K. R. Saline
& Associates, PLC

Electric Cost-of-Service and Rate Study

Prepared For:

City of Needles Public Utility Authority

Submitted By:
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August 22, 2025

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August 22, 2025

Ms. Rainie Torrance
Utility Manager
City of Needles
817 Third Street
Needles, CA 92363

Subject: NPUA 2025 Electric Rate Study Report

Dear Ms. Torrance,

K.R. Saline and Associates, PLC, is pleased to submit this 2025 Electric Rate Study Report to the Needles Public Utility Authority. This report documents the results and recommendations of the City of Needles' electric rate study. The overall goal of the study was to develop a cost-of-service study and related rate options that would support Needles' Public Utility Authority revenue requirements as well as rate options based off of the study results.

This study used standard rate-setting methods based on widely accepted industry principles, such as cost causation and fairness, and guidance from the City's policymakers. Our team has a proven track record of developing fair and equitable electric rates for many public power agencies in Arizona over the past 30 years. We are confident in our ability to create effective electric rates that meet the City's needs.

It has been our pleasure to assist the city, and we appreciate the support provided by yourself and other City staff over the course of the study.

Sincerely,

Ashley Blank

Ashley Blank
Project Manager

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Forward

K.R. Saline and Associates, PLC (KRSA) prepared this report for the sole use of Needles Public Utility Authority (NPUA) for the intended purpose as stated in the agreement between NPUA and KRSA under which this work was completed. The report may not be relied upon by any other party without the expressed written agreement of KRSA or NPUA.

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Acknowledgements

KRSA wishes to extend our appreciation to the city and its staff for their cooperation during the progress of this study. We would like to especially thank Ms. Rainie Torrance, Utility Manager, for her guidance and assistance with this project.

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Contents

1 Executive Summary

The City of Needles, through the Needles Public Utility Authority (NPUA), engaged in this Cost of Service Study (COSS) to review the electric utility's rate structure, evaluate the allocation of costs among customer classes, and assess rate design options. The analysis was conducted using Test Year 2024 data and is intended to ensure rates remain cost-based, equitable, and sufficient to meet operational and financial obligations.

1-1 Revenue Requirements

The total Test Year 2024 cost of service is $12,267,384, inclusive of purchased power, operations and maintenance, administrative and general expenses, depreciation, and capital program funding. Purchased power costs comprise the majority of the requirement, representing approximately 75% of total expenses. Current rates are sufficient to recover this amount and produce total allocated revenues of $14,856,751, resulting in an overall surplus of $2,589,367.

This surplus exceeds the minimum return required to meet the City's Annual Revenue Fund (ARF) contribution and scheduled debt service obligations, providing adequate coverage for contingencies and future capital investments.

1-2 Cost Allocation Results

Costs were allocated to each rate class based on cost-causation principles, with separate consideration for customer-related, demand-related, and energy-related costs. The table below summarizes the allocated revenues, allocated expenses, and the resulting over- or under-recovery by class.

Rate Class	Allocated Revenues	Allocated Expenses	Over / (Under) COSS	as %
Residential	$4,633,573	$4,331,735	$301,838	7%
Small Commercial (0-25kW)	$1,590,967	$1,601,352	-$10,385	-1%
Medium Commercial (25kW-100kW)	$1,010,181	$680,601	$329,579	33%
Large Commercial (100kW+)	$7,582,689	$5,567,862	$2,014,828	27%
Streetlights	$39,342	$85,834	-$46,492	-118%
Total	$14,856,751	$12,267,384	$2,589,367	17%

Results show the Residential, Medium Commercial, and Large Commercial classes generating revenues above their allocated costs, while Small Commercial and Streetlights are under-recovering.

1-3 Rate Design Options Considered

Four rate options were developed:

1. **Option 1 – Current Structure**: Maintains existing rates for all classes.
2. **Option 2 – Class-Differentiated Rates**: Introduces separate rate schedules for each major class, with a fixed monthly customer charge and separate Delivery and Power charges.
3. **Option 3 – Demand-Based Rates**: Builds on Option 2 by adding a demand charge for commercial classes.
4. **Street Lighting Rates**: Evaluated separately, with planned increases for cost recovery and a phased transition to LED fixtures.

1-4 Selected Rate Design

The Alternative Rate Ad Hoc Committee and City elected to retain the current rate structure (Option 1) for all customer classes. In addition, the City approved an update to Street Lighting rates to move toward cost-of-service recovery, with the City continuing to assume direct responsibility for these costs in its budget. The City will also proceed with a phased transition from sodium to LED fixtures as replacements are needed.

1-5 Recommendations

- The City adopt the proposed financial plan and proposed increases to the street lighting rates,
- Continue to actively monitor NPUA's evolving power resources and evolving market conditions,
- Modernize customer programs to make adoption of more complicated rate designs more feasible and data collection and reporting more accessible,
- Revisit its cost-of-service analysis periodically to ensure ongoing alignment with operational needs and ratepayer expectations.

The adopted approach maintains rate stability for all customer classes, addresses Street Lighting under-recovery, and ensures sufficient revenues to meet ARF and debt obligations.

2 Introduction

Section 2 Study Overview

2-1 Study Purpose

The purpose of this report is to evaluate the adequacy of Needles Public Utility Authority ("NPUA") existing rate charges and to recommend fair and equitable adjustments to the rates, if deemed necessary. K. R. Saline designed utility rate studies encompasses three principal steps, each intended to answer questions typically asked by utility boards, city councils, and utility management.

These questions are -

Revenue Requirements – What is the overall adjustment in rates needed to meet forecast cash requirements of the utility, meet capital requirements, and maintain debt service coverage and appropriate cash reserves?

Cost of Service – What is each class's equitable share of the utility's revenue requirements?

Rate Design – How should rates be adjusted to meet utility revenue requirements and remain sensitive to customer rate impacts?

2-2 Study Objectives

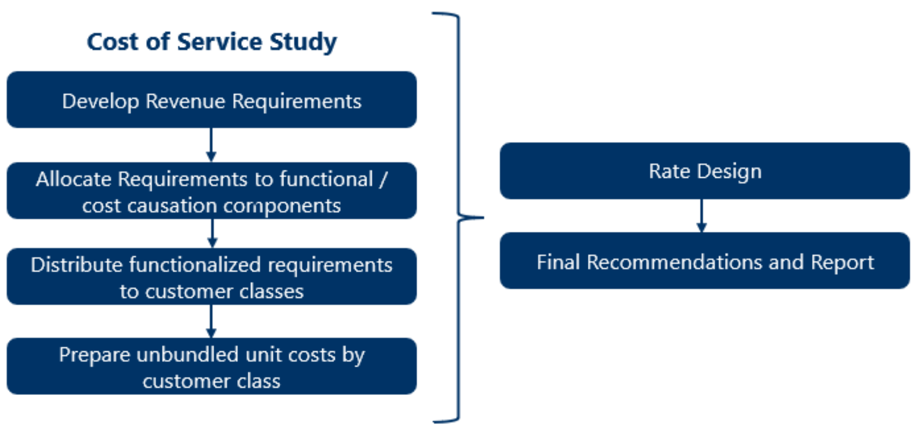
The major objectives of this study are to:

- ✓ Identify the cost of serving each of the Department's customer classes, including fixed and variable costs.
- ✓ Evaluate the current rate structure to ensure the operation & maintenance, capital and debt costs are covered.
- ✓ Currently Needles has a base meter rate only that is fixed throughout the year. Review the current rate component.
- ✓ The proposed rate structure should promote conservation through pricing strategies that are easy for the customer to understand.
- ✓ The City is particularly interested in a review of the current rate policy and corresponding annual rate calculations to ensure sufficient collection of revenues.

2-3 Study Methodology

This study follows general industry standards for cost-of-service analysis. KRSA used a process and approach based on the City's policy objectives, the City's operating needs and the current revenue projections to develop a financial plan. The resulting financial plan, cost of service analysis, and rate design follow five key steps to establish proposed rates that meet the Utility's objectives and adhere to industry standards.

1. **Revenue Requirements:** Determination of financial plan / revenue requirements,
2. **Cost-of-Service Analysis:** The revenue requirement is separated into its functional components and distributed to customer classes commensurate with their use of and burden on the system,
3. **Development of Unit Costs:** After costs are distributed to the customer classes, costs are unbundled into fixed and volumetric units of measures to determine unit costs that can be used for the basis of rate design,
4. **Rate Design:** After allocating the revenue requirement to each customer class and preparing the unit costs, the rate design and calculation process can begin. Rates do more than simply recover costs; properly designed rates should also support and optimize the City's policy objectives,
5. **Written Report and Rate adoption:** The final step in a rate study is to develop the written report for the benefit of the City's administrative record.



