Heber Light & Power

Electric Cost of Service Study and Financial Projection

March 2025

Corporate location:
Utility Financial Solutions, LLC
185 Sun Meadow Court
Holland, MI USA 49424
(616) 393-9722
Fax (888) 566-4430

Submitted Respectfully by:
Mark Beauchamp, CPA, CMA, MBA
President, Utility Financial Solutions, LLC
mbeauchamp@ufsweb.com
(616) 393-9722

This page intentionally left blank

March 2025

Jason Norlen
General Manager
Heber Light & Power
31 South 100 West
Heber, UT 84032

Dear Mr. Norlen:

We are pleased to present the Report for the electric cost of service study and financial projection for Heber Light & Power (HL&P). This report was prepared to provide HL&P with a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of this rate study are:

- Determine electric utility's revenue requirements for fiscal year 2025
- Identify cross-subsidies that may exist between rate classes
- Recommend rate adjustments needed to meet targeted revenue requirements
- Identify the appropriate monthly customer charge for each customer class

This report includes results of the electric cost of service study and financial projection and recommendations on future rate designs.

This report is intended for information and use by the utility and management for the purposes stated above and is not intended to be used by anyone except the specified parties.

Sincerely,

Utility Financial Solutions, LLC
Mark Beauchamp
CPA, MBA, CMA
185 Sun Meadow Ct
Holland, MI 49424

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. Introduction

This report was prepared to provide Heber Light & Power (HL&P) with an electric cost of service study and financial projection, and a comprehensive examination of its existing rate structure by an outside party.

The specific purposes of the study are identified below:

1) ***Determine electric utility's revenue requirements for fiscal year 2025***. HL&P's revenue requirements were projected for the period from 2025 – 2029 and included adjustments for the following:

    a. Projected power costs
    b. Projected changes in staffing levels
    c. Capital improvement plan projected over next five years

2) ***Identify if cross-subsidies exist between rate classes.*** Cross-subsidies exist when certain customer classes subsidize the electric costs of other customers. The rate study identifies if cross-subsidies exist and practical ways to reduce the subsidies. The cost of service study was completed using 2025 projected revenues and expenses. The financial projections are for the period from 2025 – 2029.

3) ***Identify cost-based power supply and distribution rates.*** The cost of providing electricity to customers consists of several components, including power generation, distribution, customer services, transmission, and transfers to the general fund. Electric unbundling identifies the cost of each component to assist the utility in preparing for electric restructuring and understanding its cost structure.

4) ***Identify the appropriate monthly customer charge for each customer class.*** The monthly customer charge consists of fixed costs to service customers that do not vary based on the amount of electricity used.

5) ***Recommend rate adjustments needed to meet targeted revenue requirements.*** The primary purpose of this study is to identify appropriate revenue requirements, and the rate adjustments needed to meet targeted revenue requirements. The report includes a long-term rate track for HL&P to help ensure the financial stability of the utility in future years.

2. Cost of Service Summary

Utility Rate Process

HL&P retained Utility Financial Solutions, LLC to review utility rates and cost of service and make recommendations on the appropriate course of action. This report includes results of the electric cost of service and unbundling study and recommendations on future rate designs.

Utility Revenue Requirements

To determine revenue requirements, the revenues and expenses for fiscal years 2022 and 2023, 2024 budget were analyzed, with adjustments made to reflect projected operating characteristics. ***The projected financial statements are for cost of service purposes only.***

Table 1 is the projected financial statement for the Electric Department from 2025 – 2029.

The following pages review cash flow, debt coverage ratio, and rate of return which are important indicators of financial health.

Table 1 – Financial Statements (without rate adjustments)

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Operating Revenues:					
Electric Sales					
Yard Lighting	$ 17,523	$ 17,926	$ 18,747	$ 19,309	$ 19,887
Residential Pumping	15,944	16,311	17,058	17,569	18,095
Small General Service	3,379,842	3,457,647	3,615,985	3,724,266	3,835,841
Small General Service Pumping	93,317	95,465	99,837	102,826	105,907
Medium General Service	3,746,011	3,832,246	4,007,738	4,127,750	4,251,412
Medium General Service Pumping	267,852	274,018	286,567	295,148	303,990
Large General Service	2,207,807	2,258,631	2,362,062	2,432,794	2,505,678
General Service Net Metering	8,706	8,906	9,314	9,593	9,880
Electric Vehicle Charging	134,551	137,648	143,951	148,262	152,704
Residential Demand	16,115,838	16,486,830	17,241,820	17,758,129	18,290,140
Residential Demand over 400 AMPS	231,932	237,271	248,137	255,567	263,224
Residential TOU Demand	480,870	491,940	514,467	529,873	545,747
Contract Customer 1	39,394	40,301	42,146	43,408	44,709
Connection Fees	136,116	136,116	136,116	136,116	136,116
Other Income	234,189	239,581	250,552	258,055	265,786
Jordanelle Electricity Sales	1,141,671	1,217,464	1,298,288	1,337,236	1,377,353
Impact Fees	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000
Additional PCA Revenues	-	3,308,710	3,875,976	3,998,400	4,198,988
Total Operating Revenues	$ 31,251,563	$ 35,257,012	$ 37,168,761	$ 38,194,301	$ 39,325,457
Operating Expenses:					
Purchases					
Purchased Power (Cost of Sales and Service	$ 12,594,117	$ 13,447,676	$ 14,481,545	$ 14,985,915	$ 15,570,075
Energy Rebates	60,665	63,319	65,201	65,510	66,084
Purchase Power Direct - Jordanelle Energy	1,712,507	1,826,195	1,947,431	2,005,854	2,066,030
System Control and Load Dispatching	989,092	1,054,755	1,124,777	1,158,520	1,193,276
Production					
Gas Generation Fuel	$ 2,379,917	$ 2,484,031	$ 2,557,872	$ 2,569,999	$ 2,592,511
Gas Generation O&M	679,791	724,921	773,046	796,237	820,124
Other Operating Expenses (Revenues)					
Salaries, Wages, Benefits	$ 1,488,306	$ 1,587,111	$ 1,692,474	$ 1,743,249	$ 1,795,546
Professional Services	252,126	268,864	286,713	295,315	304,174
Maintenance and Training	5,945,122	6,339,802	6,760,684	6,963,504	7,172,409
Materials	202,417	215,855	230,185	237,091	244,204
Building Expenses	55,153	58,814	62,719	64,600	66,539
Office Expense and Postage	169,957	181,240	193,272	199,070	205,042
Vehicle Expense	578,607	617,020	657,982	677,721	698,053
Bad Debt Expense	28,754	30,663	32,699	33,680	34,690
Miscellaneous	345,320	368,245	392,692	404,472	416,606
Depreciation Expense	3,620,492	3,757,903	3,889,549	4,053,476	4,447,364
Depreciation on Impact Fee Related Capital	1,027,396	1,093,260	1,158,994	1,220,347	1,258,399
Contributed Capital Depreciation	895,744	975,744	1,055,744	1,135,744	1,215,744
Total Operating Expenses	$ 33,025,483	$ 35,095,417	$ 37,363,578	$ 38,610,304	$ 40,166,870
Operating Income	$ (1,773,920)	$ 161,595	$ (194,817)	$ (416,004)	$ (841,413)
Other Income & Expense					
Interest and Other Income	$ 87,505	$ 132,168	$ 72,624	$ 60,230	$ -
Interest On Long Term Debt	(3,483,701)	(3,395,826)	(3,800,733)	(3,679,667)	(4,471,457)
Bond Issuance Costs	(510,000)	-	(200,000)	-	(360,000)
Transfers					
Distribution to Owners	(300,000)	(300,000)	(300,000)	(300,000)	(300,000)
Capital Contributions	2,000,000	2,000,000	2,000,000	2,000,000	2,000,000
Non Operating Income/Expense	**$ (2,206,196)**	**$ (1,563,657)**	**$ (2,228,109)**	**$ (1,919,438)**	**$ (3,131,457)**
Net Income	**$ (3,980,116)**	**$ (1,402,062)**	**$ (2,422,925)**	**$ (2,335,441)**	**$ (3,972,870)**
Adjusted Operating Income	**$ 149,219**	**$ 2,230,598**	**$ 2,019,921**	**$ 1,940,086**	**$ 1,632,730**

