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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Superior Water, Light and Power Company for Authority to Adjust Retail Electric, Gas, and Water Rates — 5820-UR-116

FINAL DECISION

This is the Final Decision in the application of Superior Water, Light and Power Company (applicant) for authority to adjust Wisconsin retail electric, natural gas, and water rates in 2023. Final overall rate changes for the test year ending December 31, 2023, are authorized consisting of a $2,481,000 annual rate increase for Wisconsin retail electric operations, which is a 2.70 percent increase; a $1,574,000 annual rate increase for Wisconsin retail natural gas operations, which is a 7.29 percent increase in total revenues; and a $724,000 annual rate decrease for Wisconsin retail water operations, which is a 6.39 percent decrease, based on a return on equity (ROE) of 10.00 percent.

Introduction

On April 29, 2022, the applicant filed an application for authority to adjust its Wisconsin retail electric, natural gas, and water rates. The applicant requested an overall increase in annual Wisconsin retail electric revenues of $2,831,000, or 3.10 percent over present revenues; an increase in annual Wisconsin retail natural gas revenues of $1,520,000, or 8.65 percent over present revenues; and an annual decrease in annual Wisconsin retail water revenues of $1,078,000, or 9.55 over present revenues. The applicant's requested increases were based on a 10.40 percent return on common equity.

The Commission issued a Notice of Proceeding on May 18, 2022. (PSC REF#: 438302.) Enbridge Energy, LP (Enbridge) and Citizens Utility Board of Wisconsin (CUB) requested and were granted intervention as parties to this proceeding. (PSC REF#: 440720.)

On August 25, 2022, the Commission issued a Notice of Hearing. (PSC REF#: 446080.) Pursuant to due notice, on September 14, 2022, a public hearing was held, via Zoom, for members of the general public. (PSC REF#: 447783.) A party hearing was also held on September 14, 2022, via Zoom, to receive testimony and technical information from the parties to the proceeding. (PSC REF#: 447783.) The Commission did not receive any comments from members of the public.

The parties for purposes of review under Wis. Stat. §§ 227.47 and 227.53 are listed in Appendix A.

The Commission considered this matter at its open meeting of November 22, 2022. (PSC REF#: 454112.)

Findings of Fact

1. The applicant is an investor-owned electric, natural gas, and water public utility as defined in Wis. Stat.01(5)(a), providing electric, natural gas, and water service to the city of Superior and adjacent areas. The applicant is a wholly-owned subsidiary of ALLETE, Inc. (ALLETE).

2. Presently authorized rates for the applicant's Wisconsin retail electric utility operations will produce total operating revenues of $91,749,196 for the test year ending December 31, 2023, which results in an adjusted net operating income of $1,929,820, which is insufficient.

3. For Wisconsin retail electric operations, the estimated rate of return on average net investment rate base of $45,130,557 at current rates subject to the Commission's jurisdiction for the test year is 4.28 percent, which is insufficient.

4. A reasonable increase in operating revenue for the test year to produce an 8.28 percent return on the applicant's average net investment rate base for Wisconsin retail electric operations is $2,481,000.

5. The applicant's filed electric operating income statement and net investment rate base for the test year, as modified by this Final Decision, are reasonable.

6. Presently authorized rates for the applicant's Wisconsin retail natural gas operations will produce total operating revenues of $21,592,573 for the test year ending December 31, 2023, which results in an adjusted net operating income of $272,983, which is insufficient.

7. For the Wisconsin retail gas operations, the estimated rate or return on average net investment rate base of $17,118,835 at current rates subject to the Commission's jurisdiction for the test year is 1.59 percent, which is insufficient.

8. A reasonable increase in operating revenue for the test year to produce an 8.28 percent return on the applicant's average net investment rate base for Wisconsin retail gas operations is $1,574,000.

9. The applicant's filed gas operating income statement and net investment rate base for the test year, as modified by this Final Decision, are reasonable.

10. Presently authorized rates for the applicant's Wisconsin retail water operations will produce total operating revenues of $11,386,381 for the test year ending December 31, 2023, which results in an adjusted net operating income of $3,436,844, which is excessive.

11. For the Wisconsin retail water operations, the estimated rate of return on average net investment rate base of $35,128,195 at current rates subject to the Commission's jurisdiction for the test year is 9.78 percent, which is excessive.

