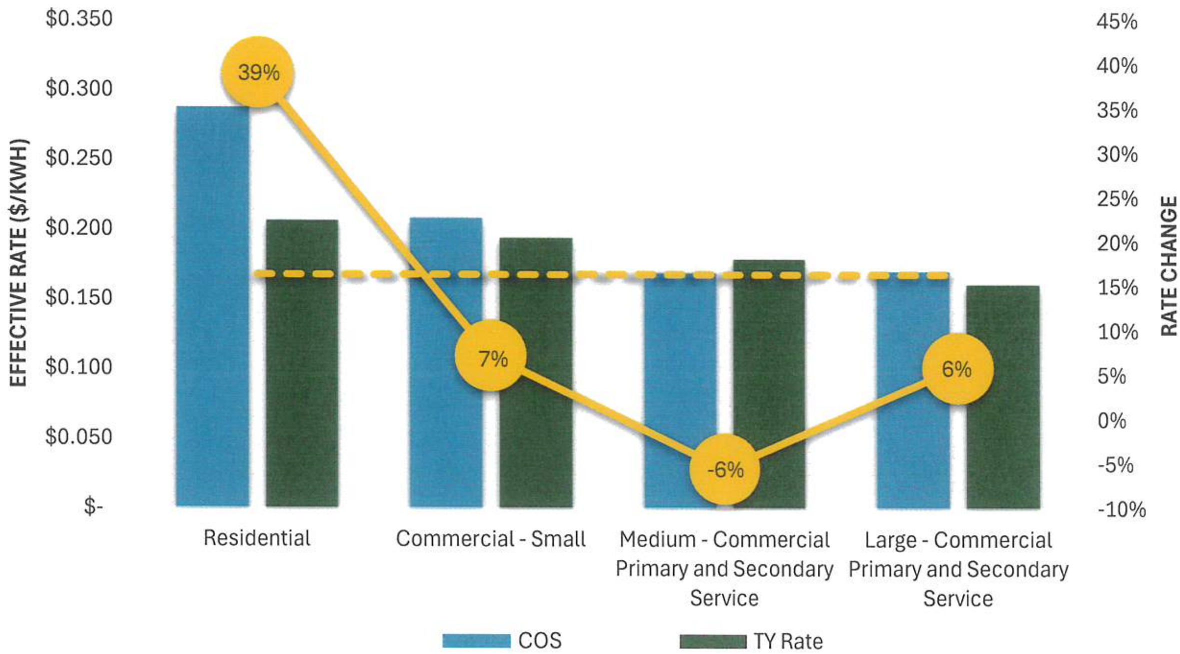


Cost of service – Aligning Cost and Pricing for Customer Types

A core objective of the Electric Rate Study is to ensure that electric rates are aligned with the actual cost of providing service. This means structuring rates so that each component—such as distribution, transmission, and power supply—is reflected in the appropriate charge. For example, the costs associated with maintaining and operating the distribution system are recovered through the distribution charge, while the costs of procuring and generating electricity are recovered through the energy services charge. In addition to aligning rates with functional costs, the study also ensures that costs are allocated to the customer classes that generate them. This principle of cost causation means that residential customers, who drive a significant portion of system demand and infrastructure needs, are responsible for covering the costs associated with their usage, rather than having those costs subsidized by other customer classes. This approach promotes fairness, transparency, and long-term financial sustainability for the utility.

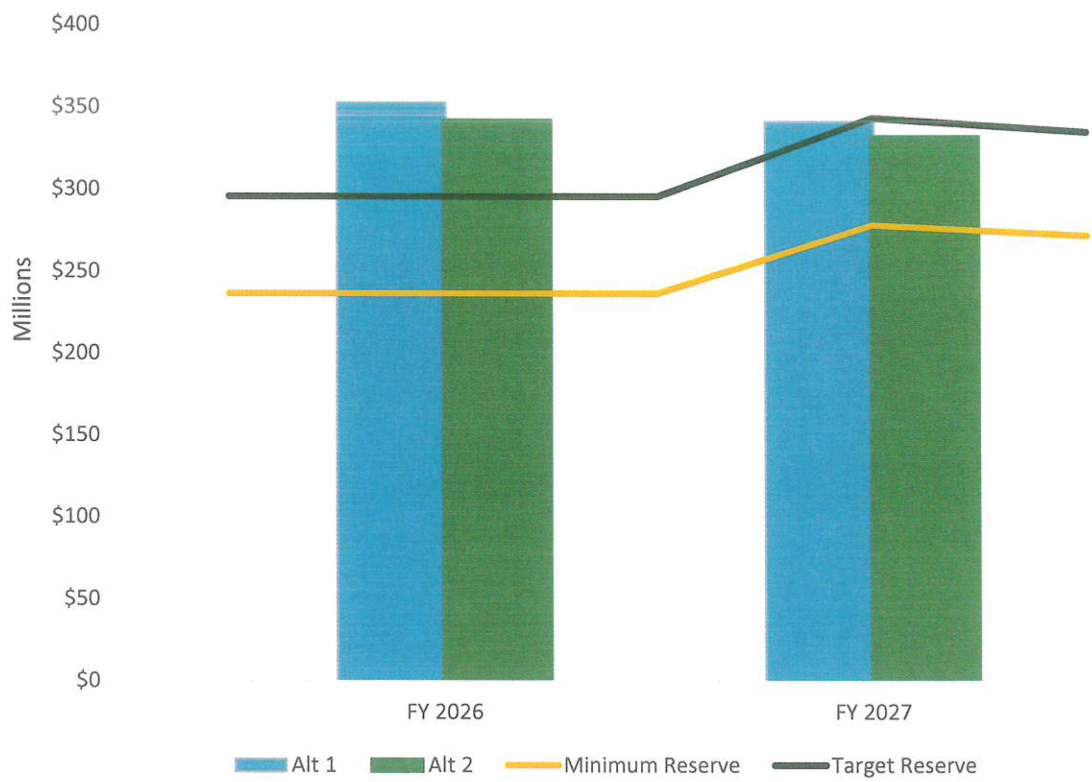
Among all customer groups, residential customers have seen the most significant reallocation of costs based on changes in their cost-to-serve. The residential sector has contributed to increased power peaks, particularly due to electrification trends and changing usage patterns. The study shows that the residential customer class is under-recovering by 39% as a customer base. Figure 3 below outlines the cost-of-service adjustments by customer class required to align the actual cost of providing service.

Figure 3: Cost-of-Service vs. Test Year Effective Rate



The cash reserve balances, resulting from the proposed systemwide rate adjustments, are consistent with industry standards and provide PWP flexibility and financial stability to support future operating and capital requirements. In addition, the reserves offer the ability to manage uncertainties related to construction timelines, project schedules, and financing costs, including interest rate fluctuations. Beyond these functions, the cash reserves serve multiple purposes, such as providing working capital, stabilizing rates to reduce volatility, and funding capital improvements. As depicted in the Figure 4 below, the rate plans maintain the power fund balance at the total minimum working capital reserves. The revenue plan also includes the issuance of $50 million dollars in debt financing.

Figure 4: Working Capital



Customer Classifications

Current customer classifications are single family residential, multifamily residential, small commercial, medium commercial, and large commercial. Each of these classifications have distinctive use patterns that enabled differentiation during the cost-of-service study. Since the last comprehensive rate study system usage has changed enough to warrant the introduction of several new customer classifications.

To continue to modernize, PWP proposes to introduce updated customer classifications that reflect the city's evolving energy priorities. These changes are grounded in a comprehensive cost-of-service analysis and support Pasadena's commitment to equity, sustainability, and grid reliability. The Electric Vehicle classification is designed to accommodate growing EV adoption while promoting efficient charging behavior. The Extra-Large Customer classification ensures that high-usage customers are billed more accurately based on their demand on the system. Additionally, the Standard Offer – Local Clean Energy also known as Feed-in Tariff classification supports local renewable energy generation by compensating customers who export power back to the grid. Collectively, these updates position Pasadena to meet its long-term clean energy goals while maintaining fair and transparent electric rates.

<u>Electric Vehicle:</u> PWP proposes adding new rate schedules for electric vehicle charging to support transportation electrification and give customers pricing that matches how EVs use energy. These schedules apply to stand-alone EV meters and are based on

charging demand levels, with separate options for variable capacity charging sites. Customers pay a standard set of charges that include customer, grid access, and time-of-use electric vehicle charging services. This structure encourages charging during lower-cost periods, supports reliable grid management, and helps customers plan charging costs with more certainty.

Extra-Large Commercial: A new extra-large commercial service category creates a distinct structure for customers with very high electricity demand. These customers now have rate schedules built around time-of-use pricing, defined billing demand, and standardized transmission and distribution treatment. The section sets a minimum demand threshold. This helps PWP match costs with usage more accurately and supports system planning for large facilities through increased options for potential collaboration to expedite common goals, through long-term contracting mechanisms and more integrated procurement planning.

Standard Offer – Local Clean Energy (Feed-in Tariff): The revised Feed-in Tariff section provides a clear framework for customers or developers who build local renewable generation and sell all of their output to PWP. The section defines eligibility, contract capacity, and program terms, and places all payment rates in the Electric Utility Rate Resolution for easier updates. It ensures generators meet interconnection and performance requirements and confirms that renewable attributes are transferred to the City. This approach promotes new local solar and other clean resources, while protecting reliability and providing consistent rules for long-term agreements.

Rate Design

Rate design is the final step of the electric rate study at which point PWP can establish recommendations and provide analysis on the impact to customers. After costs are aligned with customer classes, PWP develops the rate structure.

PWP's rate structure is made up of distinct charges, each tied to a specific cost function. These include:

- "Customer charge" is a fixed monthly charge regardless of energy use. It is generally associated with services such as billing, customer service, meter reading, and connection to the grid.
- "Distribution charge" is a usage-based charge generally associated with the cost of delivering electricity from the substations, including operation and maintenance costs, capital investment and debt service.
- "Energy services charge" (including power cost adjustment) is a usage-based charge generally associated with the solely variable cost of generating the actual amount of electricity consumed, measured in kilowatt-hours.
- "Grid access charge" is a fixed monthly charge generally associated with the fixed costs of connecting to and maintaining the electric grid, regardless of their energy consumption.

- "Public benefit charge" is a state-mandated nonbypassable, usage-based public benefit charge to fund assistance programs, energy efficiency and renewable energy projects.
- "Transmission services charge" is a usage-based charge generally associated with the cost of delivering electricity from the generating plants to our sub-stations.

After evaluation and analysis of the current rate structure, staff determined the unbundled methodology for calculation of customer bills provided a clear nexus with the cost-to-serve and enabled customers to receive price signals that align with controllable components of their bill. While analysis found that these charges can be more clearly defined, the fundamental structure is appropriate and aligns with best practice.

Each rate component was looked at with a critical eye and the energy services charge was one component that PWP recommends bringing into alignment with current best practice. For energy, TOU rates have been standard within electric utilities to encourage load shifting, support reliability, and align pricing with actual system costs throughout the day. The new proposed rate design introduces TOU rates as the default for all customers once advanced metering infrastructure is deployed. While PWP is unable to immediately implement TOU rates, the advanced metering infrastructure project is underway, and staff recommends building the capability into the rates as soon as practical. Customers will retain the ability to opt out, ensuring flexibility while encouraging participation in a rate structure that supports long-term sustainability and operational efficiency.

TOU pricing also introduces on peak, off peak, and a new critical peak, to reflect the increasing impact of increasing load peaks. While pricing is not yet suggested for critical peak, PWP included this to allow for options if current trends continue.

The updated residential rate structure introduces an inclining block design for distribution charges correcting a prior inversion where mid-tier usage was priced higher than high-tier usage. By assigning the lowest rate to usage between 0–350 kWh, a moderate rate for 351–750 kWh, and the highest rate for usage above 750 kWh, the rates align with actual costs of service while promoting conservation and improving fairness.

RECOMMENDATIONS

PWP recommendations will adjust electric rates to ensure the utility recovers the full cost of providing safe, reliable, and sustainable electric service. Rate design began with establishing the revenue requirement. This is the total amount of revenue needed to fund annual operations, maintain and upgrade the electric grid, invest in capital improvements, meet regulatory mandates, and uphold financial performance targets.

For the current Electric Rate Study, the revenue requirement is based on the FY 2026–2027 test period and totals $259.6 million on a cash-basis methodology, after applying $36.3 million in reserves to reduce upward pressure on rates.

PWP then organized all utility costs into functional categories such as power supply, distribution, transmission, customer service, metering, and grid access. These functions represent the components of the electric system. They also form the basis for assigning costs to customer classes through a cost-of-service analysis. The recommendations ensures that each customer class, Residential, Small Commercial, Medium Commercial, Large Commercial, Extra-Large Commercial, Electric Vehicle Charging, and other specialized schedules pays its proportionate share based on how it uses the system. The current study confirms that the Residential class is significantly under-recovering its cost to serve, by roughly 39 percent, and the recommendation is to provide several strategies to gradually get to realignment.

Once the structure is set, PWP calculated recommended prices. Prices are developed by dividing the cost assigned to each rate component by forecasted billing determinants, such as the number of customers, kilowatt-hours sold, or kilowatts of billing demand.

Finally, PWP evaluated how the recommended rates achieve the revenue requirement and align with policy goals. This includes maintaining financial stability, supporting the transition to a carbon-free power supply by 2030, modernizing infrastructure, reducing long-term volatility, and providing equitable treatment across customer classes. It also includes assessing customer impacts.

Rate Design Alternatives

Given the policy direction to use all strategies available to gradually adjust rates, PWP created three alternatives for consideration and is requesting further guidance on which alternative is Council's preference.

All rate design alternatives presented provide rates that are fair, transparent, compliant with Proposition 26, and able to support the utility's operational and clean energy commitments.

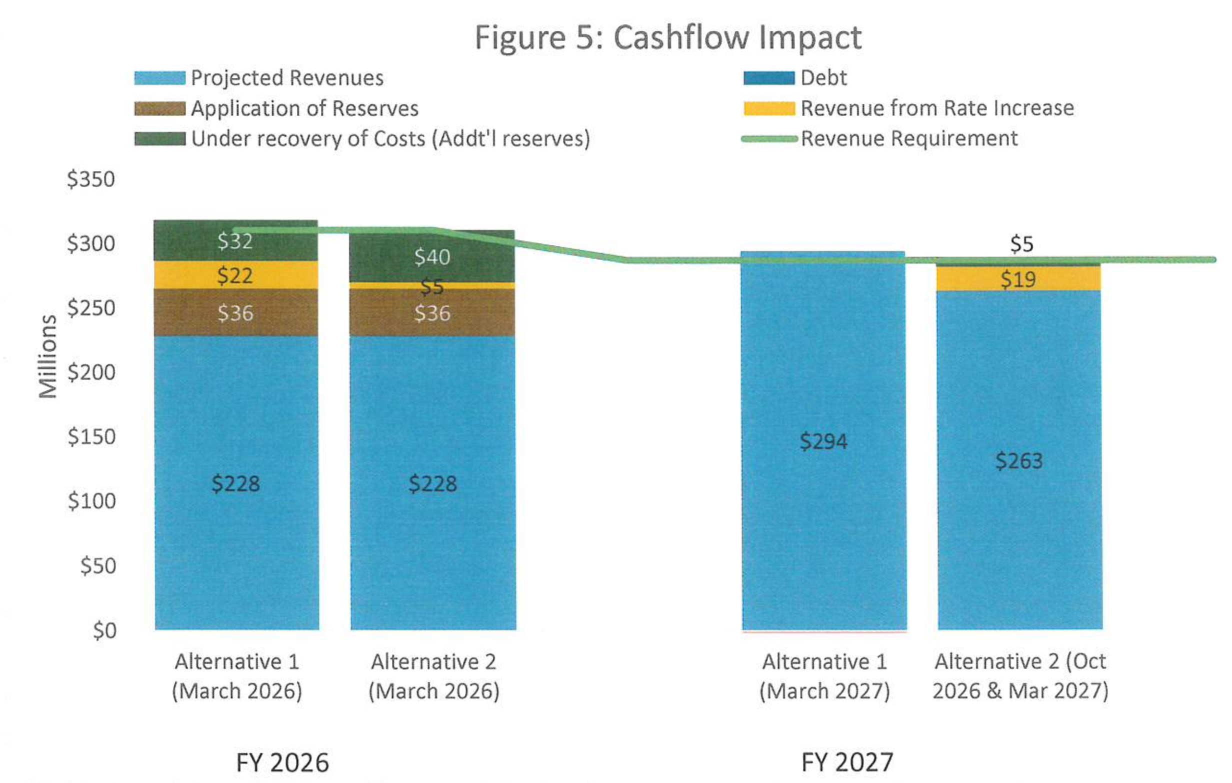
<u>Alternative 1: Immediate Full Cost Recovery – Not Recommended</u>

Alternative 1 establishes a rate plan that would, at the time of proposed adoption, achieve full-cost recovery by customer class with one adjustment. Given the drastic increase required and the implications for customer's and affordability, **staff does not recommend this alternative.**

<u>Alternative 2: Gradual Full Cost Recovery with options for three adjustments over two Fiscal Years.</u>

Alternative 2 provides a strategy for three rate adjustments over two Fiscal Years, the changes recommended to take effect March 2026 (FY26), October 2026 (FY27) and the final adjustment March 2027 (FY27). This alternative is steady and is most aligned with Municipal Services Committee guidance. The revenue collection impact would be $40 million in FY26 and $5 million in FY27.

Each strategy has an impact on the timing for revenue collection. As shown in Figure 5 below.



Customer Bill Impacts

Individual customer bill impacts will vary depending on the customer class and the amount of electricity consumed. Because of the variability of rates, PWP will develop an estimator for customers to understand the impact once one rate plan is decided on. Below are some impacts using averages for consumption. For comparison purposes, above average usage is also presented for residential customers to give a bit more context on the variability in bill impact due to usage patterns. As shown in Figures 6 and 7, the proportional usage electricity by customer classification is significantly different.

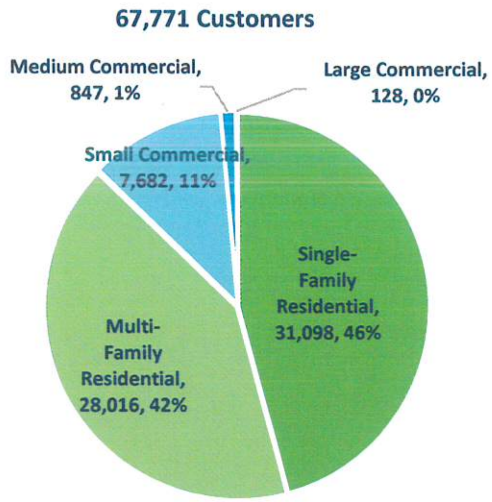


Figure 6: Customer Count FY24

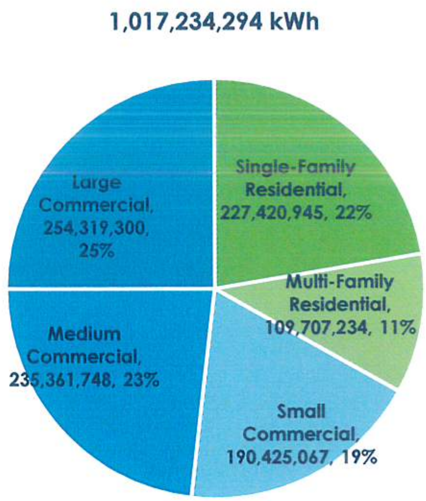


Figure 7: Customer Usage FY24

Residential Customer Bill Impacts

Single and multi-family residential customers represent nearly 88% of PWP's customer accounts, whereas they represent 22% of the total consumption for the utility. PWP ensures that the lights are on, and essential electrical services are provided reliably year-round. For comparison purposes, the bill impacts shown in Table 1 and Figure 8 below represent an approximation of the average customer, using 500 kWh monthly.

To demonstrate the different impact of the distribution charge structural change, the Tables 1 and 2 and Figures 8 and 9 below also show a residential customer with higher-than-average consumption at 1,000 kWh per month. The tables and figures below, show the impact based on the two alternative strategies to implement rate adjustments.

Table 1: Sample Electric Bills - Monthly (Residential @ 500 kWh)

		Approximate Bills			
	Current Bill	**March 2026**	**October 2026**	**March 2027**	**March 2028**
Alternative 1	$115.01	$150.24	$144.10	$144.10	$144.10
Alternative 2		$113.17	$123.17	$135.11	$135.11

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

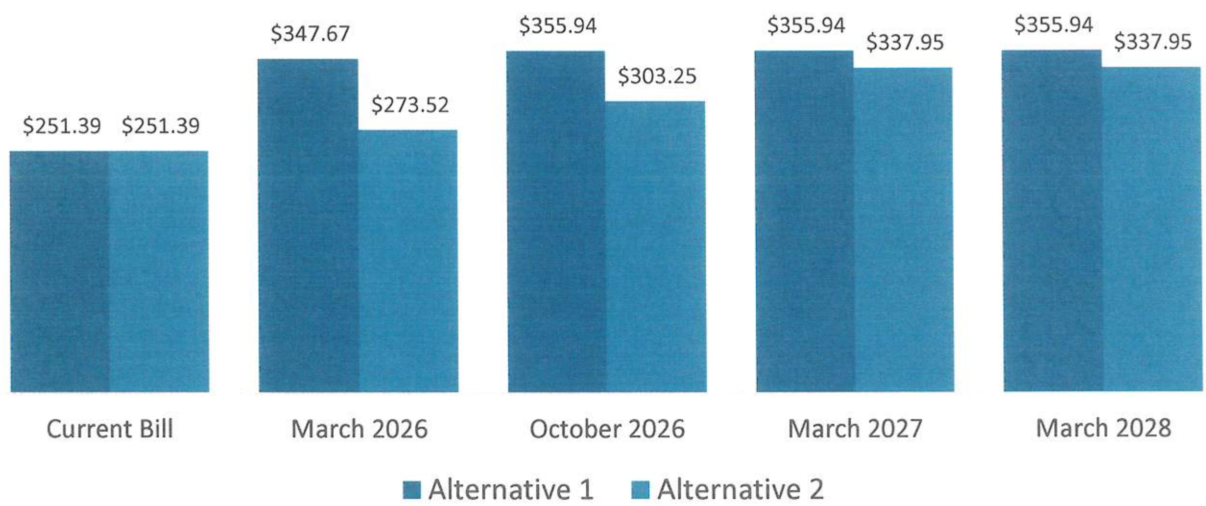
Figure 8: Residential - Average Use (500 kWh)

Table 2: Sample Electric Bills - Monthly (Residential @ 1,000 kWh)

	Current Bill	Approximate Bills			
		March 2026	**October 2026**	**March 2027**	**March 2028**
Alternative 1	$251.39	$347.67	$355.94	$355.94	$355.94
Alternative 2		$273.52	$303.25	$337.95	$337.95

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Figure 9: Residential - Above Average Use (1,000 kWh)



Small Commercial Rate Impacts:

Small commercial customers represent approximately 11% of PWP's customers and approximately 19% of the total retail power sales (in kWh) per year. Small commercial customers are the backbone of the community that includes establishments such as small retail and professional offices, cafes and small restaurants, and small dental or medical offices. An approximation of typical usage is estimated to be around 1,500 kWh per hour. The table 3 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 3: Sample Electric Bills - Monthly (Small Commercial @ 1,500 kWh)

	Current Bill	Approximate Bills: March 2026	October 2026	March 2027	March 2028
Alternative 1	$341.56	$419.88	$390.80	$390.80	$390.80
Alternative 2		$364.73	$385.44	$404.42	$404.42

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Medium Commercial Rate Impacts:

Medium commercial customers represent approximately 1% of PWP's customers and approximately 23% of the total retail power sales (in kWh) per year. Medium commercial customers include mid-size office buildings (20,000 – 30,000 sq ft), retail stores, groceries, urgent care facilities, veterinary hospitals, restaurants, fitness centers and warehouses. An approximation of typical usage is estimated to be around 15,000 kWh per hour, about ten times that of a small commercial customer. The table 4 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 4: Sample Electric Bills - Monthly (Medium Commercial Secondary @ 15,000 kWh)

	Current Bill	Approximate Bills: March 2026	October 2026	March 2027	March 2028
Alternative 1	$6,483.80	$7,384.29	$7,680.69	$7,680.69	$7,680.69
Alternative 2		$6,913.70	$7,353.40	$7,801.23	$7,801.23

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Large Commercial Rate Impacts:

Large commercial customers represent less than 1% or 130 of PWP's customers and comprise of approximately 25% of the total retail power sales (in kWh) per year. Large commercial customers include hospital, school campuses, supermarkets and departments stores. An approximation of typical usage is estimated to be around 175,000 kWh per hour, about ten times that of a small commercial customer. The table 5 below, shows the impact based on the two alternative strategies to implement rate adjustments.

Table 5: Sample Electric Bills - Monthly (Large Commercial Secondary @ 175,000 kWh)

	Current Bill	Approximate Bills			
		March 2026	**October 2026**	**March 2027**	**March 2028**
Alternative 1	$37,227.41	$41,954.67	$38,695.51	$38,695.51	$38,695.51
Alternative 2		$38,791.99	$41,588.03	$39,987.64	$39,987.64

*Amounts represent monthly total bill for a winter month. Energy Services Charge includes projected Power Cost Adjustment based on forecast and is subject to change based on future market conditions.

Customer bill impacts will vary based on customer class and electricity usage. To help customers understand their specific impacts, PWP will provide an estimator once a final rate plan is selected. For residential customers bill impacts are shown for both average (500 kWh/month) and above-average (1,000 kWh/month) usage. Small commercial customers also see varying impacts depending on the rate adjustment strategy. Medium and large commercial customers, though fewer in number, account for a significant share of total energy use and will experience larger absolute bill changes. Across all customer classes, two alternative rate adjustment strategies are modeled, with impacts shown through 2028. PWP's proposed rates remain competitive with neighboring utilities, though comparisons are influenced by many factors such as differences in infrastructure needs and operating costs.

Comprehensive Light and Power Rate Ordinance Recommendations for Restatement and Modernization

The City recently updated several provisions of the Light and Power Rate Ordinance. These updates aimed to eliminate outdated or obsolete language and align with current industry best practices. Key changes included the removal of the Direct Access Service section and revisions to long-term contract provisions. In February 2025, the City Council approved amendments to the Pasadena Municipal Code to eliminate the outdated Stranded Investment Reserve and establish a Working Capital Reserve Policy. This policy includes targets for liquidity, energy market exposure, transmission, and contingency risks. These changes align with Government Finance Officers Association best practices and support long-term financial resilience. The reserve policy ensures that PWP maintains sufficient working capital to manage volatility in energy markets, unexpected capital needs, and other operational risks without abrupt rate changes.

Staff further reviewed the overall structure of the ordinance and recommends revisions that are aligned with current industry leading practices and provide a streamlined approach for future policy revisions and include the following guiding principles:

- Streamlined governance: Propose to move all rate figures to the *Electric Utility Rate Resolution* allows faster Council-approved adjustments.
- Future-readiness: The ordinance anticipates AMI deployment, time-of-use pricing, distributed generation (NEM/FIT), and renewable integration.
- Technical alignment: Definitions and schedules now match CPUC terminology, NERC standards, and CAISO market conventions.

Staff recommends a restatement because the current rates ordinance has become too unwieldy to manage through piecemeal amendments. Over time, layers of changes, cross-references, and outdated language have made it hard for staff, customers, and decision makers to read and understand. A restatement lets us reorganize the entire structure, integrate all prior amendments, remove inconsistencies, and modernize the policy in a clear and coherent format. This approach improves transparency, supports compliance, and gives the public a complete, readable ordinance instead of another round of patchwork edits.

Changes in the restated ordinance include:

1. Structural and Formatting Updates
    - The revised document (redline) retains the same section numbering but adds clearer formatting, headings, and spacing.
    - Cross-references to the Electric Utility Rate Resolution replace older inline rate tables or numeric rate references.
    - The term "Electric Utility Rate Resolution" now governs all fees, penalties, and charges across sections, providing flexibility for rate updates without ordinance amendments.
    - Several obsolete phrases and voltage configurations were modernized, and redundant phrases (e.g., "as herein used") were removed for clarity.

2. Expanded and Updated Definitions (13.04.020)
   - New definitions added:
     - *Apparent Power*, *Distribution Charge*, *Energy Services Charge*, *Grid Access Charge*, *Interval Read Capable Meter*, *Portfolio Content Category One (PCC1)*, *Renewable Energy Credit (REC)*, *Reservation Charge*, *Time-of-Use (TOU)*, and *Electric Utility Rate Resolution*.
     - These definitions modernize terminology consistent with California Public Utilities Code and CPUC standards.
   - Terminology alignment: The definition of *Department*, *Customer Charge*, and *Transmission Services Charge* was standardized for consistent use in schedules
   - Environmental language: Added *Greenhouse Gas (GHG)* definition, reflecting PWP's decarbonization and carbon-free 2030 goals.
   - Measurement precision: Units like *kW*, *kWh*, *MW*, and *MWh* are now clearly defined, emphasizing technical accuracy and alignment with industry practice.

3. Modernization of Rate Design (13.04.031)
   - Introduced three-tiered TOU pricing: "on-peak," "off-peak," and "critical-peak."
   - Defined Seasonal Periods before and after *Interval Read Capable Meter* implementation, signaling a transition to AMI-based dynamic pricing.
   - Clarified that all rate elements (fees, charges, refunds) are governed by the *Electric Utility Rate Resolution* — a major administrative simplification

4. Residential Schedules (R-1 and R-2)
   - Structure and applicability updated: Now includes clearer descriptions of voltage types and service conditions.
   - Customer rates explicitly list six core charge components: customer, distribution, grid access, energy services, transmission, and public benefit charges.
   - Rate options: Adds clear choice between *seasonal flat* and *TOU* rates; specifies that Interval Read Capable Meters will automatically enroll customers into TOU rates once deployed
   - Lockout period of 12 months between rate option changes maintained but clarified.

5. Commercial and Institutional Schedules (S-1 through L-3)
   - Standardization of applicability thresholds:
     - S-1 (<30 kW), M-2 (30–300 kW, secondary), M-1 (30–300 kW, primary), L-2 (>300 kW, secondary), L-1 (>300 kW, primary), and L-3 (≥10 MW).
   - Power Factor Penalty and Discount sections consolidated and made consistent across schedules.
     - Existing load correction thresholds (75%) and new load thresholds (85%) are standardized.
     - Discounts for >85% power factor capped at 5%.
   - Billing demand now includes detailed measurement interval (15 minutes, adjustable for intermittent load).
   - Minimum monthly charge language harmonized across classes to include customer, distribution, and grid access charges

7. Load Management & Pilot Program Modernization (13.04.071)
- Expanded to authorize special experimental rates for:
  - Demand response,
  - Electric vehicle integration,
  - Load shifting incentives.
- Defines program caps: 3% of total system MWh and 10% per customer group, aligning with PWP's resource adequacy and innovation goals.