Projected Cash Flow

Table 2 is the projected cash flow for 2025 – 2029, including projections of capital improvements as provided by HL&P. Changes in the capital improvement plan can greatly affect the cash balance and recommended minimum cash reserve target. The cash balance for 2025 is projected at $26.43M and $-9.16M in 2029. The recommended minimum cash reserve level for 2025 is $16.57M and $20.11M for 2029.

Table 2 – Projected Cash Flows (without rate adjustments)

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Projected Cash Flows					
Net Income	$ (3,980,116)	$ (1,402,062)	$ (2,422,925)	$ (2,335,441)	$ (3,972,870)
Depreciation Expense/Amortization	5,543,631	5,826,906	6,104,286	6,409,566	6,921,506
Subtract Debt Principal	(1,843,830)	(2,169,959)	(2,491,242)	(2,596,004)	(3,132,569)
Add Bond Sale Proceeds	26,010,000	-	10,200,000	-	18,360,000
Cash Available from Operations	$ 25,729,685	$ 2,254,885	$ 11,390,119	$ 1,478,121	$ 18,176,068
Estimated Annual Capital Additions	16,797,000	14,163,750	13,869,000	15,264,000	25,597,000
Net Cash From Operations	$ 8,932,685	$(11,908,865)	$ (2,478,881)	$(13,785,879)	$ (7,420,932)
Beginning Cash Balance	$ 17,501,002	$ 26,433,686	$ 14,524,821	$ 12,045,940	$ (1,739,939)
Ending Cash Balance	$ 26,433,686	$ 14,524,821	$ 12,045,940	$ (1,739,939)	$ (9,160,871)
Total Cash Available	**$ 26,433,686**	**$ 14,524,821**	**$ 12,045,940**	**$ (1,739,939)**	**$ (9,160,871)**
Recommended Minimum	**$ 16,570,554**	**$ 17,202,536**	**$ 18,271,753**	**$ 18,575,674**	**$ 20,113,185**

Cash balances fall below the minimum in 2026 and continue to decrease throughout the projection period.

HL&P intends to bond for capital projects between CY 2025 – CY 2029. The timing of the debt is shown in Table 3 below.

Table 3 – Anticipated Bonding and Related Capital

Calendar Year	Bond Issues Including Fees	Period	Rate
2025	$ 26,010,000	25	5.00%
2026			
2027	10,200,000	25	5.00%
2028			
2029	18,360,000	25	5.00%

Minimum Cash Reserve

Table 4 details the minimum level of cash reserves required to help ensure timely replacement of assets and to provide financial stability of the utility. The methodology used to establish this target is based on an assessment of working capital needs to fund operating expenses, capital improvements, annual debt service payments, and utility's exposure to risks related to catastrophic events, exposure to market risks, changes in fuel costs, loss of major customers, and utility's ability to timely recover changes in power supply expenses. Based on these assumptions, HL&P should maintain a minimum of $16.57M in cash reserves for 2025 and $20.11M in 2029.

Table 4 – Minimum Cash Reserves (without rate adjustments)

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Minimum Cash Reserve Levels Determinants					
Operation & Maintenance Less Depreciation Expense	$ 14,048,611	$ 14,945,569	$ 15,855,075	$ 16,341,029	$ 16,824,042
Purchase Power Expense	15,356,380	16,391,945	17,618,954	18,215,799	18,895,464
Historical Rate Base	149,350,552	163,514,302	177,383,302	192,647,302	218,244,302
Current Portion of Debt Service Payment	5,327,532	5,565,785	6,291,975	6,275,671	7,604,026
Five Year Capital Improvements - Net of bond proceeds	31,120,750	31,120,750	31,120,750	31,120,750	31,120,750
Minimum Cash Reserve Allocation					
Operation & Maintenance Less Depreciation Expense	12.3%	12.3%	12.3%	12.3%	12.3%
Purchase Power Expense	17.6%	17.6%	17.6%	17.6%	17.6%
Historical Rate Base	1%	1%	1%	1%	1%
Current Portion of Debt Service Payment	83%	83%	83%	83%	83%
Five Year Capital Improvements - Net of bond proceeds	20%	20%	20%	20%	20%
% Plant Depreciated	44%	43%	41%	40%	38%
Calculated Minimum Cash Level					
Operation & Maintenance Less Depreciation Expense	$ 1,732,021	$ 1,842,604	$ 1,954,735	$ 2,014,647	$ 2,074,197
Purchase Power Expense	2,699,027	2,881,037	3,096,695	3,201,596	3,321,054
Historical Rate Base	1,493,506	1,635,143	1,773,833	1,926,473	2,182,443
Current Portion of Debt Service Reserve	4,421,851	4,619,601	5,222,339	5,208,807	6,311,342
Five Year Capital Improvements - Net of bond proceeds	6,224,150	6,224,150	6,224,150	6,224,150	6,224,150
Minimum Cash Reserve Levels	**$ 16,570,554**	**$ 17,202,536**	**$ 18,271,753**	**$ 18,575,674**	**$ 20,113,185**
Projected Cash Reserves No Changes	**$ 26,433,686**	**$ 14,524,821**	**$ 12,045,940**	**$ (1,739,939)**	**$ (9,160,871)**
HLP Required Minimum	**$ 16,694,658**	**$ 17,379,727**	**$ 18,469,900**	**$ 18,880,137**	**$ 20,580,688**

Projected cash balances fall below HLP's required minimum and UFS' recommended minimums beginning in 2026.