12. A reasonable decrease in operating revenue for the test year to produce an 8.28 percent return on the applicant's average net investment rate base for Wisconsin retail water operations is $724,000.

13. The applicant's filed water operating income statement and net investment rate base for the test year, as modified by this Final Decision, are reasonable.

14. It is reasonable to use the inflation rate at the time of application filing for purposes of determining revenue requirement.

15. A reasonable level of expensed conservation costs for retail electric operations is $863,550.

16. A reasonable level of expensed conservation costs for retail natural gas operations is $232,163.

17. It is reasonable for the applicant to continue accounting for allowable electric and natural gas conservation expenditures on an escrow basis.

18. It is reasonable for the applicant to discontinue escrow accounting for any over- or under-collection of credit card processing fees, subject to true-up in the applicant's next rate proceeding.

19. It is reasonable for the applicant to end the regulatory liability for water revenues from the Husky Superior Refinery (Husky) as of December 31, 2022.

20. It is reasonable to amortize the $201,465 regulatory liability associated with Husky over the two-year period of 2023 through 2024, for an annual amortization amount of $100,732.

21. It is reasonable to require a true-up of the regulatory liability associated with Husky in the applicant's next rate proceeding.

22. It is reasonable to amortize the remaining $24,524 of the tax reform refunds associated with the Tax Cuts and Jobs Act (TCJA) authorized in docket 5-AF-101 over the two-year period of 2023-2024, for an annual amortization amount of $12,262.

23. It is reasonable to require a true-up of the regulatory liability balance associated with the TCJA in the applicant's next rate proceeding.

24. It is reasonable to amortize the deferred COVID-19 regulatory asset of $120,485 over the two-year period of 2023 through 2024, for an annual amortization amount of $60,243.

25. It is reasonable to require a true-up of the deferred COVID-19 regulatory asset in the applicant's next rate proceeding.

26. It is reasonable to amortize the bad debt expense of $325,000 over the two-year period of 2023 through 2024, for an annual amortization amount of $162,500.

27. It is reasonable to amortize the Manufactured Gas Plant (MGP) costs of $1,559,906 over the four-year period of 2023 through 2026, for an annual amortization amount of $389,977.

28. It is reasonable that any additional MGP costs incurred after December 31, 2021 be deferred until the applicant's next rate proceeding.

29. It is reasonable for the applicant to amortize and include the revenue requirement impacts of the regulatory asset and regulatory liability amortizations as detailed in Appendix I, for all items listed for 2023, or until the Commission authorizes a different amortization expense to be recorded.

30. It is reasonable to accept Commission staff's uncontested revenue requirement adjustments.

31. An appropriate target level for the test-year average common equity measured on a financial capital structure basis is 55.00 percent.

32. A reasonable estimate of the amount of debt equivalent to be imputed into the applicant's capital structure is $1,037,820.

33. A reasonable financial capital structure for the test year consists of 55.07 percent common equity, 36.10 percent long-term debt, 8.83 percent short-term debt, and 1.53 percent debt equivalence for off-balance sheet obligations.

34. A reasonable regulatory capital structure for the test year consists of 54.69 percent common equity, 36.41 percent long-term debt and 8.91 short-term debt.

35. A reasonable rate of return on the applicant's common equity is 10.00 percent.

36. A reasonable rate for the applicant's short-term borrowing through commercial paper is 3.63 percent.

37. A reasonable average embedded cost for long-term debt is 3.62 percent.

38. A reasonable weighted average composite cost of capital is 7.11 percent.

39. It is reasonable to consider the full range of electric and natural gas cost-of-service study (COSS) results, along with other factors, such as bill impacts, when allocating revenue responsibility and designing rates among the various customer classes.

40. It is reasonable to accept the water COSS prepared by Commission staff, along with other factors, such as bill impacts, when allocating revenue responsibility and designing rates among the various customer classes.

41. It is reasonable to accept the electric revenue allocation proposed by the applicant, as adjusted for the final revenue requirement.

42. It is reasonable to approve the electric fixed customer charges as proposed by the applicant.

43. It is reasonable to direct the applicant to submit a proposal for an interruptible rate no later than April 1, 2023.

44. It is reasonable to authorize the applicant to continue to apply a Power Cost Adjustment Clause (PCAC) for retail electric service during the test year.