K. R. Saline has performed a cost-of-service and rate design study for NPUA's electric utility. The study included an analysis of estimated revenue requirements for fiscal years FY2026 through FY2030 (the "Study Period"), the preparation of detailed cost-of-service analyses based on an FY2026 Test Year, rate analysis, and the development of proposed new electric rates for each customer classification. This report summarizes the analyses undertaken in our study of NPUA's retail electric rates and describes the results of our study and our recommendations. Pursuant to instructions, and in order to perform the study, KRSA created customer class groupings appropriate for residential customers and commercial customers based on common sizes for small, medium, and large, incorporating all historical operating and capital expenses. The rate design portion of the study includes recommendations on retail rates for each customer classification.

2-4 Key Changes Since Prior Rate Study

PDP Remarketing Plan Overview and Impact on Needles. The Parker-Davis Project (PDP), administered by the Western Area Power Administration (WAPA), is undergoing a remarketing process that will take effect upon expiration of the current contracts in September 2028. Under the proposed 2024 PDP Remarketing Plan [Federal Register Notice 89 FR 43819], WAPA will allocate new long-term hydroelectric power contracts from October 1, 2028, through September 30, 2058. These contracts are designed to promote broader access among existing and new preference customers while adjusting allocations based on resource availability and evolving grid demands.

For the City of Needles, a current PDP customer, the remarketing plan is expected to result in a 3% reduction in its existing hydropower allocation beginning in FY 2029. This change is in this study’s power supply forecast, which assumes the reduced PDP allocation and increased reliance on market-based purchases beginning in October 2028. While the reduction is modest, it shifts a portion of Needles’ dependable, low-cost power supply into the more volatile market space, potentially increasing cost variability and exposure to price swings.

Class-Based Analysis Using AMI Data. A significant enhancement in this 2025 rate study, compared to the 2020 analysis, is the inclusion of a detailed customer class breakout supported by one full year of Advanced Metering Infrastructure (AMI) data. This current study applies hourly interval data to allocate costs across distinct customer classes—residential, small commercial, medium commercial, large commercial, and street lighting—based on actual usage characteristics, load patterns, and service demands.

By contrast, the 2020 study lacked the data granularity necessary to functionalize and classify costs by customer type. Rate recommendations at that time were developed using system-level averages without the ability to differentiate cost causation among classes. As a result, class-level equity and cost-of-service alignment could not be evaluated or addressed.

The inclusion of AMI-driven class-level analysis in the 2025 study ensures that rate structures more accurately reflect the cost to serve each customer group. This improves transparency, strengthens the fairness of cost recovery, and supports the long-term financial and operational integrity of the utility.

3 Background and Overview

Section 3 Needles Public Utility Authority

3-1 About NPUA

The City of Needles assumed ownership of its electric distribution system in 1991 through the acquisition of infrastructure from CP National. This transition marked the formation of the Needles Public Utility Authority (NPUA), which now oversees the City's electric, water, and wastewater services. At the time of acquisition, the electric system was characterized by aging infrastructure, limited procurement flexibility, and frequent, extended outages—conditions exacerbated by the region's extreme summer temperatures. To address these challenges, the city entered into a strategic partnership with the Western Area Power Administration (WAPA) in the early 2000s. This collaboration enabled the City to access federal hydropower through the Parker-Davis Project, diversify its energy procurement across multiple suppliers, and improve operational reliability.

Today, NPUA provides electric service to approximately 3,700 customers across a 755-square-mile service area, leveraging a stable and cost-effective energy portfolio managed in coordination with WAPA.

3-2 Governance and Rate Setting Authority

The NPUA operates with guidance from the Utility Board, which makes recommendations to the City Council. The City Council members also serve as the managing body of the NPUA, ensuring that utility services are efficiently provided to the community and meet the city's needs.

3-3 Electric Enterprise

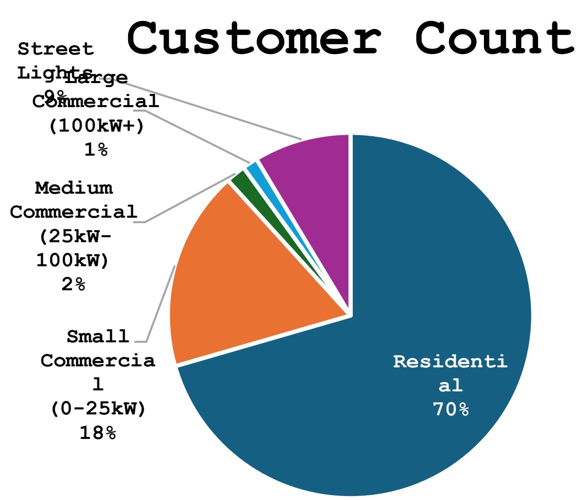
3-3-1 Service Territory

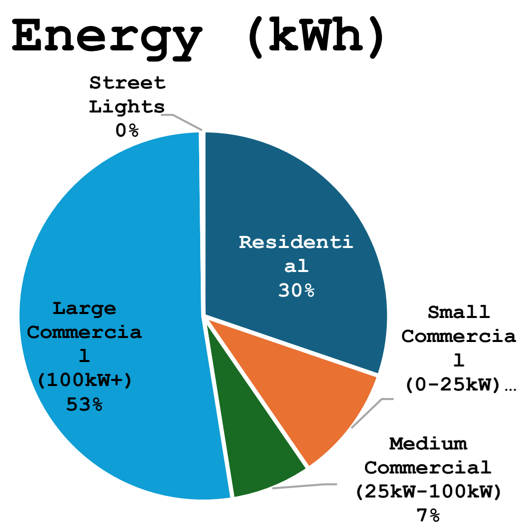
The City of Needles Electric Utility provides service to approximately 3,700 customers within the city and in certain contiguous areas extending beyond its municipal boundaries. The service territory spans from the Nevada state line—just south of Laughlin, Nevada—down to the vicinity of Topock, Arizona, along the western banks of the Colorado River. This area is part of the easternmost region of San Bernardino County and includes both residential and commercial customers. The utility operates within a 755-square-mile service area, managed by the Needles Public Utility Authority (NPUA), and is geographically isolated from other urban centers. Electricity is delivered via City-owned infrastructure, including four substations, approximately 30 miles of 69 kV transmission lines, and several hundred miles of 12 kV distribution lines.

3-3-2 *Customer Base*

The Needles Electric Utility serves a total of approximately 3,700 customers distributed across five primary customer classes. Residential customers make up about 70% of the total customer base, followed by small commercial customers at 18%. Medium commercial and large commercial customers represent approximately 2% and 1% of accounts, respectively, while street lighting accounts comprise the remaining 9%. Street lighting accounts and associated rates are paid for by the City of Needles and does not impact projected rates for other classes. Although residential users account for the majority of accounts, commercial and public infrastructure customers have a proportionally higher impact on system demand and cost allocation due to their greater load requirements. While Large Commercial accounts make up only 1% of the meter counts, they use 53% of the energy load.

Since 2018, the City has actively pursued economic development efforts to attract businesses in the marijuana cultivation industry. These efforts have successfully increased tax and utility revenues for the City and have become a notable component of NPUA's large commercial load. However, the addition of these high-demand facilities has also placed upward pressure on system peak demand, requiring adjustments to NPUA's long-term resource planning. In addition, the increased load from this sector carries implications for greenhouse gas (GHG) compliance and climate-related regulatory requirements, which must be considered in future operational and capital planning





3-3-3 Power Supply

The City of Needles maintains a diversified power supply portfolio to reliably meet customer demand across its service area. Its core supply includes federal hydropower allocations from the Parker-Davis Project (PDP), which provides a stable and renewable base supply. These contracted federal resources are supported by WAPA via the pooling, real-time balancing, and market transactions under Needles' aggregated Energy Services contract, and further supplemented by standard term WSPP short-term purchases.

This layered procurement strategy allows Needles to respond effectively to variable load conditions while enhancing overall system reliability. Network transmission arrangements and contracted delivery services further support the consistent delivery of power across the utility's geographically dispersed service territory.

Needles' power supply planning also incorporates compliance with California's Renewable Portfolio Standard (RPS) requirements. As recent load growth, particularly from energy-intensive industries such as marijuana cultivation, has increased overall system demand, NPUA's resource planning must continue to balance reliability, cost-effectiveness, and compliance with state-mandated renewable and greenhouse gas reduction targets.