Debt Coverage Ratio

Table 5 is the projected debt coverage ratios with capital additions as provided by HL&P. Debt coverage ratio is a measurement of debt affordability and measures the cash flow from operations in that fiscal year. A ratio of 1, indicates there was enough cash flow from operations to pay the debt payment one time. The minimum recommended debt coverage ratio for prudent financial planning purposes is 1.40.

Maintaining a 1.40 debt coverage ratio is good business practice and helps to achieve the following:

a. Helps to ensure debt coverage ratios are met in years when sales are low due to cold or wet summers or loss of a major customer(s).

b. When debt coverage ratios are consistently met, it may help obtain a higher bond rating if revenue bonds are sold in the future, to lower interest cost.

Table 5 – Projected Debt Coverage Ratios (without rate adjustments)

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Debt Coverage Ratio					
Net Income	$ (3,980,116)	$ (1,402,062)	$ (2,422,925)	$ (2,335,441)	$ (3,972,870)
Add Depreciation/Amortization Expense	5,543,631	5,826,906	6,104,286	6,409,566	6,921,506
Interest and Other Income	(87,505)	(132,168)	(72,624)	(60,230)	-
Bond Issuance Costs	510,000	-	200,000	-	360,000
Distribution to Owners	300,000	300,000	300,000	300,000	300,000
Capital Contributions	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)
Impact Fees	(3,000,000)	(3,000,000)	(3,000,000)	(3,000,000)	(3,000,000)
Add Interest Expense	3,483,701	3,395,826	3,800,733	3,679,667	4,471,457
Cash Generated from Operations	$ 769,711	$ 2,988,501	$ 2,909,470	$ 2,993,563	$ 3,080,094
Debt Principal and Interest	$ 5,327,532	$ 5,565,785	$ 6,291,975	$ 6,275,671	$ 7,604,026
Projected Debt Coverage Ratio (Covenants)	**0.14**	**0.54**	**0.46**	**0.48**	**0.41**
Minimum Debt Coverage Ratio	**1.40**	**1.40**	**1.40**	**1.40**	**1.40**

When adjusting for capital contribution and impact fees, revenues that may vary from year to year, debt coverage is below the minimum for the projection period without changes in rates.

Rate of Return

The optimal target for setting rates is the establishment of a target operating income to help ensure the following:

A. Funding of interest expense on the outstanding principal on debt. Interest expense is below the operating income line and needs to be recouped through the operating income balance.

B. Funding of the inflationary increase on the assets invested in the system. The inflation on the replacement of assets invested in the utility should be recouped through the Operating Income.

C. Funding of depreciation expense.

D. Adequate rate of return on investment to help ensure current customers are paying their fair share of the use of the infrastructure and not deferring the charge to future generations.

E. The rate of return identifies the target operating income and is used to identify the appropriate funding for replacement of existing infrastructure to recover in rates charged to customers.

As improvements are made to the system, the optimal operating income target will increase unless annual depreciation expense is greater than yearly capital improvements. The revenue requirements for the study are set on the utility basis. Table 6 identifies the utility basis target established for 2025 is $4.15M and increases to $6.93M in 2029.

Table 6 – Rate of Return Calculation

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Target Operating Income Determinants					
Net Book Value/Working Capital	$ 83,480,162	$ 93,886,009	$ 103,865,460	$ 115,075,984	$ 136,225,620
Outstanding Principal on Debt	70,070,028	67,900,069	75,608,827	73,012,823	88,240,254
NBV Contributed Capital Estimated	14,013,043	15,037,299	15,981,556	16,845,812	17,630,069
Historical Investment in CC	22,680,958	24,680,958	26,680,958	28,680,958	30,680,958
System Equity	$ (602,909)	$ 10,948,640	$ 12,275,077	$ 25,217,348	$ 30,355,297
Debt:Equity Ratio	84%	72%	73%	63%	65%
Target Operating Income Allocation					
Interest on Debt	4.97%	5.00%	5.03%	5.04%	5.07%
Contributed Capital Estimated	3.10%	3.10%	3.10%	3.10%	3.10%
System Equity	5.55%	5.40%	5.29%	5.19%	4.97%
Target Operating Income					
Interest on Debt	$ 3,483,701	$ 3,395,826	$ 3,800,733	$ 3,679,667	$ 4,471,457
Contributed Capital Estimated	703,110	765,110	827,110	889,110	951,110
System Equity	(33,438)	591,121	649,872	1,308,698	1,507,580
Target Operating Income	**$ 4,153,373**	**$ 4,752,057**	**$ 5,277,714**	**$ 5,877,475**	**$ 6,930,146**
Projected Operating Income	**$ 149,219**	**$ 2,230,598**	**$ 2,019,921**	**$ 1,940,086**	**$ 1,632,730**
Rate of Return in %	**5.0%**	**5.1%**	**5.1%**	**5.1%**	**5.1%**

Operating income is projected below the target operating income for each year.

Projected Rate Track

Adjusting system revenue requires balancing the financial health of the utility with the financial impact on customers and cost of service results. Table 7 is the summary financial projection without any rate changes. Cash balances, operating income and the debt coverage ratio fall to critical levels.

Table 7 – Summary of Financials without Rate Adjustment

Calendar Year	Projected Rate Adjustments	Debt Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2025	0.0%	0.14	$ 149,219	$ 4,153,373	$ 26,433,686	$ 16,570,554
2026	0.0%	0.54	2,230,598	4,752,057	14,524,821	17,202,536
2027	0.0%	0.46	2,019,921	5,277,714	12,045,940	18,271,753
2028	0.0%	0.48	1,940,086	5,877,475	(1,739,939)	18,575,674
2029	0.0%	0.41	1,632,730	6,930,146	(9,160,871)	20,113,185

The study identifies increasing current revenues in each year of the projection period to maintain financial targets. Table 8 is a summary of the financial results detailing the projected revenue adjustments.