45. It is reasonable to approve the rate changes for electric service as shown in Appendix B.

46. It is reasonable to accept the natural gas revenue allocation proposed by Commission staff.

47. It is reasonable to approve the rate changes for natural gas service as shown in Appendix C.

48. It is reasonable to approve the natural gas fixed customer charges as proposed by the applicant.

49. It is reasonable to authorize the closure of the Coal Displacement rate as proposed by the applicant.

50. It is reasonable to accept the water revenue allocation proposed by Commission staff.

51. It is reasonable to approve the rate changes for water service as shown in Appendix D.

52. It is reasonable to close the 2017 TCJA tariffs and remove them from the tariff books as of January 2023.

53. It is reasonable to approve the other uncontested tariff changes.

Conclusions of Law

1. The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.37, 196.374, 196.395, 196.40, and Wis. Admin. Code chs. PSC 113, 134, 137, and 185 to enter a Final Decision authorizing the applicant to place in effect the rates and rules for electric, natural gas, and water utility service set forth in Appendices B, C, and D.

2. The rates and rules for electric, natural gas, and water utility service set forth in Appendices B, C, and D are reasonable and appropriate as a matter of law.

3. The Commission's determinations in this Final Decision comply with the Energy Priorities Law.

Opinion

The Applicant and Its Business

The applicant is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric, natural gas, and water utility in Wisconsin. The applicant provides electric service to approximately 15,000 in the city of Superior and adjacent areas. The applicant is also engaged in the purchase, transportation, distribution, and sale of natural gas to approximately 13,000 customers in the city of Superior and adjacent areas. The applicant provides water service to approximately 10,000 customers in the city and village of Superior. The applicant is a wholly-owned subsidiary of ALLETE.

Revenue Requirement

Income Statement

The applicant, Enbridge, CUB, and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates for the applicant's 2023 electric, natural gas, and water utility operations. Significant issues pertaining to the income statement are addressed separately below.

Husky Superior Refinery

Due to an explosion at Husky in April 2018, Husky's operations ceased for a period of time. As Husky has been the applicant's largest water customer and third largest electric customer, the absence of Husky operating dramatically affected the applicant's sales forecasts.

In docket 5820-UR-115, the Commission ordered the applicant to create a regulatory liability for water revenues from Husky, net of operations and maintenance (O&M) Account 632, purchased power for pumping, and Account 641, chemicals, to record the water revenues above the amounts forecasted for Husky in that rate proceeding, for return to ratepayers in a future case. The Commission determined that the regulatory liability for water revenues provides protection to ratepayers and is necessary given the uncertainty surrounding water sales forecasts to Husky that could have a significant impact on ratepayers. The Commission also found it reasonable that carrying costs on the regulatory liability would be set at the applicant's short-term debt rate.

The applicant's expectation is that Husky will return to normal operations in 2023. Therefore, the Commission finds it reasonable to end the deferral accounting treatment as of December 31, 2022. Accordingly, the Commission finds it reasonable to amortize the regulatory liability amount of $201,465 over a two-year period from 2023 through 2024, for an annual amortization amount of $100,732. Further, the Commission finds it reasonable to require a final true-up of the Husky regulatory liability balance in the applicant's next rate proceeding.

MGP

The applicant sought Commission approval for deferral treatment of additional MGP costs for the period of 2023 through 2026. Additionally, the applicant sought to defer any additional costs incurred after December 31, 2021 until the applicant's next rate proceeding.

The Commission finds it reasonable to amortize the MGP amount of $1,559,906 over a four-year period from 2023 through 2026, for an annual amortization amount of $389,977 and finds is reasonable that any additional costs incurred after December 31, 2021 be deferred until the applicant's next rate proceeding. This approach is consistent with past Commission practice.

COVID-19

The March 24, 2020 Order in docket 5-AF-105 (PSC REF#: 386353) authorized deferral of expenditures incurred by utilities resulting from compliance with Emergency Order #11, orders by the Commission in docket 5-UI-120, to ensure the provision of safe, reliable and affordable access to utility services during the declared public health emergency for COVID-19. The December 22, 2021 Order in docket 5-AF-105 (PSC REF#: 427781) ended the deferral as of

December 31, 2021 and directed utilities seeking recovery of the deferred regulatory asset to file a rate application within a one-to-two-year period from the effective date of that Order.