3-3-4 Transmission and Distribution

The City of Needles Electric Utility owns and operates its own transmission and distribution infrastructure to serve approximately 3,700 customers across a geographically dispersed service area. The transmission system consists of approximately 30 miles of 69 kV lines that connect the city to external power supply points, including federal hydropower resources. These transmission lines feed into four primary substations that step down voltage for local distribution. The distribution network operates primarily at 12 kV and includes several hundred miles of overhead and underground lines serving residential, commercial, and municipal loads. Given the region's extreme environmental conditions and remote location, maintaining system reliability is a top priority. The city has invested in system upgrades, redundancy, and coordination with the Western Area Power Administration (WAPA) to ensure consistent delivery and operational resilience. The utility's control of both transmission and distribution assets provides flexibility in power delivery and enhances the City's ability to respond to outages and system events promptly.

3-3-5 Electric Rates

Electric rates in the City of Needles are structured with a fixed monthly Basic Service Charge and variable consumption-based energy charges. Customers are billed based on seasonal hydro allocations—summer (March–September) and winter (October–February)—with energy usage beyond these allocations subject to a higher over-hydro rate. Additional charges include a California Energy Efficiency (CAEE) rate and a discretionary Power Cost Adjustment (PCA), which allows the utility to recover unforeseen power purchase costs. The rate structure reflects cost recovery needs as detailed in the revenue requirements forecast, with total revenues from sales increasing from approximately $11.1 million in 2023 to over $15 million by 2030. Operating expenses such as purchased power, administrative costs, and surcharges are allocated across rate components using a previously defined cost allocation methodology, supporting both financial sustainability and operational efficiency.

4 Cost-of-Service study

Section 4 Financial Plan Overview

Financial planning is essential for a public power utility to ensure its long-term sustainability and operational efficiency. A prudent financial plan helps the utility manage its resources effectively, forecast future expenses and revenues, and allocate funds for maintenance, upgrades, and expansion projects. This planning process involves analyzing current financial status, understanding market trends, and assessing the impact of economic conditions. Moreover, utilities must anticipate changes in energy consumption patterns and technological advancements that could impact revenue streams. By establishing a solid financial foundation, a public power utility can maintain reliable service for its customers, invest in new technologies, and respond to unexpected challenges, such as natural disasters or significant shifts in energy demand.

One of the key considerations in financial planning for a public power utility is the management of capital and operating expenses. Capital expenses include long-term investments in infrastructure, such as the construction of new facilities or the upgrading of existing ones, while operating expenses cover the day-to-day costs of running the utility, including labor, maintenance, and fuel costs. Utilities must balance these expenses to ensure financial stability, often requiring careful budgeting and forecasting to avoid shortfalls or excesses. Additionally, utilities must consider depreciation of assets and plan for the timely replacement or upgrading of equipment to maintain efficient operations and meet safety and environmental standards.

Effective financial planning also involves maintaining adequate reserves and contingency funds to handle emergencies or unforeseen expenses without compromising service reliability or financial health. Therefore, a comprehensive financial plan reviews the following:

1. Historical electric sales and consumption patterns to determine an appropriate usage level for projecting future water demands.
2. Operating costs may change over the planning period because of inflation, unique circumstances of the city, new expenditures added to meet strategic goals, state mandates, or changes in operations.
3. Multi-year system improvement needs, and scheduling based on priority.
4. Satisfy debt service coverage ration requirements for any existing or proposed debt (120%).

5. Reserve funding to meet adopted reserve policies. The goal is to generate adequate cash on hand to mitigate financial risks related to operating cashflow needs, unexpected increases in expenses, shortages in system reinvestment, and mitigating potential failures.

4-1 Planning Assumptions

Developing a long-term financial plan requires a comprehensive understanding of the electric utility's financial position, including an evaluation of existing revenue streams, operating and capital expenses, debt obligations, and reserve policies. To support accurate forecasting, this study incorporates a series of planning assumptions developed in consultation with City staff and based on historical trends, current obligations, and anticipated system needs.

Table 6 outlines the key assumptions used to project revenues over the rate-setting period. These include annual revenue escalation, reserve interest earnings, account growth, and changes in energy consumption. Specifically, the analysis assumes an annual account growth rate of 0.63%, which reflects the City's historical trend and translates into a modest increase in energy consumption each year. Residential consumption is projected to grow at 0.8% annually, while non-residential consumption remains flat. Overall, total system consumption (kWh) is projected to increase by 0.25% per year throughout the forecast period.

These assumptions serve as the foundation for estimating revenues, expenses, and ending fund balances, and ensure the financial plan reflects realistic growth and cost dynamics.

Table 6

Revenue Forecasting					
Key Assumptions	**FY 2026**	**FY 2027**	**FY 2028**	**FY 2029**	**FY 2030**
Revenue Escalation	2.6%	2.6%	2.6%	2.6%	2.6%
Reserve Interest	1.5%	1.5%	1.5%	1.5%	1.5%
Account Growth	0.63%	0.63%	0.63%	0.63%	0.63%
Residential	0.8%	0.8%	0.8%	0.8%	0.8%
Non-Residential	0.0%	0.0%	0.0%	0.0%	0.0%
Total Consumption (kWh)	0.25%	0.25%	0.25%	0.25%	0.25%

4-2 NPUA's Financial Plan

4-2-1 Revenues Overview

The financial plan for NPUA begins with a detailed forecast of electric utility revenues over the 2024–2030 period, incorporating base usage charges, excess usage, and other non-operating sources. Revenue projections are built from historical actuals, applied account growth rates, and a modest consumption escalation aligned with population trends. The resulting forecast shows a stable and gradual revenue increase, supported by a solid base of electric sales. Revenues are expected to increase from $14.8 million in 2026 to $15.0 million in 2030, reflecting a well-balanced revenue framework with no need for additional rate increases over the forecast period. This consistent performance confirms the utility's strong revenue foundation and aligns with the goals of long-term rate stability and system sustainability.

OPERATING REVENUES	2024	2025	2026	2027	2028	2029	2030
Base Usage Charge	$12,358,070	$13,047,723	$13,079,864	$13,112,266	$13,144,930	$13,177,858	$13,211,053
Excess Usage Charge	$1,249,648	$1,479,141	$1,488,404	$1,497,743	$1,507,156	$1,516,646	$1,526,213
Other Operating Revenues	$1,264,294	$277,567	$278,483	$279,411	$280,354	$281,311	$282,282
Non-Operating Revenues	$32,277	$210,000	$10,000	$10,000	$10,000	$10,000	$10,000
Total Revenues from Sales	**$14,904,289**	**$15,014,432**	**$14,856,751**	**$14,899,420**	**$14,942,440**	**$14,985,815**	**$15,029,548**

4-2-2 Operating Expenses Overview

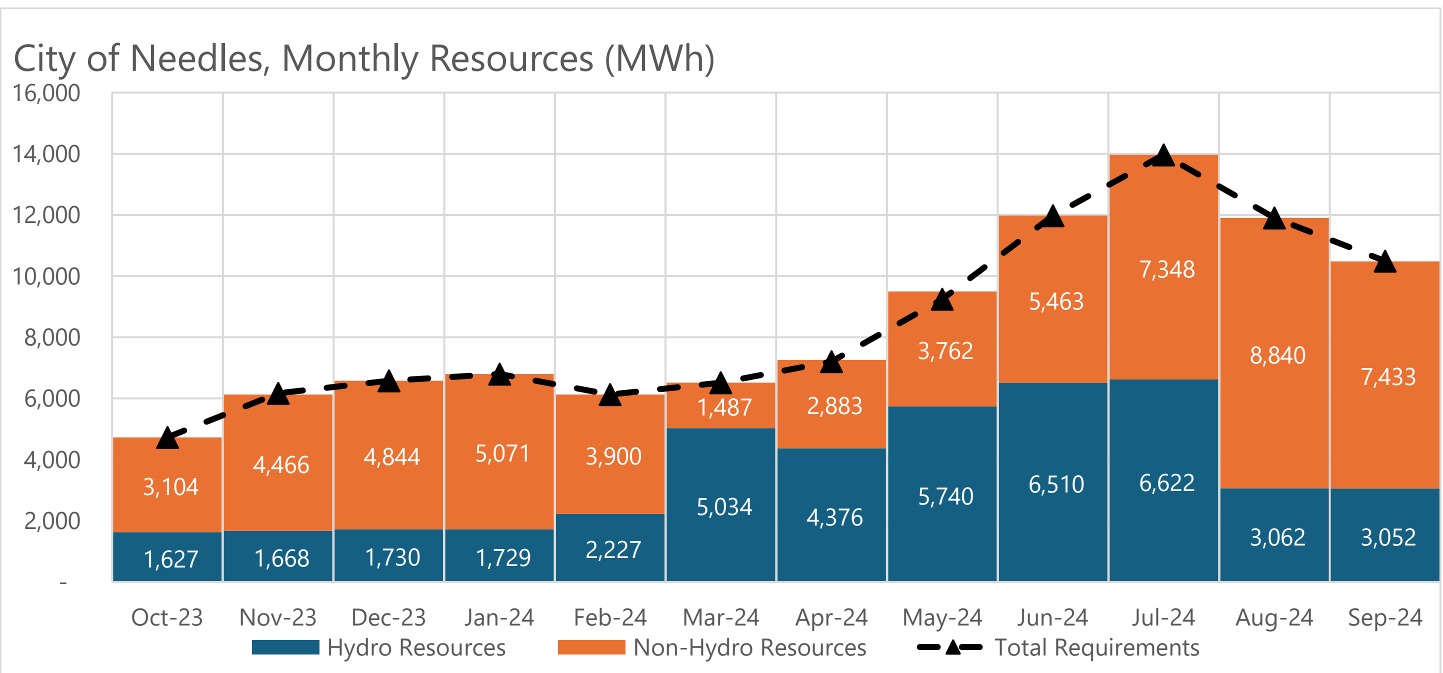
NPUA's projected operating expenses were modeled based on historical budget performance, planned capital investment activity, and power supply costs derived from forecasted market assumptions and contractual obligations. Major cost centers include purchased power, customer operations, administrative overhead, and AB32 compliance costs.