Table 8 – Projected Revenue Adjustments

Calendar Year	Projected Rate Adjustments	Debt Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2025	13.0%	0.80	$ 3,625,927	$ 4,153,373	$ 29,910,394	$ 16,570,554
2026	3.5%	1.37	6,877,617	4,752,057	22,665,931	17,202,536
2027	3.5%	1.42	8,059,881	5,277,714	26,267,715	18,271,753
2028	3.5%	1.67	9,418,933	5,877,475	20,031,791	18,575,674
2029	3.5%	1.59	10,676,691	6,930,146	21,754,979	20,113,185

This rate track ensures operating income and the projected cash balance increase through 2029. The projected cash balances would be above HLP's required minimum.

Due to cost changes, inflationary factors, and growth, financial projections should be reviewed on an annual basis. Depending on the system improvement timetable, additional changes may be needed throughout the projection period.

Debt to Equity Ratio

Debt to equity identifies the amount of existing infrastructure financed through debt and is used to determine the amount the system is leveraged in debt. For distribution systems the debt to equity ratio is normally between 30% and 35%. Table 9 details the debt/equity ratio.

Table 9 – Debt/Equity Ratio

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Target Operating Income Determinants					
Net Book Value/Working Capital	$ 83,480,162	$ 93,886,009	$ 103,865,460	$ 115,075,984	$ 136,225,620
Outstanding Principal on Debt	70,070,028	67,900,069	75,608,827	73,012,823	88,240,254
NBV Contributed Capital Estimated	14,013,043	15,037,299	15,981,556	16,845,812	17,630,069
Historical Investment in CC	22,680,958	24,680,958	26,680,958	28,680,958	30,680,958
System Equity	$ (602,909)	$ 10,948,640	$ 12,275,077	$ 25,217,348	$ 30,355,297
Debt:Equity Ratio	84%	72%	73%	63%	65%

Age of Infrastructure

HL&P is currently 44% depreciated. Average infrastructure is approximately 50% to 55% depreciated, indicating HL&P has consistently funded replacement of infrastructure. Replacement of infrastructure tends to indicate the utility's ability to consistently provide a reliable system to customers, its ability to withstand catastrophic weather events, and unexpected replacement of system infrastructure. HL&P's system age indicates it will remain in the lower range of infrastructure age. Table 10 identifies the depreciated plant.

Table 10 – Age of Infrastructure

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Asset Investments	$ 149,350,552	$ 163,514,302	$ 177,383,302	$ 192,647,302	$ 218,244,302
NBV	83,480,162	93,886,009	103,865,460	115,075,984	136,225,620
% Plant Depreciated	44%	43%	41%	40%	38%

Cost of Service Summary Results

A cost of service study was completed to determine the cost of providing service to each class of customers and to assist in the design of electric rates for customers. The cost of service study consists of the following general steps:

1) Determine utility revenue requirement for test year 2025.
2) Classify utility expenses into common cost pools.
3) Allocate costs to customer classes based on the classes' contribution to utility expenses.
4) Compare revenues received from each class to the cost of service.

The cost of service summary is included as Table 11 which compares the projected cost to serve each class with the revenue received from each class. The "% change" column is the revenue adjustment necessary to meet projected cost of service requirements. The cost of service summary uses the current rates, including any adjustment factors.

No utility charges 100% cost of service-based rates because retail rates are based on customers usage patterns that are largely driven by variations in weather. Due to these variations, it is recommended that rates move toward cost of service slowly with a general tolerance of a 10% variation between projected revenue and cost of service. The cost of service summary "% change" column indicates all major customer classes fall within this variation.

Table 11 – Cost of Service Summary

Customer Class	Cost of Service	Projected Revenues	% Change
Street Lighting	$ 156,140	$ -	0.0%
Yard Lighting	20,004	17,523	14.2%
Residential Pumping	26,198	15,944	64.3%
Small General Service	3,730,700	3,379,842	10.4%
Small General Service Pumping	122,789	93,317	31.6%
Medium General Service	4,166,155	3,746,011	11.2%
Medium General Service Pumping	367,347	267,852	37.1%
Large General Service	2,631,381	2,207,807	19.2%
General Service Net Metering	12,352	8,706	41.9%
Electric Vehicle Charging	161,263	134,551	19.9%
Residential Demand	18,472,045	16,115,838	14.6%
Residential Demand over 400 AMPS	241,474	231,932	4.1%
Residential TOU Demand	543,899	480,870	13.1%
Contract Customer 1	90,938	39,394	130.8%
Total	$ 30,742,685	$ 26,739,586	15.0%

Cost of Service Results

Table 12 shows the average cost of service per kWh and compares the cost to the average revenue per kWh for each customer class. This table is for information purposes only and is not used in the setting of rates. Average cost per kWh varies due to fixed cost recoveries such as meter costs and infrastructure needs of the customer. In general customer classes that use energy consistently have a lower average kWh cost to serve compared with customer classes that use energy only part of the day or year.

Table 12 – Average Cost per kWh vs. Average Revenue per kWh

Customer Class	Cost of Service $/kWh	Projected Revenues $/kWh
Street Lighting	$ 0.0936	$ -
Yard Lighting	0.1870	0.1638
Residential Pumping	0.3280	0.1996
Small General Service	0.1555	0.1409
Small General Service Pumping	0.1840	0.1398
Medium General Service	0.1176	0.1058
Medium General Service Pumping	0.1566	0.1142
Large General Service	0.1133	0.0951
General Service Net Metering	0.1530	0.1078
Electric Vehicle Charging	0.1486	0.1240
Residential Demand	0.1487	0.1298
Residential Demand over 400 AMPS	0.1335	0.1282
Residential TOU Demand	0.1577	0.1394
Contract Customer 1	0.0475	0.0206

Cost differences result from usage patterns of customers and how efficiently each class of customers use facilities based on load data provided by HL&P.

Distribution Costs

Separation of distribution cost helps identify distribution charges for each customer class and the fixed monthly customer charge. Distribution rates include separation of the following costs:

- Operation and maintenance of distribution & transmission system
- Contributions to general fund
- Customer service
- Customer accounting
- Meter reading
- Billing
- Meter operation & maintenance
- Administrative expenses

The distribution rates consist of two components:

- Monthly customer charge to recover the costs of meter reading, billing, customer service, and a portion of maintenance and operations of the distribution system.
- Distribution rate based on billing parameters (kW or kWh) to recover the cost to operate and maintain the distribution system. Table 13 identifies the cost-based distribution rates for customer classes.