The applicant requested Commission approval to amortize the deferred COVID-19 regulatory asset authorized in docket 5-AF-105 over a two-year period from 2023 through 2024.

The Commission's order in docket 5-AF-105 did not bind the Commission to any specific treatment for these costs in any future proceeding involving rates or other matters before the Commission.[1] The Commission finds it reasonable to amortize the deferred COVID-19 regulatory asset of $120,485 over a two-year period from 2023 through 2024, for an annual amortization amount of $60,243 and finds it reasonable that a final true-up of the regulatory liability balances be required in the applicant's next rate proceeding. This allows the applicant to recover these costs but over a period of time that mitigates the impact to customers.

Taxes

On December 22, 2017, the 2017 H.R. 1 bill, commonly referred to as the TCJA, was signed into law with an effective date of January 1, 2018. The TCJA impacted all Wisconsin investor-owned utilities (IOUs). The TCJA made significant changes to the Federal Tax Code and included changes to individual, business, and international tax provisions. Notable for Wisconsin IOUs like the applicant, the TCJA reduced the corporate tax rate from a maximum of 35 percent under the existing graduated rate structure to a flat 21 percent rate for tax years beginning after 2017.

[1] Order, *Accounting Treatment for Utility Costs Incurred Due To and During Declared Public Health Emergency for COVID-19*, docket 5-AF-105 (Wis. PSC Mar. 24, 2020) (PSC REF#: 386353, at 4).

To address the impacts of the TCJA, the Commission directed in docket 5-AF-101 that most IOUs, including the applicant provide a bill credit to customers until the rates could be adjusted to reflect the new tax rate. The Commission also directed the IOUs all to continue deferrals for any income statement savings or balance sheet tax savings.

The Orders in docket 5-AF-101 authorized and addressed the refund of these costs. The applicant sought Commission approval to amortize the remainder of the tax reform refunds associated with the TCJA authorized in docket 5-AF-101 over a two-year period of 2023 through 2024.

The Commission finds it reasonable to amortize the remainder of the TCJA refunds authorized in 5-AF-101 of $24,524 over a two-year period from 2023 through 2024, for an annual amortization amount of $12,262 and finds it reasonable that a final true-up of the regulatory liability balances be required in the applicant's next rate proceeding.

Bad Debt

In this proceeding, the applicant requested Commission approval to amortize bad debt expense over the two-year period of 2023 through 2024. In the Final Decision in dockets 5820-TE-101, 5820-TG-101, and 5820-TW-101 the Commission authorized the applicant to use deferral accounting treatment and to implement escrow accounting treatment for the bad debt associated with its Arrears Management Program for its electric, gas, and water customers.

In rebuttal testimony, the applicant clarified that the amortization of bad debt was for the authorized deferral and escrow accounting treatment for all bad debt expense not just bad debt expense related to the Arrears Management Program. Therefore, the Commission finds it reasonable to amortize the bad debt expense of $325,000 over the two-year period of 2023 through 2024, for an annual amortization amount of $162,500.

Credit Card Fees

As part of the Final Decision in docket 5820-UR-115 (PSC REF#: 355880), the Commission authorized escrow accounting for any over or under collection of credit card fees. The accounting treatment for fees was reasonable at that point as it was based on the applicant's estimate of how many customers would pay by credit card. Over the last three years the applicant has seen a steady decrease in cash and check payments with an increase in electronic payments. The applicant anticipates this trend to continue and with three years of history, asked to eliminate the need for escrow accounting and incorporate the fees directly into O&M without the ongoing tracking.

The Commission finds it reasonable for the applicant to discontinue escrow accounting for any over- or under-collection of credit card processing fees and finds it reasonable that a final true-up associated with amounts currently held in escrow would be trued up in the applicant's next rate case.

Inflation Rate

In its April 29, 2022 filing, the applicant used a 2.5 percent general inflation rate. In rebuttal testimony, applicant witness Gardner requested that the Commission update the operating and maintenance inflation rate to 5.20 percent for the 2023 test year.