Purchase Power:

A key component of the financial forecast involves the City of Needles' evolving purchased power agreement, particularly the assumptions surrounding the Parker-Davis Project (PDP) and supplemental market purchases. The forecast assumes existing PDP capacity and energy allocations remain in place through September 2028, after which a proposed new contract reduces Needles' allocation by approximately 3% beginning in October 2028.

This change will shift a portion of energy procurement toward market-based spot purchases, subject to greater price volatility. To account for this, market power purchases from April 2025 onward include a 25% pricing adder to forward market price curves, reflecting a conservative estimate of the inherently volatility of market-based supplies. PDP rates for energy, capacity, and transmission were based on the latest apportionment study and assume 3% annual increases in transmission rates. Additionally, existing federal and non-federal energy exchanges remain unchanged, and the city continues to benefit from the Agua Caliente benefit credit contract that provides additional PDP resources to the City at an affordable rate.

While these assumptions provide a reasonable and conservative foundation for projecting future power costs, the planned reduction in PDP entitlements underscores the importance of maintaining financial flexibility in the event of higher-than-expected market prices or further shifts in the resource mix. Long-term, Needles' ability to balance cost-effective power procurement with system reliability will remain a central element of rate and capital planning.



AB32:

AB32 refers to California's Global Warming Solutions Act, which requires statewide reductions in greenhouse gas emissions to 1990 levels by 2020 and continued reductions thereafter. For electric utilities, this includes participation in the Cap-and-Trade program and Renewable Portfolio Standard (RPS) compliance, both of which result in direct costs for emission allowances and renewable energy procurement.

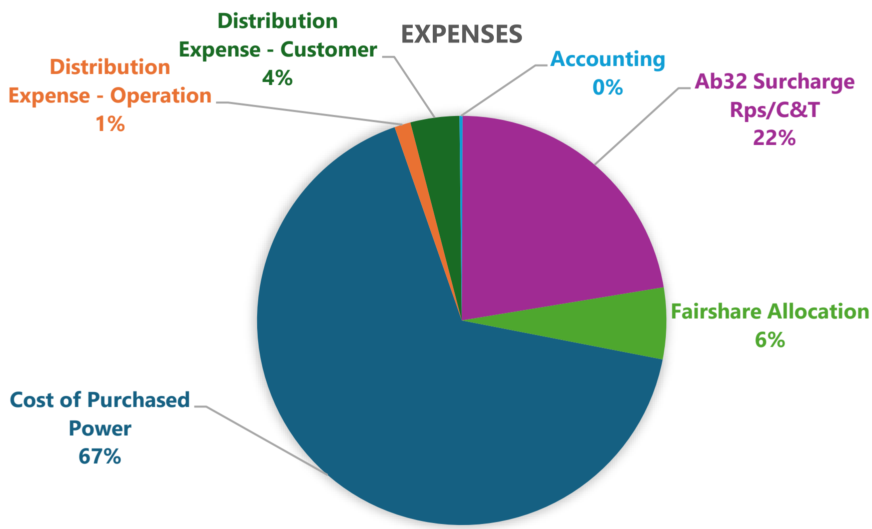
Senate Bill 100 (de León, 2018), California's latest Renewable Portfolio Standard (RPS) rules which requires Needles to power supply to be supplied from 60% of renewable resources by 2030 and from 100% of carbon-free resources by 2045.. In February 2024, the City entered a ten-year long-term transaction for the sale, purchase and delivery of Renewable Energy certificates (RECS), delivering 50,000 recs on or before March of the given year. The agreement is through December 31, 2033 at a cost of $412,500 per year. These RECs compensate for the City's non-renewable generation in accordance with AB 2514 and California Public Utilities Code § 399.11 et seq. For greenhouse gas compliance under AB 32, Needles is classified as an Electric Power Entity (EPE) and is subject to verified annual reporting. In 2024, verified CO_2-equivalent emissions totaled 23,130.26 metric tons, primarily from imports tagged at the WAPA delivery point. With an allocation of 30% free allowances, the city is responsible for offsetting the remaining 70%, or 15,491.18 metric tons. This obligation is met through the purchase of Direct Environmental Benefit (DEB) allowances or offsets, currently costing $1.138 million, paid in triennial installments. DEB credits are auction-based with an annually escalating pricing floor. However, recent auction results have seen prices float closer to the floor prices as continued uncertainty around when and how this key program will be extended continues to put a damper on near-term allowance price demand. Addressing these legislatively driven surcharges to the City's power planning, the utility is continuing to move forward in its capital improvement plans with the development of a 2-3 MW solar project to help offset these compliance obligations and augment its power supply.

Despite modest increases in personnel and administrative categories, total operating expenses remain within manageable bounds. The plan reflects expected increases in purchased power costs and distribution-related expenses, but these are offset by stable internal operations and cost containment measures. Over the planning period, expenses rise from $11.5 million in 2025 to $13.3 million in 2030, reflecting inflationary growth and power market adjustments. The financial position supports continued system reliability and compliance with operational goals without impacting customer rates.

Other Expenses:

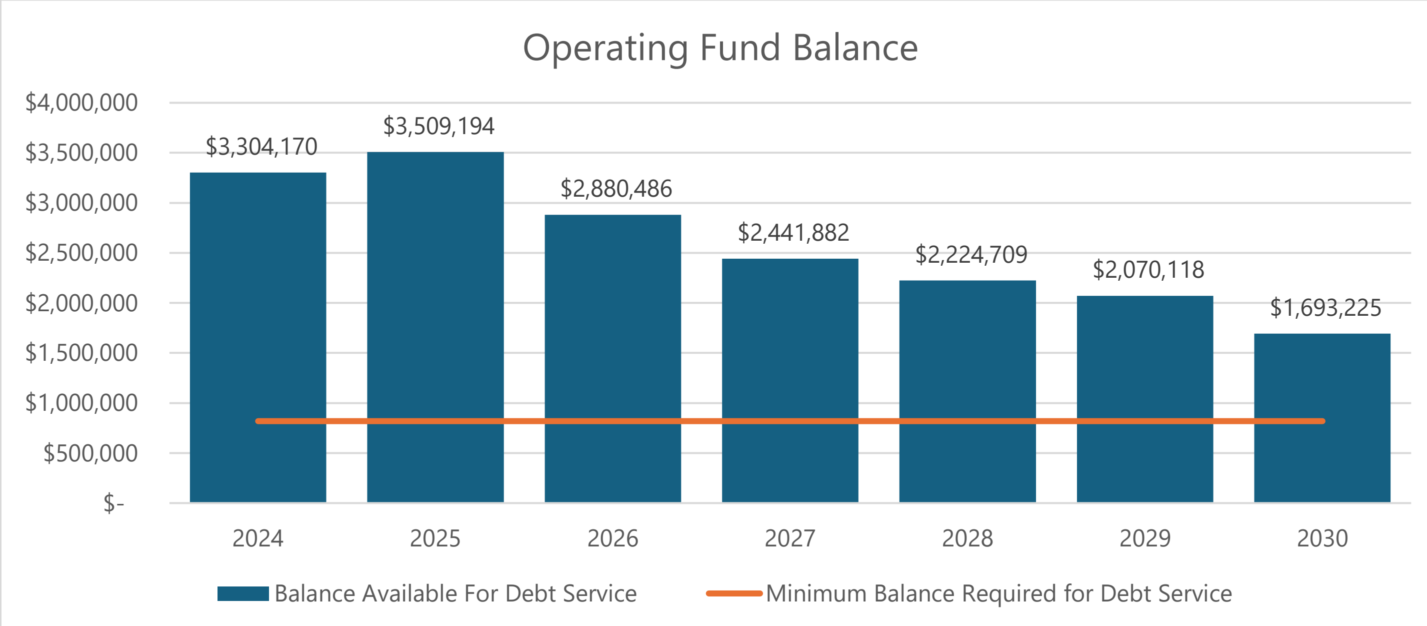
Additional expenses such as salary, labor, operating and maintenance expenses that are related to the distribution system, were calculated based on inflationary assumptions as seen in the above escalators.