Section	Topic	Previous Version	Updated Version (Redline)	🆕 / 🔄
13.04.020	Definitions	Limited technical terms	Expanded to include TOU, PCC1, RECs, Net Energy terms, etc.	🆕 Major Expansion
13.04.031	Pricing & TOU	Two TOU periods (on/off-peak)	Adds "critical-peak"; TOU default after smart meter rollout	🔄 Enhanced
13.04.040 / 045	Residential Rates (R-1/R-2)	Seasonal flat rate mainly	Adds TOU option; auto-enroll post-meter upgrade	🔄 Modernized
13.04.046	EUAP (Assistance)	Embedded in R-1 and R-2	Created distinct section.	🔄 Clarified
13.04.050–060	Commercial Rates (S-1, M-1, M-2)	Basic rate structure	Unified charges, TOU options, power factor penalties/discounts	🔄 Standardized
13.04.067–069	Large Commercial (L-1, L-2)	No TOU or PF incentives	Adds TOU, PF penalties/discounts, demand thresholds	🔄 Updated
13.04.070	Extra-Large Commercial (L-3)	Not previously defined	New schedule for 10MW+ customers	🆕 New Customer Class
13.04.071	Load Management	Limited pilot language	Formalized optional rate for experimentation	🔄 Refined

Section	**Topic**	**Previous Version**	**Updated Version (Redline)**	NEW /
13.04.074	EV Charging (EV-1 to EV-3)	Not included	New schedules by demand tier (<30kW, 30–300kW, >300kW)	NEW Added
13.04.080	Standby Service	Basic contract language	Adds reservation charge, grid access, and safety provisions	Refined
13.04.085–087	Unmetered Rates (CE-1, CE-2)	Minimal detail	Adds billing formulas, audit rights, and load change rules	Strengthened
13.04.090	Street Lighting	Flat rate tables	Adjust in Electric Utility Rate Resolution	Modernized
13.04.100	Service Regulations	General manager authority	Adds 30-day notice to Council, website posting	Transparency
13.04.110	Meter Installation	Basic specs	Interval Read Meters become standard; opt-out fees added	Upgraded
13.04.150	Rate Schedule Changes	12-month lock-in	Adds TOU auto-enroll trigger with smart meters	Clarified
13.04.170	Transmission Services Charge	Basic formula	Minor changes to detailed formula	Refined
13.04.173	Power Cost Adjustment (PCA)	Basic adjustment	Clarify monthly recalculation, detailed forecast-based formula	Refined
13.04.176	Feed-in Tariff (FIT)	Not included	Standard Contract for Local Clean	NEW New Program

Section	Topic	Previous Version	Updated Version (Redline)	NEW /
			Energy Generation for developers (not customers)	
13.04.177	Net Energy Metering (NEM)	CPUC §2827-based	Adds post-2026 structure, surplus premium tie to pricing, re-establish eligibility rules	Transition Plan
13.04.178	Self-Generation (SG)	Basic crediting	Adds TOU-based billing, demand thresholds, credit carryover	Expanded
13.04.179	Green Power (GP)	Flat premium	Adds post-2026 premium flexibility, PCC1 REC valuation	Updated
13.04.230	Public Benefit Charge	Fixed minimum	Consistent language	Refined

Key Ordinance Enhancements Supporting Local Renewable Generation

The proposed updates to Chapter 13.04 of the Pasadena Municipal Code significantly enhance the City's support for local renewable energy generation. A key addition is the establishment of a Feed-in Tariff (FIT) program or a Standard Offer for Clean Energy, which enables eligible renewable energy generators (up to 3 MW) to enter into standardized long-term contracts with PWP to sell 100% of their output. The FIT rates are updated quarterly and reflect avoided energy costs, renewable energy credit (REC) values, greenhouse gas compliance savings, and avoided transmission losses, making local generation more financially viable.

The ordinance also modernizes the City's Net Energy Metering (NEM) program. While continuing to support customer-generators under the existing framework, the ordinance introduces a new post-2026 structure that provides monthly or bi-monthly credits for surplus energy, including a premium for renewable attributes. This ensures long-term program sustainability while aligning with evolving state regulations. The proposed program does not impact existing customers who have already invested in solar under annual net metering. It also does not modify existing monthly/bi-monthly net metering customers aside from removing one obsolete premium that was relevant prior to PWP's modernized customer information system and provides clarification that incentive amount for monthly/bi-monthly customers is for the energy portion of bills.

For larger customers, the updated Self-Generation (SG) schedule supports systems of 1 MW or more, offering credits for net energy delivered to PWP and incorporating TOU billing. Additionally, the Green Power Service schedule allows all customers to voluntarily support renewable energy procurement by opting into 100% green power or purchasing in 100 kWh blocks, with premiums reinvested into renewable energy resources.

These changes are supported by a recalibrated Public Benefit Charge, which continues to fund renewable energy incentives, energy efficiency programs, and low-income assistance. Collectively, these updates position Pasadena to meet its clean energy goals by expanding access to renewable generation, modernizing rate structures, and incentivizing sustainable energy practices across all customer classes.

Program / Section	**Previous Policy**	**Updated Policy**	**Impact**
Feed-in Tariff or Standard offer – Clean Energy Contract (13.04.176)	Not previously offered	New FIT program for ≤3 MW generators with standardized contracts and quarterly rate updates	Enables local renewable developers to sell power directly to PWP
Net Energy Metering (13.04.177)	Based on CPUC §2827; capped participation	Adds post-2026 structure with monthly/bi-monthly billing, surplus crediting, and renewable premium. **No impact to existing annual net metering customers**.	Sustains rooftop solar adoption and untethers policy from State adoption
Self-Generation (13.04.178)	Basic crediting for large systems	TOU billing, net delivery credits, and grid upgrade cost recovery	Encourages large-scale on-site renewable generation
Green Power Service (13.04.179)	Flat premium for 100% green power	Adds flexible block-based participation and post-2026 premium pricing	Expands voluntary support for renewable procurement

Implementation Timeline

PWP is recommending that a public hearing be set for February 9, 2026, to receive comments on the recommended adjustments to the electric rates. Following the City Council's action to set a date for the public hearing, a notice will be mailed to all electric system customers that includes the recommended rate adjustments and provides information regarding the public hearing. Table 6 outlines the approximate timeline and implementation schedule for the proposed rate actions.

Table 6: Timeline

Date	Action Item
December	Mail public hearing notice
December 2025-February 2026	Customer Outreach and Education
February 9, 2026	Electric Rates Public Hearing
February 23, 2026	First Reading of Updated Electric Rate Ordinance
March 2, 2026	Second Reading of Updated Electric Rate Ordinance
March 1, 2026 or as soon as practicable thereafter	Effective Date of First Rate Action

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The establishment of a date to conduct a public hearing for the consideration of electric rate adjustments and the drafting of related resolutions and ordinance amendments are administrative actions that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Therefore, the proposed actions do not constitute a “project” subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required. Furthermore, the recommended electric rate adjustments themselves would be statutorily exempt from CEQA. Section 15273 of the State CEQA Guidelines identifies a statutory exemption for "Rates, Tolls, Fares, and Charges" and states (in part) that:

a. CEQA does not apply to the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or their charges by public agencies which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The estimated cost to mail information about the public hearing and recommended rate increases to all City of Pasadena electric customers is approximately $30,000. Funds are available in the Light and Power Fund.

The rate increases are expected to generate incrementally between $17 million and $24 million depending on alternative enacted. The incremental revenues will be used to offset increased O&M and capital costs of the electric system.

Respectfully submitted,

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Water and Power Department

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Water and Power Department

Approved by:

for MIGUEL MÁRQUEZ
City Manager

Attachment A: Draft Financial Report and Revenue Requirements (NewGen Document)
Attachment B: Rate Schedule Alternative 1
Attachment C: Rate Schedule Alternative 2

ATTACHMENT A: Draft Financial Report and Revenue Requirements (NewGen Document)

Draft Report | December 1, 2025

Electric Rate Study

Pasadena Water and Power
Pasadena, California

Prepared by:

NewGen Strategies & Solutions

Section 2
REVENUE REQUIREMENTS

Developing the Test Year Revenue Requirement is the first step in the cost of service and rate design process, as shown in Figure 1-1. The Test Year Revenue Requirement for the City of Pasadena's Light and Power Fund was based on the average expenses for Fiscal Year ("FY") 2026 through FY 2027 with adjustments for unusual or one-time expenses, the adopted Capital Improvement Plan ("CIP"), existing debt amortization schedules, projected debt issuances, and forecasted escalation assumptions and factors. NewGen developed a four-year financial forecast for the Study Period. The average revenue requirement for the first two years was used as the test year revenue requirement and represents all costs that must be recovered through the electric rates. The Test Year Revenue Requirement serves as a basis for determining the overall level of revenue recovery and provides a foundation for the cost of service analysis.

Financial Forecast

The financial forecast includes projections of revenues, expenses, capital spending, debt service, and changes in reserves over the four-year Study Period (FY 2026–FY 2029). Pasadena Water and Power ("PWP" or "the Utility") received guidance from the ratemaking body, City Council, on July 14, 2025, to establish the Study Period and set rates for a two-year period. To develop the financial forecast, NewGen Strategies and Solutions, LLC (NewGen) utilized the Light and Power Fund's FY 2026 budgeted expenses, load forecast documents, records of operations, customer billing data, and other detailed information and data compiled and provided by PWP. The forecast used the FY 2026 budgeted expenses as the base year in the financial forecast. Any projected non-recurring expenses or revenues were identified and incorporated in the financial forecast, as appropriate.

To forecast expenses through FY 2029, NewGen used multiple escalation and forecast factors. The forecast applied specific inflation and customer growth rates to the baseline FY 2026 budget year data and reviewed each account or group of accounts to select an applicable escalation or inflation rate for the expenses. For Power Supply-related costs, NewGen relied on a detailed forecast and resource plan from PWP that integrated their long-term purchased power agreements, fuel price forecasts, renewable energy credit forecasts, and other proprietary energy market forecasts.

The financial model also provides PWP the capability of evaluating scenarios for future financial performance by changing rates, issuing debt, and calculating key performance indicators ("KPIs"). These KPIs for PWP are based on the financial policies, bond covenants, and other financial performance targets set by the Utility and/or City Council. Typically, as a utility best practice, PWP evaluates overall forecasted expenses, revenues, and the resulting KPIs such as the Debt Service Coverage Ratio ("DSCR") and level of cash reserves. PWP evaluates varying levels of debt issuance and changes in rates over time to fund the required capital investments, while ensuring it maintains the targeted financial KPIs. These rate and debt recommendations are primarily driven by the increasing capital needs of the Utility and the need to ensure PWP maintains established DSCR and cash reserve levels.

Projected Energy Requirements

The forecasted load demand was a key driver in projections of expenses and revenues in the financial forecast. PWP developed and supplied the load forecast. The forecasted retail electric consumption includes an annual average energy growth rate of 1.3% in the Study Period, which reflects sales to PWP's retail customers.

Table 2-1
Estimated Energy Requirements During Study Period

	FY 2026	FY 2027	FY 2028	FY 2029
PWP Retail Load (MWh)	1,037,516	1,042,651	1,054,593	1,078,494

Financial Forecast Results

The results of PWP's evaluation of the financial forecast are shown in Table 2-2. As discussed previously, PWP evaluated the overall financial performance to recommend balanced system-wide rate changes and debt issuances in the Study Period. Based on the forecast, the recommended total rate increase or total bill change for the Test Year period is 9.5% in FY 2026 and 9.5% in FY 2027. For the remaining years in the forecasted Study Period, PWP initially forecasts no total rate change or total change in bills for FY 2028 and 2029. Future rate changes in FY 2028 and 2029 are initial estimates based on guidance and may change based on progress, timing, fuel costs, power market prices, and execution of the Optimized Strategic Plan.

Table 2-2
Financial Forecast Results

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
O&M Expenses	$203,774,257	$215,204,439	$209,252,937	$229,852,057
Debt Service	$15,624,250	$18,000,250	$18,780,848	$18,779,473
Capital Paid from Current Earnings (1)	$106,015,456	$73,701,937	$99,636,557	$93,648,293
Capital Paid from Low Carbon Fuel Standard and Undergrounding Fund (2)	$8,052,160	$7,604,000	$8,392,000	$5,692,000
Capital Paid from Customers (3)	$5,574,406	$5,512,500	$5,512,500	$5,512,500
City Transfer	$28,500,000	$29,963,471	$33,034,435	$33,402,912
Other Expenses (Income)	($56,997,751)	($62,870,311)	($54,186,209)	($53,082,907)
Revenue Requirement	$310,542,778	$287,116,286	$320,423,067	$333,804,327
Debt Issuance Recommendations	$0	$50,000,000	$0	$0
Total Rate Change Recommendations (4)	9.5%	9.5%	0.0%	0.0%
Projected Revenues at Recommended Rates	$249,695,590	$275,286,961	$278,357,598	$314,104,442
Difference (5)	($60,847,188)	($11,829,325)	($42,065,469)	($19,699,885)

(1) Capital funded by grants nor grant revenue are included in the financial forecast results.
(2) Corresponding revenues for Low Carbon Fuel Standard ("LCFS") and Underground are included in Other Expenses (Income).
(3) Corresponding revenues for capital paid from customers are included in Other Expenses (Income).

Table 2-2
Financial Forecast Results

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029

(4) Rate changes represent rate changes implemented on January 1st, 2026, and 2027.

(5) The difference in the revenues and total expenses is managed by cash reserves. The results of the annual change in cash reserves are summarized later in this section.

The remainder of this section will summarize and describe the key components of the financial forecast results, in addition to quantifying the Test Year Revenue Requirement for FY 2026 and 2027 that will support the rate change recommendations for those years. As discussed previously, the Test Year and recommended rate plan do not include FY 2028 and 2029, as the operating and capital expenses for those years will change and are dependent on future decisions related to the implementation of the OSP.

Operations and Maintenance Expenses

The first step in developing the revenue requirement forecast was the creation of the base year operations and maintenance ("O&M") expenses. PWP'S historical data and FY 2026 budget provide the Light and Power Fund O&M expenses. In discussions with PWP management, NewGen selected the detailed FY 2026 budget as the base year in the financial forecast for projections of O&M expenses.

Based on the FY 2026 budget from PWP, NewGen forecasted the O&M costs for the Study Period. In addition to the projected other expenses/revenues (including interest income, capital contributions, miscellaneous revenues, and sales to other utilities), CIP, debt service projections, and City Transfer, these forecasted O&M expenses supported the eventual development of the Test Year Revenue Requirement. The Test Year Revenue Requirement includes all costs required to operate the Utility and ensure financial stability for the Electric Utility over the desired period of time the rates are in effect.

O&M Forecast Account Detail

Table 2-3 summarizes the forecasted O&M expenses for the Study Period. NewGen used the average two-year O&M expenses for FY 2026 and 2027 for the Test Year Revenue Requirement as seen in Table 2-4.

Table 2-3
Forecasted O&M Detailed Funds

Account	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Personnel				
General Manager	$539,001	$558,136	$577,949	$598,467
Public Benefit Charge	$1,491,644	$1,544,597	$1,599,431	$1,656,210
Finance and Administration	$3,949,226	$4,089,424	$4,234,598	$4,384,926
Customer Service and Administration	$7,337,358	$7,597,834	$7,867,557	$8,146,856
Power Delivery	$19,307,534	$19,992,951	$20,702,701	$21,437,647
Power Supply	$11,392,208	$11,796,631	$12,215,412	$12,649,059
External Affairs	$875,675	$893,189	$911,052	$929,273
Services & Supplies				
General Manager	$566,813	$578,149	$589,712	$601,506
Public Benefit Charge	$9,911,155	$10,109,378	$10,311,566	$10,517,797
Finance and Administration	$4,240,328	$4,325,135	$4,411,637	$4,499,870
Customer Service and Administration	$2,801,969	$2,858,008	$2,915,169	$2,973,472
Power Delivery	$9,801,632	$14,235,765	$14,435,718	$14,639,670
Power Supply	$119,848,203	$124,501,244	$115,928,569	$133,821,597
External Affairs	$793,902	$809,780	$825,976	$842,495
Internal Service Charge				
General Manager	$122,761	$127,671	$132,778	$138,089
Public Benefit Charge	$300,358	$312,372	$324,867	$337,862
Finance and Administration	$1,299,538	$1,351,520	$1,405,580	$1,461,804
Customer Service and Administration	$986,850	$1,026,324	$1,067,377	$1,110,072
Power Delivery	$4,778,438	$4,969,576	$5,168,359	$5,375,093
Power Supply	$1,261,922	$1,312,399	$1,364,895	$1,419,491
External Affairs	$162,992	$169,512	$176,292	$183,344
Other Operating Expenses				
General Manager	$0	$0	$0	$0
Public Benefit Charge	$0	$0	$0	$0
Finance and Administration	$36,415	$37,143	$37,886	$38,644
Customer Service and Administration	$72,835	$74,292	$75,778	$77,293
Power Delivery	$1,868,500	$1,905,870	$1,943,987	$1,982,867
Power Supply	$27,000	$27,540	$28,091	$28,653
External Affairs	$0	$0	$0	$0
Total	**$203,774,257**	**$215,204,439**	**$209,252,937**	**$229,852,057**

Table 2-4
O&M Revenue Requirement

Account	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Personnel	$44,892,646	$46,472,762	$45,682,704
Services & Supplies	$147,964,002	$157,417,459	$152,690,730
Internal Service Charge	$8,912,859	$9,269,373	$9,091,116
Other Operating Expenses	$2,004,750	$2,044,845	$2,024,798
Total	**$203,774,257**	**$215,204,439**	**$209,489,348**

A summary of the key elements of the O&M expenses in addition to other expenses, such as debt service and transfers, are included below.

Power Supply Expenses

Power Supply expenses are the largest portion of the total O&M expenses and are associated with take or pay contracts (i.e., Intermountain Power Plant, Magnolia Power Plant, Palo Verde Power Plant, and Hoover Hydro Power), purchased power agreements (i.e., numerous renewable energy contracts), resource adequacy costs, and all other purchases to meet system demand. PWP provided the projected power supply costs incorporated into the Study. Additional power supply expenses include PWP labor and other supporting O&M accounts for the power plant, wholesale operations, and power supply management and planning. The tables below summarize the total power supply expenses for the Study Period and the power supply expenses for the revenue requirement.

Table 2-5
Power Supply Expenses

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Power Supply				
Personnel	$11,392,208	$11,796,631	$12,215,412	$12,649,059
Fuel Cost	$5,513,608	$6,610,536	$6,651,127	$6,626,018
Purchased Power	$102,925,795	$105,078,270	$96,895,814	$114,226,684
Other Power Supply Expenses	$4,287,961	$3,580,699	$3,095,374	$3,709,607
Other Services & Supplies	$7,147,839	$9,259,278	$9,314,345	$9,287,940
Internal Service Charge	$1,261,922	$1,312,399	$1,364,895	$1,419,491
Total Power Supply O&M	**$132,529,333**	**$137,637,814**	**$129,536,966**	**$147,918,799**

Table 2-6
Power Supply Revenue Requirement

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Power Supply			
Personnel	$11,392,208	$11,796,631	$11,594,420
Fuel Cost	$5,513,608	$6,610,536	$6,062,072
Purchased Power	$102,925,795	$105,078,270	$104,002,033
Other Power Supply Expenses	$4,287,961	$3,580,699	$3,934,330
Other Services & Supplies	$7,147,839	$9,259,278	$8,203,558
Internal Service Charge	$1,261,922	$1,312,399	$1,287,160
Total Power Supply O&M	**$132,529,333**	**$137,637,814**	**$135,083,574**

Transfer to the City General Fund (City Transfer)

The annual contribution for any municipal purpose ("City Transfer") is defined in the Section 1408 stating, "each fiscal year, the City Council shall transfer from the Light and Power Fund an amount equal to twelve percent (12%) of the gross income of the electric works received during the immediately preceding fiscal year from the sale of electric energy at rates and charges." In the financial forecast and Test Year Revenue Requirement, the City Transfer forecast was calculated according to the City Charter.

Debt Service

The debt service represents existing and projected debt service. The existing debt service within the Study Period and the Test Year Revenue Requirement includes the three outstanding bond issuances and associated amortization schedules.

For the Study Period, one new debt issuance was forecasted. The new debt issue supports the large CIP plans over the Study Period and Test Year. Key capital projects funded through the debt issuance include major investments in power delivery modernization—such as sizing infrastructure for projected load growth from electrification, addressing aging infrastructure, and strengthening system resilience against risks like wildfires. Funding these projects are investments that will serve future generations of customers with substantial asset lives. PWP identified $50 million in total debt issuances within the Study Period would be sufficient with the expectation that rate revenues and cash reserves will fund all other anticipated CIP.

Table 2-7 summarizes the projected debt service for the Electric Utility, and Table 2-8 summarizes the debt service revenue requirement.

Table 2-7
Electric Debt Service (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Debt Service				
Existing Direct	$15,624,250	$15,625,250	$15,620,375	$15,619,000
Future	$0	$2,375,000	$3,160,473	$3,160,473
Total	**$15,624,250**	**$18,000,250**	**$18,780,848**	**$18,779,473**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

Table 2-8
Electric Debt Service Revenue Requirement (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Debt Service			
Existing Direct	$15,624,250	$15,625,250	$15,624,750
Future	$0	$2,375,000	$1,187,500
Total	**$15,624,250**	**$18,000,250**	**$16,812,250**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

As mentioned previously, PWP evaluates the financial forecast and possible rate and debt issuance actions by monitoring financial KPIs. By bond covenants, PWP must maintain a minimum 1.5 DSCR. Pasadena Municipal Code 13.04.17513 outlines the Light and Power Fund's working capital reserves, which includes maintaining a minimum and target reserve equivalent to one year of debt service payments for outstanding bond or credit obligations. Table 2-9 summarizes the DSCR for PWP at the recommended rate increases for FYs 2026 and 2027. The operating expenses shown in Table 2-9 do not include capital paid from rate revenues and cash reserves, which is explained later in this section.

Table 2-9
Electric Debt Service Coverage Ratio (1)

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Operating Revenues (2)	$303,008,999	$336,542,314	$319,775,657
Operating Expenses	$203,774,257	$215,204,439	$209,489,348
Net Revenues Available	$99,234,742	$121,337,875	$110,286,308
Debt Service			
Existing Direct (3)	$15,624,250	$15,625,250	$15,624,750
Future	$0	$2,375,000	$1,187,500
Total	**$15,624,250**	**$18,000,250**	**$16,812,250**
Debt Service Coverage Ratio (4)	**6.4**	**6.7**	**6.6**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.
(2) Operating revenues include retail rate revenues, interest income, and other or miscellaneous revenues.
(3) DSCR equals the Net Revenues Available divided by the total Debt Service.

Capital Paid from Current Earnings

The Electric Utility's capital expenses are identified within the FY 2026 Budget four-year CIP. To finance these capital investments and system upgrades over the Study Period, the Utility plans to utilize a combination of debt, rate revenues, and cash reserves. These projects are most notably the implementation of the advanced metering infrastructure, a software and hardware investment, and the PWP battery energy storage system. These projects are critical modernization projects that have been delayed and are time-critical within the Study Period. However, in the absence of rate adjustments, a significant portion of the annual CIP would need to be funded through cash reserves. The average annual capital expenses funded through rate revenues or cash reserves—reflected in FY 2026, FY 2027, and the Test Year Revenue Requirement— totals $89.9 million. Table 2-10 presents the annual capital outlays funded through cash sources over the Study Period, while Table 2-11 summarizes the capital outlays attributed to cash sources in the Test Year.

Table 2-10
Electric Capital Funded with Cash Sources

Item	Year 1 FY 2026	Year 2 FY 2027	Year 3 FY 2028	Year 4 FY 2029
Cash-Funded Capital	$106,015,456	$73,701,937	$99,636,557	$93,648,293

Table 2-11
Electric Capital Funded with Cash Sources for Revenue Requirement

Item	Year 1 FY 2026	Year 2 FY 2027	Two-Year Average
Cash-Funded Capital	$106,015,456	$73,701,937	$89,858,696

Capital funded through grants and contributions in aid of construction ("CIAC") from customers are excluded from the revenue requirement and COS as they do not contribute to costs that must be recovered in PWP's rates. All expenses associated with construction in these two categories are independently funded and have no impact on revenue requirement. As such, CIAC is adjusted out of the revenue requirement as seen in Table 2-12.

Other Income and Expenses

Other income and expenses represent miscellaneous non-operating revenues or expenses that are a net $57.3 million in revenues in the Test Year. This amount reflects non-operating revenues, which include interest income, grants, charges for internal services, and miscellaneous revenues (e.g., late fees, connection fees, etc.). These net revenues act to reduce the overall revenue requirement and eventual rates paid by PWP customers. Adjustments have been made to other income to arrive at the Test year Revenue Requirement. Corresponding with the CIAC removal from capital expenses, the CIAC associated revenues are also removed from other income. Additionally, adjustments are made to the revenues associated with the public benefit charge and LCFS as these expenses and revenues be equal in practice. PWP targets annual public benefit charge and LCFS related expenses to be equal to the revenues generated. After adjustments, these net revenues reduce the overall Test Year Revenue Requirement by $57 million.

Revenue Requirement

There are two primary revenue requirement methodologies employed in the utility industry: the cash basis and the utility basis. The primary differences between the cash basis and the utility basis involve the treatment of depreciation, return on invested capital, and debt service. The cash basis, which is the most common method used by municipalities, includes debt service but excludes depreciation and return on invested capital in the revenue requirement determination. The cash basis focuses on meeting the cash demands of the utility. The utility basis, commonly used by private or for-profit utilities, includes depreciation and return on invested capital, but excludes debt service from the revenue requirement determination.

In this cost of service analysis, NewGen utilized the cash basis as it follows the traditional cash-oriented budgeting practices frequently used by government entities. Furthermore, the cash basis is generally easier to communicate to customers, as it aligns revenue with expenditures.

NewGen developed the Test Year Revenue Requirement for the two-year Study Period, including all costs required to operate the Utility and ensure its financial stability. The Test Year Revenue Requirement of $259,540,672 is the two-year average of the annual revenue requirements and is shown in Table 2-12.

The current rates are insufficient to fully recover the projected operating and capital costs by approximately $31.6 million.

Table 2-12
Test Year Revenue Requirement [1]

Account	2-Year Average	Adjustments	Test Year
O&M Expenses [2]	$209,489,348		$209,489,348
Debt Service [3]	$16,812,250		$16,812,250
Capital Paid from Rates	$89,858,696		$89,858,696
Capital Paid from Low Carbon Fuel Standard and Undergrounding Fund [4]	$7,828,080		$7,828,080
Capital Paid from Customers [5]	$5,543,453	($5,543,453)	$0
City Transfer	$29,231,735		$29,231,735
Other Expenses/(Income) [6]	(59,934,031)	$2,592,850	($57,341,181)
Application of Reserves	($36,338,257)		($36,338,257)
Revenue Requirement [7]	**$262,491,275**	**($2,950,603)**	**$259,540,672**
Test Year Projected Revenues [8]			**$227,962,131**
Over (Under) Recovery of Costs			**($31,578,541)**

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.
(2) O&M Expenses exclude non-cash related items such as Depreciation.
(3) Debt service reflects the annual total principal and interest payments associated with current and expected new debt financing.
(4) Corresponding revenues for Low Carbon Fuel Standard (LCFS) and Underground are included in Other Income.
(5) Corresponding revenues to capital paid from customers are included in Other Income.
(6) Other Expenses/(Income) include interest income, non-operating expenses, miscellaneous revenues, and non-operating revenues.
(7) Please note the 2-year average revenue requirement shown here does not equal the revenue requirements shown in Table 2-2 as Table 2-12 applies the use of cash reserves to reduce the revenue requirement
(8) Test Year Projected Revenues assume the current Power Cost Adjustment.

NewGen has included the application of cash reserves to decrease the Test Year Revenue Requirement in Table 2-12. Existing reserves meet and exceed its financial policies and minimums and maintains them after the Test Year period and use of a portion of the reserves.

Reserves

Unrestricted cash reserves serve multiple purposes, including providing working capital, funding capital projects, mitigating market and price volatility risks to customers, and supporting the Utility's overall cash flow management. The annual balances and contributions to or use of reserves, assuming PWP does not adjust base rates, are shown in Table 2-13.

If PWP does not implement rate increases, the estimated annual shortfall of $31.5 million in the revenue requirement will further draw down the cash reserves beyond the levels already planned and shown in Table 2-12. The estimated reserve balance as of July 1, 2025, is $409 million or 741 days of cash on hand. Without any rate increases, PWP's cash reserve balance is projected to decline by $137 million over the Study Period, decreasing from $409 million to $271 million.

Table 2-13
Electric Cash Reserve Balances – No Rate Increases (1)

	Year 1 FY 2026	Year 2 FY 2027
Fund Balance – BOY	$408,829,565	$327,709,874
Deposits from Earnings (2)	$38,522,331	$30,914,198
Withdrawals (Capital & Operating)	($119,642,022)	($86,818,437)
Fund Balance – EOY	$327,709,874	$271,805,635
Days Cash on Hand BOY	741	564
Days Cash on Hand EOY	595	469

(1) Please note that the total amounts shown in the table may not properly add as shown due to rounding.

(2) Deposits from earnings represent the operating revenues less operating expenses, City Transfer, and debt service.

If the proposed total rate increases of 9.5% for both FY 2026 and FY 2027 are implemented, the projected ending balance in FY 2027 increases from $271 million to $336 million, equivalent to 578 days cash on hand. The cash reserve balances, resulting from the proposed systemwide rate adjustments, are consistent with industry standards and provide PWP flexibility and financial stability to support future operating and capital requirements. Additionally, the reserves offer the ability to manage uncertainties related to construction timelines, project schedules, and financing costs, including interest rate fluctuations. Beyond these functions, the cash reserves serve multiple purposes within the Utility, such as providing working capital, stabilizing rates to reduce volatility, and funding capital improvements.

PWP has a working capital policy reflected in Pasadena Municipal Code Chapter 13.04.175 which establishes the "Working Capital targets to be the sum of an Operational Reserve, a Debt Service Reserve, a Capital Expenditures Reserve, a General Fund Transfer Reserve, an Energy Services Charge Reserve, a Transmission Services Charge Reserve, and a Contingency Reserve."