Table 13 – Distribution Costs by Customer Class (COS)

Customer Class	Monthly Customer Charge	Distribution Rate	Billing Basis
Street Lighting	$ 896.17	$ 0.0324	kWh
Yard Lighting	890.34	0.0323	kWh
Residential Pumping	40.60	10.25	kW
Small General Service	47.94	4.47	kW
Small General Service Pumping	58.39	8.14	kW
Medium General Service	193.93	7.86	kW
Medium General Service Pumping	201.81	6.49	kW
Large General Service	471.15	10.36	kW
General Service Net Metering	51.07	7.94	kW
Electric Vehicle Charging	22.77	5.02	kW
Residential Demand	22.73	3.56	kW
Residential Demand over 400 AMPS	39.74	8.44	kW
Residential TOU Demand	22.72	2.80	kW
Contract Customer 1	101.07	16.23	kW

The cost of service based monthly customer charge for residential customers recovers 49% of the fixed cost of delivery of electricity. UFS averages across the United States show 40% to 60% fixed cost recovery in the residential customer charge.

Power Supply Costs

Table 14 identifies the average cost of providing power supply to customers of HL&P.

Table 14 – Power Supply Costs by Customer Class

Customer Class	Demand	Billing Basis	Energy	Billing Basis
Street Lighting	$ -	kWh	$ 0.0548	kWh
Yard Lighting	-	kWh	0.0548	kWh
Residential Pumping	2.86	KW	0.0608	kWh
Small General Service	6.51	KW	0.0557	kWh
Small General Service Pumping	6.85	KW	0.0601	kWh
Medium General Service	9.25	KW	0.0565	kWh
Medium General Service Pumping	3.55	KW	0.0628	kWh
Large General Service	9.95	KW	0.0565	kWh
General Service Net Metering	7.82	KW	0.0578	kWh
Electric Vehicle Charging	5.30	KW	0.0571	kWh
Residential Demand	5.07	KW	0.0568	kWh
Residential Demand over 400 AMPS	11.24	KW	0.0562	kWh
Residential TOU Demand	3.60	KW	0.0562	kWh
Contract Customer 1	5.25	KW	(0.0318)	kWh

Demand recovers costs for power supply and transmission fixed demand related costs. Energy is cost recovery for variable power supply costs.

Combined Cost Summary

Table 15 identifies the cost of service rates for each customer class. Charging these rates would directly match the cost of providing service to customers identified in this study.

Table 15 – Total Costs by Customer Class

Customer Class	Current Average Customer Charge	COS Customer Charge	Demand	Energy
Street Lighting	$ -	$ 896.17	$ -	$ 0.0872
Yard Lighting	-	890.34	-	0.0871
Residential Pumping	26.00	40.60	13.11	0.0608
Small General Service	24.70	47.94	10.97	0.0557
Small General Service Pumping	38.50	58.39	14.99	0.0601
Medium General Service	145.00	193.93	17.11	0.0565
Medium General Service Pumping	145.00	201.81	10.04	0.0628
Large General Service	342.00	471.15	20.31	0.0565
General Service Net Metering	-	51.07	15.75	0.0578
Electric Vehicle Charging	17.90	22.77	10.32	0.0571
Residential Demand	17.90	22.73	8.63	0.0568
Residential Demand over 400 AMPS	33.90	39.74	19.68	0.0562
Residential TOU Demand	17.90	22.72	6.41	0.0562
Contract Customer 1	91.00	101.07	21.48	(0.0318)

Residential Customer Charge

The customer charge consists of expenses related to, 1) providing a minimum amount of electricity to the residential customer, and 2) expenses related to servicing a meter on the customer's premises; together they reflect the cost to deliver a single kWh of electricity to the customer. The methodology used in this study is consistent with methodologies and practices used in the electric industry.

The customer charge includes two types of charges called minimum system charges and direct charges.

Minimum System Charges:

The cost to provide the minimum level of service. HL&P provides wires to connect the transmission system to customer homes and businesses. This wire is required to provide even the minimal amount of service to a customer. For cost of service purposes, the total cost of the distribution infrastructure is broken into two components: 1) the minimum system costs, in effect to provide a customer with a single kWh of electricity which should be recovered through the customer charge, and 2) demand related costs to recover the additional infrastructure costs for when a customer uses more than a single kWh, which should be recovered through the usage component. The distribution system is sized to handle the customers' peak demands and the cost above the minimum system is recovered through the usage component (for residential customers this is included in the kWh charge).

The first step in identifying the cost related to the minimum system is obtaining information on the number and current replacement costs of HL&P distribution system. For example: UFS used information on the number and size of all the poles and the cost to replace the poles. The minimum size pole was identified and the cost to construct HL&P's system at the minimum sizing was determined. This process was completed for all HL&P's distribution system, including overhead and underground conductors and devices, line transformers, etc. Based on this methodology, 51% of HL&P's total distribution costs should be recovered by the usage component and 49% recovered in the fixed customer charge component.

Direct Charges

Costs related to maintaining a customer's account. These costs include the cost to operate and maintain the meter, including meter installation, meter repair and replacement costs, the cost to read the meter, billings and collections, customer service personnel to assist with questions and maintain the account, and the cost of the "service drop" to connect the home to the distribution line. These costs are direct costs of serving a residential account.

3. Functionalization of Costs

Delivery of electricity consists of many components that bring electricity from the power supply facilities to the communities and eventually into customer facilities. The facilities consist of four major components: transmission, distribution, customer-related services, and administration. Following are general descriptions of each of these facilities and the sub-breakdowns within each category.

Transmission

The transmission system is comprised of four types of subsystems that operate together:

1) Backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources are integrated.
2) Generation set-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages.
3) Sub-transmission plant consists of lower voltage facilities to transfer electric energy from convenient points on a utility's backbone system to its distribution system.
4) Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

Operation of the transmission system also consists of providing certain services that ensure a stable supply of power. These services are typically referred to as ancillary services. The Federal Energy Regulatory Commission (FERC) has defined six ancillary service charges for the use of transmission facilities. For HL&P, these charges will be passed-through charges by the control area operator. Ancillary services consist of the following:

- **Mandatory Ancillary Service Charges:**
  Reactive Supply and Voltage Control
  Regulation and Frequency Response Service
  Energy Imbalance Charges
  Operating Reserves Spinning
  Operating Reserves Supplemental
  Reactive Power Supply
  Power losses from use of transmission system

Terminology of Cost of Service

FUNCTIONALIZATION – Cost data arranged by functional category (e.g., power supply, transmission, distribution

CLASSIFICATION – Assignment of functionalized costs to cost components (e.g., demand, energy and customer related).