OPERATING EXPENSES	2024	2025	2026	2027	2028	2029	2030
Cost of Purchased Power	$6,544,362	$5,703,290	$6,077,077	$6,350,087	$6,392,963	$6,364,016	$6,548,287
Distribution Expense - Operation	$68,694	$109,666	$114,842	$120,263	$125,939	$131,883	$138,108
Distribution Expense - Customer	$219,922	$330,252	$343,811	$360,400	$377,687	$395,824	$414,256
Accounting	$14,547	$21,500	$22,605	$23,767	$24,989	$26,273	$27,624
Ab32 Surcharge Rps/C&T	$1,799,997	$1,912,000	$2,002,246	$2,096,751	$2,195,717	$2,299,354	$2,407,883
Fairshare Allocation	$469,547	$483,633	$498,142	$513,086	$528,479	$544,333	$560,663
A&G Expense	$2,483,050	$2,944,897	$2,917,543	$2,993,183	$3,071,958	$3,154,014	$3,239,503
Total Expenses	**$11,600,119**	**$11,505,238**	**$11,976,266**	**$12,457,538**	**$12,717,731**	**$12,915,697**	**$13,336,323**



4-2-3 Debt Service Coverage

Debt obligations were evaluated against projected net revenues to assess compliance with NPUA's required 1.2x debt service coverage ratio. The model indicates that the utility consistently meets and significantly exceeds this benchmark each year, with coverage ranging from a high of 5.14x in 2025 to 2.48x in 2030. This strong coverage demonstrates the electric utility's capacity to support existing debt without jeopardizing financial stability or requiring additional revenue from rate increases.



Debt Service Coverage Test	2024	2025	2026	2027	2028	2029	2030
Annual Debt Service Payment	$682,350	$682,350	$682,351	$682,351	$682,351	$682,351	$682,350
Calculated Debt Service Coverage	4.84	5.14	4.22	3.58	3.26	3.03	2.48
Debt Covenants (Req. 1.2)	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**

4-2-4 Capital Plan

The City of Needles Utility Authority maintains a comprehensive Capital Improvement Plan (CIP) that supports system reliability, modernization, and long-term capacity needs. The CIP spans FY 2025 through FY 2030 and totals approximately $47.1 million in project commitments, reflecting a mix of developer-driven infrastructure, system upgrades, fleet enhancements, and renewable energy integration.

Key Projects Include:

- **230kV Transmission Line** – A $30 million developer-funded transmission line to expand regional reliability.
- **Substation Projects** – Including the South Hwy 95 substation, Cure Farms substation, and SCADA upgrades, supporting load growth and control system modernization.
- **Solar Projects** – Continued development of a 2–3 MW solar farm on Wastewater Plant Road and planning for a future solar microgrid.
  - This was not included in power forecasts in the "power cost" section above.
- **Distribution System Enhancements** – Upgrades to lines feeding Park Moabi, the Mohave line, and Eagle Pass-to-Cemetery routing.

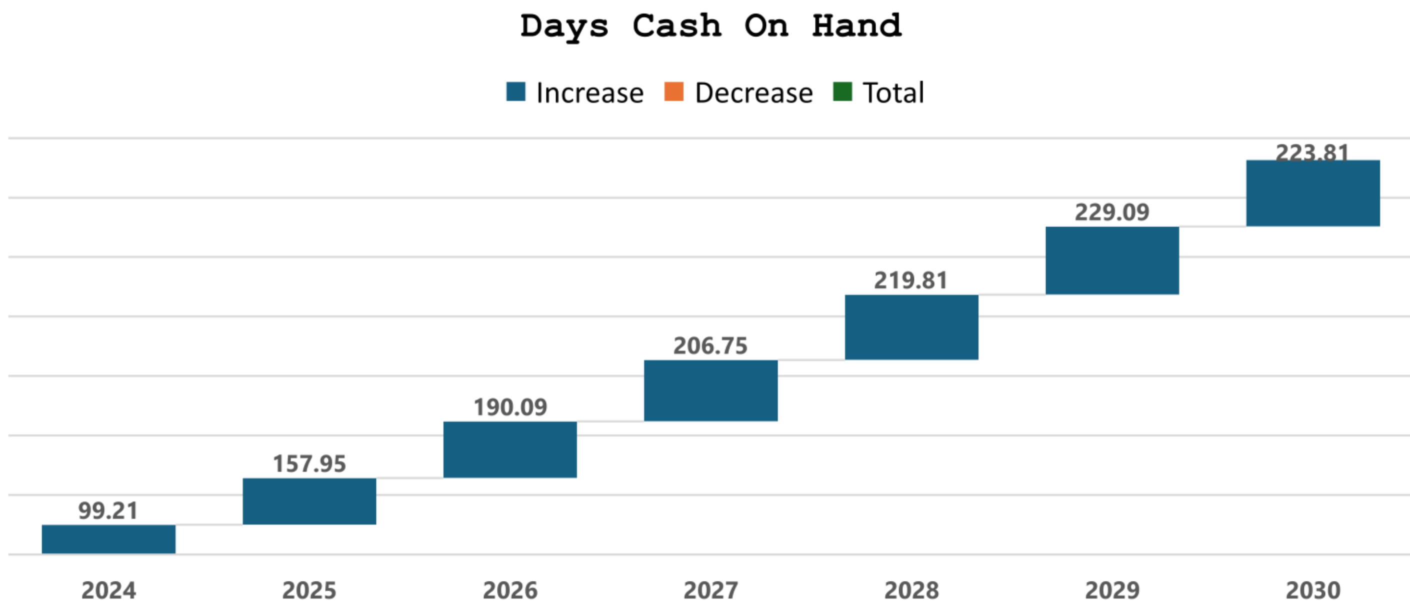
- **Streetlight & Fleet** – A citywide LED streetlight program and the purchase of an 80-ft double bucket truck to support operations.

The annual capital budget is allocated evenly across all forecast years at approximately $7.9 million per year, with funding sources distributed across multiple categories to ensure financial flexibility and sustainability. Developer contributions represent the largest share, providing approximately $7.3 million annually to support system expansion and interconnection infrastructure tied to growth-related projects. Rate-funded projects are supported through consistent transfers of approximately $611,667 per year from the Asset Replacement Fund, covering utility-owned infrastructure improvements, vehicle replacements, and operational facility needs. Additionally, projects such as the planned solar microgrid and SCADA upgrades remain scheduled within the planning window but currently unfunded, allowing the city to respond to future grant opportunities or allocate ARF reserves as needed. The capital plan is fully integrated into the long-term financial forecast and does not require any new debt issuance during the forecast period. By maintaining a stable, rate-supported infrastructure investment strategy and leveraging outside funding for expansion projects, the utility is well-positioned to preserve system reliability while accommodating future service demands.

4-2-5 Balance Sheet and Days Cash on Hand

The long-term financial plan also includes a forecast of NPUA's unrestricted cash balances and liquidity. Beginning with just over $4.9 million in 2025, the plan builds unrestricted reserves to over $8.1 million by 2030. Days cash on hand, a key financial health indicator, increases from approximately 158 days in 2025 to over 223 days by 2030, well above industry best practice thresholds of 180 days. These results reinforce that the utility maintains a strong balance sheet and is well-positioned to weather short-term financial stress or unanticipated capital needs. The financial strategy integrates ARF transfers, ongoing capital replacement, and consistent operating surpluses, all contributing to NPUA's ability to avoid rate increases while continuing to meet its service obligations.