ATTACHMENT B: RATE SCHEDULE ALTERNATIVE 1

MUNICIPAL COD	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2
13.04.040	**Residential single-family service (R-1)**			
13.04.040	Customer Charger per meter per month	$8.96000	$11.15000	$13.25000
13.04.040	Grid Access Charge per meter per month	$4.50000	$6.50000	$8.50000
13.04.040	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04836
13.04.040	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.19345
13.04.040	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.34822
13.04.040	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609
13.04.040	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.15057	$0.12072
13.04.040	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.13085	$0.10492
13.04.040	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.31399	$0.25175
13.04.040	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.10112	$0.08107
13.04.040	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.11150	$0.23736
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.05100	$0.10857
13.04.040	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.045	**Residential multi-family service (R-2)**			
13.04.045	Customer Charger per meter per month	$8.96000	$11.15000	$13.25000
13.04.045	Grid Access Charge per meter per month	$4.50000	$6.50000	$8.50000
13.04.045	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04836
13.04.045	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.19345
13.04.045	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.34822
13.04.045	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609
13.04.045	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.15057	$0.12072
13.04.045	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.13085	$0.10492
13.04.045	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.31399	$0.25175
13.04.045	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.10112	$0.08107
13.04.045	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.11150	$0.23736
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.05100	$0.10857
13.04.045	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.050	**Small commerical and institutional serivce (S-1)**			
13.04.050	Customer Charger per meter per month	$9.42000	$15.00000	$20.65000
13.04.050	Grid Access Charge per meter per month	$17.00000	$17.00000	$17.00000
13.04.050	Distribution Charge per kWh per month	$0.06423	$0.06862	$0.07300
13.04.050	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609
13.04.050	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.06901	$0.13988	$0.13107
13.04.050	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06030	$0.12223	$0.11453
13.04.050	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10463	$0.21208	$0.19872
13.04.050	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05706	$0.11566	$0.10837
13.04.050	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06431	$0.13036	$0.12214
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05611	$0.11373	$0.10657
13.04.050	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.050	Minimum Monthly Charge (Customer Charge + Grid Access Charge)	$26.42000	$32.00000	$37.65000
13.04.060	**Medium commerical and institutional service - secondary (M-1)**			
13.04.060	Customer Charger per meter per month	$23.40000	N/A	N/A
13.04.060	Grid Access Charge per meter per month	$250.00000	N/A	N/A
13.04.060	Distribution Charge per kW of billing demand per month	$16.09000	N/A	N/A
13.04.060	Transmission Charge per kWh per month	$0.01609	N/A	N/A
13.04.060	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07338	N/A	N/A
13.04.060	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06213	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10218	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.06063	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06578	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05785	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.060	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Cha	$756.10000	N/A	N/A
13.04.060	**Medium commerical service - secondary (M-2)**			
13.04.060	Customer Charger per meter per month	N/A	$35.00000	$50.00000
13.04.060	Grid Access Charge per meter per month	N/A	$250.00000	$250.00000
13.04.060	Distribution charge per kW of billing demand per month	N/A	$18.00000	$20.90000

ATTACHMENT B: RATE SCHEDULE ALTERNATIVE 1

MUNICIPAL COD	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2
13.04.060	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609
13.04.060	Energy Service Charge Flat Rate Option per kWh in the High Season	N/A	$0.12465	$0.11316
13.04.060	Energy Service Charge Flat Rate Option per kWh in the Low Season	N/A	$0.10554	$0.09581
13.04.060	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.17358	$0.15757
13.04.060	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.10299	$0.09349
13.04.060	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.11174	$0.10144
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.09827	$0.08921
13.04.060	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.060	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Cha	N/A	$825.00000	$927.00000
13.04.064	**Medium commerical and institutional service - primary (M-2)**			
13.04.064	Customer Charger per meter per month	$29.75000	N/A	N/A
13.04.064	Grid Access Charge per meter per month	$250.00000	N/A	N/A
13.04.064	Distribution Charge per kW of billing demand per month	$11.49000	N/A	N/A
13.04.064	Transmission Charge per kWh per month	$0.01590	N/A	N/A
13.04.064	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07154	N/A	N/A
13.04.064	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06121	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10128	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05970	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06481	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05713	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.064	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Cha	$624.45000	N/A	N/A
13.04.064	**Medium commercial service - primary (M-1)**			
13.04.064	Customer Charger per meter per month	N/A	$44.50000	$63.60000
13.04.064	Grid Access Charge per meter per month	N/A	$250.00000	$250.00000
13.04.064	Distribution Charge per kW of billing demand per month	N/A	$12.00000	$14.00000
13.04.064	Transmission Charge per kWh per month	N/A	$0.01590	$0.01590
13.04.064	Energy Service Charge Flat Rate Option per kWh in the High Season	N/A	$0.12153	$0.11032
13.04.064	Energy Service Charge Flat Rate Option per kWh in the Low Season	N/A	$0.10398	$0.09439
13.04.064	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.17205	$0.15618
13.04.064	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.10153	$0.09217
13.04.064	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.11009	$0.09994
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.09705	$0.08810
13.04.064	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.064	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Cha	N/A	$654.50000	$733.60000
13.04.067	**Large commercial and institutional service—secondary (L-1)**			
13.04.067	Customer Charger per meter per month	$47.91000	N/A	N/A
13.04.067	Grid Access Charge per meter per month	$1,500.00000	N/A	N/A
13.04.067	Distribution Charge per kW of billing demand per month	$18.76000	N/A	N/A
13.04.067	Transmission Charge per kWh per month	$0.01609	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10394	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05843	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06579	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05659	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.067	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Ch	$7,175.91000	N/A	N/A
13.04.067	**Large commercial and institutional service—secondary (L-2)**			
13.04.067	Customer Charger per meter per month	N/A	$75.00000	$100.00000
13.04.067	Grid Access Charge per meter per month	N/A	$1,500.00000	$1,500.00000
13.04.067	Distribution Charge per kW of billing demand per month	N/A	$20.40000	$22.80000
13.04.067	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609
13.04.067	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.16979	$0.15868
13.04.067	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.09545	$0.08920
13.04.067	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.10747	$0.10044
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.09244	$0.08639
13.04.067	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.067	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Ch	N/A	$7,695.00000	$8,440.00000

ATTACHMENT B: RATE SCHEDULE ALTERNATIVE 1

MUNICIPAL COD	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2
13.04.069	**Large commercial and institutional service—primary (L-1)**			
13.04.069	Customer Charger per meter per month	N/A	$84.40000	$112.50000
13.04.069	Grid Access Charge per meter per month	N/A	$1,500.00000	$1,500.00000
13.04.069	Distribution Charge per kW of billing demand per month	N/A	$18.00000	$20.00000
13.04.069	Transmission Charge per kWh per month	N/A	$0.01590	$0.01590
13.04.069	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.16094	$0.15040
13.04.069	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.09115	$0.08519
13.04.069	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.10809	$0.10102
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.09195	$0.08593
13.04.069	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.069	Minimum Monthly Charge (Customer Charge + Distribution Charge x 300kW + Grid Access Ch	N/A	$6,984.40000	$7,612.50000
13.04.070	**Large commercial and institutional service—primary (L-2)**			
13.04.070	Customer Charger per meter per month	$53.90000	N/A	N/A
13.04.070	Grid Access Charge per meter per month	$1,500.00000	N/A	N/A
13.04.070	Distribution Charge per kW of billing demand per month	$11.89000	N/A	N/A
13.04.070	Transmission Charge per kWh per month	$0.01590	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.09852	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05580	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06617	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05629	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.070	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Ch	$5,120.90000	N/A	N/A
13.04.070	**Extra-Large commercial and institutional service—primary (L-3)**			
13.04.070	Customer Charger per meter per month	N/A		
13.04.070	Grid Access Charge per meter per month	N/A		
13.04.070	Distribution Charge per kW of billing demand per month	N/A		
13.04.070	Transmission Charge per kWh per month	N/A		
13.04.070	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A		
13.04.070	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A		
13.04.070	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A		
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A		
13.04.070	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A
13.04.070	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Ch	N/A	$0.00000	$0.00000
13.04.080	**Standby Service (SBY)**			
13.04.080	Distribution Charge per kW of standby capacity	$10.87000		
13.04.080	Customer Charge	N/A		
13.04.080	Grid Access Charge per meter per month	N/A		
13.04.080	Minimum Monthly charge (if less than demand charge)	$201.40000		
13.04.080	Standby service application charge on-time fee for each application or customer account	$5.00000		
13.04.080	Reservation Charge	N/A		
13.04.085	**Unmetered rates- Non-demand (CE-1)**			
13.04.085	Customer Charge per meter per month (single-phase service)	$14.16000		
13.04.085	Customer Charge per meter per month (three-phase service)	$19.07000		
13.04.085	Distribution Charge per kWh of billing demand per month	$0.04475		
13.04.085	Energy Service Charge Flat Rate per kWh in the High Season	$0.06901		
13.04.085	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06030		
13.04.087	**Unmetered rates- Demand (CE-2)**			
13.04.087	Customer Charge per meter per month	$60.22000		
13.04.087	Distribution Charge per kWh of billing demand per month	$10.87000		
13.04.087	Energy Service Charge Flat Rate per kWh in the High Season	$0.07338		
13.04.087	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06213		
13.04.090	**Street lighting and traffic signal service (SL)**		may have new lamp types	
13.04.090	Incandescent 1,000 lumens per lamp per month	$0.94000	$1.24798	$1.24798
13.04.090	Incandescent 1,500 lumens per lamp per month	$1.11000	$1.47368	$1.47368
13.04.090	Incandescent 2,500 lumens per lamp per month	$1.95000	$2.58889	$2.58889
13.04.090	Incandescent 4,000 lumens per lamp per month	$3.14000	$4.16878	$4.16878
13.04.090	Incandescent 6,000 lumens per lamp per month	$4.47000	$5.93454	$5.93454
13.04.090	Incandescent 10,000 lumens per lamp per month	$6.79000	$9.01466	$9.01466
13.04.090	Incandescent 67 watts per lamp per month	$0.86000	$1.14177	$1.14177

ATTACHMENT B: RATE SCHEDULE ALTERNATIVE 1

MUNICIPAL COD	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2
13.04.090	Incandescent 69 watts per lamp per month	$0.88000	$1.16832	$1.16832
13.04.090	Incandescent 103 watts per lamp per month	$1.30000	$1.72593	$1.72593
13.04.090	Incandescent 150 watts per lamp per month	$1.89000	$2.50923	$2.50923
13.04.090	Incandescent 202 watts per lamp per month	$2.54000	$3.37220	$3.37220
13.04.090	Incandescent 303 watts per lamp per month	$3.80000	$5.04502	$5.04502
13.04.090	Mercury Vapor 3,500 lumens per lamp per month	$1.61000	$2.13750	$2.13750
13.04.090	Mercury Vapor 7,000 lumens per lamp per month	$2.64000	$3.50496	$3.50496
13.04.090	Mercury Vapor 11,000 lumens per lamp per month	$3.66000	$4.85915	$4.85915
13.04.090	Mercury Vapor 20,000 lumens per lamp per month	$5.80000	$7.70030	$7.70030
13.04.090	Mercury Vapor 35,000 lumens per lamp per month	$9.81000	$13.02412	$13.02412
13.04.090	Mercury Vapor 54,000 lumens per lamp per month	$13.87000	$18.41433	$18.41433
13.04.090	Mercury Vapor Fluorescent per lamp per month			
13.04.090	Mercury Vapor 213 watts per lamp per month	$2.68000	$3.55807	$3.55807
13.04.090	Mercury Vapor 248 watts per lamp per month	$3.14000	$4.16878	$4.16878
13.04.090	High Pressure Sodium 35 watts per lamp per month	$0.51000		
13.04.090	High Pressure Sodium 50 watts per lamp per month	$0.72000		
13.04.090	High Pressure Sodium 70 watts per lamp per month	$1.28000	$1.69938	$1.69938
13.04.090	High Pressure Sodium 100 watts per lamp per month	$1.76000	$2.33664	$2.33664
13.04.090	High Pressure Sodium 150 watts per lamp per month	$2.43000	$3.22616	$3.22616
13.04.090	High Pressure Sodium 200 watts per lamp per month	$3.09000	$4.10240	$4.10240
13.04.090	High Pressure Sodium 250 watts per lamp per month	$3.94000	$5.23089	$5.23089
13.04.090	High Pressure Sodium 310 watts per lamp per month	$4.81000	$6.38593	$6.38593
13.04.090	High Pressure Sodium 400 watts per lamp per month	$5.98000	$7.93927	$7.93927
13.04.090	High Pressure Sodium 4—60 watts unit bus stop per lamp per month	$4.82000	$6.39921	$6.39921
13.04.090	High Pressure Sodium 2—40 watts unit bus stop per lamp per month	$4.82000	$6.39921	$6.39921
13.04.090	Metal Halide per lamp per month	$3.99000	$5.29727	$5.29727
13.04.090	Distrlcution Charge for metered street lighting per kWh	$0.03923	$0.05208	$0.05208
13.04.090	Distribution Charge metered traffic signals and signs per kWh	$0.05807	$0.09465	$0.09465
13.04.090	Distribution Charge Unmetered traffic signals and signs	$0.05807	$0.09465	$0.09465
13.04.090	Energy Charge per kWh	$0.06500	$0.18361	$0.18361
13.04.150	**Rate schedule change**			
13.04.150	Load change in less than 12 months per meter affected	$3.00000	Not specified	Not specified
13.04.176	**Feed-in-tariff (FIT)**	N/A		
13.04.177	**Net energy metering (NEM)**			
13.04.177	B. Annual NEM	B. Annual NEM: energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, rate for net surplus electricity compensation shall be equal to the applicable energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, rate for net surplus electricity compensation shall be equal to the applicable energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs
13.04.177	C. Monthly/Bi-Monthly NEM	C. Monthly/Bi-Monthly NEM: energy services charge over the billing period plus 6.6¢ per kWh plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus 2.5¢ per kWh for RECs
13.04.177	D. Net Energy Metering (on or after January 1, 2026)	D. sum of all rates set forth in the applicable rate schedule on the gross electric metered usage for all charges except the energy service charge. 1.receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.	On or after 1/1/2026 net surplus electricity or net neutral electricity, customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus the premium established for renewable energy attributes credits in the Green Power Program set forth in 13.04.179	On or after 1/1/2026 net surplus electricity or net neutral electricity, customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus the premium established for renewable energy attributes credits in the Green Power Program set forth in 13.04.179

ATTACHMENT B: RATE SCHEDULE ALTERNATIVE 1

MUNICIPAL COD	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2
13.04.178	**Self-generation service (SG)**	B. Rates. Rates for this service shall be the same as for the schedule under which the customer would ordinarily take service, with the following exceptions: 1. For self-generation service customers in the residential and small commercial and industrial groups, the monthly customer charge and the distribution services charge shall respectively be the same as those of the medium commercial and industrial class—secondary. 2. In each month, billing demand will be the greater of the maximum fifteen minute kW of the absolute net power that the customer received from or injected into the PWP power system during the current month or preceding eleven months. 3. In each month, the billing determinant for the Transmission Services Charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month.4.For energy charges and energy credits, billing determinants shall be quantified as follows:a.For customers on seasonal flat energy rates, the monthly billing determinant shall be the net power that the customer received from the PWP power system during the month.b.For customers on time-of-use (TOU) energy rates, the billing determinant for each TOU period shall be the net power that the customer received from the PWP power system during each period.5.For any period during which the customer's net power received from the PWP power system is negative (i.e., during which the customer injects net power into the PWP power system), the customer shall not pay an Energy Charge but shall instead receive an energy credit.a.The applicable energy credit periods shall be one month for customers on seasonal flat rates and TOU periods for customers on TOU rates.b.The energy credit for each period shall equal the product of:1.The customer's net injection into the PWP power system during the period and PWP's average power cost applicable to that period.	1. Time-of-use rates under which the customer would ordinarily take service except, (1) in each month, billing demand will be the greater of the maximum 15 minute kW of the absolute net electricity delivered to customer during the current month or preceding 11 months and (2) in each month, the billing determinant for the transmission services charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. 2. Customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.	1. Time-of-use rates under which the customer would ordinarily take service except, (1) in each month, billing demand will be the greater of the maximum 15 minute kW of the absolute net electricity delivered to customer during the current month or preceding 11 months and (2) in each month, the billing determinant for the transmission services charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. 2. Customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.
13.04.179	**Green power service (GP)**			
13.04.179	Green power premium per kWh	$0.01800		
13.04.179	Green power premium for 100 kWh block	$1.80000		
13.04.180	Theft of energy			
13.04.180	Minimum charge per occurrence of energy theft	$300.00000		

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.040	**Residential single-family service (R-1)**				
13.04.040	Customer Charger per meter per month	$8.96000	$11.15000	$12.75000	$13.25000
13.04.040	Grid Access Charge per meter per month	$4.50000	$6.50000	$7.50000	$8.50000
13.04.040	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04170	$0.04836
13.04.040	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.16682	$0.19345
13.04.040	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.30027	$0.34822
13.04.040	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.040	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.06525	$0.09056	$0.10002
13.04.040	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.05671	$0.07870	$0.08693
13.04.040	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.13607	$0.18885	$0.20859
13.04.040	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.04382	$0.06081	$0.06717
13.04.040	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.11150	$0.10286	$0.14276
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.05100	$0.04705	$0.06530
13.04.040	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.045	**Residential multi-family service (R-2)**				
13.04.045	Customer Charger per meter per month	$8.96000	$11.15000	$12.75000	$13.25000
13.04.045	Grid Access Charge per meter per month	$4.50000	$6.50000	$7.50000	$8.50000
13.04.045	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04170	$0.04836
13.04.045	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.16682	$0.19345
13.04.045	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.30027	$0.34822
13.04.045	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.045	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.06525	$0.09056	$0.10002
13.04.045	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.05671	$0.07870	$0.08693
13.04.045	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.13607	$0.18885	$0.20859
13.04.045	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.04382	$0.06081	$0.06717
13.04.045	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.11150	$0.10286	$0.14276
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.05100	$0.04705	$0.06530
13.04.045	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.050	**Small commerical and institutional serivce (S-1)**				
13.04.050	Customer Charger per meter per month	$9.42000	$15.00000	$18.50000	$20.65000
13.04.050	Grid Access Charge per meter per month	$17.00000	$17.00000	$17.00000	$17.00000
13.04.050	Distribution Charge per kWh per month	$0.06423	$0.06862	$0.07081	$0.07300
13.04.050	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.050	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.06901	$0.09780	$0.13113	$0.14147
13.04.050	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06030	$0.08546	$0.11458	$0.12361
13.04.050	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10463	$0.14828	$0.19882	$0.21448
13.04.050	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05706	$0.08087	$0.10842	$0.11697
13.04.050	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06431	$0.09114	$0.12220	$0.13183
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05611	$0.07952	$0.10662	$0.11502
13.04.050	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.050	Minimum Monthly Charge (Customer Charge + Grid Access Charge)	$26.42000	$32.00000	$35.50000	$37.65000
13.04.060	**Medium commerical and institutional service - secondary (M-1)**				
13.04.060	Customer Charger per meter per month	$23.40000	N/A	N/A	N/A
13.04.060	Grid Access Charge per meter per month	$250.00000	N/A	N/A	N/A
13.04.060	Distribution Charge per kW of billing demand per month	$16.09000	N/A	N/A	N/A
13.04.060	Transmission Charge per kWh per month	$0.01609	N/A	N/A	N/A
13.04.060	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07338	N/A	N/A	N/A
13.04.060	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06213	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10218	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.06063	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06578	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05785	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Ch	$756.10000	N/A	N/A	N/A
13.04.060	**Medium commerical service - secondary (M-2)**				
13.04.060	Customer Charger per meter per month	N/A	$35.00000	$42.00000	$50.00000
13.04.060	Grid Access Charge per meter per month	N/A	$250.00000	$250.00000	$250.00000

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.060	Distribution charge per kW of billing demand per month	N/A	$18.00000	$19.50000	$20.90000
13.04.060	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609	$0.01609
13.04.060	Energy Service Charge Flat Rate Option per kWh in the High Season	N/A	$0.08760	$0.11557	$0.12265
13.04.060	Energy Service Charge Flat Rate Option per kWh in the Low Season	N/A	$0.07417	$0.09785	$0.10384
13.04.060	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.12198	$0.16093	$0.17078
13.04.060	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.07238	$0.09549	$0.10134
13.04.060	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.07853	$0.10360	$0.10994
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.06906	$0.09111	$0.09669
13.04.060	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Ch	N/A	$825.00000	$877.00000	$927.00000
13.04.064	**Medium commerical and institutional service - primary (M-2)**				
13.04.064	Customer Charger per meter per month	$29.75000	N/A	N/A	N/A
13.04.064	Grid Access Charge per meter per month	$250.00000	N/A	N/A	N/A
13.04.064	Distribution Charge per kW of billing demand per month	$11.49000	N/A	N/A	N/A
13.04.064	Transmission Charge per kWh per month	$0.01590	N/A	N/A	N/A
13.04.064	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07154	N/A	N/A	N/A
13.04.064	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06121	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10128	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05970	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06481	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05713	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Ch	$624.45000	N/A	N/A	N/A
13.04.064	**Medium commercial service - primary (M-1)**				
13.04.064	Customer Charger per meter per month	N/A	$44.50000	$53.40000	$63.60000
13.04.064	Grid Access Charge per meter per month	N/A	$250.00000	$250.00000	$250.00000
13.04.064	Distribution Charge per kW of billing demand per month	N/A	$12.00000	$13.00000	$14.00000
13.04.064	Transmission Charge per kWh per month	N/A	$0.01590	$0.01590	$0.01590
13.04.064	Energy Service Charge Flat Rate Option per kWh in the High Season	N/A	$0.08540	$0.11268	$0.11957
13.04.064	Energy Service Charge Flat Rate Option per kWh in the Low Season	N/A	$0.07307	$0.09641	$0.10231
13.04.064	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.12091	$0.15952	$0.16928
13.04.064	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.07135	$0.09414	$0.09990
13.04.064	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.07737	$0.10208	$0.10832
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.06820	$0.08998	$0.09549
13.04.064	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Ch	N/A	$654.50000	$693.40000	$733.60000
13.04.067	**Large commercial and institutional service—secondary (L-1)**				
13.04.067	Customer Charger per meter per month	$47.91000	N/A	N/A	N/A
13.04.067	Grid Access Charge per meter per month	$1,500.00000	N/A	N/A	N/A
13.04.067	Distribution Charge per kW of billing demand per month	$18.76000	N/A	N/A	N/A
13.04.067	Transmission Charge per kWh per month	$0.01609	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10394	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05843	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06579	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05659	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access C	$7,175.91000	N/A	N/A	N/A

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.067	**Large commercial and institutional service—secondary (L-2)**				
13.04.067	Customer Charger per meter per month	N/A	$75.00000	$87.50000	$100.00000
13.04.067	Grid Access Charge per meter per month	N/A	$1,500.00000	$1,500.00000	$1,500.00000
13.04.067	Distribution Charge per kW of billing demand per month	N/A	$20.40000	$21.60000	$22.80000
13.04.067	Transmission Charge per kWh per month		$0.01609	$0.01609	$0.01609
13.04.067	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.11876	$0.15959	$0.17136
13.04.067	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.06676	$0.08972	$0.09633
13.04.067	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.07517	$0.10102	$0.10846
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.06466	$0.08689	$0.09330
13.04.067	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access C	N/A	$7,695.00000	$8,067.50000	$8,440.00000
13.04.069	**Large commercial and institutional service—primary (L-1)**				
13.04.069	Customer Charger per meter per month	N/A	$84.40000	$98.50000	$112.60000
13.04.069	Grid Access Charge per meter per month	N/A	$1,500.00000	$1,500.00000	$1,500.00000
13.04.069	Distribution Charge per kW of billing demand per month	N/A	$18.00000	$19.00000	$20.00000
13.04.069	Transmission Charge per kWh per month		$0.01590	$0.01590	$0.01590
13.04.069	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.11257	$0.15127	$0.16242
13.04.069	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.06376	$0.08568	$0.09199
13.04.069	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.07561	$0.10160	$0.10909
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.06432	$0.08643	$0.09280
13.04.069	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Minimum Monthly Charge (Customer Charge + Distribution Charge x 300kW + Grid Access C	N/A	$6,984.40000	$7,298.50000	$7,612.60000
13.04.069	**Large commercial and institutional service—primary (L-2)**				
13.04.069	Customer Charger per meter per month	$53.90000	N/A	N/A	N/A
13.04.069	Grid Access Charge per meter per month	$1,500.00000	N/A	N/A	N/A
13.04.069	Distribution Charge per kW of billing demand per month	$11.89000	N/A	N/A	N/A
13.04.069	Transmission Charge per kWh per month	$0.01590	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.09852	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05580	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06617	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05629	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access C	$5,120.90000	N/A	N/A	N/A
13.04.070	**Extra-Large commercial and institutional service—primary (L-3)**				
13.04.070	Customer Charger per meter per month	N/A			
13.04.070	Grid Access Charge per meter per month	N/A			
13.04.070	Distribution Charge per kW of billing demand per month	N/A			
13.04.070	Transmission Charge per kWh per month	N/A			
13.04.070	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A			
13.04.070	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A			
13.04.070	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A			
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A			
13.04.070	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	
13.04.070	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access C	N/A	$0.00000	$0.00000	calculation
13.04.074	**Electric vehicle charging below 30 kW (EV-1)**				
13.04.074	Customer Charger per meter per month	N/A			
13.04.074	Grid Access Charge per meter per month	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A			
13.04.074	**Electric vehicle charging at or above 30kW and less than 300 kW (EV-2)**				
13.04.074	Customer Charger per meter per month	N/A			
13.04.074	Grid Access Charge per meter per month	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A			

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A			
13.04.074	**Electric vehicle charging at or above 300 kW (EV-3)**				
13.04.074	Customer Charger per meter per month	N/A			
13.04.074	Grid Access Charge per meter per month	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A			
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A			
13.04.074	**City-owned retail charging stations**				
13.04.074	Electric Vehicle Charging Fee Peak Hours 3:00 pm to 8:00 pm	N/A			
13.04.074	Electric Vehicle Charging Fee Off-Peak Hours (all other times)	N/A			
13.04.074	Electric Vehicle Charger Connection Fee	N/A			
13.04.074	Electric Vehicle Charger Connection Overstay Fee	N/A			
13.04.080	**Standby Service (SBY)**				
13.04.080	Distribution Charge per kW of standby capacity	$10.87000			
13.04.080	Customer Charge	N/A			
13.04.080	Grid Access Charge per meter per month	N/A			
13.04.080	Minimum Monthly charge (if less than demand charge)	$201.40000			
13.04.080	Standby service application charge on-time fee for each application or customer account	$5.00000			
13.04.080	Reservation Charge	N/A			
13.04.085	**Unmetered rates- Non-demand (CE-1)**				
13.04.085	Customer Charge per meter per month (single-phase service)	$14.16000			
13.04.085	Customer Charge per meter per month (three-phase service)	$19.07000			
13.04.085	Distribution Charge per kWh of billing demand per month	$0.04475			
13.04.085	Energy Service Charge Flat Rate per kWh in the High Season	$0.06901			
13.04.085	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06030			
13.04.087	**Unmetered rates- Demand (CE-2)**				
13.04.087	Customer Charge per meter per month	$60.22000			
13.04.087	Distribution Charge per kWh of billing demand per month	$10.87000			
13.04.087	Energy Service Charge Flat Rate per kWh in the High Season	$0.07338			
13.04.087	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06213			

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.090	**Street lighting and traffic signal service (SL)**		may have new lamp types		
13.04.090	Incandescent 1,000 lumens per lamp per month	$0.94000	$1.04163	$1.23481	$1.30703
13.04.090	Incandescent 1,500 lumens per lamp per month	$1.11000	$1.23000	$1.45813	$1.54341
13.04.090	Incandescent 2,500 lumens per lamp per month	$1.95000	$2.16082	$2.56158	$2.71140
13.04.090	Incandescent 4,000 lumens per lamp per month	$3.14000	$3.47947	$4.12480	$4.36605
13.04.090	Incandescent 6,000 lumens per lamp per month	$4.47000	$4.95326	$5.87193	$6.21537
13.04.090	Incandescent 10,000 lumens per lamp per month	$6.79000	$7.52408	$8.91955	$9.44124
13.04.090	Incandescent 67 watts per lamp per month	$0.86000	$0.95298	$1.12972	$1.19580
13.04.090	Incandescent 69 watts per lamp per month	$0.88000	$0.97514	$1.15599	$1.22361
13.04.090	Incandescent 103 watts per lamp per month	$1.30000	$1.44055	$1.70772	$1.80760
13.04.090	Incandescent 150 watts per lamp per month	$1.89000	$2.09433	$2.48276	$2.62797
13.04.090	Incandescent 202 watts per lamp per month	$2.54000	$2.81461	$3.33662	$3.53178
13.04.090	Incandescent 303 watts per lamp per month	$3.80000	$4.21083	$4.99180	$5.28376
13.04.090	Mercury Vapor 3,500 lumens per lamp per month	$1.61000	$1.78406	$2.11494	$2.23865
13.04.090	Mercury Vapor 7,000 lumens per lamp per month	$2.64000	$2.92542	$3.46798	$3.67082
13.04.090	Mercury Vapor 11,000 lumens per lamp per month	$3.66000	$4.05569	$4.80789	$5.08909
13.04.090	Mercury Vapor 20,000 lumens per lamp per month	$5.80000	$6.42705	$7.61906	$8.06468
13.04.090	Mercury Vapor 35,000 lumens per lamp per month	$9.81000	$10.87058	$12.88671	$13.64044
13.04.090	Mercury Vapor 54,000 lumens per lamp per month	$13.87000	$15.36952	$18.22005	$19.28572
13.04.090	Mercury Vapor Fluorescent per lamp per month				
13.04.090	Mercury Vapor 213 watts per lamp per month	$2.68000	$2.96974	$3.52053	$3.72644
13.04.090	Mercury Vapor 248 watts per lamp per month	$3.14000	$3.47947	$4.12480	$4.36605
13.04.090	High Pressure Sodium 35 watts per lamp per month	$0.51000			
13.04.090	High Pressure Sodium 50 watts per lamp per month	$0.72000			
13.04.090	High Pressure Sodium 70 watts per lamp per month	$1.28000	$1.41838	$1.68145	$1.77979
13.04.090	High Pressure Sodium 100 watts per lamp per month	$1.76000	$1.95028	$2.31199	$2.44721
13.04.090	High Pressure Sodium 150 watts per lamp per month	$2.43000	$2.69271	$3.19212	$3.37882
13.04.090	High Pressure Sodium 200 watts per lamp per month	$3.09000	$3.42407	$4.05912	$4.29653
13.04.090	High Pressure Sodium 250 watts per lamp per month	$3.94000	$4.36596	$5.17570	$5.47842
13.04.090	High Pressure Sodium 310 watts per lamp per month	$4.81000	$5.33002	$6.31856	$6.68813
13.04.090	High Pressure Sodium 400 watts per lamp per month	$5.98000	$6.62651	$7.85551	$8.31497
13.04.090	High Pressure Sodium 4—60 watts unit bus stop per lamp per month	$4.82000	$5.34110	$6.33170	$6.70203
13.04.090	High Pressure Sodium 2—40 watts unit bus stop per lamp per month	$4.82000	$5.34110	$6.33170	$6.70203
13.04.090	Metal Halide per lamp per month	$3.99000	$4.42137	$5.24138	$5.54795
13.04.090	Districution Charge for metered street lighting per kWh	$0.03923	$0.04347	$0.05153	$0.05455
13.04.090	Distribution Charge metered traffic signals and signs per kWh	$0.05807	$0.06912	$0.08307	$0.09301
13.04.090	Distribution Charge Unmetered traffic signals and signs	$0.05807	$0.06912	$0.08307	$0.09301
13.04.090	Energy Charge per kWh	$0.06500	$0.15325	$0.18168	$0.19230
13.04.150	**Rate schedule change**				
13.04.150	Load change in less than 12 months per meter affected	$3.00000	Not specified	Not specified	
13.04.176	**Feed-in-tariff (FIT)**	N/A			
13.04.177	**Net energy metering (NEM)**				
13.04.177	B. Annual NEM	B. Annual NEM: energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, rate for net surplus electricity compensation shall be equal to the applicable energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, rate for net surplus electricity compensation shall be equal to the applicable energy services charge over the customer's billing period plus 2.5¢ per kWh for RECs	
13.04.177	C. Monthly/Bi-Monthly NEM	C. Monthly/Bi-Monthly NEM: energy services charge over the billing period plus 6.6¢ per kWh plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus 2.5¢ per kWh for RECs	No new cust after 1/1/2026, credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus 2.5¢ per kWh for RECs	

ATTACHMENT C: RATE SCHEDULE ALTERNATIVE 2

MUNICIPAL	MUNICIPAL CODE DESCRIPTION	Current Rates	Phase 1	Phase 2	Phase 3
13.04.177	D. Net Energy Metering (on or after January 1, 2026)	D. sum of all rates set forth in the applicable rate schedule on the gross electric metered usage for all charges except the energy service charge. 1.receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.	On or after 1/1/2026 net surplus electricity or net neutral electricity, customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus the premium established for renewable energy attributes credits in the Green Power Program set forth in 13.04.179	On or after 1/1/2026 net surplus electricity or net neutral electricity, customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge over the billing period plus the premium established for renewable energy attributes credits in the Green Power Program set forth in 13.04.179	
13.04.178	**Self-generation service (SG)**	B. Rates. Rates for this service shall be the same as for the schedule under which the customer would ordinarily take service, with the following exceptions: 1. For self-generation service customers in the residential and small commercial and industrial groups, the monthly customer charge and the distribution services charge shall respectively be the same as those of the medium commercial and industrial class—secondary. 2. In each month, billing demand will be the greater of the maximum fifteen minute kW of the absolute net power that the customer received from or injected into the PWP power system during the current month or preceding eleven months. 3. In each month, the billing determinant for the Transmission Services Charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month.4.For energy charges and energy credits, billing determinants shall be quantified as follows:a.For customers on seasonal flat energy rates, the monthly billing determinant shall be the net power that the customer received from the PWP power system during the month.b.For customers on time-of-use (TOU) energy rates, the billing determinant for each TOU period shall be the net power that the customer received from the PWP power system during each period.5.For any period during which the customer's net power received from the PWP power system is negative (i.e., during which the customer injects net power into the PWP power system), the customer shall not pay an Energy Charge but shall instead receive an energy credit.a.The applicable energy credit periods shall be one month for customers on seasonal flat rates and TOU periods for customers on TOU rates.b.The energy credit for each period shall equal the product of:1.The customer's net injection into the PWP power system during the period and PWP's average power cost applicable to that period.	1. Time-of-use rates under which the customer would ordinarily take service except, (1) in each month, billing demand will be the greater of the maximum 15 minute kW of the absolute net electricity delivered to customer during the current month or preceding 11 months and (2) in each month, the billing determinant for the transmission services charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. 2. Customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.	1. Time-of-use rates under which the customer would ordinarily take service except, (1) in each month, billing demand will be the greater of the maximum 15 minute kW of the absolute net electricity delivered to customer during the current month or preceding 11 months and (2) in each month, the billing determinant for the transmission services charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. 2. Customer shall receive a credit in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy services charge.	
13.04.179	**Green power service (GP)**				
13.04.179	Green power premium per kWh	$0.01800	$0.01800		
13.04.179	Green power premium for 100 kWh block	$1.80000	$1.80000		
13.04.180	Theft of energy				
13.04.180	Minimum charge per occurrence of energy theft	$300.00000	$300.00000		

PASADENA WATER AND POWER

MEMORANDUM

The following document is section 2 of the Electric Rate Study, this next phase of the study evaluates how current electric rates align with the actual costs of providing service to each customer class. This next step within the rate-making process comes after determining the system revenue requirement and then establishes a revenue requirement for each customer class, which is determined based on the specific costs to serve that class.