ALLOCATION – Allocating classified costs to each class of service based on each class's contribution to that specific cost component.

DEMAND COSTS – Costs that vary with the maximum or peak usage. Measured in kilowatts (kW)

ENERGY COSTS – Costs that vary over an extended period of time. Measured in kilowatt-hours (kWh)

CUSTOMER COSTS – Costs that vary with the number of customers on the system (e.g. metering costs).

DIRECT ASSIGNMENT – Costs identified as belonging to a specific customer or group of customers.

Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles, and line transformers that are jointly used and in the public right-of-way.

Substations typically separate the distribution plant from the transmission system. The substation power transformer "steps down" the voltage to a level that is more practical to install on and under city streets.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 kV and 4 kV and the secondary below 4 kV.

Distribution Customer Types

Sub-transmission customers are served directly from the substation feeder and bypass both the secondary and primary distribution lines. The charges for this type of customer should reflect the cost of the substation and not include the cost of primary or secondary line charges.

Primary customers are typically referred to as customers who have purchased, owned, and maintained their own transformers that convert the voltage to the secondary voltage level. The rates for these customers should reflect the cost of substations and the cost of primary distribution lines and not include the cost of secondary line extensions.

Secondary customers have the services provided by the utilities directly into their facilities. The utility provides the customer with the transformer and the connection on the customers' facilities.

Customer-Related Services

Certain administrative-type services are necessary to ensure customers are provided service connections and disconnections in a timely manner and the facilities are in place to read meters and bill for customer usages. These services typically consist of the following components:

- Customer Services – The cost of providing personnel to assist customers with questions and dispatch personnel to connect and disconnect meters.
- Billing and Collections – The cost of billing and collections personnel, postage, and supplies.
- Meter Reading – The cost of reading customers' meters.
- Meter Operation and Maintenance – The cost of installing and maintaining customer meters.

Administrative Services

These costs are sometimes referred to as overhead costs and relate to functions that cannot be directly-attributed to any service. These costs are spread to the other services through an allocator such as labor, expenses, or total rate base. These costs may consist of City Commission expenses, property insurance, and wages for higher level management of the utility.

System Losses

As energy moves through each component of the transmission and distribution system, some of the power is lost and cannot be sold to customers. Losses vary based on time of day and season. Typically, as system usage increases or ambient temperature increases, the percentages of losses that occur also increase. These losses are recovered from distribution customers through an analysis of the peak losses that occur in the system. The average system losses and unaccounted for energy for HL&P are approximately 5.5%. (Typical municipal system losses are approximately 5.4%)

4. Unbundling Process

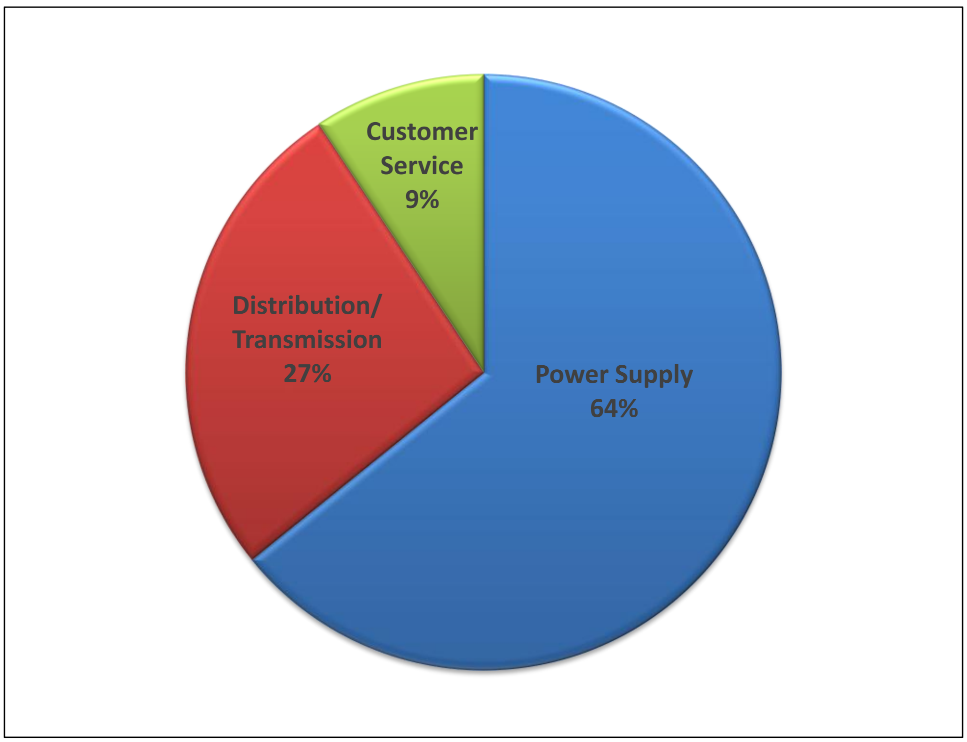
The cost of power supply, distribution, and customer services are identified as part of the unbundling process and are the first step in determining unbundled charges to customers. The total revenue requirements of $30.74M are separated into four categories identified in Table 16.

Table 16 – Breakdown of HL&P Cost Structure

Expense Type	Amount	Percentage
Power Supply	$ 19,729,955	64%
Distribution/Transmission	8,149,815	27%
Customer Service	2,862,916	9%
Total	$ 30,742,685	100%

HL&P is projected to expend 64% of its total costs toward power supply. Distribution/transmission-related costs are 27%, and customer service 9%. These components are broken down into each of the subcomponents and are identified in the following sections.