Balance Sheet	2024	2025	2026	2027	2028	2029	2030
Beginning Unrestricted Cash & Equivalents	**$1,115,726**	**$3,153,092**	**$4,978,909**	**$6,237,020**	**$7,056,527**	**$7,658,861**	**$8,106,605**
Cash from Operations	$3,304,170	$3,509,194	$2,880,486	$2,441,882	$2,224,709	$2,070,118	$1,693,225
ARF Transfers	$(584,454)	$(672,670)	$(611,667)	$(611,667)	$(611,667)	$(611,667)	$(611,667)
Debt Service Outlays	$(682,350)	$(682,350)	$(682,351)	$(682,351)	$(682,351)	$(682,351)	$(682,350)
Purchase Payment		$(313,223)	$(313,223)	$(313,223)	$(313,223)	$(313,223)	$(313,223)
Bank & Trustee Charges		$(15,134)	$(15,134)	$(15,134)	$(15,134)	$(15,134)	$(15,134)
End of Year Unrestricted Cash & Equivalents	**$3,153,092**	**$4,978,909**	**$6,237,020**	**$7,056,527**	**$7,658,861**	**$8,106,605**	**$8,177,456**



4-3 Financial Reserves

Utilities' reserve balances are funds established and maintained for specific cash flow requirements, financial needs, project funding, or legal covenants. These balances are maintained to meet short-term cash flow requirements, mitigate potential rate shocks from sudden changes in revenue or expenditures, minimize the risk associated with financial obligations, and cover operational and capital needs under adverse conditions. Most utilities, rating agencies, and the investment community place significant emphasis on having sufficient reserves and designations. The level of reserves maintained by a utility is an important component when developing a multi-year financial management plan.

It is beneficial to periodically review reserve policies given changes in outstanding debt obligations, potential operational and financial risks, and the condition and vulnerability of system infrastructure. This type of review ensures reserve policies remain aligned with the present state of operations and financial management.

The Electric Utility currently maintains five designated reserves:

- **Unrestricted (Electric Revenue Fund)** – Serves as the primary operating reserve, providing liquidity for day-to-day operations, emergency expenses, and unforeseen cost fluctuations. The FY 2024 balance is **$3.15 million**, equivalent to 99 Days Cash on Hand, with a projected FY 2030 balance of **$8.18 million** (223 days). Recommended target is 180 days; adequately funded.

- **Administrative and Replacement Fund (ARF)** – Supports long-term capital reinvestment and asset replacement. The ARF balance grows from $1.90 million in FY 2024 to $2.54 million in FY 2025, after which it remains steady at that level through FY 2030. Annual contributions range from $584,454 in FY 2024 to $672,670 in FY 2025, with subsequent years receiving consistent transfers of $611,666.67. Annual outflows of $611,666.67 are planned beginning in FY 2026 for capital reinvestment, matching the annual contribution and maintaining the balance at the $2.54 million target. Current and projected funding levels meet identified capital contribution requirements and preserve the target balance; adequately funded.

- **Large User Connection Fee Fund –** Established to fund capital improvements or system upgrades required due to the addition of large-load customers. Funded through Connect Fee revenues, averaging $20,000 annually in the FY 2025–FY 2030 period, with a higher actual in FY 2024 of $38,726. While funding is consistent, the scale is modest relative to potential infrastructure costs for major large-user connections; partially funded.

- **Rate Stabilization Fund** – Intended to offset potential short-term rate increases caused by sudden changes in revenue or expenditure levels. Annual reserve transfers of $511,066 are programmed each year in the financial plan, indicating an active funding mechanism; adequately funded.

- **Power Cost Adjustment (PCA) Balancing Fund** – Established to mitigate unanticipated, significant changes in the cost of purchased power. When drawn upon, funds are replenished through a PCA rate applied to usage. Annual reserve transfers noted above may also contribute to this fund; based on planned contributions, adequately funded.

The financial plan ensures that reserves with defined targets—specifically the Unrestricted Fund, ARF, Rate Stabilization Fund, and PCA Balancing Fund—remain at or above minimum policy levels throughout the planning horizon. The Large User Connection Fee Fund should be periodically reviewed to confirm adequacy relative to anticipated load growth and system upgrade needs.

4-4 Financial Performance Criteria

The financial health of the electric utility is guided by three key performance criteria. These benchmarks ensure that electric rates remain sufficient to support operations, debt obligations, and long-term sustainability:

- **Reserve Balance**: The city maintains an electric resource reserve account designed to provide operating liquidity and capital flexibility. The minimum balance in this account is targeted at 180 days of operating expenses, consistent with industry best practices.

- **Financial Metrics:**
  - **Operating Ratio:** Determined by taking the operating expenses divided by the operating revenues and multiplied by 100**.** Results for the test year are 80.6%. Industry average is 87%.
  - **Debt Service Coverage Ratio (DSCR):** Tracks the utility's capacity to meet debt service requirements. The current plan maintains a DSCR of no less than 2.4x in all forecast years, well above the 1.2x covenant
  - **Days Cash on Hand**: Recommended days cash on hand is 180 days. The utility meets this for the forecasted years as part of this study.
  - **ARF Reserve Transfer** – This fund is used to pay for capital improvement projects and serves as a capital reserve. The City's current policy states that annual transfers should equate to 4% of net plant value. The forecast includes an estimate of this transfer amount based on the City's 2025 Capital Improvement Plan which equates to $611,667 annually over the forecasted period.
  - **PCA balancing fund** – For the fiscal year (FY 25) over-hydro budget is $5,280,000. Twenty percent (20%) of the over-hydro budget for FY 25 is $1,056,000 which is the current PCA fund balance. Balancing fund as of November 2024 was $1,830,284, exceeding policy requirements. Pursuant to the PCA policy, on January 21, 2025, the Public Utility Board voted to approve to reduce the PCA rate by $0.02 to refund the over collected reserve funds starting February 1.
  - **Rate Stabilization Fund** - The City's Financial Policies currently maintain a minimum operating reserve balance of 10% of budgeted annual O&M expenditures, or approximately 1.2 months of O&M expenses, consistent with General Fund policies.

4-5 Proposed Financial Plan

The proposed financial plan for FY 2025 through FY 2030 maintains rate stability while meeting all operational, capital, and debt service obligations. No rate increases are proposed during the planning horizon. The plan leverages stable electric sales revenue, conservative load growth assumptions, and prudent cost forecasting. Annual transfers to capital reserves and ARF accounts are preserved, and all debt covenants are satisfied throughout the forecast.

While the plan sustains adequate coverage ratios and reserve targets, projected net cash from operations narrows in the later years of the forecast, declining from $3.51 million in FY 2025 to $1.69 million in FY 2030. This tightening margin is primarily driven by rising operating costs—particularly purchased power and administrative expenses—outpacing the modest growth in revenues. Continued monitoring of expenditure trends and load performance will be important to ensure the utility maintains sufficient flexibility to respond to unanticipated cost pressures or revenue fluctuations.

By aligning expenditures with actual consumption patterns and maintaining healthy financial metrics, the proposed plan supports both financial sustainability and long-term system reliability.

5 Cost-of-Service Analysis

Section 5 Cost of Service Overview

A Cost-of-Service Analysis (COSA) is an analysis of a utility's annual revenue requirements and a methodology for allocating these expenses across each customer category based on customer characteristics.

A utility's revenue requirement is the amount of revenue the utility must generate annually to recover the costs incurred by the utility in the provision of service. Costs may include typical operating expenses, capital investments, and a necessary margin of revenue to ensure the utility's ability to continue to safely operate. Costs included in a revenue requirement may be different whether the utility is privately or publicly held and will be based upon recent operating expenses and may include forecast adjustments.

In this study, the fiscal-year operating results for 2022 through 2024 were used as a starting point and projected forward to include changes from rising power costs, inflation, and other inputs made by NPUA staff. Needles Public Utility Authority must rely on its revenues from rates to fund operations and capital improvements to the electric system. Therefore, the following items have been included in NPUA's revenue requirements and are further detailed below:

Determination of Revenue Requirements

+ Purchased Power Expense

+ Operation & Maintenance Expense

+ Administration & General Expense

+ Capital Projects funded from Rates

+ Reserve fund

= Revenue Requirements

The next step in the cost-of-service study is to separate the revenue requirements into the functional areas of the utility such as power supply, power distribution, and customer metering and billing functions. Costs may be further classified based on whether the costs are related to the supply of energy or a function of system capacity. Customer-specific costs may also be directly assigned to their own functional category.

Once the revenue requirements have been functionalized and classified according to the proper cost components, they are allocated among the separate customer categories. The goal of cost allocation is to properly assign costs using a cost causation model, ensuring that each customer is being sufficiently charged for the impact they have on the utility. Many of the allocation methods are widely accepted across utilities as standard practice based on the type of expense and cost function that is being allocated. This includes the use of energy sales data to pass through variable related costs such as fuel supply costs, and customer demand data to assign fixed costs associated with customer capacity/sizing requirements.