The COS analysis reveals that 77% of PWP's costs are fixed, driven by infrastructure, power supply contracts, and customer service operations. Only 23% are variable, such as fuel and purchased power. This fixed-cost structure underscores the importance of rate design that ensures stable revenue recovery.

Key findings include:

- Residential customers currently under-recover by approximately 39%, while Medium Commercial customers slightly over-recover.
- The cost to connect to the PWP system, regardless of energy usage, is $125/month for Residential customers, reflecting the infrastructure and service readiness costs.

The COS framework also introduces a new Electric Vehicle (EV) customer class, laying the groundwork for future rate structures tailored to EV charging needs.

This analysis will inform the next phase of the study: rate design, which aims to align rates with actual service costs, promote equity, and support long-term financial sustainability.

Section 3
ELECTRIC COST-OF-SERVICE

After determining the system revenue requirement, a revenue requirement for each customer class was determined based on the specific costs to serve each class. Customer class revenues are compared to class revenue requirements to evaluate the current rate's abilities to fully recover costs. NewGen analyzed the cost to serve each customer class based on the 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 new electric rates.

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

- Revenue requirements and revenues based on current rates.
- Total system and customer class demand and energy requirements.
- Actual and assumed customer service characteristics.
- Information obtained from customer accounts and records.

Cost-of-Service Process

NewGen performed an analysis of the cost to serve each customer class based on the revenue requirement developed in Section 2. There are three steps in developing the COS for each customer class, as illustrated in steps 2–4 in Figure 3-1 below.

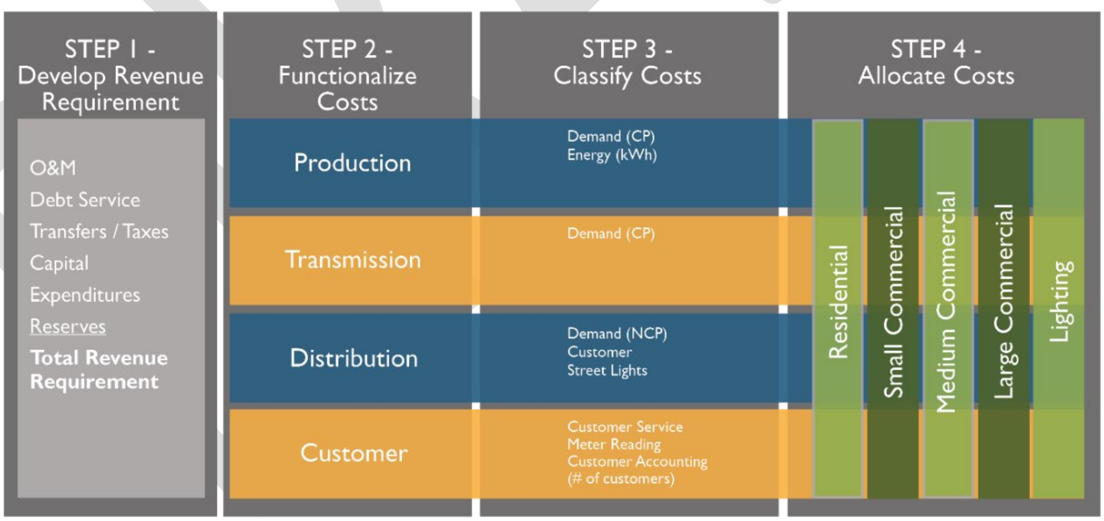

Figure 3-1. Cost-of-Service Process

Step 1 is the development of the revenue requirement as explained in Section 2.

Step 2 is the functional unbundling of the revenue requirement. Functional unbundling provides detailed descriptions of the utility's revenue requirement by core utility function. Accounting information is provided by PWP budget accounts. If an item has been adjusted, the amount of the adjustment is identified with an associated supporting calculation. Once the detailed revenue requirement has been established, the amount is assigned to the production, transmission, distribution, and customer functions. Assignments are made either through direct assignments or other allocation methodology. The results of the Component A analyses for each function of the revenue requirement are expressed on a functional basis.

Step 3 is the classification and sub-functional unbundling of the revenue requirement. Sub-functionalizing the production, transmission, distribution, and customer functions developed in Step 2 provides additional detail and accuracy to PWP's costs. Additionally, costs are classified as demand related, energy related, customer related, or a direct assignment. Like functionalizing, sub-functionalization is accomplished either through direct assignments or other allocation methodology. Specific allocation factors are found at the bottom of each sub-function worksheet. Step 3 analyses result in PWP's revenue requirement expressed on a sub-functional basis for each cost classification (e.g., Production Demand or Production Energy Costs).

Step 4 is the allocation of the classified and sub-functionalized costs to the customer classes. Using the information developed in Step 3, the sub-functionalized and classified revenue requirement is allocated to each of the rate classes using various customer class allocation methodologies. These allocation methodologies or allocators are developed in alignment with the cost classification. For example, production demand costs are allocated utilizing the customer's contributions to system demand such as four-coincident peak (4CP) or the highest four months of PWP system peaks.

Once completed, the COS results indicate the degree to which existing rates recover the costs to serve customers. These results are then used in designing new electric rates.

Functionalization

PWP's electric rates have been unbundled into four functions: production, transmission, distribution, and customer. Descriptions of each utility function are below.

Production Function

The production function consists of costs associated with operating and maintaining electric generation facilities and making capital investments, as necessary. This function also includes purchased power, fuel, and power labor costs.

Transmission Function

The transmission function consists of costs associated with transmitting power from generation plants or the CAISO markets to PWP's local load. These costs include market transmission costs, operating and maintaining transmission lines and related infrastructure, and making capital investments, as necessary.

Distribution Function

The distribution function consists of costs associated with operating and maintaining the localized distribution portion of the electric grid and making capital investments, as necessary. The distribution facilities deliver power to the retail customers after it has been transmitted. This includes primary and secondary voltage distribution lines, distribution poles, underground lines, customer service connections, meters, and lighting-related assets. PWP has 1,660 miles of overhead and underground lines.

Customer Function

The customer 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, and billing and collection. PWP services approximately 68,000 electric customers, and over 59,000 are in the Residential Service class.

Functionalized Revenue Requirement

The revenue requirement was "unbundled" into the four functional areas of the system: production, transmission, distribution, and customer. The results of the functional unbundling are summarized in Table 3-1.

Table 3-1
Functionalized Revenue Requirement

Function	Revenue Requirement	$/kWh(1)	% of Total
Production	$127,296,677	$0.1224	49%
Transmission	$12,494,313	$0.0120	5%
Distribution	$105,410,519	$0.1013	41%
Customer	$14,355,356	$0.0138	6%
Total	$259,556,865	$0.2496	100%

(1) Based on Test Year energy sales of 1,040,083,319 kWh.

The production function, including PWP's operating expenses and purchased power, represents 49% of the revenue requirement. The distribution function is the second largest cost center, representing 41% of the revenue requirement. The customer function is the third largest cost center, representing 6% of the revenue requirement. The remaining 5% of the revenue requirement is associated with the transmission function.

Classification

System costs can be classified into four generally accepted rate-making cost classifications: (i) demand or fixed costs, (ii) energy or variable costs, (iii) customer-related costs, and (iv) directly assignable costs. To provide a reasonable basis for the assignment or allocation of total revenue requirements (costs) to each customer class, costs for each function in the electric system have been analyzed and classified into four categories. PWP's functional costs were classified on the following basis:

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.
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, service connections, and meter-related expenses.

4. Direct Assignment Costs – Direct assignment costs are those costs that are readily identifiable and applicable to a customer or customer class (e.g., street 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 seen in Table 3-2, three major cost categories (demand, energy, and customer) cover most of all functional costs. This breakdown of demand, energy, customer, and direct assignment costs is later applied to each customer class to facilitate the electric system rate design, as provided in Section 4. The classified revenue requirement is shown below in Table 3-2.

Classified Revenue Requirement

In total, 23% of PWP's total revenue requirement is energy-related or variable costs. The remaining 77% of the revenue requirement is fixed in nature and classified as demand, customer, or directly assigned to particular customer classes. Table 3-2 shows additional details regarding the classified costs within each function and classifies the costs within each.

Table 3-2
Classified Revenue Requirement

Classification	Revenue Requirement	$/kWh(1)	% of Total(2)
Production			
Demand	$80,394,286	$0.0773	31%
Energy	$46,902,391	$0.0451	18%
Subtotal	$127,296,677	$0.1224	49%
Transmission			
Demand	$0	$0.0000	0%
Energy	$12,494,313	$0.0120	5%
Subtotal	$12,494,313	$0.0120	5%
Distribution			
Demand	$88,989,628	$0.0856	34%
Customer	$12,725,008	$0.0122	5%
Other	$3,695,883	$0.0036	1%
Subtotal	$105,410,519	$0.1013	41%
Customer			
Customer	$14,355,356	$0.0138	6%
Subtotal	$14,355,356	$0.0138	6%
Demand	$169,383,914	$0.1629	65%
Energy	$59,396,704	$0.0571	23%
Customer	$30,776,248	$0.0296	12%
Total Costs	$259,556,865	$0.2496	100%

(1) Based on Test Year energy sales of 1,040,083,319 kWh.

(2) Percentages may not add to 100% due to rounding.

Allocation

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 rate-making principles and were based upon sufficiently distributed embedded cost allocation procedures. The following summary describes the specific allocation factors used in the Study.

Once revenue requirements are classified, they are allocated to the individual customer classes based on customer usage characteristics. For the system and customer classes, we have developed demand-related, energy-related, customer-related, and direct assignment allocation factors as described below.

Demand Allocations

Demand allocation refers to the basis on which capacity-related costs are distributed or assigned (i.e., allocated) among the various customer classes for the purpose of determining the COS for each class. The demand allocation factors that were developed reflect the cost responsibility of the various customer classes with respect to their contribution to demand-related system characteristics (i.e., contribution to monthly peak demand).

For example, monthly coincident peak demand by customer class reflects the customer class's contribution to the monthly system peak demand. The peak demand is often referred to as the "Coincident Peak" (CP) because it is the amount of total load from all customers collectively at the same time (coincident with each other).

Non-coincident peak (NCP) demand reflects the customer class's peak demand, whenever that may occur, and does not have to coincide with the overall system peak. The NCP demand allocation method is based on the theory that demand costs are strongly influenced by the highest demand of each customer class, regardless of when that class peak demand occurs. NCP demand allocators are primarily used to allocate distribution-related costs because the design of these facilities is more consistent with the demand of the classes, rather than the demand of the entire system. Coincident and non-coincident demands are typically calculated considering a one, three, four, or twelve-month period.

The data used to calculate CP and NCP were developed utilizing PWP's billing database and Proxy Advanced Metering Infrastructure (AMI) from a nearby utility with similar usage profiles. AMI meters record energy usage on a 15-minute or hourly basis which can be used to pinpoint each class's contribution to system or local peaks. These system and local peaks are the key driver for PWP's costs to deliver electric service. Figure 3-2 shows the customer class contributions to PWP's monthly system peak demands, or the CPs.

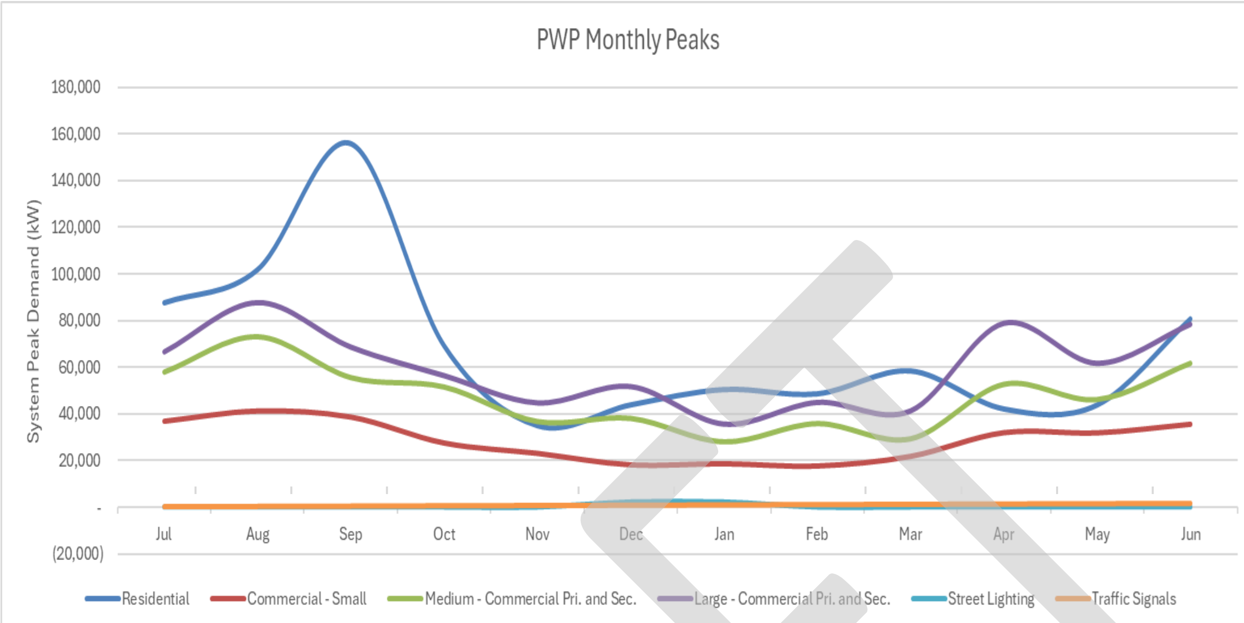

Figure 3-2. Monthly PWP System Peak Demands

Production Demand Allocation

As seen in Figure 3-2, the PWP system has a dramatic peak during the summer months of June through September. This system peak is what PWP must design, construct, and operate their generation and transmission system to serve. However, as PWP must plan and build infrastructure to supply production services for those four peak months, those costs and assets may not be utilized year-round to meet the other eight months of system demands. As such, PWP's production functionalized costs were sub-functionalized into a base load PWP-owned and peak load costs. Subsequently, the base load costs which support year-round system peaking needs are allocated to customer classes on a 12 CP method. Similarly, the peak load costs associated with meeting summer peaking demands are allocated to the customer classes using the 4CP method. This is an appropriate cost allocation methodology for the southern California climate and load profile as it captures the class-level contributions to the peak system demand in the summer months but also recognizes some costs and assets are used year-round.

Distribution Demand Allocation

Similarly, distribution costs are designed to meet the maximum demands of the localized system or customers, so 4 non-coincident peak (4 NCP) and the sum of maximum demands (SMD) allocation factors are used. 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. The 4 NCP method was used to allocate the distribution system demand-related costs associated with substations, primary lines, and secondary lines. The SMD was used to allocate demand costs related to distribution transformers near customer service locations. The SMD is reflective of the localized demands customers place on the system at and near the meter. For customer classes that are billed for demand, the SMD represents annual measured demand.

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

Table 3-3
Demand Allocation Factors

Customer Class	4 CP	4 NCP	SMD
Residential	37.65%	43.41%	52.20%
Commercial - Small	13.45%	11.80%	13.77%
Medium - Commercial Primary and Secondary Service	21.95%	19.19%	16.10%
Large - Commercial Primary and Secondary Service	26.71%	24.58%	17.31%
Street Lighting	0.00%	0.93%	0.59%
Traffic Signals	0.24%	0.09%	0.04%
Total	**100.00%**	**100.00%**	**100.00%**

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 include fuel, variable O&M costs, and purchased power. 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 generator, as it takes into consideration energy losses that occur on the transmission and distribution systems between the power generation facility and the customer's meter. For PWP all transmission costs are energy related as a result, NEFL was used as the allocation method. Table 3-4 lists the energy allocation factors utilized in the Study.

Table 3-4
Energy Allocation Factors

Customer Class	Net Energy for Load
Residential	31.03%
Commercial - Small	13.32%
Medium - Commercial Primary and Secondary Service	24.87%
Large - Commercial Primary and Secondary Service	29.76%
Street Lighting	0.90%
Traffic Signals	0.12%
Total	**100%**

Customer Allocations

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.

At times in a COS study, certain customer-related costs can be allocated to the various customer classifications based on a weighted customer allocation factor. Weighting reflects that servicing certain types of customers requires more effort and expense than other types of customers. For PWP, weighting factors were not required, nor developed, based on discussions with PWP as there were limited customer service related costs. Public benefits costs were also included in this function; however, they were allocated based on the revenue requirement of each class to reflect the cost causation of the public benefit charge mechanism.

Cost-of-Service Results

The COS process is an industry-accepted framework that assigns costs to customer classes. This process determines the "cost to serve" each customer class within a utility.

Fixed and Variable Costs

Electric utility costs are typically characterized as either fixed or variable; fixed costs are those that do not change with the production of electricity, whereas variable costs are related to the amount of electricity produced and/or purchased. PWP's fixed costs are 77% of the total revenue requirement. The remaining 23% of costs are variable and include fuel, purchased power, and variable O&M. PWP's fixed costs are higher than some industry peers due to the number of power supply contracts or power purchase agreements that have fixed components to the contracts or cost structure. These contracts also provide PWP physical assets and hedges in the CAISO market to mitigate market risks to customers.

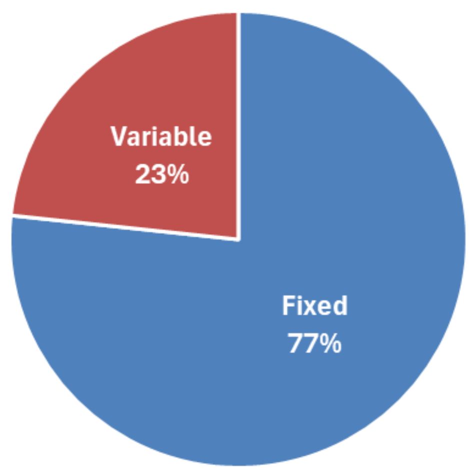

Figure 3-3. Test Year Fixed and Variable Costs

Fixed Cost to Connect to the PWP System

As stated above, the test year fixed costs are 77% of the total revenue requirement. There is a cost for each customer to attach to the PWP system whether or not that customer uses any energy. As shown in Table 3-5, it costs $125 per month for each Residential customer to be attached to the PWP system, whether they use 0 kWh or 1,000 kWh. The fixed cost per a customer for each class is displayed below.

Table 3-5
Fixed Cost Per Customer to Connect to the PWP System

Function	Residential	Small - Commercial	Medium - Commercial	Large - Commercial	Street Lighting	Traffic Signals	System
Power Supply	$40	$121	$1,946	$16,928	$2,637	$123	$99
Transmission	$0	$0	$0	$0	$0	$0	$0
Distribution	$56	$118	$1,857	$15,306	$26,782	$33	$109
Customer	$29	$36	$199	$903	$29	$29	$38
Total $/Month/customer	$125	$275	$4,002	$33,137	$29,448	$185	$246

The power supply and distribution fixed costs represent the demand-related costs of infrastructure and expenses translated into a monthly cost per customer. The customer-related costs are associated with customer service and customer accounting serving the classes. As seen in the table it costs PWP a minimum of $125 per customer per month to provide service, and that cost does not vary with the amount of energy or kWhs consumed.

Cost-of-Service Results by Class

Table 3-6 summarizes the total cost of service for each customer class. These costs are delineated into the discrete classified costs within each function. Please note the Electric Vehicle (EV) customer class shown in Table 3-6 is a new customer class that does not currently have any customers or billed consumption. Existing services to EV charging stations or locations are provided under an existing applicable commercial class such as Medium or Large Commercial tariff rates. As there are no customers, there are no revenues. The EV cost of service will be used in supporting the tracking of costs for these types of sites and services in addition to the development of new rates and tariffs focused on serving EV charging locations and loads.

Table 3-6
Cost-of-Service Results by Class

Classification	Residential	Small - Commercial	Medium - Commercial	Large - Commercial	Street Lighting	Traffic Signals	EV - Electric Vehicle	Total
Production								
Demand	$28,404,624	$11,009,880	$18,113,051	$22,495,897	$81,736	$289,097	$0	$80,394,286
Energy	$14,553,395	$6,247,648	$11,666,870	$13,956,636	$421,047	$56,794	$0	$46,902,391
Subtotal Production	$42,958,019	$17,257,528	$29,779,921	$36,452,534	$502,784	$345,891	$0	$127,296,677
Transmission								
Demand	$0	$0	$0	$0	$0	$0	$0	$0
Energy	$3,876,874	$1,664,309	$3,107,934	$3,717,904	$112,163	$15,129	$0	$12,494,313
Subtotal Transmission	$3,876,874	$1,664,309	$3,107,934	$3,717,904	$112,163	$15,129	$0	$12,494,313
Distribution								
Demand	$39,683,928	$10,773,454	$17,283,753	$20,340,010	$830,254	$78,229	$0	$88,989,628
Customer	$11,098,069	$1,423,515	$145,370	$20,756	$484	$36,814	$0	$12,725,008
Other	$0	$0	$0	$0	$0	$0	$3,695,883	$3,695,883
Subtotal Distribution	$50,781,997	$12,196,969	$17,429,123	$20,360,766	$830,738	$115,042	$3,695,883	$105,410,519
Customer								
Customer Service	$2,309,645	$974,724	$974,724	$974,724	$101	$7,661	$0	$5,241,579
Customer Accounting	$5,375,670	$689,521	$704,144	$201,076	$235	$17,832	$0	$6,988,476
Meter Reading	$1,796,618	$230,447	$23,533	$3,360	$78	$5,960	$0	$2,059,996
EV - Electric Vehicle	$0	$0	$0	$0	$0	$0	$65,305	$65,305
Subtotal Customer	$9,481,933	$1,894,691	$1,702,401	$1,179,160	$414	$31,453	$65,305	$14,355,356
Total Costs (Revenue Requirement)	$107,098,823	$33,013,498	$52,019,379	$61,710,363	$1,446,098	$507,516	$3,761,188	$259,556,865
Summarized Total								
Demand	$68,088,552	$21,783,334	$35,396,804	$42,835,907	$911,990	$367,326	$0	$169,383,914
Energy	$18,430,269	$7,911,957	$14,774,804	$17,674,540	$533,210	$71,924	$0	$59,396,704
Customer	$20,580,002	$3,318,207	$1,847,772	$1,199,916	$898	$68,266	$3,761,188	$30,776,248
Total	**$107,098,823**	**$33,013,498**	**$52,019,379**	**$61,710,363**	**$1,446,098**	**$507,516**	**$3,761,188**	**$259,556,865**

Cost-of-Service Results Compared to Current Revenue

To evaluate the ability of current rates to adequately recover the COS, NewGen calculated revenues based on Test Year 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 3-7. This represents a snapshot of the test year revenue requirements which include costs for FY 2025/26 and FY 2026/27 compared to the current rates.

At a system level, current rates and revenues require a one-time 13.9% increase to collect the full COS. Also shown in Table 3-7 is the approximate percentage increase/(decrease) in each customer class's revenues necessary to fully recover the COS for the test year. The percentage increase or decrease shown in the table provides guidance for future rate design without subsidization and with full rate revenue recovery.

Table 3-7
Current Rate Revenues Compared to Cost-of-Service

Class/Service	Revenue Requirement	Estimated Test Year Revenues with Current Rates	Projected Over (Under) Recovery	COS Rate Increase (Decrease) Needed (%)
Residential	$107,098,823	$76,972,473	($30,126,350)	39.14%
Commercial - Small	$33,013,498	$31,068,587	($1,944,911)	6.26%
Medium - Commercial Primary and Secondary Service	$52,019,379	$54,463,401	$2,444,022	-4.49%
Large - Commercial Primary and Secondary Service	$61,710,363	$62,371,800	$661,436	-1.06%
Street Lighting	$1,446,098	$2,721,576	$1,275,478	-46.87%
Traffic Signals	$507,516	$392,553	($114,963)	29.29%
EV - Electric Vehicle	$3,761,188	$0	($3,761,188)	0%
Total	**$259,556,865**	**$227,990,390**	**($31,566,476)**	**13.85%**

(1) EV customer class is not yet in-service or available. Costs are being tracked for the development of future classes and tariffs. As such, no revenues or COS rate changes are identified at this time.

The comparison of the COS results to the current revenues informs the eventual rate design and strategy for FY 2025/26 and beyond. While the COS results represent a one-time rate adjustment to achieve the test year revenue requirement, PWP has multiple options regarding the implementation of rates and the potential to phase-in the rate changes over multiple years. By phasing in rate changes over multiple years, PWP can reduce the potential bill change and increase impacts to customers.

Section 13.04.010 Short title~~.~~

This chapter shall be named and may hereafter be designated as "the light and power rate ordinance."

13.04.020 Definitions~~.~~

~~A. Abbreviations.~~

~~1. "K.W.H.," as herein used, indicates and~~ "Apparent power" means ~~"kilowatt hours."~~

~~2. "K.W.," as herein used, means "kilowatt," an~~the total electrical ~~unit of power.~~

~~3. "H.P.," as herein used, means "horsepower," a mechanical unit of power.~~

A. ~~B."Air conditioning apparatus" is an electrically driven mechanically operated compressed-refrigerant-type cooler of sufficient~~ capacity required to ~~properly cool that portion~~supply a load, regardless of how efficiently the ~~enclosed rooms normally~~power is used~~ for business purposes.~~ .

B. "Customer charge" is a fixed monthly charge regardless of energy use. It is generally associated with services such as billing, customer service, meter reading, and connection to the grid.

C. "Billing demand" means the greater of (i) the kilowatts of measured maximum demand occurring during the current month or (ii) the highest demand recorded in the last four months, including the current billing month. ~~C."~~Billing demand is determined to the nearest kW.

~~B.~~D. "Department," "Pasadena Water and Power" or "PWP," as herein used, means the ~~"~~municipal water and power department of the ~~c~~City of Pasadena~~."~~ .

~~D. "Electric water heater" must not exceed the following limitations. The base heating element shall be controlled by a thermostat located near the bottom of the tank and shall not exceed a total rating of 2500 watts or 50 watts per gallon for tanks over 50-gallon capacity. A booster heating element will be allowed in the tank and shall not exceed a total rating of 2500 watts or 50 watts per gallon for tanks over 50-gallon capacity when individually controlled by a separate thermostat set to cut in only when the temperature of the top ⅓ of the tank capacity is 20 degrees Fahrenheit below the temperature setting of the bottom thermostat. Large storage-type tanks are recommended which have heavy insulation.~~

E. ~~E.~~"Distribution charge" is a usage-based charge generally associated with the cost of delivering electricity from the substations, including operation and maintenance costs, capital investment and debt service.

F. "Electric Utility Rate Resolution" means a schedule of pricing for all fees, penalties, refunds, reimbursements, and charges of any kind collected by the Department and adopted by City Council.

G. "Energy services charge" (including power cost adjustment) is a usage-based charge generally associated with the solely variable cost of generating the actual amount of electricity consumed, measured in kilowatt-hours.

H. "Greenhouse gas" or "GHG" is a collective term for those gases that reduce the loss of heat from the earth's atmosphere, and thus contribute to global warming and climate change.

I. "Grid access charge" is a fixed monthly charge generally associated with the fixed costs of connecting to and maintaining the electric grid, regardless of their energy consumption.

J. "Holidays" refer to days recognized by the North American Electric Reliability Corporation (NERC) that typically impact electricity demand and pricing. Holidays include New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). These holidays may be updated from time to time based on NERC guidelines.

K. "Horsepower" or "hp," as herein used means a mechanical unit of power.

L. "Interval Read Capable Meter" refers to electric meters that can record and transmit energy usage data at regular, predefined intervals, rather than providing a cumulative total once per billing cycle.

M. “kilowatt” or "kW" is a unit of power equal to one thousand watts. It measures the rate at which energy is used or produced.

N. "kWh" as herein used, indicates and means "kilowatt hours." A kWh is a standard unit of energy used to measure electricity consumption. It represents the amount of energy used when a device that consumes 1,000 watts (or 1 kilowatt) operates for one hour.“

O. “megawatt” or "MW" is a unit of power equal to one million watts. A MW is a unit of power that measures the rate at which energy is used or produced.

P. "MWh" as herein used, indicates and means "megawatt hours." A MWh is a standard unit of energy used to measure electricity consumption. It represents the amount of energy used when a device that consumes one million watts and operates for one hour.

Q. “Net deficit electricity” means the electricity consumed by a customer-generator, as measured in kWh, exceeds electricity generated by that eligible customer-generator.

R. “Net neutral electricity” means the electricity consumed by a customer-generator, as measured in kWh, equals the electricity generated by that eligible customer-generator.

S. “Net surplus electricity” means the electricity generated by a customer-generator, as measured in kWh, exceeds the amount of electricity consumed by that eligible customer-generator.

T. "Portfolio content category one (PCC1)" means an eligible renewable energy resource interconnected or scheduled into a California balancing authority at the same time of generation pursuant to Sections 399.16(b)(1), 399.16(c)(1) and 399.30(c)(3) of the California Public Utilities Code.

~~C.~~U. "Power equipment" means electrical machinery such as motors, welding machines, battery chargers, radio-sending and X-ray equipment will normally be operated on a separate power meter. However, some power equipment, especially smaller size equipment, may be added and operated on the regular lighting meter, provided the starting and stopping or fluctuating load characteristics do not cause objectionable voltage fluctuations in any service rendered by the ~~d~~Department. The use of power equipment on lighting or combination meters must have the approval of the general manager of the ~~d~~Department.

~~F. Power:~~

~~1. Real Power. The work producing part of "apparent power" or rate of supply of energy—usually expressed in kilowatts (kW).~~

V. ~~2.~~“Power Factor“ means the ratio of real power (kilowatts) to apparent power (kilovolt-amperes) for any given load and time (maximum value = 1.0). Power Factor = Real Power/Apparent Power

W. “Public benefit charge” is a state-mandated nonbypassable, usage-based public benefit charge to fund assistance programs, energy efficiency and renewable energy projects.

~~D.~~X. “Reactive Power~~. The~~“ means the portion of "apparent power" which does no work but must be supplied to power equipment, such as motors—usually expressed in kilovars (kvar).

Y. ~~3.~~“Real Power~~ Factor. The ratio~~” means the work producing part of ~~real power (kilowatts) to~~ "apparent power ~~(kilovolt-amperes) for any given load~~" or rate of supply of energy—usually expressed in kilowatts (kW).

Z. "Renewable energy credit" or "REC" means a certificate of proof that one unit of electricity was generated by an eligible renewable energy resource. RECs are accumulated on a kWh basis and one REC represents the green attributes associated with the generation of one MWh from the electric generation facility.

AA. “Reservation Charge” is the monthly demand charge applied to the customer’s total nameplate capacity (kW) CC.

BB. "Retail customers" means customers who choose PWP as their energy supplier.

CC. "System energy sales" means the estimated total energy sales delivered to all customers.

DD. “Time-of-Use” or “TOU” is electricity pricing where the price of electricity varies depending on the time ~~(maximum value = 1.0).~~ of day, day of the week, and season. Electricity is more expensive during peak demand periods.

EE. “Transmission services charge” is a usage-based charge generally associated with the cost of delivering electricity from the generating plants to our sub-stations.