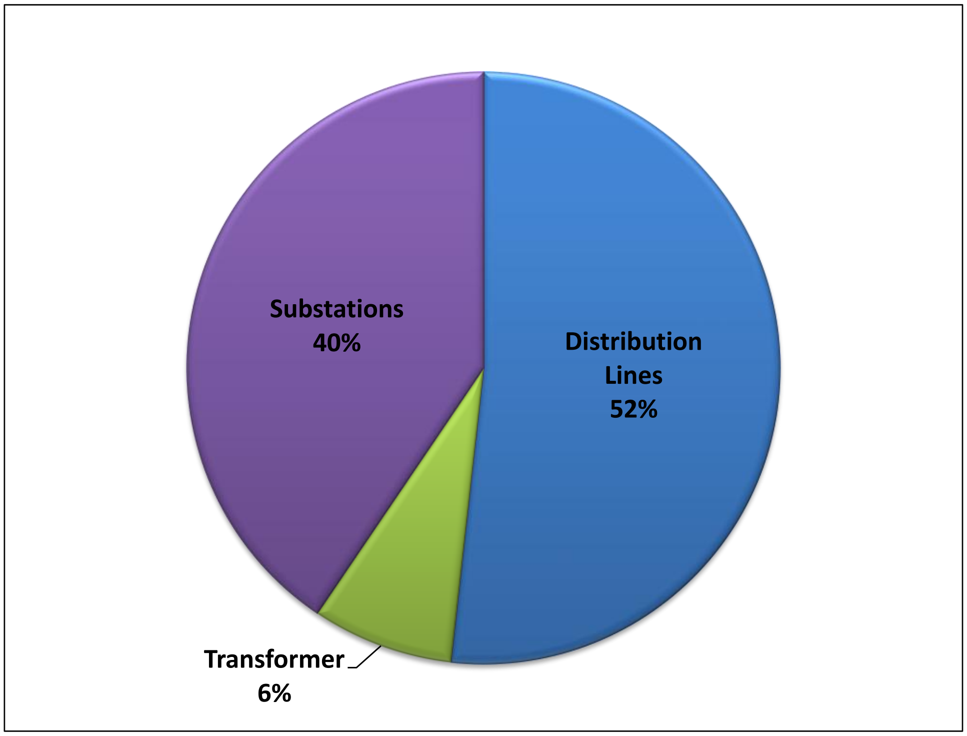
Figure 1 – Breakdown of HL&P Cost Structure



Distribution Breakdown

Distribution rates consist of several different components. Total distribution-related costs of $8.15M for 2025 are broken down into the main components including substations, transformers, and distribution lines. Figure 2 shows the breakdown of distribution components identified in the study.

Figure 2 – Breakdown of Distribution Costs

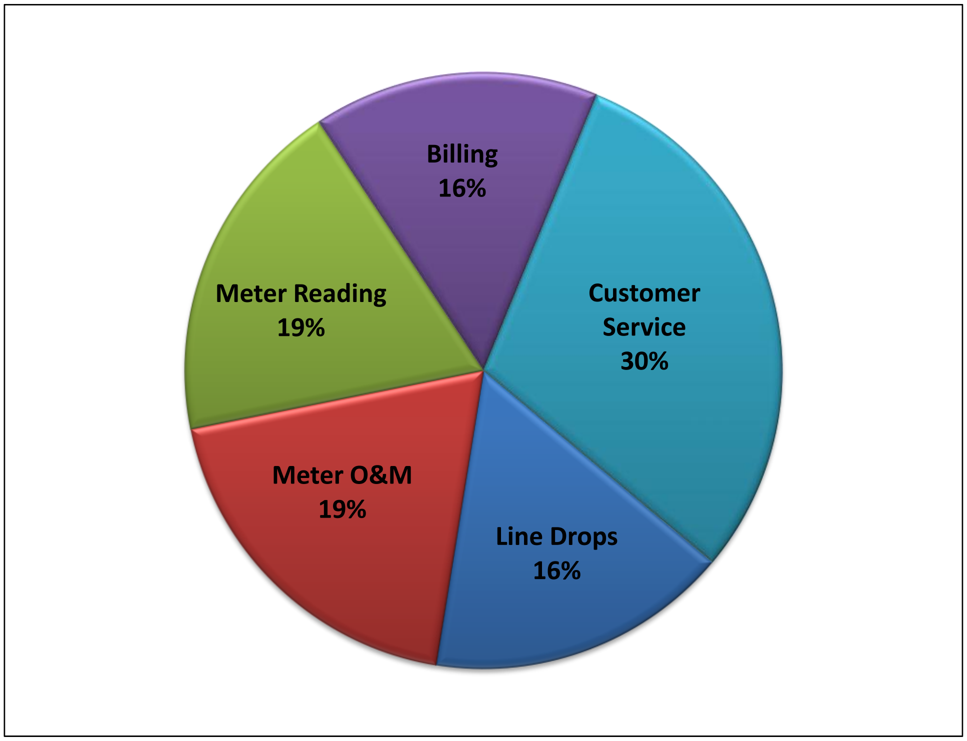


Each of these components is allocated to customer groups based on certain factors established in the study. These factors are based on the efficiency of each customer class and the time of day or the season the electricity is used. Other factors are also considered, such as the length of line extensions to reach certain customer classes.

Customer-Related Cost Breakdown

HL&P total expenses for customer-related costs are $2.86M for 2025. The cost is broken down into the components identified in Figure 3.

Figure 3 – Breakdown of Customer Costs



Power Supply Cost Breakdown

Power supply costs for 2025 were made up of purchased power and fuel and internal generation expenses.

5. Significant Assumptions

This section outlines the procedures used to develop the cost of service and unbundling study for HL&P and the related significant assumptions.

Forecasted Operating Expenses

Forecasted expenses were based on 2022 and 2023, 2024 budget adjusted for power supply costs and inflation. The table below is a summary of the expenses used in the analysis. The projected operating expenses include an adjustment for any city contributions.