5-1 Functionalization

NPUA's electric utility expenses were evaluated and assigned to various functional categories within the electric system. The functional categories include the following:

- **Power Supply – Capacity:** Fixed charges and capacity costs associated with the purchase of power.
- **Power Supply - Energy:** Volumetric or fuel-related costs associated with the production of power.
- **Power Supply - Transmission:** System delivery related charges for moving bulk power to the utility's service territory.
- **Delivery:** Local distribution or repair related costs associated with delivering power to end-use customers.
- **Customer: Connection:** Costs related to connecting customers to the distribution grid.
- **Customer: Metering & Billing:** Costs related to the metering, meter reading, and customer billing services provided to end-use customers.
- **Administrative & General:** Costs related to employee expenses and functioning of administrative services related to supporting end-use customers.
- **Direct Assignment:** Costs that may be purposefully assigned to cost-causers, i.e. Street Lights.

Table 7

Allocator	Power - Energy	Power - Capacity	Power - Transmission	Delivery	Customer Connection	Cust. Metering & Billing	A&G	Direct Assignment
Direct Assignment	0%	0%	0%	0%	0%	0%	0%	100%
DA Power-Energy	100%	0%	0%	0%	0%	0%	0%	0%
DA Power-Capacity	0%	100%	0%	0%	0%	0%	0%	0%
DA Power-Transmission	0%	0%	100%	0%	0%	0%	0%	0%
Purchased Power	40%	50%	10%	0%	0%	0%	0%	0%
Parker Davis Purchase Power	47%	41%	12%	0%	0%	0%	0%	0%
Power/Cap Split	50%	50%	0%	0%	0%	0%	0%	0%
Delivery	0%	0%	0%	50%	50%	0%	0%	0%
Service Drop	0%	0%	0%	0%	100%	0%	0%	0%
Metering	0%	0%	0%	0%	0%	100%	0%	0%
Billing	0%	0%	0%	0%	0%	100%	0%	0%
A&G	0%	0%	0%	0%	0%	0%	100%	0%
Salaries	0%	0%	15%	30%	30%	20%	5%	0%

Operating expenses for FY 2026 were evaluated and allocated to the most closely associated functional categories within the electric system, as shown in Table 7. The detailed functionalization of the operating budget is included below in Table 8.

Table 8

Line	Cost Function	Operating Expense
1	Power Supply – Capacity	$1,001,123
2	Power Supply – Energy	$1,499,265
3	Power Supply – Transmission	$229,241
4	Delivery	$1,062,869
5	Customer: Connection	$1,133,772
6	Customer: Metering & Billing	$330,683
7	Administrative & General	$160,977
8	Direct Assignment	$0
9	**Total**	$11,976,266

5-2 Cost Causation Classification

Cost causation classification is the process of attributing utility costs to the customers or services that generate those costs, ensuring equity in rate development. For this study, NPUA's FY 2026 operating expenses were functionalized into discrete categories—power supply, delivery, customer services, administration, and direct assignments—so that costs are aligned with the specific utility functions they support.

Power supply costs, including both capacity and energy, are assigned based on each customer class's contribution to system demand and total energy consumption. Delivery-related costs are allocated according to the infrastructure requirements necessary to serve each class, while customer-related expenses are distributed based on the level of service activity (e.g., billing, metering) required. Direct assignments are made where costs can be specifically attributed to a particular class or function.

This classification and allocation process also incorporates NPUA's minimum revenue requirement necessary to meet ongoing Administrative and Replacement Fund (ARF) transfers, debt service obligations, and other fixed financial commitments. For the test year, this equates to a minimum required return of approximately 17% above operating expenses to maintain compliance with reserve policies and debt covenants. The functionalized approach ensures that these fixed obligations are proportionally recovered from all customer classes based on cost responsibility, supporting both financial sustainability and rate fairness. The end results of the cost allocation process are detailed in the table below:

Rate Class	Allocated Revenues	Allocated Expenses	Over / (Under) COSS	as %
Residential	$4,633,573	$4,331,735	$301,838	7%
Small Commercial (0-25kW)	$1,590,967	$1,601,352	-$10,385	-1%
Medium Commercial (25kW-100kW)	$1,010,181	$680,601	$329,579	33%
Large Commercial (100kW+)	$7,582,689	$5,567,862	$2,014,828	27%
Streetlights	$39,342	$85,834	-$46,492	-118%
Total	$14,856,751	$12,267,384	$2,589,367	17%

5-3 Unbundling / Unit Costs

Following the classification of costs by functional category, the next step in the cost-of-service analysis is to unbundle those costs into unitized components that reflect how costs are incurred and recovered. Unbundling unit costs involves translating the total costs within each function—such as capacity, energy, delivery, customer service, and administration—into cost metrics that can be applied to specific billing units like kilowatts (kW), kilowatt-hours (kWh), meters, or customer accounts. This process provides the foundation for rate design by identifying the unit cost basis for each portion of the customer bill. For example, capacity-related costs are typically expressed on a $/kW basis to reflect demand-related cost recovery, while energy-related costs are expressed on a $/kWh basis to align with volumetric consumption. Customer-related costs are unbundled into a $/meter or $/account metric to support the development of fixed monthly charges. By unbundling costs in this way, the rate design process can ensure that each rate component corresponds to the service being provided, supporting transparency, equity, and alignment with cost causation principles.

Unbundled Unit Costs	TOTAL	Residential	Small Commercial (0-25kW)	Medium Commercial (25kW-100kW)	Large Commercial (100kW+)	Streetlights
Customer - Related						
Metering & Billing (Monthly)	$19.32	$18.73	$19.25	$31.75	$157.55	$0.09
Service Connection (Monthly)	$27.51	$21.03	$42.07	$105.17	$147.24	$15.87
Delivery						
Per MWh	$22.15	$33.19	$33.05			$6.31
Per kW				$5.79	$5.08	
Generation - Energy per MWh	$43.92	$26.54	$26.54	$26.55	$59.62	$59.62
Generation - Capacity Per MWh	$50.58	$59.92	$69.34	$46.81		$21.66
Generation - Capacity Per kW					$8.31	

6 Electric Rates

Section 6 Rate Options

6-1 General Rate-Making Principles

Utilities need to establish rates that are fair and equitable for customers while also covering all operational costs and providing for necessary capital investments. Rate structures should be designed to promote energy conservation and reflect the true cost of service delivery, which may vary by customer class or usage level.

Utility rates are typically required to be fair and not unduly discriminatory among customer classes. In addition to this equitable standard, rate experts also recognize other considerations in the setting of utility rates, including recovery of costs by the utility, efficient use of resources, simplicity, stability, and competition with other suppliers or alternatives. After a class COSA is prepared, it must be decided how much weight should be given to the COSA versus the results indicated by other analyses and considerations in adjusting the rates of each customer class. Though some agencies, councils and boards give great deference to the results recommended by the COSA, many others use it only as one of several considerations given weight in the rate setting process. In part, this willingness of regulatory agencies or boards to depart from the results of a COSA is because there is no single or right way to develop a COSA.

The results of designing electric rates, especially unbundled rates, are not as definitive or unassailable as designing the electric distribution system, which is paid for through electric rates. Nonetheless, the result (or a range of alternative results) of a class COSA provides valuable information as to the relationship between the electric service used by class and the utility's overall costs. While there is a range of reasonable results for a COSA, that range is not unbounded and there are clearly times when the rates of a class fall outside of this range, resulting in a class subsidizing or being subsidized by other customer classes. In the end, the principles by which rate practitioners are guided is that rates designed for any utility should strike a reasonable balance between several key factors. In general, rates should:

- Generate a stable rate revenue stream which, when combined with other sources of funds, is sufficient to meet the financial requirements and goals of the utility,
- Be equitable – that is, they should generate revenues from customer classes that are reasonably proportionate to the cost to provide service to that customer class,
- Be easy to understand by customers, and
- Be easy to administer by the utility.

Finding the right balance in ratemaking involves a thorough evaluation of revenue needs and service costs. This process determines how to design rates that comply with legal requirements and meet the utility's specific goals given its operating conditions.

6-2 Current Rate Design

The City of Needles electric utility employs a single rate structure for all NPUA customers that distinguishes between winter and summer periods to account for varying energy demand and hydro allocation availability. Winter rates, effective from December 1 through February 28, include a monthly Basic Service Charge and provide a 401-kWh hydroelectric allocation at the "under hydro" current rate. Any usage beyond this hydro allocation is charged at an Over Hydro rate.

In contrast, the summer rates, effective from June 1 through September 30, keep the same Basic Service Charge but increase the hydro allotment to 754 kWh, with a lower hydro rate than the summer hydro rate. The Over Hydro rate during the summer is also reduced due to a planned Power Cost Adjustment (PCA. Both seasonal periods include a California-mandated Conservation Charge of $0.0025 per kWh and a Utility User Tax—applied only in the summer—at a rate of 2.5%. This structure reflects a policy goal of distributing lower-cost hydro resources evenly amongst all customers, adjusted seasonally for resource availability.