13.04.030 Light and power rate standards~~.~~

The rates to be charged and collected for furnishing and delivering electrical energy, and the terms, provisions and conditions respecting such rates, delivery of electrical energy and for service supplied by the ~~municipal light and power department of the city to customers served by the department~~Department shall be fixed as set forth in the following sections.

13.04.031 Pricing, pricing periods, and seasons

A. Pricing: The pricing for all fees, penalties, refunds, reimbursements, and charges of any kind collected by the Department pursuant to the provisions of this chapter shall be specified in the Electric Utility Rate Resolution, as amended by the Council from time to time. Whenever applicable throughout this chapter, reference shall be made to the Electric Utility Rate Resolution in lieu of any reference to specific fee amounts.

B. Seasonal Periods: Pricing varies between high and low demand months and the associated costs to provide services during those time periods. Prior to Interval Read Capable Meter Implementation, there are two time-period blocks on-peak and off-peak defined in the Electric Utility Rate Resolution. After Interval Read Capable Meter Implementation, there will be three time- period blocks, on-peak, off-peak and critical peak.

C. Prior to Interval Read Capable Meter implementation: “High Season” means the period of June through September and “Low Season” means the period of October through July.

D. After Interval Read Capable Meter Implementation: “High Season” means the period of July through October and “Low Season” means the period of November through June.

E. Time-of-Use Periods. “Time-of-Use” or “TOU” periods reflect when systems costs are high or low to signal to customers to shift usage to times that are better for the overall electric system and provide pricing for service components which varies by time of day and season of the year. The three time-of-use periods are “on-peak”, “off-peak” and “critical-peak” that vary in their times based on electric system energy costs.

13.04.040 Residential single-family service~~.~~ (Schedule R-1)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule R-1, as ~~follows~~found in the Electric Utility Rate Resolution:

~~SCHEDULE R-1~~
~~Residential Single-Family Service~~

A. ~~A.~~Applicability. Applies to separately metered single-family dwellings and to individual family accommodations~~.~~ with single phase 120/240-volt or 120/208-volt, and three-phase 120/208 or 240 volt service when used for residential purposes only, 60-cycle alternating current service. Motors with more than 150 amps locked motor are not served under this schedule.

~~B. Character of Service Furnished. Single phase 120/240-volt or 120/208-volt, and 3-phase 120/208 or 240 volt service when used for residential purposes only, 60-cycle alternating current service.~~

~~C. Conditions of Use. Motors with more than 150 amps locked rotor are not served under this schedule.~~

~~D.~~ Customer ~~Rates. Customers~~ shall pay the sum of the following charges (1) customer charge, ~~grid access charge,~~ (2) distribution charge, (3) grid access charge, (4) energy services charge, (5) transmission services charge, and ~~energy services charge as specified below.~~

B. ~~1.Customer Charge and Grid Access Charge. Customers taking service under Schedule R-~~(6) public benefit charge. The minimum monthly charge shall be equal to the sum of the (1~~-shall pay a~~) customer charge and ~~a~~(2) the grid access charge~~ during the billing month as follows: ~~.

~~B.~~C. Customers taking service under Schedule R-1 shall have two energy rate option for the energy services charge, the seasonal flat rate option or the Time-of-Use rate option. A customer may choose to receive energy under either option. Upon the adoption of Interval Read Capable Meters for billing, all customers will be automatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed.

~~Effective July 2017:~~

~~Customer Charge~~	~~Per Meter Per Month~~ ~~$8.96~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$4.50~~

~~2. Distribution Charge. Customers taking service under Schedule R-1 shall pay a distribution charge based on kWh used during the billing month as follows:~~

~~Effective July 2017:~~

~~Usage~~	~~$ per kWh~~
~~First 350 kWh per month~~	~~$0.01889~~
~~Next 400 kWh per month~~	~~$0.14673~~
~~All additional kWh per month~~	~~$0.10706~~

~~3. Transmission Services Charge. Customers taking service under Schedule R-1 shall pay a transmission services charge for each kWh delivered to the in accordance with Section 13.04.170.~~

~~4. Energy Services Charge. Customers taking service under Schedule R-1 shall have two energy rate options.~~

~~4.1 Option A—Seasonal Flat Rate:~~

~~Season~~	~~Energy Services Charge per kWh~~
~~Summer~~	~~$0.07073~~
~~Winter~~	~~$0.06147~~

~~4.2 Option B—Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.14750~~
~~Summer Off-Peak~~	~~$0.04750~~
~~Winter On-Peak~~	~~$0.11150~~
~~Winter Off-Peak~~	~~$0.05100~~

~~This option is subject to meter availability. The customer shall be responsible for the cost of installing the metering equipment required for this service.~~

~~4.3 Power Cost Adjustment: Power cost adjustment to be added to energy services charge. Rate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~E.General Conditions.~~

~~1.Selection of Energy Rate Option. The default energy rate option for customers under Schedule R-1 is Option A—Seasonal Flat Rate. A customer may choose to receive energy under either option A or B; however, when a customer requests a change of energy rate option, that customer may not change to another energy rate option before twelve months have elapsed.~~

~~F.Special Provisions.~~

~~1.Electric Utility Assistance Program.~~

~~a.Electric Utility Assistance Program (Basic Benefit). Any customer taking service under this schedule shall be eligible for a monthly credit against their electricity bills equal to the fixed charge rate components (customer charge and grid access charge), if the gross annual income per calendar year of the household in which such customer resides does not exceed the greater of: (i) the income level that qualifies for rental assistance under the city's low income rental assistance program; or, (ii) the income eligibility criteria established by the California Public Utilities Commission ("CPUC") Low-Income Oversight Board for rate assistance programs. The department shall periodically certify that the customer is eligible for the basic benefit.~~

~~b.Electric Utility Assistance Program (Pasadena Cares). Any customer eligible for the basic benefit shall also be eligible for a credit equal to the public benefit charge provided the customer is either: a) sixty-two years of age or older; or b) meets the criteria of disability as established by the Social Security Administration's Supplemental Income Program for the Aged, Blind and Disabled under Title XVI of the Social Security Act, as amended. The department shall periodically certify that the customer is eligible for the Pasadena Cares benefit.~~

~~c.Electric Utility Assistance Program (Medical). Any customer taking service under this schedule with doctor-prescribed life support equipment requiring electric utility service from the department in order to operate shall be eligible for the Basic Benefit regardless of income. To qualify, a customer must submit satisfactory proof to the department that a full-time occupant of the customer's premises requires a life support device. A qualifying life support device may be any one of the following or such other equipment as the department may deem eligible: aerosol tents, apnea monitors, compressors or concentrators, electrostatic or ultrasonic nebulizers, electric nerve stimulators, hemodialysis machines, kidney dialysis machines, intermittent positive pressure breathing machines, iron lungs, pressure pads, pressure pumps, respirators, or suction machines.~~

~~2.Time Periods. Time periods are defined as follows:~~

~~a.Summer months are defined as June through September. Winter months are defined as October through May.~~

~~b.On-peak hours: 3:00 p.m. to 8:00 p.m.~~
~~Off-peak hours: 8:00 p.m. to 3:00 p.m.~~

13.04.045 Residential multi-family service~~.~~ (Schedule R-2)

The ~~ra~~te rms and conditions of services hereunder shall be ~~as~~ provided by Schedule R-2, as ~~follows~~found in the Electric Utility Rate Resolution:

~~**SCHEDULE R-2**~~
~~**Residential Multi-Family Service**~~

A. ~~A.~~Applicability. Applies to separately metered multi-family dwellings, including properties permitted as "live-work" space when used for residential purposes, and to individual family dwellings in multi-family dwellings. Multi-family dwellings are apartments, condominiums or town houses with at least four meters at the same physical location. The character of service furnished includes single phase 120/240-volt or 120/208-volt, and 3-phase 120/208 or 240 volt service when used for residential purposes only, 60-cycle alternating current service. Motors with more than 150 amps locked motor are not served under this schedule.

~~B. Character of Service Furnished. Single phase 120/240-volt or 120/208-volt, and 3 phase 120/208 or 240 volt service when used for residential purposes only, 60-cycle alternating current service.~~

~~C. Conditions of Use. Motors with more than 150 amps locked rotor are not served under this schedule.~~

B. ~~D.Rates. Customers~~ Customer shall pay the sum of the following charges (1) customer charge, ~~the~~(2) distribution charge, ~~the~~ (3) grid access charge, (4) energy services charge, (5) transmission services charge, and (6) public benefit charge. The minimum monthly charge shall be equal to the sum of (1) the customer charge and (2) the grid access charge.

C. Customers taking service under Schedule R-2 shall have two energy rate options for the energy services charge, the seasonal flat rate option or the Time-of-Use rate option. A customer may choose to receive energy under either option. Upon the adoption of Interval Read Capable Meters for billing, all customers will be automatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed.

~~the energy services charge as specified below.~~

~~1. Customer Charge and Grid Access Charge. Customers taking service under Schedule R-2 shall pay a customer charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Customer Charge~~	~~Per Meter Per Month~~ ~~$8.96~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$4.50~~

~~2. Distribution Charge. Customers taking service under Schedule R-2 shall pay a distribution charge based on kWh used during the billing month as follows:~~

~~Effective July 2017:~~

~~Usage~~	~~$ per kWh~~
~~First 350 kWh per month~~	~~$0.01889~~
~~Next 400 kWh per month~~	~~$0.14673~~
~~All additional kWh per month~~	~~$0.10706~~

~~B. 3.Transmission Services Charge. Customers taking service under Schedule R-2 shall pay a transmission services charge for each kWh delivered to the in accordance with Section 13.04.170.~~

~~C. 4.Energy Services Charge. Customers taking service under Schedule R-2 shall have two energy rate options to choose from for their energy services.~~

~~D. 4.1. Option A—Seasonal Flat Rate:~~

~~Season~~	~~Energy Services Charge per kWh~~
~~Summer~~	~~$0.07073~~
~~Winter~~	~~$0.06147~~

~~E.~~

~~F. 4.2 Option B—Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.14750~~
~~Summer Off-Peak~~	~~$0.04750~~
~~Winter On-Peak~~	~~$0.11150~~
~~Winter Off-Peak~~	~~$0.05100~~

~~This option is subject to meter availability. The customer shall be responsible for the cost of installing the metering equipment required for this service.~~

~~4.3 Power Cost Adjustment: Power cost adjustment to be added to energy services charge. Rate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~E.General Conditions.~~

~~1.Selection of Energy Rate Option. The default energy rate option for customers under Schedule R-2 is Option A—Seasonal Flat Rate. A customer may choose to receive energy under either option A or B; however when a customer requests a change of energy rate option that customer may not change to another energy rate option before twelve months have elapsed.~~

~~F. Special Provisions.~~

~~1.~~ 13.04.046 Electric ~~Utility Assistance Program.~~ utility assistance program (EUAP)

~~a.~~

The programs hereunder are applicable to customers taking service under the Residential Single-Family Service (Schedule R-1) or Residential Multi-Family Service (Schedule R-2) in addition to the provisions set forth for each program:

A. Electric Utility Assistance Program ~~(~~-Basic Benefit~~)~~.. Any customer taking service under this schedule shall be eligible for a monthly credit against their electricity bills equal to the fixed charge rate components (customer charge and grid access charge), if the gross annual income per calendar year of the household in which such customer resides does not exceed the greater of~~: (i)~~ the: (i) income level that qualifies for rental assistance under the ~~c~~City's low income rental assistance program; or, (ii) ~~the~~ income eligibility criteria established by the California Public Utilities Commission ("CPUC") Low-Income Oversight Board for rate assistance programs. The ~~d~~Department shall periodically certify that the customer is eligible for the basic benefit.

B. ~~b.~~Electric Utility Assistance Program ~~(~~- Pasadena Cares~~)~~.. Any customer eligible for the basic benefit shall also be eligible for a credit equal to the public benefit charge provided the customer is either: a) sixty-two years of age or older; or b) meets the criteria of disability as established by the Social Security Administration's Supplemental Income Program for the Aged, Blind and Disabled under Title XVI of the Social Security Act, as amended. The ~~d~~Department shall periodically certify that the customer is eligible for the Pasadena Cares benefit.

C. ~~c.~~Electric Utility Assistance Program ~~(-~~ Medical~~)~~. Any customer taking service under this schedule with doctor-prescribed life support equipment requiring electric utility service from the ~~department in order~~Department to operate shall be eligible for the Basic Benefit regardless of income. To qualify, a customer must submit satisfactory proof to the ~~d~~Department that a full-time occupant of the customer's premises requires a life support device. A qualifying life support device may be any one of the following or such other equipment as the ~~d~~Department may deem eligible: aerosol tents, apnea monitors, compressors or concentrators, electrostatic or ultrasonic nebulizers, electric nerve stimulators, hemodialysis machines, kidney dialysis machines, intermittent positive pressure breathing machines, iron lungs, pressure pads, pressure pumps, respirators, or suction machines.

~~2. Time Periods. Time periods are defined as follows:~~

~~a. Summer months are defined as June through September. Winter months are defined as October through May.~~

~~b.On-peak hours: 3:00 p.m. to 8:00 p.m.~~
~~Off-peak hours: 8:00 p.m. to 3:00 p.m.~~

13.04.050 Small commercial ~~and industrial~~ service~~.~~ (Schedule S-1)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule S-1, as ~~follows~~found in the Electric Utility Rate Resolution:

~~SCHEDULE S-1~~
~~Small Commercial and Industrial Service~~

~~A. Applicability. Applies to single-phase and 3-phase general service, including lighting and incidental small power, through a single meter. Applies to service below 30 kW demand.~~

~~B. Character of Service Furnished. Single-phase 120/240 or 120/208 volt, and 3-phase, 120/208, 240, 480, or 277/480 volt, 60-cycle alternating current service.~~

~~C. Conditions of Use. Single-phase motors 1/2 HP and larger shall be connected at 240 volts or 208 volts. Motors 5 HP and larger shall be connected 3 phase. Motor-connected loads in excess of 49 HP are not served under this schedule for new service after April 1, 1969.~~

~~D. Rates. Customers shall pay the sum of customer charge, grid access charge, distribution charge, transmission services charge, and energy services charge as specified below.~~

~~1. Customer Charge and Grid Access Charge. Customers taking service under Schedule S-1 shall pay a customer charge and a grid access charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Customer Charge:~~	~~Per Meter Per Month~~ ~~$9.42~~

~~Effective July 2019:~~

~~Grid Access Charge:~~	~~Per Meter Per Month~~ ~~$17.00~~

~~2. Distribution Charge. Customers taking service under Schedule S-1 shall pay a distribution charge during the billing month as follows:~~

~~Effective July 2017:~~

~~All kWh per month~~	~~$0.06423~~

~~3. Transmission Services Charge. Customers taking service under Schedule S-1 shall pay a transmission services charge for each kWh delivered in accordance with Section 13.04.170.~~

~~4. Energy Services Charge. Customers taking service under Schedule S-1 shall have two energy rate options:~~

~~4.1 Option A—Seasonal Flat Rate:~~

~~Season~~	~~Energy Services Charge per kWh~~
~~Summer~~	~~$0.06901~~
~~Winter~~	~~$0.06030~~

~~4.2 Option B—Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.10463~~
~~Summer Off-Peak~~	~~$0.05706~~
~~Winter On-Peak~~	~~$0.06431~~
~~Winter Off-Peak~~	~~$0.05611~~

~~This option is subject to meter availability. The customer shall be responsible for the cost of purchasing and installing the metering equipment required for this service.~~

~~4.3 Power Cost Adjustments: Customers taking service under Schedule S-1 shall pay a PCA, as provided in Section 13.04.173. Rate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~5. Minimum Monthly Charge: Customers shall pay a minimum charge equal to the customer charge and the grid access charge under Schedule S-1.~~

~~E. General Condition.~~

~~1. Selection of Energy Rate Option. The default energy rate option for customers under Schedule S-1 is Option A—Seasonal Flat Rate. Customers may choose to receive energy under either option A or B; however, a customer who receives a change of energy rate option may not change to another energy rate option before twelve months have elapsed.~~

~~F. Special Provisions.~~

~~A. 1.Customers connected to 120/208 volt service whose sole usage of electricity is for residential purposes as defined by the PWP, shall be billed on the residential rate schedule.~~

~~A.~~ Applicability. Applies to single-phase and three-phase general service, including lighting and incidental small power, through a single meter. Applies to service below 30 kW demand. The character of service furnished may be single-phase 120/240 or 120/208 volt, and three-phase, 120/208, 240, 480, or 277/480 volt, 60-cycle alternating current service. Customers connected to 120/208 volt service whose sole usage of electricity is for residential purposes as defined by the PWP, shall be billed on the residential rate schedule. Single-phase motors 1/2 hp and larger shall be connected at 240 volts or 208 volts. Motors 5 hp and larger shall be connected 3-phase. Motor-connected loads more than 49 hp are not served under this schedule. ~~2.Time Periods. Time periods are defined as follows:~~

B. ~~a.Summer months are defined as June through September. Winter months are defined as October through May.~~

C. ~~b.Summer On-peak hours: 12:00 noon to 8:00 p.m.~~

D. ~~Summer Off-peak hours: 8:00 p.m. to 12:00 noon~~

E. ~~Winter On-peak hours: 6:00 a.m. to 10:00 p.m.~~

F. ~~Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.~~

G. ~~c.Weekend and holiday hours are all off-peak.~~

A. ~~d.Holidays are New Year's Day, Martin Luther King Jr. Day, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, Day after Thanksgiving, and Christmas.~~

B. Customer shall pay the sum of the following charges (1) customer charge for either (a) single-phase service or (b) three-phase service, (2) distribution charge, (3) grid access charge, (4) energy services charge, (5) transmission services charge, and (6) public benefit charge. The minimum monthly charge shall be equal to (1) the sum of the customer charge and (2) the grid access charge.

C. Customers taking service under Schedule S-1 shall have two energy rate options for the energy services charge, the seasonal flat rate option or the Time-of-Use rate option. A customer may choose to receive energy under either option. Upon the adoption of Interval Read Capable Meters for billing, all customers will be automatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed.

13.04.060 Medium commercial ~~and industrial~~ service—~~Secondary.~~secondary (Schedule M-2)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule M-~~1, as follows~~2, as found in the Electric Utility Rate Resolution:

~~SCHEDULE M-1~~
~~Medium Commercial and Industrial~~
~~Service—Secondary~~

~~A. A.Applicability. Applies to 3 phase general service, including power and lighting, measured with demand meter. Applies to service at 30 kW demand or greater, but less than 300 kW demand. Any customer served under this schedule whose monthly maximum demand has registered less than 30 kW or greater than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule M-1 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages less than 17 kV.~~

~~B. Character of Service Furnished. 3 phase 240, 480, 120/208 or 277/480 volt, 60 cycle alternating current service.~~

~~C. Conditions of Use. Motors of 50 HP or more shall be served as determined by PWP.~~

~~D. Rates. Customers shall pay the sum of customer charge, grid access charge, distribution charge, transmission services charge, and energy services charge as specified below.~~

~~1. Customer Charge and Grid Access Charge. Customers taking service under Schedule M-1 shall pay a customer charge and a grid access charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Per Meter Per Month~~
~~$23.40~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$250.00~~

~~2. Distribution Charge. Customers taking service under Schedule M-1 shall pay a distribution charge during the billing month as follows:~~

~~Effective July 2017:~~

~~All kilowatts of demand~~	~~$16.09 per kW~~

~~3.Transmission Services Charge. Customers taking service under Schedule M-1 shall pay a transmission services charge for each kWh delivered in accordance with Section 13.04.170.~~

~~4.Energy Services Charge. Customers taking service under Schedule M-1 shall have two energy rate options.~~

~~4.1 Option A—Seasonal Flat Rate:~~

~~Season~~	~~Energy Services Charge per kWh~~
~~Summer~~	~~$0.07338~~
~~Winter~~	~~$0.06213~~

~~4.2 Option B—Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.10218~~
~~Summer Off-Peak~~	~~$0.06063~~
~~Winter On-Peak~~	~~$0.06578~~
~~Winter Off-Peak~~	~~$0.05785~~

A. Applicability. Applies to three-phase general service, including power and lighting, measured with demand meter. Applies to service at 30 kW demand or greater, but less than 300 kW demand. Any customer served under this schedule whose monthly maximum demand has registered less than 30 kW or greater than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule M-2 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages less than ~~17~~4 kV. The character of service furnished shall be three-phase 240, 480, 120/208 or 277/480 volt, 60 cycle alternating current service. Motors of 50 hp or more shall be served as determined by PWP. Billing demand shall not be less than 30 kW.

B. Customer shall pay the sum of the following charges (1) customer charge, (2) distribution charge, (3) grid access charge, (4) energy services charge, and (5) transmission services charge, and (6) public benefit charge.

~~A.~~ Customers taking service under Schedule M-2 for the energy services charge, the seasonal flat rate option or the Time-of-Use rate option. A customer may choose to receive energy under either option. Upon the adoption of Interval Read Capable Meters for billing, all customers will be automatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed. The minimum monthly charge shall be equal to the sum of the customer charge, the distribution charge, and the grid access charge.

C.

D. Power Factor Penalty and Discount.

1. Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.

2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest one-tenth of one percent.

3. New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.

4. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest one-tenth of one percent.

~~H. This option is subject to meter availability. Customers shall be responsible for the cost of purchasing and installing the metering equipment required for this service.~~

~~I. 4.3 Power Cost Adjustment: Customers taking service under Schedule M-1 shall pay a PCA, as provided in Section 13.04.173. Rate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~J. 5.Minimum monthly charge: Customers shall pay a minimum charge equal to the customer charge, distribution charge, and the grid access charge under Schedule M-1.~~

~~K. E.General Condition.~~

~~L. 1.Selection of Energy Rate Option. The default energy rate option for customers under Schedule M-1 is Option A—Seasonal Flat Rate. Customers may choose to receive energy under either option A or B; however, a customer who receives a change of energy rate optionmay not change to another energy rate option before twelve months have elapsed.~~

~~M. F.Special Provision.~~

~~N. 1.Determination of Billing Demand. "Billing Demand" shall not be less than 30 KW. "Billing demand" means the greater of (i) the kilowatts of measured maximum demand occurring during the current month or (ii) the highest demand recorded in the last four months, including the current billing month. Demand is determined to the nearest kW. Demand meters will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand is of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval.~~

~~O. 2.Time Periods. Time periods are defined as follows:~~

~~P. a.Summer months are defined as June through September. Winter months are defined as October through May.~~

~~Q. b.Summer On-peak hours: 12:00 noon to 8:00 p.m.~~

~~R. Summer Off-peak hours: 8:00 p.m. to 12:00 noon~~

~~S. Winter On-peak hours: 6:00 a.m. to 10:00 p.m.~~

~~T. Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.~~

~~U. c.Weekend and holiday hours are all off-peak.~~

~~V. d.Holidays are New Year's Day, Martin Luther King Jr. Day, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, Day after Thanksgiving, and Christmas.~~

~~W. 3.Power Factor Penalty and Discount.~~

~~1. a.Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.~~

~~A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest 1/10 of one percent.~~

~~2. b.New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.~~

~~A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power actor shall be computed to the nearest one percent. The discount shall be computed to the nearest 1/10 of one percent.~~

4. ~~Regulation by PWP. PWP may at any time inspect or test any power equipment and estimate or measure the demand, starting currents, power factor or other characteristics of such equipment to determine proper billing or compliance with the requirements of this chapter.~~

5. ~~Curtailable Service.~~

   a. ~~Rates: PWP may solicit customer bids for curtailable service. In making such solicitations, PWP shall inform bidders of: i) the time period(s) that would likely be subject to curtailment; and ii) limitations, if any, on PWP's right to curtail service, including limitations on the number of curtailments, the duration of each curtailment, and minimum notice of curtailments. Bidders shall specify the minimum load level to which their service may be curtailed; and the minimum price that they would accept for each kWh curtailed. For hours in which the bidder provides this service to PWP, the bidder shall receive from PWP a billing credit equal to the product of the quantity of customer load actually curtailed and the hourly curtailment price which was bid and accepted by PWP.~~

~~b.Actual Curtailment Quantities: In each hour that PWP curtails a customer's service, PWP will quantify that hour's actual curtailment quantity by subtracting the customer's metered load in that hour from the customer's "normal load" for that hour. The customer's "normal load" for an hour is defined as the average of the customer's loads for the same hours of the five most recent "comparable days" that have not been subject to curtailments or objectively identifiable abnormal circumstances that have significantly affected customer consumption. "Comparable days" are as follows: for curtailments on Sundays and holidays, recent Sundays and holidays; for curtailments on non-holiday weekdays (Monday through Friday), recent non-holiday weekdays; and for Saturdays, recent Saturdays. Thus, by way of an example, the "normal load" for a Tuesday on the hour ending 3:00 p.m. would be the average of the loads in each of the hours ending 3:00 p.m. on the five most recent non-holiday weekdays that were not subject to curtailment.~~

~~13.04.064 Medium Commercial and Industrial Service—Primary.~~

~~The rates and conditions of services hereunder shall be as provided by Schedule M-2, as follows:~~

~~SCHEDULE M-2~~
~~Medium Commercial and Industrial~~
~~Service—Primary~~

A. ~~Applicability. Applies to 3 phase general service, including power and lighting, measured with demand meter. Applies to service at 30 kW demand or greater, but less than 300 kW demand. Any customer served under this schedule whose monthly maximum demand has registered less than 30 kW or greater than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule M-2 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages equal to or greater than 17 kV.~~

B. ~~Character of Service Furnished. 3 phase, 60 cycle alternating current service at normal primary or sub-transmission voltages.~~

C. ~~Conditions of Use. Motors of 50 HP or more shall be served as determined by PWP.~~

D. ~~Rates. Customers shall pay the sum of customer charge, distribution charge, transmission services charge, and energy services charge as specified below.~~

   1. ~~Customer Charge and Grid Access Charge. Customers taking service under Schedule M-2 shall pay a customer charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Customer Charge~~	~~Per Meter Per Month~~ ~~$29.75~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$250.00~~

~~2. Distribution Charge. Customers taking service under Schedule M-2 shall pay a distribution charge during the billing month as follows:~~

~~Effective July 2017:~~

~~All kilowatts of demand~~	~~$11.49 per kW~~

~~3. Transmission Services Charge. Customers taking service under Schedule M-2 shall pay a transmission services charge for each kWh delivered in accordance with Section 13.04.170.~~

~~4. Energy Services Charge. Customers taking service under Schedule M-2 shall have two energy rate options.~~

~~4.1 Option A—Seasonal Flat Rate:~~

~~Season~~	~~Energy Services Charge per kWh~~
~~Summer~~	~~$0.07154~~
~~Winter~~	~~$0.06121~~

~~4.2 Option B—Time-of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.10128~~
~~Summer Off-Peak~~	~~$0.05970~~
~~Winter On-Peak~~	~~$0.06481~~
~~Winter Off-Peak~~	~~$0.05713~~

~~This option is subject to meter availability. The customer shall be responsible for the cost of purchasing and installing the metering equipment required for this service.~~

~~4.3 Power Cost Adjustment: Customers taking service under Schedule M-2 shall pay a PCA, as provided in Section 13.04.173. Rate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~5. Minimum Monthly Charge: Customers shall pay a minimum charge equal to the customer charge, distribution charge, and the grid access charge under Schedule M-2.~~

~~E. General Condition.~~

~~1. Selection of Energy Rate Option. The default energy rate option for customers under Schedule M-2 is Option A—Seasonal Flat Rate. Customers may choose to receive energy under either option A or B; however, a customer who receives a change of energy rate option may not change to another energy rate option before twelve months have elapsed.~~

~~F. Special Provisions.~~

~~1. Determination of Billing Demand. "Billing demand" shall not be less than 30 KW. "Billing demand" means the greater of (i) the kilowatts of measured maximum demand occurring during the~~

~~current month or (ii) the highest demand recorded in the last four months, including the current billing month. Demand is determined to the nearest kW. Demand meters will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand is of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval.~~

~~2. Time Periods. Time periods are defined as follows:~~

~~a. Summer months are defined as June through September. Winter months are defined as October through May.~~

~~b. Summer On-peak hours: 12:00 noon to 8:00 p.m.~~

~~Summer Off-peak hours: 8:00 p.m. to 12:00 noon~~

~~Winter On-peak hours: 6:00 a.m. to 10:00 p.m.~~

~~Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.~~

~~c. Weekend and holiday hours are all off-peak.~~

~~d. Holidays are New Year's Day, Martin Luther King Jr. Day, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, Day after Thanksgiving, and Christmas.~~

~~A. 3.Power Factor Penalty and Discount.~~

~~1. a.Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.~~

~~2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest~~ $\cancel{^{1}/_{10}}$ ~~of one percent.~~

~~3. b.New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.~~

~~4. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest~~ $\cancel{^{1}/_{10}}$ ~~of one percent.~~

~~4. Regulation by PWP. PWP may at any time inspect or test any power equipment and estimate or measure the demand, starting currents, power factor or other characteristics of such equipment to determine proper billing or compliance with the requirements of this chapter.~~

~~5. Curtailable Service.~~

~~a. Rates: PWP may solicit customer bids for curtailable service. In making such solicitations, PWP shall inform bidders of: i) the time period(s) that would likely be subject to curtailment; and ii) limitations, if any, on PWP's right to curtail service, including limitations on the number of curtailments, the duration of each curtailment, and minimum notice of curtailments. Bidders shall specify the minimum load level to which their service may be curtailed; and the minimum price that they would accept for each kWh curtailed. For hours in which the bidder provides this service to PWP, the bidder shall receive from PWP a billing credit equal to the product of the quantity of customer load actually curtailed and the hourly curtailment price which was bid and accepted by PWP.~~

~~b. Actual Curtailment Quantities: In each hour that PWP curtails a customer's service, PWP will quantify that hour's actual curtailment quantity by subtracting the customer's metered load in that hour from the customer's "normal load" for that hour. The customer's "normal load" for an hour is defined as the average of the customer's loads for the same hours of the five most recent "comparable days" that have not been subject to curtailments or objectively identifiable abnormal circumstances that have significantly affected customer consumption. "Comparable days" are as follows: for curtailments on Sundays and holidays, recent Sundays and holidays; for curtailments on non-holiday weekdays (Monday through Friday), recent non-holiday weekdays; and for Saturdays, recent Saturdays. Thus, by way of an example, the "normal load" for a Tuesday on the hour ending 3:00 p.m. would be the average of the loads in each of the hours ending 3:00 p.m. on the five most recent non-holiday weekdays that were not subject to curtailment.~~

13.04.~~067 Large~~064 Medium commercial ~~and industrial~~ service—~~Secondary.~~primary (Schedule M-1)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule ~~L-1, as follows:~~

~~**SCHEDULE L**~~M-1
~~**Large Commercial and Industrial**~~
~~**Service—Secondary**~~, as found in the Electric Rate Utility Resolution:

~~A.~~ Applicability. Applies to three-phase general service, including power and lighting, measured with demand meter. Applies to service at 30 kW demand or greater, but less than 300 kW demand. Any customer served under this schedule whose monthly maximum demand has registered less than 30 kW or greater than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule M-~~3 phase general service, including power and lighting, measured with demand meter. Applies to service at 300 kW demand or greater. Any customer served under this schedule whose monthly maximum demand has registered less than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule L-~~1 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages equal to or greater than ~~17~~4 kV. ~~This schedule is subject to meter availability. Applies to services metered and delivered at voltages less than 17 kV.~~

~~B. Character of Service Furnished. 3 phase 240, 480, 120/208 or 277/480 volt~~The character of service furnished shall be three-phase, 60 cycle alternating current service~~.~~

A. ~~C.Conditions of Use.~~ at normal primary or sub-transmission voltages. Motors of 50 ~~HP~~hp or more shall be served as determined by PWP. Billing demand shall not be less than 30 kW.

B. Customer shall pay the sum of the following charges (1) customer charge, (2) distribution charge, (3) grid access charge, (4) energy services charge, and (5) transmission services charge, and (6) public benefit charge. Customers taking service under Schedule M-1 shall have two energy rate options for the energy services charge, the seasonal flat rate option or the Time-of-Use rate option. A customer may choose to receive energy under either option. Upon the adoption of Interval Read Capable Meters for billing, all customers will be automatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed. The minimum monthly charge shall be equal to sum of the customer charge, the distribution charge, and the grid access charge.