Table 17 – Projected Operating Expenses for 2025 – 2029

Description	Projected 2025	Projected 2026	Projected 2027	Projected 2028	Projected 2029
Operating Expenses:					
Purchases					
Purchased Power (Cost of Sales and Service)	$ 12,594,117	$ 13,447,676	$ 14,481,545	$ 14,985,915	$ 15,570,075
Energy Rebates	60,665	63,319	65,201	65,510	66,084
Purchase Power Direct - Jordanelle Energy	1,712,507	1,826,195	1,947,431	2,005,854	2,066,030
System Control and Load Dispatching	989,092	1,054,755	1,124,777	1,158,520	1,193,276
Production					
Gas Generation Fuel	$ 2,379,917	$ 2,484,031	$ 2,557,872	$ 2,569,999	$ 2,592,511
Gas Generation O&M	679,791	724,921	773,046	796,237	820,124
Other Operating Expenses (Revenues)					
Salaries, Wages, Benefits	$ 1,488,306	$ 1,587,111	$ 1,692,474	$ 1,743,249	$ 1,795,546
Professional Services	252,126	268,864	286,713	295,315	304,174
Maintenance and Training	5,945,122	6,339,802	6,760,684	6,963,504	7,172,409
Materials	202,417	215,855	230,185	237,091	244,204
Building Expenses	55,153	58,814	62,719	64,600	66,539
Office Expense and Postage	169,957	181,240	193,272	199,070	205,042
Vehicle Expense	578,607	617,020	657,982	677,721	698,053
Bad Debt Expense	28,754	30,663	32,699	33,680	34,690
Miscellaneous	345,320	368,245	392,692	404,472	416,606
Depreciation Expense	3,620,492	3,757,903	3,889,549	4,053,476	4,447,364
Depreciation on Impact Fee Related Capital	1,027,396	1,093,260	1,158,994	1,220,347	1,258,399
Contributed Capital Depreciation	895,744	975,744	1,055,744	1,135,744	1,215,744
Total Operating Expenses	$ 33,025,483	$ 35,095,417	$ 37,363,578	$ 38,610,304	$ 40,166,870

Power supply costs from 2025 – 2029 are based on HL&P's current charges adjusted for system growth factors and inflation.

Load Data

Load data is one of the most critical components of a cost of service study. Information from the billing statistics were used to determine the usage patterns of each customer class after reconciling revenues with financial statements to ensure a good basis for development of the study.

Annual Projection Assumptions

The kWh sales forecast is based on FY2023 actual adjusted for growth. Table 18 details growth, inflation of expenses, changes in purchase power costs, interest earned on investments.

Table 18 – Projection Annual Escalation Factors 2025 – 2029

Calendar Year	Inflation	Growth	Power Supply Cost Change	Investment Income	Capital Improvements Plan	Impact Fees
2025	6.6%	5.0%	5.2%	0.5%	$ 16,797,000	$ 3,000,000
2026	6.6%	2.3%	4.4%	0.5%	14,163,750	3,000,000
2027	6.6%	4.6%	3.0%	0.5%	13,869,000	3,000,000
2028	3.0%	3.0%	0.5%	0.5%	15,264,000	3,000,000
2029	3.0%	3.0%	0.9%	0.5%	25,597,000	3,000,000

System Loss Factors

Losses occurring from the transmission and distribution of electricity can vary from year to year depending upon weather and system loading. The distribution loss factor used for the cost of service study was based on historic losses at 5.5%.

Revenue Forecast

The revenue forecast was based on FY2023 usages adjusted for growth rate assumptions.

6. Considerations and Additional Information

HL&P Financial Considerations

1. HL&P is projected to require increases in rates charged to customers in order to move toward financial targets over the projection period.

Calendar Year	Projected Rate Adjustments	Debt Coverage Ratio	Adjusted Operating Income	Target Operating Income	Projected Cash Balances	Recommended Minimum Cash
2025	13.0%	0.80	$ 3,625,927	$ 4,153,373	$ 29,910,394	$ 16,570,554
2026	3.5%	1.37	6,877,617	4,752,057	22,665,931	17,202,536
2027	3.5%	1.42	8,059,881	5,277,714	26,267,715	18,271,753
2028	3.5%	1.67	9,418,933	5,877,475	20,031,791	18,575,674
2029	3.5%	1.59	10,676,691	6,930,146	21,754,979	20,113,185

2. Cash balances fall below the minimum in 2026 and continue to decrease without changes in rates. Projected cash balances are below the recommended minimums during the projection period and HL&P's required minimum cash reserve.

3. Debt Coverage Ratio is below the recommended minimum levels throughout the projection period without changes in rates.

4. Current rate related revenues are projected to result in the operating income to be below the target for each year. Meeting the operating income target indicates current rates are fully funding system revenue requirements and future replacement cost of current infrastructure.

5. Infrastructure of HL&P is newer than the national average. The infrastructure in total is approximately 44% compared with the national average between 50% - 55%. This indicates HL&P has newer infrastructure.

6. HL&P system losses are average, resulting in average power supply costs for customers. The average system losses and unaccounted for energy for HL&P are approximately 5.5% compared to typical municipal system losses of approximately 5.4%.

Rate-Related Considerations

1. The cost-based residential customer charge represents 49% of the fixed cost of delivery of electricity.

2. Customer charges are under-recovering for all customer classes. The table below compares the current customer charges with the cost-based customer charge. It is recommended that movements toward the cost-based customer charge occur with the additional revenue used to lower the energy rates for customers in the class.

Customer Class	Current Average Customer Charge	COS Customer Charge
Street Lighting	$ -	$ 896.17
Yard Lighting	-	890.34
Residential Pumping	26.00	40.60
Small General Service	24.70	47.94
Small General Service Pumping	38.50	58.39
Medium General Service	145.00	193.93
Medium General Service Pumping	145.00	201.81
Large General Service	342.00	471.15
General Service Net Metering	-	51.07
Electric Vehicle Charging	17.90	22.77
Residential Demand	17.90	22.73
Residential Demand over 400 AMPS	33.90	39.74
Residential TOU Demand	17.90	22.72

3. Power Cost Adjustment (PCA) mechanism is proposed to be suspended for the 2025 rate year and reinstated for the 2026 rate year. This will allow HLP to adjust the base rate structures without additional variations in customer bills due to fluctuations in power supply cost.
4. HL&P may consider movements toward cost of service. The cost of service study indicates a variance exists between revenues and costs for certain rate classes. The study results are listed below:

Customer Class	Cost of Service	Projected Revenues	% Change
Street Lighting	$ 156,140	$ -	0.0%
Yard Lighting	20,004	17,523	14.2%
Residential Pumping	26,198	15,944	64.3%
Small General Service	3,730,700	3,379,842	10.4%
Small General Service Pumping	122,789	93,317	31.6%
Medium General Service	4,166,155	3,746,011	11.2%
Medium General Service Pumping	367,347	267,852	37.1%
Large General Service	2,631,381	2,207,807	19.2%
General Service Net Metering	12,352	8,706	41.9%
Electric Vehicle Charging	161,263	134,551	19.9%
Residential Demand	18,472,045	16,115,838	14.6%
Residential Demand over 400 AMPS	241,474	231,932	4.1%
Residential TOU Demand	543,899	480,870	13.1%
Contract Customer 1	90,938	39,394	130.8%
Total	$ 30,742,685	$ 26,739,586	15.0%