6-3 Rate Design Theory

Rate Design is rooted in time and court-tested theories and aims for rates that are just and reasonable, are fair and avoid undue discrimination, are simple to understand, are stable, are designed to promote the efficient use of energy, and are effective at yielding the revenue requirements. The allocation process during the cost-of-service analysis plays a critical role in determining the starting point for the rate design. Continual investigation of costs and analysis of customer usage data can further our abilities to make sure rates are just and reasonable and are equitably allocated amongst revenue classes. The design of rates themselves plays the critical role in determining whether rates are effective to yield the revenue requirements, are understandable, and promote efficient use of energy. Several alternative rate options is provided below:

6-3-1 Flat Rates

Flat rates can come in several forms such as a monthly customer charge typical of streetlighting and unmetered devices, customer and energy charges that differentiate between the metering and billing costs from the delivery of power, or customer, energy, and demand charges that differentiate between billing, fixed system, and variable energy costs. The benefit of flat rates is that they typically are easy to understand and implement and may be well suited for yielding the revenue requirements. The disadvantage of flat rates is that they might not promote efficient use of energy and may lead to costs being socializing across customers who may have different cost impacts on the system.

6-3-2 Inclining Block Rate

Inclining block rates are designed with rate charges that increase with the increased use of the system. Inclining block rates are great at promoting energy conservation, but may be more difficult to understand by customers, more difficult to implement, may disadvantage efficient users of the system, and may be less effective at yielding the revenue requirements.

6-3-3 Declining Block Rate

Opposite from inclining block rates, declining rates decline with greater use of the system. Often used as an alternative to demand-based rates, declining block rates can help ensure the revenue requirements are collected, but may be more difficult to understand and implement, discourages conservation, and may discriminate against low-use customers.

6-3-4 Time-of-Use Rates

Time-of-use rates may be implemented if the time-variance of system use affects the costs of operating the system. Examples of this would include power supply and transmission costs that increase during peak system hours. Time-of-Use rates would be designed to mimic the intervals of higher system costs through increased prices during peak periods. Time-of-Use rates may be considered fairer since they align power supply costs with the cost-causers to a better degree and maybe more efficient at yielding revenue requirements, however they are significantly more difficult to understand and to implement.

6-4 Proposed Rate Options

As part of the City's efforts to ensure fair, sustainable, and transparent electric rates, three-rate design options and a separate evaluation of street lighting charges were presented to the Alternative Rate Ad Hoc Committee for review and discussion. The Committee was tasked with evaluating how best to align the utility's cost of service findings with ratepayer expectations, affordability goals, and long-term financial stability. The rate options explored a range of structures—keeping the current approach, simplifying the allocation of power and delivery costs, and integrating demand-based billing—all with the goal of improving fairness and consistency across customer classes. The Committee's feedback was critical in shaping the recommendations included in this report.

6-4-1 Rate Option 1

Rate Option 1 keeps the City's existing pricing structure without change. This approach maintains the current rate design, customer classifications, and rate levels, offering continuity for customers while avoiding the need to revise any billing system components. It preserves the simplicity of the existing structure, although it does not address underlying cost allocation imbalances shown in the cost-of-service study.

SAMPLE BILLING (SUMMER)		
	Residential (1500 kWh)	**Large Commercial (100kW+)**
Basic Service Charge	$36.22	$36.22
Hydro Allotment (754 kWh)	$53.08	$53.08
Over Hydro	$92.35	$29,351.25
CA Cons. Charge	$3.75	$594.60
	$185.41	**$30,035.15**

6-4-2 Rate Option 2

Rate Option 2 introduces a class-based rate structure that differentiates between Residential, Small Commercial (0–25 kW), Medium Commercial (25–100 kW), and Large Commercial (over 100 kW) customers. Each class includes a fixed customer charge, with remaining costs split between a Power Charge and a Delivery Charge. This unbundled structure creates greater transparency, improves cost alignment, and supports the utility's ability to adapt charges as wholesale power costs change.

SAMPLE BILLING (SUMMER)		
	Residential (1500 kWh)	**Large Commercial (100kW+)**
Customer Charge	$45.15	$346.08
Delivery Charge Per MWh	$29.75	$1,744.26
Power Charge Per MWh	$174.04	$24,001.19
CA Cons. Charge	$3.75	$594.60
	$252.69	**$26,686.12**

6-4-3 Rate Option 3

Rate Option 3 builds upon Option 2 by introducing a Demand Charge for Medium and Large Commercial customers. This component better reflects the cost of infrastructure needed to support higher usage and demand profiles. By recovering a portion of costs through a demand-based mechanism, the utility can more accurately assign costs to the customers who place the greatest load on the system, while incentivizing more efficient energy use.

SAMPLE BILLING (SUMMER)		
	Residential (1500 kWh)	**Large Commercial (100kW+)**
Customer Charge	$45.15	$346.08
Delivery Charge Per MWh	$29.75	$0.00
Delivery Charge Per kW	$0.00	$1,525.00
Power Capacity Charge Per kW	$0.00	$5,231.12
Power Energy Charge Per MWh	$174.04	$18,017.97
CA Cons. Charge	$3.75	$594.60
	$252.69	**$25,714.77**

6-4-4 Street Lighting Rate Option

Street Lighting Rate Option presents a separate analysis of streetlight charges, which have not been revisited in many years. The proposed rates were developed based on available records of bulb types and sizes and reflect a cost-to-serve model based on assumed dusk-to-dawn operation. While the analysis could be refined further with updated inventory data, the current proposal provides a more equitable baseline for recovering streetlight service costs and encourages future evaluation by lamp type, fixture style, and mounting method.

STREETLIGHTS				
Type	**Size**	**KWh**	**Current Rate**	**Proposed Rate**
Decorator	100	43	$11.74	$22.39
Sodium	100	43	$8.62	$22.39
Sodium	200	85	$14.58	$26.57
Sodium	400	171	$27.15	$35.12
LED	38	16	$4.24	$19.71

Section 7 Cost of Service Rate Summary and Recommendations

7-1 Proposed Rate Design

7-1-1 Electric Rate Adoption

The proposed rate design for the City of Needles maintains the current seasonal rate structure and customer class distinctions, preserving its familiar and easy-to-understand application for all users. Following a review with the Alternative Rate Ad Hoc Committee, the rate structure was evaluated for equity across customer classes. The Committee's feedback highlighted that the largest commercial customers are sharing the cost burden under the existing structure, effectively subsidizing residential customers. The retained design incorporates this input, ensuring a continued balanced cost recovery across classes while still supporting the City's overarching rate policy goals. These goals include maintaining affordable residential rates, offering a transparent and straightforward rate structure for all customers, and ensuring commercial rates stay competitive to attract and keep large commercial and industrial development. This design strategy aligns with the City's economic development goals while promoting fairness and long-term stability.

The Alternative Rate Ad Hoc Committee's decision does not shut the door on alternative rate designs in the future; however, given limitations in NPUA's customer billing system and likelihood of rate-shock inducing shifts between rate designs, it was not appropriate to change at this time.

7-1-2 Street Light Rate Adoption

The City has accepted the proposed adjustments to the streetlight rate structure, acknowledging the need to better align charges with the actual cost of service. As the City bears full financial responsibility for these assets, the updated rates provide a more accurate reflection of operating costs while preserving fiscal accountability. The rate modifications will be implemented to ensure that charges are proportional to usage and technology type. In addition, the city has started a transition plan to replace high-pressure sodium fixtures with LED alternatives as existing bulbs reach the end of their service life. This phased LED conversion is expected to enhance energy efficiency and reduce long-term maintenance and operating costs, further supporting the sustainability of the city's street lighting system.

7-2 Recommendations

Based on the comprehensive findings of this study, the City of Needles is well-positioned to maintain financial stability without requiring immediate rate increases. The utility's strong cash position, consistent revenue growth, and fully funded capital improvement plan demonstrate prudent financial stewardship. With a diverse customer base and a well-structured supply portfolio, Needles can continue to meet its operational and capital obligations while investing in infrastructure that supports long-term system reliability and growth. The proposed rate design retains the simplicity and fairness of the current structure, aligns with community input received through the Alternative Rate Ad Hoc Committee, and supports the City's policy priorities of maintaining low residential rates, promoting transparency, and ensuring equitable cost recovery across all customer classes.

Based on our findings, we recommend that:

- The City adopt the proposed financial plan and proposed increases to the street lighting rates,
- Continue to actively monitor NPUA's evolving power resources and evolving market conditions,
- Modernize customer programs to make adoption of more complicated rate designs more feasible and data collection and reporting more accessible,
- Revisit its cost-of-service analysis periodically to ensure ongoing alignment with operational needs and ratepayer expectations.