~~D. Rates. Customers Customer shall pay the sum of the following charges (1) customer charge, grid access charge, (2) distribution charge, (3) grid access charge, (4) energy services charge, and (5) transmission services charge, and energy services(6) public benefit charge as specified below.~~

~~1. Customer Charge and Grid Access Charge. Customers taking service under Schedule LM-1 shall pay a customer charge and a grid access charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Customer Charge~~	~~Per Meter Per Month~~ ~~$47.91~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$1,500.00~~

~~2. Distribution Charge. Customers taking service under Schedule L-1 shall pay a distribution charge during the billing month as follows:~~

~~Effective July 2017:~~

~~All kilowatts of demand~~	~~$18.76 per kW~~

~~3. Transmission Services Charge. Customers taking service under Schedule L-1 shall pay a transmission services charge for each kWh delivered in accordance with Section 13.04.170.~~

~~4. Energy Services Charge. Customers taking service under Schedule L-1 shall payhave two energy services charge as follows:~~

~~4.1 Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.10394~~
~~Summer Off-Peak~~	~~$0.05843~~
~~Winter On-Peak~~	~~$0.06579~~
~~Winter Off-Peak~~	~~$0.05659~~

~~4.2 Power Cost Adjustment: Customers taking service under Schedule L-1 shall pay a PCA, as provided in Section 13.04.173. Raterate options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~5. Minimum Monthly Charge: Customers shall pay a minimum charge equal to for the energy services charge, the customer charge, distribution charge, and seasonal flat rate option or the grid access charge under Schedule L-1.~~

~~E. Special Provisions.~~

~~B. 1.Determination of Billing Demand. "Billing demand" shall not be less than 300 KW. "Billing demand" meansTime-of-Use rate option. A customer may choose to receive energy under either option. Upon the greater of (i) the kilowatts of measured maximum demand occurring during the current month or (ii) the highest demand recorded in the last four months, including the current billing month. Demand is determined to the nearest kW. Demand metersadoption of Interval Read Capable Meters for billing, all customers will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand isautomatically enrolled in the Time-of-Use rates. Until such time, Time-of-Use rates are subject to meter availability. When a customer requests a change of energy rate option, they may do so in writing and that customer may not change to another energy rate option before twelve months have elapsed. The minimum monthly charge shall be equal to sum of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval. the customer charge, the distribution charge, and the grid access charge.~~

~~2. Time Periods. Time periods are defined as follows:~~

~~a. Summer months are defined as June through September. Winter months are defined as October through May.~~

~~b. Summer On-peak hours: 12:00 noon to 8:00 p.m.~~

~~Summer Off-peak hours: 8:00 p.m. to 12:00 noon~~

~~Winter On-peak hours: 6:00 a.m. to 10:00 p.m.~~

~~Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.~~

~~c. Weekend and holiday hours are all off-peak.~~

~~d. Holidays are New Year's Day, Martin Luther King Jr. Day, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, Day after Thanksgiving, and Christmas.~~

C. ~~3.~~Power Factor Penalty and Discount.

1. ~~a.~~Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.

2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the ~~nearest 1/10~~nearest one-tenth of one percent.

3. ~~b.~~New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.

4. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the ~~nearest 1/10~~nearest one-tenth of one percent.

13.04.067 ~~0~~ Large commercial and in~~du~~st~~r~~itutional service—~~Primary.~~secondary (Schedule L-2)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule L-2, as ~~follows:~~ found in the Electric Rate Utility Resolution:

~~**SCHEDULE L-2**~~
~~**Large Commercial and Industrial**~~
~~**Service—Primary**~~

~~A.~~ Applicability. Applies to three-phase general service, including power and lighting, measured with demand meter. Applies to service at 300 kW demand or greater. Any customer served under this schedule whose monthly maximum demand has registered less than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule L-2 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages less than ~~17~~4 kV. ~~3 phase general service, including power and lighting, measured with demand meter. Applies to service at 300 kW demand or greater. Any customer served under this schedule whose monthly maximum demand has registered less than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule L-1 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages equal to or greater than 17 kV.~~

~~B. Character of Service Furnished. 3 phase~~The character of service furnished shall be three-phase 240, 480, 120/208 or 277/480 volt, 60 cycle alternating current service~~ at normal primary or sub-transmission voltages.~~

~~C. Conditions of Use.~~. Motors of 50 ~~HP~~hp or more shall be served as determined by PWP.

~~D. Rates. Customers shall pay the sum of customer charge, grid access charge, distribution charge, transmission services charge, and energy services charge as specified below.~~

~~1. Customer Charge and Grid Access Charge. Customers taking service under Schedule L-2 shall pay a customer charge and a grid access charge during the billing month as follows:~~

~~Effective July 2017:~~

~~Customer Charge~~	~~Per Meter Per Month~~ ~~$53.90~~

~~Effective July 2019:~~

~~Grid Access Charge~~	~~Per Meter Per Month~~ ~~$1,500.00~~

~~2. Distribution Charge. Customers taking service under Schedule L-2 shall pay a distribution charge during the billing month as follows:~~

~~Effective July 2017:~~

~~All kilowatts of demand~~	~~$11.89 per kW~~

~~3. Transmission Services Charge. Customers taking service under Schedule L-2 shall pay a transmission services charge for each kWh delivered in accordance with Section 13.04.170.~~

~~4. Energy Services Charge. Customers taking service under Schedule L-2 shall pay an energy services charge as follows:~~

~~4.1 Time-Of-Use Rate:~~

~~Time-of-Use~~	~~Energy Services Charge per kWh~~
~~Summer On-Peak~~	~~$0.09852~~
~~Summer Off-Peak~~	~~$0.05580~~
~~Winter On-Peak~~	~~$0.06617~~
~~Winter Off-Peak~~	~~$0.05629~~

~~4.2 Power Cost Adjustment: Customers taking service under Schedule L-2 shall pay a PCA, as provided in Section 13.04.173. Rate Options A and B are subject to adjustment as provided in Section 13.04.173.~~

~~5. Minimum Monthly Charge: Customers shall pay a minimum charge equal to the customer charge, distribution charge, and the grid access charge under Schedule L-2.~~

~~E. Special Provisions.~~

A. ~~1.Determination of~~ Billing ~~Demand. "Billing~~ demand~~"~~ shall not be less than 300 ~~KW. "Billing demand" means the greater of (i) the kilowatts of measured maximum demand occurring during the current month or (ii) the highest monthly demand recorded in the last four months, including the current billing month. Demand is determined to the nearest kW. Demand meters will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand is of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval.~~ kW

~~2. Time Periods. Time periods are defined as follows:~~

~~a. Summer months are defined as June through September. Winter months are defined as October through May.~~

~~b. Summer On-peak hours: 12:00 noon to 8:00 p.m.~~

~~Summer Off-peak hours: 8:00 p.m. to 12:00 noon~~

~~Winter On-peak hours: 6:00 a.m. to 10:00 p.m.~~

~~Winter Off-peak hours: 10:00 p.m. to 6:00 a.m.~~

~~c. Weekend and holiday hours are all off-peak.~~

~~d. Holidays are New Year's Day, Martin Luther King Jr. Day, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, Day after Thanksgiving, and Christmas.~~

B. ~~3.~~Customer shall pay the sum of the following charges (1) customer charge, (2) distribution charge, (3) grid access charge, (4) energy services charge, and (5) transmission services charge, and (6) public benefit charge. The minimum monthly charge shall be equal to the sum of the customer charge, the distribution charge, and the grid access charge.

~~B.~~C. Power Factor Penalty and Discount.

1. ~~a.~~Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.

2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the ~~nearest 1/10~~nearest one-tenth of one percent.

3. ~~b.~~New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.

4. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the ~~nearest 1/10~~nearest one-tenth of one percent.

. ~~4.Regulation by PWP. PWP may at any time inspect or test any power equipment and estimate or measure the demand, starting currents, power factor or other characteristics of such equipment to determine proper billing or compliance with the requirements of this chapter.~~

~~5. Curtailable Service.~~

~~a. Rates: PWP may solicit customer bids for curtailable service. In making such solicitations, PWP shall inform bidders of: i) the time period(s) that would likely be subject to curtailment; and ii) limitations, if any, on PWP's right to curtail service, including limitations on the number of curtailments, the duration of each curtailment, and minimum notice of curtailments. Bidders shall specify the minimum load level to which their service may be curtailed; and the minimum price that they would accept for each kWh curtailed. For hours in which the bidder provides this service to PWP, the bidder shall receive from PWP a billing credit equal to the product of the quantity of customer load actually curtailed and the hourly curtailment price which was bid and accepted by PWP.~~

~~b.Actual Curtailment Quantities: In each hour that PWP curtails a customer's service, PWP will quantify that hour's actual curtailment quantity by subtracting the customer's metered load in that hour from the customer's "normal load" for that hour. The customer's "normal load" for an hour is defined as the average of the customer's loads for the same hours of the five most recent "comparable days" that have not been subject to curtailments or objectively identifiable abnormal circumstances that have significantly affected customer consumption. "Comparable days" are as follows: for curtailments on Sundays and holidays, recent Sundays and holidays; for~~

~~curtailments on non-holiday weekdays (Monday through Friday), recent non-holiday weekdays; and for Saturdays, recent Saturdays. Thus, by way of an example, the "normal load" for a Tuesday on the hour ending 3:00 p.m. would be the average of the loads in each of the hours ending 3:00 p.m. on the five most recent non-holiday weekdays that were not subject to curtailment.~~ 7046 § 7, 2006: Ord. 6901 § 8, 2002) (Ord.

13.04.069 Large commercial and institutional service—primary (Schedule L-1)

The terms and conditions of services hereunder shall be provided by Schedule L-1, as found in the Electric Utility Rate Resolution.

A. Applicability. Applies to 3-phase general service, including power and lighting, measured with demand meter. Applies to service for a customer at 300 kW demand or greater for one month out of the previous 12 months. Any customer served under this schedule whose monthly maximum demand has registered less than 300 kW for twelve consecutive months is no longer eligible for service under this Schedule L-1 and must take service under another applicable rate schedule. This schedule is subject to meter availability. Applies to services metered and delivered at voltages equal to or greater than ~~17~~4 kV. The character of service furnished shall be 3-phase, 60 cycle alternating current service at normal primary or sub-transmission voltages. Motors of 50 hp or more shall be served as determined by PWP. Billing demand shall not be less than 300 kW.

B. Customer shall pay the sum of the following charges (1) customer charge, (2) distribution charge, (3) grid access charge, (4) energy services charge, and (5) transmission services charge, and (6) public benefit charge. The minimum monthly charge shall be equal to the sum of the customer charge, the distribution charge, and the grid access charge.

C. Power Factor Penalty and Discount.

   1. Existing Loads: If a customer's load operates at a power factor of less than 75 percent, PWP may require installation of equipment to correct the power factor to 75 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 75 percent shall be added to the distribution charge.

   2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest one-tenth of one percent.

   3. New Loads: On or after July 1, 2002, if a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.

   4. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest one-tenth of one percent.

13.04.070 Extra-large commercial and institutional service—primary (Schedule L-3)

The terms and conditions of services hereunder shall be provided by Schedule L-3, as found in the Electric Utility Rate Resolution.

A. Applicability. Applies to customers with one or more dedicated circuit(s), including power and lighting, and aggregate demand of 10MW measured with demand meter. Applies to customers that meet or exceed 10 MW aggregate demand or greater in one month of the prior 12-month period.

B. Customer shall pay the sum of the following charges (1) customer charge, (2) distribution charge, (3) grid access charge, (4) transmission services charge, and (5) public benefit charge. The minimum monthly charge shall be equal to the sum of the customer charge, the distribution charge, and the grid access charge. The minimum monthly charge shall be equal to the sum of the customer charge, the distribution charge under Schedule L-3, and the grid access charge. The customer shall also pay the energy services charge if an alternative rate for energy services is not established through an approved long-term contract pursuant to section 13.04.075.

C. Power Factor Penalty and Discount.

1. If a customer's load operates at a power factor of less than 85 percent, PWP may require installation of equipment to correct the power factor to 85 percent or better. A penalty of one percent of the distribution charge for each percent the average monthly power factor falls below 85 percent shall be added to the distribution charge.

2. A customer having a maximum demand of 50 kW or more shall be allowed a discount on the distribution charge of 0.333 percent for each percent the average monthly power factor exceeds 85 percent. The discount shall not exceed 5 percent. The power factor shall be computed to the nearest one percent. The discount shall be computed to the nearest one-tenth of one percent.

13.04.071 Special load management and conservation service~~.~~

~~A.Subject to the conditions set forth in this section,~~The special load management and conservation service rate is an optional temporary rate that PWP may enter into~~ temporary special rate agreements and/or rate schedules~~ with qualifying customers in order to: encourage experimentation in load management and conservation programs within customer premises and allow evaluation of load management's effect on the power system; evaluate how best to accommodate the load impacts of new technologies on the power system; experiment with electricity rates and the timing of customer payments for ~~time-of-use~~TOU meters and other interconnection facilities in order to incentivize customers to shift their electric usage from on-peak to off-peak hours when system costs are lower; and/or reduce the power system's aggregate on-peak electricity demand.

~~B~~A. PWP shall publish the temporary rate schedules listing the effective date, customer qualification requirements, and all relevant terms.

~~C~~B. Customer shall make application to PWP to take service under any rates schedule offered under this section. All applications meeting the published requirements shall be accepted in the order of receipt by PWP, subject to the limitations in subsection (E) of this section.

~~D~~C. Said temporary special rate agreements and/or rate schedules may be cancelled by PWP, at any time, on notice to the customer, but in no event shall be in effect for a period exceeding thirty-six (36) months.

~~E~~D. The energy sales under this section shall be limited to three percent~~ (3%)~~ of the total system energy sales in megawatt-hours, as reported in PWP's most recent annual report. Each customer group shall be allocated a percentage of the energy sales based on the customer group's contribution to the total system energy sales.

~~F~~E. Each participating customer shall be limited to ten percent ~~(10%) ~~of the energy sales within its customer group.

13.04.~~073 Economic development~~074 Electric vehicle charging rates~~.~~ (Schedules EV-1, EV-2, ~~and ~~EV-3, and City-owned retail charging stations)

The ~~rates~~Electric Vehicle (EV) rate is an optional rate designed to encourage EV adoption and support clean transportation. The terms and conditions of services hereunder shall be ~~as ~~provided by ~~Schedule ED, as follows:~~

~~Schedule ED~~

~~Economic Development Rates for Medium and Large Commercial and Industrial Customers~~

~~A.~~ schedules EV-1, EV-2, and EV-3, and ~~City~~City-Owned Retail Charging Stations -as found in the Electric Utility~~Applicability.~~

~~1.The Economic Development~~ Rate ~~is available to new medium and large commercial and industrial customers that:~~Resolution.

~~i. Have a 2012 North American Industry Classification System ("NAICS") code in one of the following categories: Construction (23), Manufacturing (31-33), Information (51), Scientific, Technical, and Professional Services (54), or restaurants (722511 or 722110);~~

~~ii. Must upgrade the existing building and/or the electrical service interconnection thereto; and~~

~~A. iii.Are adding a minimum of 50Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and the applicable energy services charge TOU rate schedule subject to all changes in accordance with the Electric Utility Rate Resolution. The minimum monthly charge shall be equal to the sum of the customer charge and the grid access charge.~~

A. Electric vehicle charging below 30 kW ~~of projected electrical~~(Schedule EV-1)

1. Applicability. Applies to stand-alone meters or similarly PWP approved metering technology for plug-in electric vehicles charging purposes and having a maximum demand of less than 30 k-W.

2. Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and the applicable EV charges in accordance with the Electric Utility Rate Resolution. The minimum monthly charge shall be equal to the sum of the customer charge and the grid access charge.~~.~~

3. Customers who meet low-income eligibility requirements including EUAP customers, as defined in Section 13.04.046, may receive discounted EV rates in accordance with the Electric Utility Rate Resolution.

~~1.~~

B. ~~2.For existing medium~~Electric vehicle charging at or above 30 kW and ~~large commercial~~less than 300 kW (Schedule EV-2)

1. Applicability. Applies to stand-alone meters or similarly PWP approved metering technology for plug-in electric vehicles charging purposes and ~~industrial customers, the projected incremental~~ having a maximum demand ~~must be a minimum of 50kW~~of greater than or equal to 30 kW and less than 300 kW.

2. Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and the applicable EV charges in accordance with the Electric Utility Rate Resolution. ~~and the applicable energy services charge TOU rate schedule subject to all changes in accordance with the Electric Utility Rate Resolution.~~ The minimum monthly charge shall be equal to the sum of the customer charge and the grid access charge. ~~or 10% of existing~~

C. Electric vehicle charging at or above 300 kW (Schedule EV-3)

1. Applicability. Applies to stand-alone meters or similarly PWP approved metering technology for plug-in electric vehicles charging purposes and having a maximum demand~~, whichever is greater~~ of greater than or equal to 300 kW.

2. Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and the applicable EV charges in accordance with the Electric Utility Rate Resolution.~~and the applicable energy services charge TOU rate schedule subject to all changes in accordance with the Electric Utility Rate Resolution.~~ The minimum monthly charge shall be equal to the sum of the customer charge and the grid access charge.~~.~~

D~~E~~. City-owned retail charging stations

1. Applicability. Applies to retail customers charging EVs at City-owned stations and shall pay in accordance with the Electric Utility Rate Resolution.

~~1.~~2. Customers who meet low-income eligibility requirements including EUAP customers, as defined in Section 13.04.046, may receive discounted EV rates in accordance with the Electric Utility Rate Resolution.~~Customers who meet low-income eligibility requirements including EUAP customers, as defined in Section 13.04.046, may receive discounted EV rates in accordance with the Electric Utility Rate Resolution.~~

~~3. Customer shall make application to PWP to take service under this schedule. Such application shall indicate whether customer elects to take service under Section 13.04.073(C) (three year rate discount) or Section 13.04.073(D).~~

~~4. The City's Economic Development Manager will evaluate the applications to determine whether they meet the proposed business use criteria and the PWP General Manager shall determine whether the customer meets the electrical requirements and qualifies to take service under this Schedule ED.~~

~~B. Agreement. Customers shall execute an economic development rate agreement as specified by PWP prior to the effective date of any discount.~~

~~C. Option 1 Rate Discount.~~

~~1. Except as provided herein, all rates charged will be in accordance with customer's otherwise applicable rate schedule as set forth in the applicable sections of this chapter.~~

~~2. The total of the unbundled electric service charges for the distribution, energy, and transmission service charges under the customer's otherwise applicable rate schedule on customer's electric bill associated with the new or incremental load shall be reduced by 20% in the first contract year, 10% in the second contract year; and, 5% in the third and final contract year.~~

~~3. For existing customers, the discount will be prorated to reflect only the incremental load that qualifies for the Economic Development Rate.~~

~~4. Customer shall compensate PWP for the full cost of electric service connection fees in accordance with Section X of Regulation 21 to qualify for the Rate Discount. Customer must remit 100% of the total estimated cost in advance of PWP performing the work.~~

~~D. Option 2 Discounted Interconnection Fees. In lieu of the Rate Discount provided in section C, customer may choose to receive a discount on labor and materials on work performed by PWP to install a new or upgraded electric service connection in accordance with Section X of Regulation 21. The maximum discount for each customer would be $200 per kilowatt of new or incremental load or $100,000, whichever is less. Customer must remit the balance of the total estimated cost in advance of PWP performing the work.~~

~~E. Special Provisions.~~

~~1. Customer shall comply with all applicable PWP rules and regulations, including without limitation, Regulation 21.~~

~~2. Customer must meet Economic Development Rate Qualifying Criteria as determined by the City's Economic Development Manager.~~

~~3. Discounts are limited to a maximum of $100,000 per customer over the term of the agreement.~~

~~4. The Economic Development Rate will be offered to eligible customers on a first-come first-served basis for three years (from the rate effective date) or until cumulative estimated discounts reach $1,000,000, whichever occurs first.~~

13.04.080 Standby service~~.~~ (Schedule SBY)

The ~~ra~~te<u>rm</u>s and conditions of services hereunder shall be ~~as~~ provided by Schedule ~~S, as follows:~~SBY, as found in the Electric Utility Rate Resolution.

A. Applicability. Applicable to customers who in part or in whole have their own generating equipment and who rely on the PWP grid in case of an on-site outage. Standby service shall be furnished solely to the individual contracting customer. Applies to medium and large commercial customers. Character of service shall be three-phase 240, 480, 120/208 or 277/480 volt, 60 cycle alternating current service. Other voltages and types of service may be approved by the Department for certain specific installations.

B. Customer shall sign a contract for this service, which contract shall state the number of kW of standby capacity required. "Standby capacity" shall not exceed the nameplate rating of the customer's generating equipment.

C. Service connections shall be made so that at no time will the customer's generating equipment be connected to or operated in parallel with PWP's system. Switching devices used for service connections shall be approved by PWP.

D. Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and (3) the reservation charge.

~~A. **SCHEDULE S**~~

~~B. Standby Service~~

~~C. A.Applicability. Applicable to customers who in part or in whole have their own generating equipment and who contract for standby service from the department.rely on the PWP grid in case of an on-site outage. Standby service shall be furnished solely to the individual contracting customer in a single enterprise, located entirely on a single, contiguous premise.~~

~~D. B.. Applies to medium and large commercial customers. Character of Service. 3service shall be three-phase 240, 480, 120/208 or 277/480 volt, 60 cycle alternating current service. Other voltages and types of service may be approved by the dDepartment for certain specific installations.~~

~~E. C.Rate.~~

~~F. Effective July 15, 2012:~~

	~~Per Meter Per Month~~
~~All kW of standby capacity~~	~~$10.87 per kW~~
~~2. Energy Charge~~	~~Energy shall be billed in accordance with the rate schedule which would otherwise apply if the customer had no generating equipment.~~
~~3. Minimum Monthly Charge~~	~~The demand charge or $201.40, whichever is greater.~~

~~4.Application Charge: For each application for new service, or customer originated account change, to be added to the first bill: $5.00.~~

~~D.Special Conditions.~~

~~1.Contract Required. Customer shall sign a contract for this service, which contract shall state the number of kW of standby capacity required. "Standby capacity" shall not exceed the nameplate rating of the customer's generating equipment.~~

~~2.Service Connections. B. Service connections shall be made so that at no time will the customer's generating equipment be connected to or operated in parallel with PWP's system. Switching devices used for service connections shall be approved by PWP.~~

~~C.Customer shall pay the sum of the following charges (1) customer charge, (2) grid access charge, and (3) the reservation charge.~~

13.04.085 Unmetered rates—~~N~~non-demand~~.~~ below 30 kW (Schedule CE-1)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule CE-1~~—Non~~, non-demand, as ~~follows:~~found in the Electric Utility Rate Resolution.

~~**SCHEDULE CE-1**~~

~~**Non-Demand**~~

A. Applicability. Applies to any unmetered telecommunications devices and other equipment with less than 30 kW demand where metering installations would be impractical, unavailable, uneconomical or restricted by the City.

B. Monthly energy consumption. PWP shall determine the monthly energy consumption by multiplying the number of hours in the billing period by the maximum hourly energy consumption of the unmetered equipment based on the manufacturer's specifications and operating characteristics. For the purpose of this schedule, monthly energy consumption shall be deemed to be the kWh delivered.

C. Customer shall pay the sum of the following charges (1) customer charge for either (a) single-phase service or (b) three-phase service. (2) distribution charge, (3) grid access charge, (4) energy services charge based on the monthly energy consumption, (5) transmission services charge, and (6) public benefit charge.

D. Customer shall be solely responsible to install, own, operate, and maintain all equipment. City shall not be responsible for any damage to customer's equipment under any circumstances.

E. Customer and PWP shall mutually agree upon each location for unmetered telecommunications devices and other equipment installations. Each location or connection shall be deemed a separate account.

F. Customer shall not increase connected load or change the character of telecommunications devices and other equipment without providing written prior notice to PWP of at least 30 days. Customer shall furnish PWP written notice of any change in the connection configuration, rated electrical load, or operating characteristics of such equipment. In event customer does not provide such written notice, PWP may estimate customer's actual energy use and back bill the customer.

G. From time to time, PWP may audit customer's equipment using a temporary meter. Customer's fixed electric rate shall be adjusted based upon the results of the audit. Customer shall provide City personnel with access to customer's equipment and provide assistance as necessary to complete the audit.

~~A. A.Applicability. Applies to any unmetered telecommunications devices and other equipment with less than 30 kW demand where metering installations would be impractical, unavailable, uneconomical or restricted by the cCity.~~

~~B. B.Monthly Energy Consumptionenergy consumption. PWP shall determine the monthly energy consumption by multiplying the number of hours in the billing period by the maximum hourly energy consumption of the unmetered equipment based on the manufacturer's specifications and operating characteristics. For the purpose of this schedule, monthly energy consumption shall be deemed to be the kWh delivered.~~

~~C. Rates. Customer shall pay the sum of the following charges:~~

~~(1. C) customer charge per connection per month:~~

~~Singlefor either (a) single-phase service: $14.16~~

~~Three or (b) three-phase service: $19.07~~

~~. (2. D) distribution charge for all kWh per month:~~

~~$0.04475 per kWh~~

~~, (3. Transmission Services Charge. Customer shall pay a) grid access charge, (4) energy services charge based on the monthly energy consumption, (5) transmission services charge in accordance with Section 13.04.170 for each kWh delivered.~~

~~4. Energy Services Charge. Customer shall pay an energy service charge as follows:~~

~~Seasonal Flat Rate:~~	
~~Season~~	**~~Energy Service Charge per kWh~~**
~~Summer~~	~~$0.06901~~
~~Winter~~	~~$0.06030~~

~~a.Power Cost Adjustment. Customer shall pay a power cost adjustment in accordance with Section 13.04.173.~~

~~5.Public Benefit Charge. Customer shall pay a, and (6) public benefit charge in accordance with Section 13.04.230 for each kWh delivered. .~~

~~D. General Conditions.~~

~~C. 1.Customer shall be solely responsible to install, own, operate, and maintain all equipment. City shall not be responsible for any damage to customer's equipment under any circumstances.~~

~~D. 2.Customer and PWP shall mutually agree upon each location for unmetered telecommunications devices and other equipment installations. Each location or connection shall be deemed a separate account.~~

~~Customer shall not increase connected load or change the character of telecommunications devices and other equipment without providing written prior notice to PWP of at least 30 days. Customer shall furnish PWP written notice of any change in the connection configuration, rated electrical load, or operating characteristics of such equipment. In event customer does not provide such written notice, PWP may estimate customer's actual energy use and back bill the customer.~~

~~1. 3.Customer shall not increase connected load or change the character of telecommunications devices and other equipment without providing written prior notice to PWP of at least 30 days. Customer shall furnish PWP written notice of any change in the connection configuration, rated electrical load, or operating characteristics of such equipment. In event customer does not provide such written notice, PWP may estimate customer's actual energy use and back bill the customer.~~

~~E. 4.From time to time, PWP may audit customer's equipment using a temporary meter. Customer's fixed electric rate shall be adjusted based upon the results of the audit. Customer shall provide cCity personnel with access to customer's equipment and provide assistance as necessary to complete the audit.~~

13.04.087 Unmetered rates—~~Demand.~~demand at or above 30 kW (Schedule CE-2)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule CE~~-2—Demand, as follows:~~

~~SCHEDULE CE~~ -2, demand, as found in the Electric Utility Rate Resolution.

~~Demand~~

A. ~~A.~~Applicability. Applies to any unmetered telecommunications devices and other equipment with 30 kW demand or greater, but less than 300 kW demand where metering installations would be impractical, unavailable, uneconomical or restricted by the ~~c~~City.

B. ~~B.~~Billing Determinants.

~~2.~~1. ~~1.~~Monthly Energy Consumption. PWP shall determine the monthly energy consumption by multiplying the number of hours in the billing period by the maximum hourly energy consumption of the unmetered equipment based on the manufacturer's specifications and operating characteristics. For the purpose of this schedule, monthly energy consumption shall be deemed to be the kWh delivered.

~~3.~~2. ~~2.~~Monthly Billing Demand. PWP shall determine the monthly billing demand based on the maximum demand (kW) of the telecommunications devices and other equipment as set forth in the manufacturer's specifications.

~~C. Rates.~~ Customer shall pay the sum of the ~~following charges:~~

(1~~. Customer Charge Per Connection Per Month:~~

~~Customer~~) customer charge~~: $60.22~~

for either (a) single-phase service or (b) three-phase service. (2~~.Distribution Charge. The~~) distribution ~~rate for customer shall be as follows:~~

~~All kilowatts of demand: $10.87 per kW~~

~~4.~~3. charge, (3~~.Transmission Services Charge. Customer shall pay a~~) grid access charge, (4) energy services charge based on monthly energy consumption, and (5) transmission services charge ~~in accordance with Section 13.04.170 for each kWh delivered.~~ .

~~4. Energy Services Charge. Customer shall pay an energy service charge as follows:~~

~~Seasonal Flat Rate:~~	
~~Season~~	**~~Energy Services Charge per kWh~~**
~~Summer~~	~~$0.07338~~
~~Winter~~	~~$0.06213~~

~~a. Power Cost Adjustment. Customers shall pay a power cost adjustment in accordance with Section 13.04.173.~~

~~5. Public Benefit Charge. Customer shall pay a public benefit charge in accordance with Section 13.04.230 for each kWh delivered.~~

~~D. General Conditions.~~

~~5.~~4. ~~1.~~Customer shall be solely responsible to install, own, operate, and maintain all equipment. City shall not be responsible for any damage to customer's equipment under any circumstances.

~~6.~~5. ~~2.~~Customer and PWP shall mutually agree upon each location for unmetered telecommunications devices and other equipment installations. Each location or connection shall be deemed a separate account.

~~F. 3.Customer shall not increase connected load or change the character of telecommunications devices and other equipment without providing written prior notice to PWP of at least 30 days. Customer shall furnish PWP written notice of any change in the connection configuration, rated electrical load, or operating characteristics of such equipment. In event customer does not provide such written notice, PWP may estimate customer's actual energy use and back bill the customer.~~

6. ~~4.~~Customer shall not increase connected load or change the character of telecommunications devices and other equipment without providing written prior notice to PWP of at least 30 days. Customer shall furnish PWP written notice of any change in the connection configuration, rated electrical load, or operating characteristics of such equipment. In event customer does not provide such written notice, PWP may estimate customer's actual energy use and back bill the customer.

7. ~~From time to time,~~ PWP may audit customer's equipment using a temporary meter. Customer's fixed electric rate shall be adjusted based upon the results of the audit. Customer shall provide ~~c~~City personnel

with access to customer's equipment and provide assistance as necessary to complete the audit within seven calendar days of written request.

13.04.090 Street lighting and traffic signal service~~.~~ (Schedule SL)

The ~~ra~~terms and conditions of services hereunder shall be ~~as~~ provided by Schedule SL, as ~~follows:~~found in the Electric Utility Rate Resolution.

~~**SCHEDULE SL**~~

~~**Street Lighting and Traffic Signals**~~

A. ~~A.~~Applicability. Applies to outdoor street, highway and area lights and traffic signals, whether publicly or privately owned, where the poles, electrolier standards and lighting equipment are owned by the customer. For such lights as are burned from 30 minutes after sunset to 30 minutes before sunrise, 4140 hours of service per year will be used for cost calculation purpose.

B. ~~B.~~Rate. Unmetered street lighting and signs not included in the flat rate section will be billed under the metered rate section using the hours of service per year set forth in subsection A. Unmetered load, including without limitation, traffic signals, street lighting, signs with extended hours of operation, bus shelters, and irrigation controllers will be billed under the metered rate section by extrapolating usage from a sample test metering period. All services covered under this section, whether billed under the flat rate or metered rate section shall ~~also~~ be ~~subject to the transmission services charge and power adjustment charge~~billed in accordance with ~~Sections 13.04.170 and 13.04.173.~~ the Electric Utility Rate Resolution.

~~**Effective July 15, 2012:**~~

~~**1. Flat Rate—Lamp Size**~~	~~**Monthly Charge Per Lamp ($)**~~
~~**Incandescent**~~	
~~1,000 lumens~~	~~$0.94~~
~~1,500 lumens~~	~~1.11~~
~~2,500 lumens~~	~~1.95~~
~~4,000 lumens~~	~~3.14~~
~~6,000 lumens~~	~~4.47~~
~~10,000 lumens~~	~~6.79~~
~~67 watts~~	~~0.86~~
~~69 watts~~	~~0.88~~
~~103 watts~~	~~1.30~~
~~150 watts~~	~~1.89~~
~~202 watts~~	~~2.54~~
~~303 watts~~	~~3.80~~
~~**Mercury Vapor**~~	
~~3,500 lumens~~	~~1.61~~
~~7,000 lumens~~	~~2.64~~
~~11,000 lumens~~	~~3.66~~
~~20,000 lumens~~	~~5.80~~
~~35,000 lumens~~	~~9.81~~
~~54,000 lumens~~	~~13.87~~
~~**Fluorescent**~~	
~~213 watts~~	~~2.68~~
~~248 watts~~	~~3.14~~
~~**High Pressure Sodium**~~	
~~35 watts~~	~~0.51~~
~~50 watts~~	~~0.72~~
~~70 watts~~	~~1.28~~

~~100 watts~~	~~1.76~~
~~150 watts~~	~~2.43~~
~~200 watts~~	~~3.09~~
~~250 watts~~	~~3.94~~
~~310 watts~~	~~4.81~~
~~400 watts~~	~~5.98~~
~~4—60 watts unit bus stop~~	~~4.82~~
~~2—40 watts unit bus stop~~	~~4.82~~
~~Metal Halide~~	~~3.99~~

~~2. Metered Distribution Rate.~~

~~a. For metered street lighting, all energy will be billed at $0.03923 per kWh.~~

~~b. For metered traffic signals and signs, all energy will be billed at $0.05807 per kWh.~~

~~3. Unmetered Distribution Rate.~~

~~a. For unmetered traffic signals and signs, all energy will be billed at $0.05807 per kWh.~~

~~4. Transmission Services Charge. Customers taking service under Schedule SL shall pay a transmission services charge for each kWh delivered to in accordance with Section 13.04.170.~~

~~5. Energy Services Charge. Customers taking service under Schedule SL shall pay energy services charge of $0.065 for each kWh delivered.~~

~~6. Power Cost Adjustment. Customers taking service under Schedule SL shall pay a PCA, as provided in Section 13.04.173.~~

13.04.100 Service regulations and charges~~.~~

A. The general manager of the ~~water and power department~~Department shall, from time to time, approve service regulations and procedures relating to conditions of service, application, administration and interpretation of rates, or to any other provision of this chapter; provided, however, that any proposed new or revised charges or fees for reconnections and for various special services not otherwise provided for in this chapter shall be effective upon adoption thereof by resolution of the ~~city council~~City Council. No later than 30 days prior to the effective date of any amendments to such regulations, the proposed amendments shall be posted on PWP's website and the ~~city council~~City Council shall be notified in writing of such proposed amendments.

B. On failure to comply with the service regulations of the ~~d~~Department, or to pay charges, or to comply with penalties imposed for such failure as herein provided, electric service may be turned off until the regulations, charges, or said penalties are complied with or payment is made of the amount due.

13.04.110 Meter and service installation~~.~~

All meters and services shall be installed and located in accordance with specifications and drawings ~~entitled "Electric~~detailed in the Electrical Service Requirements~~, Regulation No. 21."~~ Regulations set forth by PWP. In the event that meter and service connections are not so installed, the ~~d~~Department will delay making service connections to such premises until the service requirements are satisfied. Demand meters will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand is of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval.

All meters and services shall be installed and located in accordance with specifications and drawings detailed in the Electrical Service Requirements Regulations set forth by PWP. In the event that meter and service connections are not so installed, the Department will delay making service connections to such premises until the service requirements are satisfied. Demand meters will be adjusted to measure the maximum integrated demand over a 15-minute interval, or if the demand is of an intermittent character, PWP may adjust the meters to measure the demand during a shorter interval. Advanced Meters with Interval Read Capability will be the standard of installation, customers wishing to opt out are subject to fees as stated in the Utility Rate Resolution.

Advanced Meters with Interval Read Capability will be the standard of installation, customers wishing to opt out are subject to fees as stated in the Utility Rate Resolution.

13.04.120 Inspections~~.~~

A. Entry on Premises. Department employees may enter private premises to make inspections or examinations of wires, fixtures or attachments, to read meters, or to determine if there has been unlawful tampering with department equipment, devices or seals, or unlawful installation of devices to evade department metering of energy. Department employees whose duty it is to enter upon private premises will be provided with a badge or other identification. Such identification shall be shown to customer at the time of entry on customer's premises.

B. Interference with Authorized Employees. The general manager may discontinue service of electrical energy to any premises after written notice to the customer of his intent to do so, for the following causes:

1. The customer has refused admittance to an authorized employee, at a reasonable hour, in the performance of his duty; or
2. The customer, by his personal conduct, or by maintaining a dangerous condition or vicious animal upon the premises, has hindered or interfered with an authorized employee in the performance of his duty. The general manager shall serve such notice by mailing one copy to the customer at his last known address, and one copy to the premises, if a different address. The general manager need not reconnect the service until the customer has given satisfactory assurance to the general manager that an authorized employee will not be interfered with or hindered, or refused admittance, in the performance of his duty.

C. Access to electric meters at the customers facilities shall be provided at all times. If access to the customers meter is prohibited by a locking device on a gate, door or other access entries, customers shall provide PWP with a key to allow access by meter readers or other authorized personnel for the purpose of inspecting and/or maintaining and/or reading the meter. PWP is authorized to install at the customer's facility a lock box accessible only to PWP authorized personnel for the purpose of securing the key on site to gain ready access to the customer's electric meter.

D. PWP may inspect or test any power equipment and estimate or measure the demand, starting currents, power factor or other characteristics of such equipment to determine proper billing or compliance with the requirements of this chapter.

13.04.125 Private underground electric vaults~~.~~

A. On reasonable notice, typically within five business days, the ~~d~~Department may enter upon private property to inspect, repair or replace any private underground electrical vault. It shall be the duty of the owner of a private underground vault to: (i) make the vault freely accessible to ~~department employees~~Department employees; (ii) maintain the vault in good repair free from water or other unsafe conditions; and (iii) comply with all state and local regulations applicable to underground electrical vaults. Any vault which fails to meet these requirements is hereby deemed a nuisance~~ per se~~.

B. In event the condition of a private underground vault does not meet the requirements set forth in subsection A of this section, the ~~d~~Department may proceed with code enforcement proceedings pursuant to Chapters 1.24, 1.26 or 1.30 of the Pasadena Municipal Code. The ~~d~~Department may also, in its discretion, remediate the condition of any private underground vault. Prior to such remediation, the ~~d~~Department shall notify the vault owner of the problems to correct and the time for correcting them. If the problems are not timely corrected, the ~~d~~Department shall notify the vault owner of the ~~d~~Department's proposed solutions to the problems and the ~~department's~~ cost to complete them. The vault owner shall have the right to contest the ~~d~~Department's proposed action by filing an administrative appeal with the general manager of the ~~d~~Department not later than ten days from the date set forth on the ~~d~~Department's notice. In event an appeal is not timely taken, the ~~d~~Department's proposed action shall be the final administrative decision and no resort to the courts may be taken therefrom due to failure to exhaust remedies.

C. All costs of remediating the condition of a private electrical vault shall be the responsibility of the vault owner. Such costs shall be billed to the vault owner according to the normal billing procedures and requirements applicable to ~~department~~ customers. In event the vault owner does not timely pay in full, the ~~d~~Department may exercise any remedies available to it under this code or other law, including shut-off of electrical service to the premises served by the private underground vault. Costs incurred by the ~~d~~Department in remediating the condition of a private underground vault shall also be recoverable in any proceeding brought pursuant to Chapters 1.24, 1.26 or 1.30 of the Pasadena Municipal Code.

13.04.130 City not liable for damages relating to delivery failures~~.~~

The ~~c~~City is not liable for any damage to persons or property caused in any manner by the use or application of electric current, nor is it liable for any damage caused by its failure to deliver current, proper voltage or frequency, all or part of ~~3~~three-phase current, or electrical energy for any length of time.

13.04.140 Financial responsibility—Delinquency penalty~~.~~

A. Customer Liability. The customer is responsible for and shall pay the ~~c~~City for all electrical energy delivered to the premises as registered on the ~~c~~City meter. The meter bill is due and payable when rendered~~,~~ and is delinquent ~~30~~21 days after the date rendered. If delinquent bills for any electrical service are not paid upon presentation, such service may be discontinued without further notice. In addition, there shall be ~~assessed~~ a penalty assessment for delinquent bills pursuant to Section 1.08.080. The amount of such penalty shall be as set forth on the general fee schedule.

B. Responsibility for Schedule. It is the responsibility of the customer to determine that he is being served under the proper schedule. In the event the customer feels he is not being so served, he shall file with the ~~d~~Department a written statement, stating the reasons therefor. The ~~d~~Department shall then promptly make an investigation and shall inform the customer in writing of its conclusions, and shall adjust the rate or not, accordingly. Department is not liable for excess charges to customer prior to the time customer files the written statement.

C. Deposits. The general manager of the ~~d~~Department may require a deposit in reasonable amount to guarantee payment for electrical energy to be used subsequent to date of demand for such deposit. If any customer fails to make such deposit after demand therefor, electrical service may be discontinued until the deposit required has been made.

D. Reconnection Charge. If electrical service is disconnected for nonpayment of bills, nonpayment of required deposit, by customer request or because of interference with authorized employees of ~~department~~PWP, the appropriate reconnection and special service charges, in addition to all previously accrued charges, shall be made prior to reconnection of service.

13.04.150 Rate schedule changes~~.~~

A customer qualifying for a particular rate schedule will not be transferred to another rate schedule because of temporary or seasonal conditions for the purpose of reducing the minimum or energy charges. Unless there is a major change in the customer's type of load, a particular rate will continue in effect for at least 12 months~~.~~ except upon the adoption of Interval Read Capable Meters for billing, at which time customer may be automatically enrolled in the Time-of-Use rates. If a major change in type of load occurs in less than 12 months, the ~~d~~Department may charge and collect ~~$3.00~~ for each meter affected.

13.04.160 Meter readings combined~~.~~

~~The municipal light and power department~~The Department will not ordinarily combine meter readings for billing purposes. However, in the event a consumer has brought out all ~~of~~ his electric leads to a central and convenient location and more than one meter of a given class is deemed necessary by the ~~d~~Department, the ~~d~~Department may combine the readings of such meters for billing purposes.

13.04.170 Transmission services charge~~.~~

A. The transmission services charge (TSC) is designed to capture the transmission revenue requirement (TRR) and net cost savings from joining participating transmission owner (PTO) with California Independent System Operator (CAISO) as defined in subsection (C)(4) of this section and shall be based on actual data obtained from the ~~c~~City's accounting system, forecast data obtained from the annual ~~operational plan~~budget approved by the ~~city council~~City Council, and updated forecast data prepared monthly by PWP.

B. PWP shall calculate the TSC on ~~a quarterly~~an as needed basis~~,~~ and ~~the revised value for this charge~~ shall remain in effect for no less than three months.

C. For purposes of this section, the following definitions apply:

~~"Full service customers" means customers who choose PWP as their energy supplier.~~

1. ~~"~~Net cost savings from being a participating transmission owner with California Independent System Operator (NCS PTO CAISO~~)~~") means all PTO revenues received from CAISO, including, but not limited to, PTO TRR, net firm transmission right ~~(FTR)~~ revenues, and high voltage wheeling revenues less all expenses paid to CAISO including, but not limited to, transmission access charges (TAC) and grid-management charges. NCS PTO CAISO shall be subject to an adjustment by CAISO transmission revenue balancing adjustment account.

~~E. "System energy sales" means the estimated total energy sales delivered to all customers.~~

2. ~~"~~Transmission revenue requirement~~" means~~ is the sum of all costs related to the high-voltage transmission of energy, including, but not limited to, all transmission contracts, wheeling fees, pertinent labor and operating costs, associated general fund transfer, operating margin, debt service, and ~~ISO~~Independent System Operator access fees, less the sum of all wholesale revenues received in connection with the sale of any transmission entitlements.

D. The transmission services charge shall be calculated ~~quarterly~~ as follows:

1. Commencing July 1, 2002, a ~~separate transmission services charge fund (TSCF)~~TSC account shall be maintained for balancing costs and revenues associated with high-voltage transmission and related services. Any ~~transmission access charge fund (TACF)~~TAC over collection or under collection existing on July 1, 2002 shall be ~~deposited~~maintained in the ~~TSCF~~TSC account balance.

2. The TSC~~F~~ account balance shall be calculated as the sum of actual revenues from the TSC less the actual TRR plus NCS PTO CAISO.

3. The transmission services charge shall be calculated based on the forecasts for the following twelve months for TRR, NCS PTO CAISO, system energy sales, and the TSC~~F~~ balance as follows:

[TRR Forecast - NCS PTO CAISO Forecast - TSC~~F~~ Balance]
[System Energy Sales Forecast]

4. The ~~result of the formula~~TSC shall be calculated and rounded to the nearest mill per kilowatt-hour. ~~This shall be the transmission service charge to be implemented.~~

5. The transmission services charge for customers ~~served under Schedules M-2 and L-2 or for~~whose service are metered and delivered at ~~17kV~~ 4 kV or higher shall be reduced by $ 0.00019 per kWh.

13.04.173 Power cost adjustment~~.~~ (PCA)

A. A ~~Power Cost Adjustment (~~PCA~~)~~ shall be added to the energy services charge set forth in the ~~service schedules of this chapter~~Electric Utility Rate Resolution. Each customer shall pay the applicable energy services charge plus a PCA for each kWh delivered to the customer.

B. The PCA shall be based on actual data obtained from the ~~c~~City's accounting system, forecast data obtained from the annual operational ~~plan~~budget approved by the City Council, and updated forecast data prepared as frequently as monthly by PWP.

C. PWP shall recalculate the PCA ~~each month~~as frequently as monthly, and the resulting values for these charges shall be ~~automatically~~ implemented on the first day of the following month.

D. For purposes of this section, the following definitions apply:

1. ~~1.~~"Energy ~~Costs" means~~costs" is the sum of all costs related to the procurement and generation of energy for delivery to ~~Full Service~~Retail Customers, including, but not limited to, Power Production Costs and Purchased Power Costs, operating margin, debt service and the general fund transfer associated with these costs.

2. ~~2.~~"Energy ~~Cost Forecast" means~~ cost forecast" is the forecast of projected ~~Energy Costs~~energy costs for the twelve months immediately following the last actual billing period. ~~This forecast shall be updated monthly by PWP.~~

3. ~~3.~~"Energy ~~Services Charge Revenue Forecast" means~~services charge revenue forecast" is the forecast of projected ~~Energy Services Charge Revenue~~ energy services charge revenue for the twelve months immediately following the last actual billing period. ~~The energy services charge set forth in the schedules reflects the energy cost forecast as of July 1, 2002, based on the approved rate restructuring plan approved by the City Council adjusted to each customer group's load profile, and shall remain in effect until modified by Ordinance.~~

4. ~~4.~~"Energy revenue credit" is a percentage of the ~~Wholesale Net Income~~wholesale net income used to reduce the ~~Energy Charge. The Energy Revenue Credit shall be applied~~energy charge. The energy revenue credit is 75% of the wholesale net income, when ~~the Wholesale Net Income is~~ greater than zero ~~and shall be determined at least quarterly based on the actual accounting data as follows: (i) 75% of the Wholesale Net Income shall be applied as a credit; (ii) additional amounts may be authorized by Council Resolution~~.

5. ~~5.~~"Energy revenue forecast" ~~means~~is the forecast of projected ~~Energy Revenue Credits~~energy revenue credits for the twelve months immediately following the last actual billing period. ~~This forecast shall be updated monthly by PWP.~~

6. ~~6.~~"Fuel costs" means the sum of the cost of fuel gas consumed, the cost of fuel oil consumed, and the cost of procuring, scheduling, testing and in-plant handling of that fuel gas and fuel oil. Fuel oil includes both residual fuel oil and distillate fuel oil.

~~7. "Full service customers" shall mean customers who choose PWP as their energy supplier.~~

7. ~~8."Full service energy~~"Retail Energy sales forecast" ~~means~~is the forecast of projected energy sales (in kilowatt-hours) to ~~Full Service~~ Customers for the twelve months immediately following the last actual billing period. This forecast shall be updated monthly by PWP.

8. ~~9.~~"Power production costs" ~~means~~is the sum of all costs for the generation of electric energy at facilities owned and operated by PWP, including, but not limited to, Fuel Costs, labor, operating and maintenance expenses, materials, and emissions credits.

10. "Purchased power costs" ~~means~~is the cost of energy and ancillary services, including, but not limited to, capacity and energy charges from third parties and all non-transmission charges charged by the California Independent System Operator (ISO).

11. "System energy sales" means the estimated total energy sales delivered to all customers.

12. "Wholesale net income" means the sum of revenues realized from wholesale energy and ancillary service sales, less the associated production cost and purchased power cost attributable to the wholesale sales.

[E—G.Reserved.]

H. The PCA shall be added to the energy service charge set forth in the service schedules, and shall be calculated monthly as follows:

1. Commencing July 1, 2002, ~~a separate Energy Services Charge Fund (ESCF)~~energy services account balance shall be maintained for balancing costs, revenues, and credits associated with energy delivered to ~~Full Service Customers. Any Energy Charge Fund over collection or under collection existing on July 1, 2002 shall be deposited in the ESCF balance.~~retail customers.

2. The ~~ESCF account balance shall be calculated as the sum of actual revenues from the Energy Services Charge, the Energy Revenue Credit, and any other credits authorized by the City Council, less the actual Energy Costs inched.~~

~~3. Reserved.~~

~~4. The Energy Services Charge~~energy services charge shall be calculated based on the ~~Energy Cost Forecast, Energy Revenue Credit Forecast, Full Service Energy Sales Forecast, and the ESCF~~energy cost forecast, energy revenue credit forecast, retail service energy sales forecast, and the energy services charge account balance as follows:

~~[Energy Cost Forecast - Energy Revenue Credit Forecast - Fund Balance]~~
~~[Full Service Energy Sales Forecast]~~

~~5~~[energy cost forecast - energy revenue credit forecast – energy services charge account balance]
[retail energy sales forecast]

3. The PCA shall be calculated based on the twelve month forecast of ~~Energy Services Revenue, Energy Cost, Energy Revenue Credit, Full Service Energy Sales, ESCF~~energy services revenue, energy cost, energy revenue credit, retail energy sales, energy services charge account balance and ~~Fund Reserve Target~~account reserve levels as follows:

~~[Energy Cost Forecast - Energy Revenue Credit Forecast - Fund Balance - Energy Services Revenue Forecast + Reserve Target]~~
~~[Full Service Energy Sales Forecast]~~

~~6~~[energy cost forecast - energy revenue credit forecast –

energy services charge account balance - energy services revenue forecast + reserve levels]

[retail energy sales forecast]

4. The result of the formula shall be rounded to the nearest ~~mill~~one thousandth per kilowatt-hour. This shall be the PCA to be implemented.

13.04.178 Self-generation service~~.~~ (Schedule SG)

~~**Schedule SG**~~

~~**Self-Generation Service**~~

~~A.Availability. Available and mandatory~~To encourage the development of local renewable energy generation by customer-generators, self-generation service shall be as provided by Schedule SG as follows and as found in the Electric Utility Rate Resolution.

A. Applicability.

1. Applies to customers with self-generation or cogeneration not less than one megawatt capacity and billing demand not less than 300 kW.

2. Customers shall sign an interconnection and metering agreement with PWP.

3. This schedule will be applied to each meter at point of delivery or receipt, and in no event will meter readings be combined.~~B.Rates.~~

B. Self-generation service.

1. Rates for this service shall be the ~~same as for the schedule~~time-of-use rates under which the customer would ordinarily take service~~, with the following exceptions:~~

~~1. For self-generation service customers in the residential and small commercial and industrial groups, the monthly customer charge and the distribution services charge shall respectively be the same as those of the medium commercial and industrial class—secondary (M-l).~~

~~2.~~ ~~In~~ except, (1) in each month, billing demand will be the greater of the maximum ~~fifteen~~15 minute kW of the absolute net ~~power that the~~electricity delivered to customer ~~received from or injected into the PWP power system~~ during the current month or preceding ~~eleven~~11 months~~.~~

~~3.~~ ~~In~~ and (2) in each month, the billing determinant for the ~~Transmission Services Charge~~transmission services charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month.

~~4. For energy charges and energy credits, billing determinants~~2. Customer shall ~~be quantified as follows:~~

~~a. For customers on seasonal flat energy rates, the monthly billing determinant shall be the net power that the customer received from the PWP power system during the month.~~

~~b. For customers on time-of-use (TOU) energy rates, the billing determinant for each TOU period shall be the net power that the customer received from the PWP power system during each period.~~

~~5. For any period during which the customer's net power received from the PWP power system is negative (i.e., during which the customer injects net power into the PWP power system), the customer shall not pay an Energy Charge but shall instead~~ receive ~~an energy~~a credit~~.~~

~~a. The~~ in an amount equal to the net electricity delivered to PWP multiplied by the applicable energy ~~credit periods shall be one month for customers on seasonal flat rates and TOU periods for customers on TOU rates~~services charge.

~~b. The energy credit for each period shall equal the product of:~~

~~1. The customer's net injection into the PWP power system during the period and PWP's average power cost applicable to that period.~~

~~c.~~ 3. Billing.

a. Customers shall receive a monthly or bi-monthly bill from PWP. Customers shall pay the outstanding balance, if any, owed to PWP.

b. Credits shall be given to the customer in the form of offsets to charges on the customer's ~~bill.~~future electric bills. If, in any month, a customer's electric credits (including any credit carry-forwards from previous months exceed that customer's charges~~,~~) the net credit will carry forward to the customer's bill for the following twelve months. Credits shall expire upon termination of electric service.

~~6~~4. The customer shall be responsible to reimburse PWP for any and all upgrades to PWP's power system which are necessary due to the customer's generation, including, without limitation, metering equipment.

~~C. Conditions:~~

~~1. The above service is subject to PWP rules and regulations.~~

~~2. This schedule will be applied to each meter at point of delivery or receipt, and in no event will meter readings be combined.~~

~~3. Customers shall sign an interconnection agreement with PWP.~~

~~4. Customers shall comply with Regulation 23.~~

13.04.179 Green power service~~.~~

(Schedule GP)

~~**Green Power Service**~~

A. Applicability. The charges set forth in this schedule apply to those customers who choose green power service. By subscribing to green power service customers will accelerate the procurement and development of renewable energy resources by paying a green power premium which PWP will then apply to green power procurement on behalf of such customers. Customers choosing this service shall either select a 100% Green power service option or nominate the amount of green service in blocks of 100 kWh per month. All other rates and charges for electric services apply to these customers as specified in their otherwise applicable schedule. "Green power" as used in this section shall mean energy procured from an "Eligible renewable energy resource" as defined in California Public Utility Code Section 399.12(e) to serve customers that have selected Green power service.

B. Green Power Premium. The Green Power Premium shall be $0.018 per kWh of metered electricity use for customers choosing 100% Green power service, or, $1.80 per month for each 100 kWh block of green power nomination.

C. For customers enrolling after March 1, 2026, the Green Power Premium shall be established in the Electric Utility Rate Resolution as of the enrollment date. the value of portfolio content category one (PCC1) renewable energy credits (RECs) based on recent actual transactions by Pasadena Water and Power ($/MWh)

C. Use of Green Power. Consistent with PWP's Renewable Portfolio Standard Procurement Plan and Enforcement Program, as may be amended from time to time, PWP shall account for energy procured on behalf of Green power service customers separately from that procured for non-Green power service customers~~, and shall not utilize the renewable attributes associated with Green power procurement for compliance purposes~~.

D. The Green Power Premium shall not be included as gross income for purposes of calculating the light and power fund transfer under Section~~s 1407 and~~ 1408 of the Charter.

13.04.180 Theft of energy~~.~~

A. In applying for service the customer agrees that the department may install and maintain equipment on the customer's premises for the proper metering of energy and distribution of current to prevent the theft thereof. Any customer who tampers with department's equipment to avoid payment of the rates herein prescribed, or to reconnect service that has been disconnected by department, is liable to punishment therefor pursuant to law. Upon discovery of such tampering, the general manager may cause the service to be disconnected and remove all equipment installed by the department forthwith. If the premises is vacant or the equipment installed is no longer needed, such equipment may be removed at any time upon order of the general manager of the department.

B. Any person or agency apprehended using electricity without permission from a power line, electrical service, or other system connection will be charged for each occurrence ~~a minimum of $300.00, or such other charge~~ as established by ~~resolution~~ Electric Utility Rate Resolution of the ~~city council~~City Council, plus the cost of electricity estimated to have been used. Investigation costs may be added thereto at the option of the general manager.

13.04.190 Apparatus causing interference~~.~~

The department may disconnect any service on its lines to which is connected any device or apparatus causing a distortion of the wave form of the voltage or current supplied, or generating or causing high frequency electrical radiation or other electrical disturbance, which interferes with radio or television broadcast reception or with other forms of communication, or with the operation of any of department's protection or control facilities. The owner of such device or apparatus shall have a reasonable time within which to repair, modify or adjust, or to agree to pay department's costs of devices, apparatus and installation, to prevent interference.

13.04.200 Billing procedure~~.~~

A. The rates established apply basically to monthly periods. The meter reading dates shall be determined by the ~~d~~Department and bills will be rendered monthly or bimonthly at the option of the department. Bimonthly bills will be computed by doubling the monthly energy block and the monthly customer or minimum charge. When service to a customer is initiated or terminated between regular meter reading dates for a particular premises, the bill will be prorated on a basis established by the general manager.

B. Notwithstanding anything in this chapter to the contrary, billing may be made and charges collected for service furnished hereunder to any customer at such times as the department considers to be in the best interests of the department and the customer so billed. Charges billed for a period of more than ~~1~~one month are made as though monthly meter readings had been taken and had shown equal use of service each month within the period and charges had been billed monthly thereon.

13.04.210 Gaseous lighting units

All vapor or discharge tube type lighting units, such as neon, argon and fluorescent lighting, shall include power factor corrective equipment so that the overall power factor shall not be less than 90%. All installations of corrective equipment rated at 250 volt-amperes or more shall be approved by the Department.

13.04.220 Added load~~.~~

Customers shall notify and secure approval of ~~d~~Department before adding any power load of 3 ~~HP~~hp or appliance load of 3 KW or greater to an existing service.

13.04.230 Public benefit charge~~.~~

A. Pursuant to the requirements of Section 385 of the Public Utilities Code of the state of California, there is established a nonbypassable, usage based public benefit charge on local distribution service for each kilowatt-hour delivered to the customer.

B. The ~~public benefit charge shall be based on data obtained from the city's accounting system and updated forecast data prepared quarterly by the department.~~

~~C. The department~~Department shall recalculate the public benefit charge ~~quarterly~~annually and the resulting value for this charge shall be automatically implemented on the first day of the following month.

~~D~~C. For the purpose of calculating the public benefit charge, the following definitions shall apply:

1. "Public benefit cost" means expenditures pursuant to subsections (G)(1) through (G)(4), inclusive.
2. "Public benefit cost forecast" means the forecast of public benefit cost for the twelve months immediately following the last billing period.
3. "Public benefit fund balance" means the sum of all prior revenues from the public benefit charge, less the sum of all prior public benefit cost and committed public benefit cost.
4. "~~Full service~~Retail energy sales forecast" means the forecast of projected energy sales (in kilowatt-hours) to all electric customers taking service under this chapter for the twelve months immediately following the last billing period.

~~E~~D. The public benefit charge shall be calculated based on the public benefit cost forecast, the public benefit fund balance, and the ~~full~~retail service energy sales forecast as follows: the public benefit cost forecast minus the public benefit fund balance, which sum shall be divided by the ~~full~~retail service energy sales forecast. The result shall be rounded to the nearest mill per kilowatt-hour.

~~F~~E. In no event shall the public benefit charge be less than $0.00271 per kilowatt-hour.

~~G~~F. Moneys collected through the public benefit charge will be used exclusively to fund investments in any or all of the following:

1. Cost-effective demand-side management services to promote energy efficiency, energy conservation, and electric demand reduction;
2. New investment or incentives to promote the installation and use of renewable energy resources and technologies consistent with existing statutes and regulations which promote those resources and technologies;
3. Research, development and demonstration programs for the public interest to advance science or technology which is not adequately provided by competitive and regulated markets; and
4. Services provided for low-income electricity customer, including but not limited to, targeted energy efficiency service and rate discounts.

~~H~~G. This public benefit charge shall not be subject to any taxes or surcharges imposed pursuant to the Pasadena Municipal Code.

~~I~~H. This public benefit charge shall not be included as gross income for purposes of calculating the light and power fund transfer under ~~Sections 1407 and~~Section 1408 of the Charter.

Agenda Report

February 23, 2026

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (February 10, 2026)

FROM: Water and Power Department

SUBJECT: **SET A DATE OF MARCH 2, 2026, TO CONDUCT A PUBLIC HEARING FOR RECOMMENDED ELECTRIC RATE ADJUSTMENTS AND DIRECT THE CITY ATTORNEY'S OFFICE TO PREPARE AN ORDINANCE AMENDING THE LIGHT AND POWER RATE ORDINANCE AND ADOPT THE UTILITY RATE RESOLUTION**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed action is not a project subject to the California Environmental Quality Act (CEQA) pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3), and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project;
2) Set a date of March 2, 2026, to conduct a public hearing for the recommended electric rate adjustments, with changes to take effect on March 10, 2026, or as soon thereafter as practicable;
3) Direct staff to prepare the Utility Rate Resolution using a two-year, three-phase rate adjustment (effective March 10, 2026, October 1, 2026, and March 1, 2027); and
4) Direct the City Attorney's Office to prepare an ordinance within 20 days amending the Light and Power Rate Ordinance, Title 13, Chapter 13.04 – Power Rates and Regulations, to reflect the proposed electric rate adjustments, eliminate outdated or obsolete provisions, and align the ordinance with current industry best practices.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") has completed a comprehensive Electric Rate Study to ensure that electric rates remain equitable, cost-based, and aligned with the City's long-term goals of fiscal responsibility, infrastructure modernization, and achieving 100% carbon-free electricity by 2030. Conducted in partnership with NewGen

Strategies and Solutions, LLC ("NewGen"), the study includes a full cost-of-service ("COS") analysis, financial modeling, and extensive public engagement. The study confirms that current electric rates are insufficient to meet projected revenue needs, with a shortfall of approximately $67.9 million over 2 years.

In addition to the rate adjustments, PWP recommends a full restatement of the Light and Power Rate Ordinance (Chapter 13.04) except for items related to Net Energy Metering and any new provisions for local solar that will have further discussion. This restatement will modernize the ordinance by eliminating outdated provisions, aligning terminology with current industry standards, and streamlining governance by moving all rate figures to the Electric Utility Rate Resolution. The updated ordinance also anticipates future needs, including time-of-use pricing, advanced metering infrastructure, and expanded support for distributed energy resources such as electric vehicles.

PWP's proposed rates remain among the most affordable in the region. The utility continues to prioritize equity by offsetting fixed charges for income-qualified customers and energy efficiency programs. Public engagement has been central to the process, with outreach efforts including webinars, open houses, and a dedicated website. Feedback from residential and commercial customers has informed the rate design and highlighted interest in clean energy options, electric vehicle incentives, and bill transparency tools. PWP recommends that the City Council set a public hearing for March 2, 2026, to present the proposed rate adjustments and ordinance restatement, and to gather community input. If approved, the new rates would take effect beginning March 10, 2026, or as soon thereafter as practicable.

BACKGROUND:

The electric rate study has been ongoing since May of 2024 to review and rethink the electric rates and rate ordinance. The rate study has included the following presentations, approvals, and direction throughout the process:

- May 6, 2024 - Council approved of the contract with NewGen
- October 22, 2024 - Introduced the rate study and process
- January 13, 2025 – Approved the removal of the obsolete Direct Access ordinance provisions
- March 11, 2025 - Presented the community engagement plan and strategy
- June 9, 2025- Amended the Stranded Investment Reserve provisions in the municipal code and establish a Working Capital Reserve Policy
- June 24, 2024 - Presented Power Fund revenue requirements projections and scenarios
- July 14, 2025 - City Council directed PWP to proceed in ratemaking with a two-year rate adjustment plan
- December 15, 2025 - MSC directed staff to return to MSC with the cost-of-service report and rate alternatives prior to recommending City Council set a public hearing date
- January 13, 2026 - MSC requested advice from the City Attorney's office prior to setting a public hearing date

ANALYSIS:

The following table represents a strategy to meet the revenue requirements for a two-year study period sufficient to support the operating expenses and capital investments for the study year period ending in FY2027. This alternative will draw down an additional $32 million draw down of cash reserves if implemented in March 2026, October 2026 and March 2027.

Table 1: Percentage Bill Adjustments by Class

Classes	Phase 1 March 2026	Phase 2 October 2026	Phase 3* March 2027
Residential	7%	7%	7%
Commercial - Small	7%	7%	7%
Medium - Commercial	7%	7%	7%
Large - Commercial	7%	7%	7%
Street Lighting	7%	7%	7%
Traffic Signals	7%	7%	7%
Total System	7%	7%	7%

Pricing and impact schedules will be developed based on MSC direction and City Council's approval.

RECOMMENDATIONS:

Staff recommends the adoption of the rate adjustments in order to meet the revenue requirement needs to provide safe, reliable services to PWP customers at an affordable rate.

Staff also recommends a restatement of a substantial portion of the rates ordinance as the piecemeal approach has led to discontinuity and obsolete language unreviewed for many years. A restatement enables a reorganization of the structure in a clear and coherent format.

Implementation Timeline

PWP is recommending that a public hearing be set for March 2, 2026, to receive comments on the recommended adjustments to the electric rates. Following the City Council's action to set a date for the public hearing, the City Clerk's Office will notice in accordance with standard procedures. Table 6 outlines the approximate timeline and implementation schedule for the proposed rate actions.

Table 11: Timeline

Date	Action Item
March 2, 2026	Electric Rates Public Hearing
March 9, 2026	First and Second Reading of Updated Electric Rate Ordinance
March 10, 2026 or as soon as practicable thereafter	Effective Date of First Rate Action

COUNCIL POLICY CONSIDERATION:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

ENVIRONMENTAL ANALYSIS:

The establishment of a date to conduct a public hearing for the consideration of electric rate adjustments and the drafting of related resolutions and ordinance amendments are administrative actions that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Therefore, the proposed actions do not constitute a "project" subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required. Furthermore, the recommended electric rate adjustments themselves would be statutorily exempt from CEQA. Section 15273 of the State CEQA Guidelines identifies a statutory exemption for "Rates, Tolls, Fares, and Charges" and states (in part) that:

a. CEQA does not apply to the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or their charges by public agencies which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The rate increases are expected to generate revenue of approximately $84 million annually. The incremental revenues will be used to offset increased operating and capital costs of the electric system.

Respectfully submitted,

DAVID M. REYES
General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

Attachment A: Utility Rate Resolution Pricing

MUNICIPAL CODE SECTION	Description of Charge	Current Rates	Phase 1 Rates effective 3/2026	Phase 2 Rates effective 10/1/2026	Phase 3 Rates effective 3/1/2027
13.04.040	**Residential single-family service (R-1)**				
13.04.040	Customer Charger per meter per month	$8.96	$11.00	$12.60	$13.10
13.04.040	Grid Access Charge per meter per month	$4.50	$6.50	$7.50	$8.50
13.04.040	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04170	$0.04836
13.04.040	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.16682	$0.19345
13.04.040	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.30027	$0.34822
13.04.040	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.040	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.05660	$0.07134	$0.06845
13.04.040	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.04919	$0.06200	$0.05949
13.04.040	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.11804	$0.14877	$0.14275
13.04.040	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.03801	$0.04791	$0.04597
13.04.040	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.08923	$0.11246	$0.10791
13.04.040	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.04081	$0.05144	$0.04936
13.04.040	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.045	**Residential multi-family service (R-2)**				
13.04.045	Customer Charger per meter per month	$8.96	$11.00	$12.60	$13.10
13.04.045	Grid Access Charge per meter per month	$4.50	$6.50	$7.50	$8.50
13.04.045	Distribution Charge per kWh on the first 350 kWh per month	$0.01889	$0.03505	$0.04170	$0.04836
13.04.045	Distribution Charge per kWh on the 351 to 750 kWh per month	$0.14673	$0.14018	$0.16682	$0.19345
13.04.045	Distribution Charge per kWh on use over 751 kWh per month	$0.10706	$0.25233	$0.30027	$0.34822
13.04.045	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.045	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07073	$0.05660	$0.07134	$0.06845
13.04.045	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06147	$0.04919	$0.06200	$0.05949
13.04.045	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.14750	$0.11804	$0.14877	$0.14275
13.04.045	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.04750	$0.03801	$0.04791	$0.04597
13.04.045	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.11150	$0.08923	$0.11246	$0.10791
13.04.045	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05100	$0.04081	$0.05144	$0.04936
13.04.045	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.050	**Small commercial and institutional service (S-1)**				
13.04.050	Customer Charger per meter per month	$9.42	$14.70	$18.20	$20.50
13.04.050	Grid Access Charge per meter per month	$17.00	$17.00	$17.00	$17.00
13.04.050	Distribution Charge per kWh per month	$0.06423	$0.06862	$0.07081	$0.07300
13.04.050	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.050	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.06901	$0.09021	$0.12516	$0.14069
13.04.050	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06030	$0.07882	$0.10937	$0.12294
13.04.050	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10463	$0.13677	$0.18977	$0.21331
13.04.050	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05706	$0.07459	$0.10349	$0.11633
13.04.050	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06431	$0.08406	$0.11664	$0.13111
13.04.050	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05611	$0.07334	$0.10177	$0.11439
13.04.050	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.050	Minimum Monthly Charge (Customer Charge + Grid Access Charge)	$26.42	$31.70	$35.20	$37.50
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.060	**Medium commercial service - secondary (M-2)**				
13.04.060	Customer Charger per meter per month	$23.40	$35.00	$45.00	$55.00
13.04.060	Grid Access Charge per meter per month	$250.00	$250.00	$250.00	$250.00
13.04.060	Distribution charge per kW of billing demand per month	$16.09	$18.00	$19.50	$20.90
13.04.060	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.060	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07338	$0.09484	$0.12805	$0.14100
13.04.060	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06213	$0.08030	$0.10842	$0.11938
13.04.060	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10218	$0.13206	$0.17831	$0.19634
13.04.060	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.06063	$0.07836	$0.10580	$0.11650
13.04.060	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06578	$0.08501	$0.11479	$0.12640
13.04.060	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05785	$0.07476	$0.10095	$0.11116
13.04.060	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.060	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Charge)	$756.10	$825.00	$880.00	$932.00
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD

13.04.064	**Medium commercial service - primary (M-1)**				
13.04.064	Customer Charger per meter per month	$29.75	$44.50	$57.20	$69.90
13.04.064	Grid Access Charge per meter per month	$250.00	$250.00	$250.00	$250.00
13.04.064	Distribution Charge per kW of billing demand per month	$11.49	$12.50	$13.50	$14.50
13.04.064	Transmission Charge per kWh per month	$0.01590	$0.01590	$0.01590	$0.01590
13.04.064	Energy Service Charge Flat Rate Option per kWh in the High Season	$0.07154	$0.09246	$0.12484	$0.13746
13.04.064	Energy Service Charge Flat Rate Option per kWh in the Low Season	$0.06121	$0.07911	$0.10681	$0.11762
13.04.064	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10128	$0.13089	$0.17674	$0.19461
13.04.064	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05977	$0.07725	$0.10430	$0.11485
13.04.064	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06481	$0.08376	$0.11310	$0.12453
13.04.064	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05713	$0.07383	$0.09969	$0.10978
13.04.064	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.064	Minimum Monthly Charge (Distribution Charge x 30kW + Customer Charge + Grid Access Charge)	$624.45	$669.50	$712.20	$754.90
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.067	**Large commercial and institutional service—secondary (L-2)**				
13.04.067	Customer Charger per meter per month	$47.91	$75.00	$87.50	$100.00
13.04.067	Grid Access Charge per meter per month	$1,500.00	$1,500.00	$1,500.00	$1,500.00
13.04.067	Distribution Charge per kW of billing demand per month	$18.76	$20.70	$22.10	$23.50
13.04.067	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.067	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.10394	$0.12780	$0.17707	$0.19649
13.04.067	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05843	$0.07184	$0.09954	$0.11046
13.04.067	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06579	$0.08089	$0.11208	$0.12437
13.04.067	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05659	$0.06958	$0.09640	$0.10698
13.04.067	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.067	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Charge)	$7,175.91	$7,785.00	$8,217.50	$8,650.00
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.069	**Large commercial and institutional service—primary (L-1)**				
13.04.069	Customer Charger per meter per month	$53.90	$84.40	$98.50	$112.60
13.04.069	Grid Access Charge per meter per month	$1,500.00	$1,500.00	$1,500.00	$1,500.00
13.04.069	Distribution Charge per kW of billing demand per month	$11.89	$18.00	$19.00	$20.00
13.04.069	Transmission Charge per kWh per month	$0.01590	$0.01590	$0.01590	$0.01590
13.04.069	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.09852	$0.12114	$0.16783	$0.18624
13.04.069	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05580	$0.06861	$0.09506	$0.10548
13.04.069	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06617	$0.08136	$0.11272	$0.12509
13.04.069	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05629	$0.06921	$0.09589	$0.10641
13.04.069	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.069	Minimum Monthly Charge (Customer Charge + Distribution Charge x 300kW + Grid Access Charge)	$5,120.90	$6,984.40	$7,298.50	$7,612.60
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.070	**Extra-Large commercial and institutional service—primary (L-3)**				
13.04.070	Customer Charger per meter per month	$53.90	$84.40	$98.50	$112.60
13.04.070	Grid Access Charge per meter per month	$1,500.00	$1,500.00	$1,500.00	$1,500.00
13.04.070	Distribution Charge per kW of billing demand per month	$11.89	$18.00	$19.00	$20.00
13.04.070	Transmission Charge per kWh per month	$0.01590	$0.01590	$0.01590	$0.01590
13.04.070	Energy Service Charge Time-of-Use per kWh High Season On-Peak	$0.09852	$0.12114	$0.16783	$0.18624
13.04.070	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	$0.05580	$0.06861	$0.09506	$0.10548
13.04.070	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	$0.06617	$0.08136	$0.11272	$0.12509
13.04.070	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	$0.05629	$0.06921	$0.09589	$0.10641
13.04.070	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.070	Minimum Monthly Charge (Distribution Charge x 300kW + Customer Charge + Grid Access Charge)	$5,120.90	$6,984.40	$7,298.50	$7,612.60
13.04.070	Negotiated rate pursuant to agreement through a Long Term Contract as defined in section	TBD	TBD	TBD	TBD
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.074	**Electric vehicle charging below 30 kW (EV-1)**				
13.04.074	Customer Charger per meter per month	N/A	$14.70	$20.50	$20.50
13.04.074	Grid Access Charge per meter per month	N/A	$17.00	$17.00	$17.00
13.04.074	Distribution Charge per kWh per month	N/A	$0.06423	$0.00	$0.00
13.04.074	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609	$0.01609
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.13677	$0.28840	$0.28840
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.07459	$0.07210	$0.07210
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.08406	$0.21630	$0.21630
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.07334	$0.07210	$0.07210
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD

13.04.074	**Electric vehicle charging at or above 30kW and less than 300 kW (EV-2)**				
13.04.074	Customer Charger per meter per month	N/A	$35.00	$55.00	$55.00
13.04.074	Grid Access Charge per meter per month	N/A	$250.00	$200.00	$200.00
13.04.074	Distribution Charge per kW of billing demand per month	N/A	$18.00	$0.00	$0.00
13.04.074	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609	$0.01609
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.13206	$0.28478	$0.28478
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.07836	$0.07120	$0.07120
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.08501	$0.21359	$0.21359
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.07476	$0.07120	$0.07120
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.074	**Electric vehicle charging at or above 300 kW (EV-3)**				
13.04.074	Customer Charger per meter per month	N/A	$75.00	$165.00	$165.00
13.04.074	Grid Access Charge per meter per month	N/A	$1,500.00	$250.00	$250.00
13.04.074	Distribution Charge per kW of billing demand per month	N/A	$20.70	$0.00	$0.00
13.04.074	Transmission Charge per kWh per month	N/A	$0.01609	$0.01609	$0.01609
13.04.074	Energy Service Charge Time-of-Use per kWh High Season On-Peak	N/A	$0.12780	$0.23218	$0.23218
13.04.074	Energy Service Charge Time-of-Use per kWh High Season Off-Peak	N/A	$0.07184	$0.05805	$0.05805
13.04.074	Energy Service Charge Time-of-Use per kWH High Season Critical Peak	N/A	N/A	N/A	N/A
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season On-Peak	N/A	$0.08089	$0.17414	$0.17414
13.04.074	Energy Service Charge Time-of-Use per kWh Low Season Off-Peak	N/A	$0.06958	$0.05805	$0.05805
13.04.074	Energy Service Charge Time-of-Use per kWH Low Season Critical Peak	N/A	N/A	N/A	N/A
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.074	**City-Owned retail charging stations**	$0.30 per kWh	TBD	TBD	TBD
13.04.080	**Standby Service (SBY)**				
13.04.080	Distribution Charge per kW of standby capacity	$10.87000	TBD	TBD	TBD
13.04.080	Customer Charge	N/A	TBD	TBD	TBD
13.04.080	Grid Access Charge per meter per month	N/A	TBD	TBD	TBD
13.04.080	Minimum Monthly charge (if less than demand charge)	$201.40000	TBD	TBD	TBD
13.04.080	Standby service application charge on-time fee for each application or customer account	$5.00000	TBD	TBD	TBD
13.04.080	Reservation Charge	N/A	TBD	TBD	TBD
13.04.085	**Unmetered rates- Non-demand (CE-1)**				
13.04.085	Customer Charge per meter per month (single-phase service)	$14.16	$14.16	$14.16	$14.16
13.04.085	Customer Charge per meter per month (three-phase service)	$19.07	$19.07	$19.07	$19.07
13.04.085	Distribution Charge per kWh of billing demand per month	$0.04475	$0.04475	$0.04475	$0.04475
13.04.085	Energy Service Charge Flat Rate per kWh in the High Season	$0.06901	$0.06901	$0.06901	$0.06901
13.04.085	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06030	$0.06030	$0.06030	$0.06030
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.087	**Unmetered rates- Demand (CE-2)**				
13.04.087	Customer Charge per meter per month	$60.22	$60.22	$60.22	$60.22
13.04.087	Distribution Charge per kWh of billing demand per month	$10.87	$10.87	$10.87	$10.87
13.04.087	Energy Service Charge Flat Rate per kWh in the High Season	$0.07338	$0.07338	$0.07338	$0.07338
13.04.087	Energy Service Charge Flat Rate per kWh in the Low Season	$0.06213	$0.06213	$0.06213	$0.06213
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD

13.04.090	**Street lighting and traffic signal service (SL)**				
13.04.090	Incandescent 1,000 lumens per lamp per month	$0.94	$1.08194	$1.26648	$1.36997
13.04.090	Incandescent 1,500 lumens per lamp per month	$1.11	$1.27761	$1.49552	$1.61773
13.04.090	Incandescent 2,500 lumens per lamp per month	$1.95	$2.24446	$2.62727	$2.84197
13.04.090	Incandescent 4,000 lumens per lamp per month	$3.14	$3.61415	$4.23057	$4.57629
13.04.090	Incandescent 6,000 lumens per lamp per month	$4.47	$5.14498	$6.02250	$6.51466
13.04.090	Incandescent 10,000 lumens per lamp per month	$6.79	$7.81531	$9.14828	$9.89587
13.04.090	Incandescent 67 watts per lamp per month	$0.86	$0.98986	$1.15869	$1.25338
13.04.090	Incandescent 69 watts per lamp per month	$0.88	$1.01288	$1.18564	$1.28253
13.04.090	Incandescent 103 watts per lamp per month	$1.30	$1.49630	$1.75151	$1.89464
13.04.090	Incandescent 150 watts per lamp per month	$1.89	$2.17540	$2.54643	$2.75452
13.04.090	Incandescent 202 watts per lamp per month	$2.54	$2.92355	$3.42218	$3.70184
13.04.090	Incandescent 303 watts per lamp per month	$3.80	$4.37381	$5.11980	$5.53819
13.04.090	Mercury Vapor 3,500 lumens per lamp per month	$1.61	$1.85311	$2.16918	$2.34644
13.04.090	Mercury Vapor 7,000 lumens per lamp per month	$2.64	$3.03865	$3.55692	$3.84758
13.04.090	Mercury Vapor 11,000 lumens per lamp per month	$3.66	$4.21267	$4.93118	$5.33415
13.04.090	Mercury Vapor 20,000 lumens per lamp per month	$5.80	$6.67582	$7.81443	$8.45303
13.04.090	Mercury Vapor 35,000 lumens per lamp per month	$9.81	$11.29134	$13.21717	$14.29727
13.04.090	Mercury Vapor 54,000 lumens per lamp per month	$13.87	$15.96	$18.69	$20.21
13.04.090	Fluorescent 213 watts per lamp per month	$2.68	$3.08469	$3.61081	$3.90588
13.04.090	Fluorescent 248 watts per lamp per month	$3.14	$3.61415	$4.23057	$4.57629
13.04.090	High Pressure Sodium 35 watts per lamp per month	$0.51	N/A	N/A	N/A
13.04.090	High Pressure Sodium 50 watts per lamp per month	$0.72	N/A	N/A	N/A
13.04.090	High Pressure Sodium 70 watts per lamp per month	$1.28	$1.47328	$1.72456	$1.86550
13.04.090	High Pressure Sodium 100 watts per lamp per month	$1.76	$2.02576	$2.37128	$2.56506
13.04.090	High Pressure Sodium 150 watts per lamp per month	$2.43	$2.79694	$3.27398	$3.54153
13.04.090	High Pressure Sodium 200 watts per lamp per month	$3.09	$3.55660	$4.16321	$4.50342
13.04.090	High Pressure Sodium 250 watts per lamp per month	$3.94	$4.53495	$5.30843	$5.74223
13.04.090	High Pressure Sodium 310 watts per lamp per month	$4.81	$5.53632	$6.48059	$7.01018
13.04.090	High Pressure Sodium 400 watts per lamp per month	$5.98	$6.88300	$8.05695	$8.71536
13.04.090	High Pressure Sodium 4—60 watts unit bus stop per lamp per month	$4.82	$5.54783	$6.49406	$7.02476
13.04.090	High Pressure Sodium 2—40 watts unit bus stop per lamp per month	$4.82	$5.54783	$6.49406	$7.02476
13.04.090	Metal Halide per lamp per month	$3.99	$4.59250	$5.37579	$5.81510
13.04.090	Distribution Charge for metered street lighting per kWh	$0.03923	$0.04515	$0.05286	$0.05717
13.04.090	Distribution Charge metered traffic signals and signs per kWh	$0.05807	$0.06639	$0.07712	$0.08335
13.04.090	Distribution Charge Unmetered traffic signals and signs	$0.05807	$0.06639	$0.07712	$0.08335
13.04.090	Transmission Charge per kWh per month	$0.01609	$0.01609	$0.01609	$0.01609
13.04.090	Energy Charge per kWh	$0.06500	$0.15918	$0.18633	$0.20156
13.04.173	Energy Service Charge Power Cost Adjustment (subject to change based on monthly calculation)	$0.06830	$0.05165	TBD	TBD
13.04.150	**Rate schedule change**				
13.04.150	Load change in less than 12 months per meter affected	$3.00	Not specified	Not specified	
13.04.178	**Self-generation service (SG)**	B. Rates. Rates for this service shall be the same as for the schedule under which the customer would ordinarily take service, with the following exceptions: 1. For self-generation service customers in the residential and small commercial and industrial groups, the monthly customer charge and the distribution services charge shall respectively be the same as those of the medium commercial and industrial class—secondary. 2. In each month, billing demand will be the greater of the maximum fifteen minute kW of the absolute net power that the customer received from or injected into the PWP power system during the current month or preceding eleven months. 3. In each month, the billing determinant for the Transmission Services Charge shall be the sum, over the hours of the month, of the hourly net power that the customer received from the PWP power system, but in no event less than zero for the month. 4. For energy charges and energy credits, billing determinants shall be quantified as follows: a. For customers on seasonal flat energy rates, the monthly billing determinant shall be the net power that the customer received from the PWP power system during the month. b. For customers on time-of-use (TOU) energy rates, the billing determinant for each TOU period shall be the net power that the customer received from the PWP power system during each period. 5. For any period during which the customer's net power received from the PWP power system is negative (i.e., during which the customer injects net power into the PWP power system), the customer shall not pay an Energy Charge but shall instead receive an energy credit. a. The applicable energy credit periods shall be one month for customers on seasonal flat rates and TOU periods for customers on TOU rates. b. The energy credit for each period shall equal the product of: 1.The customer's net injection into the PWP power system during the period and PWP's average power cost applicable to that period.			
13.04.179	**Green power service (GP)**				
13.04.179	Green power premium per kWh	$0.018	$0.018	$0.018	$0.018
13.04.179	Green power premium for 100 kWh block	$1.80	$1.80	$1.80	$1.80
13.04.180	**Theft of energy**				
13.04.180	Minimum charge per occurrence of energy theft	$300.00	$300.00	$300.00	$300.00

Agenda Report

February 23, 2026

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (February 10, 2026)

FROM: Water and Power Department

SUBJECT: **SET A DATE OF MARCH 2, 2026, TO OPEN A PUBLIC HEARING FOR ELECTRIC RATE ADJUSTMENTS AND DIRECT THE CITY ATTORNEY'S OFFICE TO PREPARE AN ORDINANCE AMENDING THE LIGHT AND POWER RATE ORDINANCE AND ADOPT THE UTILITY RATE RESOLUTION**

RECOMMENDATION:

It is recommended that the City Council:

1) Find that the proposed action is not a project subject to the California Environmental Quality Act (CEQA) pursuant to Section 21065 of CEQA and Sections 15060(c)(2), 15060(c)(3), and 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project;

2) Set a date of March 2, 2026, to open a public hearing for the recommended electric rate adjustments;

3) Direct staff to prepare the Utility Rate Resolution with a three-phase rate adjustment plan (effective March 2026, October 1, 2026, and March 1, 2027); and

4) Direct the City Attorney's Office to prepare an ordinance amending the Light and Power Rate Ordinance, Title 13, Chapter 13.04 – Power Rates and Regulations, to reflect the proposed electric rate adjustments, eliminate outdated or obsolete provisions, and align the ordinance with current industry best practices.

MUNICIPAL SERVICES COMMITTEE RECOMMENDATION:

On February 10, 2026, the Municipal Services Committee received the report and unanimously recommended that this item be placed on the February 23 agenda to open a public hearing on March 2, and subsequently continue the public hearing to March 16.

EXECUTIVE SUMMARY:

Pasadena Water and Power ("PWP") has completed a comprehensive Electric Rate Study to ensure that electric rates remain equitable, cost-based, and aligned with the City's long-term goals of fiscal responsibility, infrastructure modernization, and achieving 100% carbon-free electricity by 2030. Conducted in partnership with NewGen Strategies and Solutions, LLC ("NewGen"), the study includes a full cost-of-service ("COS") analysis, financial modeling, and extensive public engagement. The study confirms that current electric rates are insufficient to meet projected revenue needs, with a shortfall of approximately $67.9 million over 2 years.

In addition to the rate adjustments, PWP recommends a full restatement of the Light and Power Rate Ordinance (Chapter 13.04) except for items related to Net Energy Metering and any new provisions for local solar that will have further discussion. This restatement will modernize the ordinance by eliminating outdated provisions, aligning terminology with current industry standards, and streamlining governance by moving all rate figures to the Electric Utility Rate Resolution. The updated ordinance also anticipates future needs, including time-of-use pricing, advanced metering infrastructure, and expanded support for distributed energy resources such as electric vehicles.

PWP's proposed rates remain among the most affordable in the region. The utility continues to prioritize equity by offsetting fixed charges for income-qualified customers and energy efficiency programs. Public engagement has been central to the process, with outreach efforts including webinars, open houses, and a dedicated website. Feedback from residential and commercial customers has informed the rate design and highlighted interest in clean energy options, electric vehicle incentives, and bill transparency tools. PWP recommends that the City Council set a public hearing for March 2, 2026, to present the proposed rate adjustments and ordinance restatement, and to gather community input. If approved, the new rates would take effect beginning March 16?, 2026, or as soon thereafter as practicable.

BACKGROUND:

The electric rate study has been ongoing since May of 2024 to review and rethink the electric rates and rate ordinance. The rate study has included the following presentations, approvals, and direction throughout the process:

- May 6, 2024 - Council approved of the contract with NewGen
- October 22, 2024 - Introduced the rate study and process
- January 13, 2025 – Approved the removal of the obsolete Direct Access ordinance provisions
- March 11, 2025 - Presented the community engagement plan and strategy
- June 9, 2025 - Amended the Stranded Investment Reserve provisions in the municipal code and establish a Working Capital Reserve Policy
- June 24, 2024 - Presented Power Fund revenue requirements projections and scenarios

- July 14, 2025 - City Council directed PWP to proceed in ratemaking with a two-year rate adjustment plan
- December 15, 2025 - MSC directed staff to return to MSC with the cost-of-service report and rate alternatives prior to recommending City Council set a public hearing date
- January 13, 2026 - MSC requested advice from the City Attorney's office prior to setting a public hearing date

ANALYSIS:

The following table represents a strategy to meet the revenue requirements for a two-year study period sufficient to support the operating expenses and capital investments for the study year period ending in FY2027. This alternative will draw down an additional $32 million of cash reserves if implemented in March 2026, October 2026 and March 2027.

Table 1: Percentage Bill Adjustments by Class

Classes	Phase 1 March 2026	Phase 2 October 2026	Phase 3* March 2027
Residential	7%	7%	7%
Commercial - Small	7%	7%	7%
Medium - Commercial	7%	7%	7%
Large - Commercial	7%	7%	7%
Street Lighting	7%	7%	7%
Traffic Signals	7%	7%	7%
Total System	7%	7%	7%

Pricing and impact schedules will be developed based on MSC direction and City Council's approval.

The pricing for the residential customer and impact is detailed in Tables 2-4.

Table 2: Residential Customer Class Proposed Pricing per Phase

Residential single-family service (R-1)		Current	Phase 1 Mar-26	Phase 2 Oct-26	Phase 3 Mar-27
Fixed Charges	Customer Charge	$ 8.96000	$ 11.00000	$ 12.60000	$ 13.10000
per month	Grid Access Charge	$ 4.50000	$ 6.50000	$ 7.50000	$ 8.50000
Demand Charges	Distribution Charge: first 350 kWh per month	$ 0.01889	$ 0.03505	$ 0.04170	$ 0.04836
per kWh	Distribution Charge: 351 to 750 kWh	$ 0.14673	$ 0.14018	$ 0.16682	$ 0.19345
	Distribution Charge: over 751 kWh per month	$ 0.10706	$ 0.25233	$ 0.30027	$ 0.34822
	Transmission Charge	$ 0.01609	$ 0.01609	$ 0.01609	$ 0.01609
Energy Charges[1]	Energy Service Charge - High Season	$ 0.07073	$ 0.05660	$ 0.07134	$ 0.06845
per kWh	Energy Service Charge -Low Season	$ 0.06147	$ 0.04919	$ 0.06200	$ 0.05949
	Power Cost Adjustment[2]	$ 0.06830	$ 0.05165	TBD	TBD

[1] Flat rate option

[2] Subject to change based on monthly calculation

Table 3: Residential Customer Class Price Changes per Phase

Residential single-family service (R-1)		Phase 1 $ Change Mar-26	Phase 2 $ Change Oct-26	Phase 3 $ Change Mar-27	Phase 1 % Change Mar-26	Phase 2 % Change Oct-26	Phase 3 % Change Mar-27
Fixed Charges	Customer Charge	$ 2.04	$ 1.60	$ 0.50	23%	15%	4%
per month	Grid Access Charge	$ 2.00	$ 1.00	$ 1.00	44%	15%	13%
Demand Charges	Distribution Charge: first 350 kWh per month	0.02¢	0.01¢	0.01¢	86%	19%	16%
per kWh	Distribution Charge: 351 to 750 kWh	-0.01¢	0.03¢	0.03¢	-4%	19%	16%
	Distribution Charge: over 751 kWh per month	0.15¢	0.05¢	0.05¢	136%	19%	16%
	Transmission Charge	0.00¢	0.00¢	0.00¢	0%	0%	0%
Energy Charges[1]	Energy Service Charge - High Season	-0.01¢	0.01¢	0.00¢	-20%	26%	-4%
per kWh	Energy Service Charge -Low Season	-0.01¢	0.01¢	0.00¢	-20%	26%	-4%
	Power Cost Adjustment[2]	-0.02¢			-24%		

[1] Flat rate option

[2] Subject to change based on monthly calculation

Full rates and pricing are as stated in Attachment A: Utility Rate Resolution Pricing.

RECOMMENDATIONS:

Staff recommends adoption of the rate adjustments to meet the revenue requirement needs to provide safe, reliable services to PWP customers at an affordable rate.

Staff also recommend an amendment to a substantial portion of the rates with a reorganization of the structure in a clear and coherent format.

Implementation Timeline

PWP is recommending that a public hearing be opened March 2, 2026, to receive comments on the recommended adjustments to the electric rates. Following the City

Council's action to set a date for the public hearing, the City Clerk's Office will notice in accordance with standard procedures. Table 6 outlines the approximate timeline and implementation schedule for the proposed rate actions.

Table 11: Timeline

Date	Action Item
March 2, 2026	Open Electric Rates Public Hearing
March 16, 2026	First and Second Reading of Updated Electric Rate Ordinance
March 17, 2026 or as soon as practicable thereafter	Effective Date of First Rate Action

<u>COUNCIL POLICY CONSIDERATION</u>:

The recommendations are consistent with the City Council's goals to maintain fiscal responsibility and stability; improve, maintain, and enhance public facilities and infrastructure; and increase conservation and sustainability.

<u>ENVIRONMENTAL ANALYSIS</u>:

The establishment of a date to conduct a public hearing for the consideration of electric rate adjustments and the drafting of related resolutions and ordinance amendments are administrative actions that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Therefore, the proposed actions do not constitute a "project" subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required. Furthermore, the recommended electric rate adjustments themselves would be statutorily exempt from CEQA. Section 15273 of the State CEQA Guidelines identifies a statutory exemption for "Rates, Tolls, Fares, and Charges" and states (in part) that:

a. CEQA does not apply to the establishment, modification, structuring, restructuring, or approval of rates, tolls, fares, or their charges by public agencies which the public agency finds are for the purpose of:

1. Meeting operating expenses, including employee wage rates and fringe benefits,
2. Purchasing or leasing supplies, equipment, or materials,
3. Meeting financial reserve needs and requirements,
4. Obtaining funds for capital projects, necessary to maintain service within existing service areas, or
5. Obtaining funds necessary to maintain such intra-agency transfers as are authorized by city charter.

FISCAL IMPACT:

The rate increases are expected to generate revenue of approximately $84 million annually. The incremental revenues will be used to offset increased operating and capital costs of the electric system.

Respectfully submitted,

DAVID M. REYES
General Manager
Water and Power Department

Prepared by:

Lynne Chaimowitz
Assistant General Manager
Water and Power Department

Approved by:

MIGUEL MÁRQUEZ
City Manager

Attachment A: Utility Rate Resolution Pricing