The Commission rejects this request and finds that it is reasonable to use the inflation rate of 2.35 percent at the time of filing. It is long standing Commission practice that the inflation rate is established at the date the application is filed and is generally not updated thereafter. The

Commission finds no reason to deviate from this past practice. There are other tools available to the applicant to address rising costs and uncertainty.

Conservation Budget and Escrow Adjustment

The applicant proposed Customer Service Conservation (CSC) activities in this proceeding. In its Order in docket 5-BU-102 dated July 13, 2012, the Commission provided guidance regarding appropriate CSC activities. The Commission defined CSC activities as "those activities and services that a utility provides its customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus and federal and state energy programs." Based on this guidance, the Commission finds the applicant's proposed CSC activities to be appropriate.

The reasonable level of expensed conservation costs recoverable in rates for the 2023 test year is $863,550 for electric utility operations and $232,163 for natural gas operations. The Commission finds it is reasonable to direct the applicant to record these expense amounts annually in its conservation escrow until they are superseded by a Commission order authorizing new conservation escrow accruals.

Uncontested Revenue Requirement Adjustments

There were a number of Commission staff adjustments made to the applicant's filed electric, natural gas and water revenue requirements that were not contested by any party. The Commission finds it reasonable to accept all of those adjustments.

Depreciation Rates

The depreciation expense included in the revenue requirement for the 2023 test year was computed using the depreciation rates shown in Appendices E-H. These depreciation rates are effective on January 1, 2023, for computing the depreciation expense on the average investment for each plant account.

Regulatory Amortizations

The Commission finds the regulatory asset and liability amortizations as reflected in this Final Decision in Appendix I to be reasonable. The annual amortization expense amounts identified shall be recorded for 2023, or until the Commission authorizes a different amortization amount to be recorded.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, no parties contested the other Commission staff adjustments to the applicant's filed operating income statements. The Commission therefore finds it reasonable to approve the other uncontested adjustments to the operating income statements proposed by Commission staff. Accordingly, the estimated Wisconsin retail electric, natural gas, and water utility operating income statements at present rates for 2023 test year, which are considered reasonable for the purpose of determining the revenue requirement in this proceeding are as follows:

	Retail Electric	Retail Natural Gas	Retail Water
Operating Revenues			
Sales Revenues	$91,749,196	$21,592,573	$11,328,720
Other Operating Revenues	3,061,840	89,469	57,661
Total Operating Revenues	$94,811,036	$ 21,682,042	11,386,381
Operation and Maintenance Expenses			
Purchased Gas	---	$14,103,069	---
Other Purchased Gas Expense	---	670,277	---
Purchased Power	$79,521,546	---	---
Other Production	2,880	---	---
Source of Supply	---	---	205,228
Pumping	---	---	69,220
Water Treatment	---	---	951,033
Transmission Expenses	269,671	---	---
Distribution Expenses	1,575,183	2,160,466	1,464,228
Customer Accounts Expenses	877,624	758,107	410,077
Customer Service Expenses	1,079,905	404,896	29,456
Sales Promotion Expenses	---	---	---
Administrative and General Expenses	3,425,562	1,441,425	1,342,441
Total Operation and Maintenance Expenses	$86,752,371	$19,538,240	$4,471,683
Depreciation Expense	3,163,762	1,763,310	2,022,867
Amortization Expense	(119,522)	(113,298)	(197,684)
Taxes Other Than Income Taxes	2,881,205	380,807	672,078
State and Federal Income Taxes	153,000	(3,523,000)	1,033,000
Deferred Income Tax and Tax Credits	50,400	3,363,000	(52,408)
Total Operating Expenses	$92,881,216	$21,409,059	$7,949,537
Net Operating Income	$1,929,820	$272,983	$3,436,844

Average Net Investment Rate Base

All uncontested Commission staff adjustments to the applicant's filed average electric, natural gas, and water net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric, natural gas, and water utility average net investment rate bases for the 2023 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding are as follows:

Net Investment Rate Base

	Retail Electric	Retail Natural Gas	Retail Water
Plant in Service	$92,262,319	$45,561,796	$69,347,402
Less: Accumulated Depreciation	43,852,163	26,957,206	26,123,260
Net Utility Plant	$48,410,156	$18,604,590	$43,224,142
Add: Gas in Storage	---	911,141	---
Materials and Supplies	524,475	219,548	475,687
Plant Acquisition Adjustment	---	---	---
Regulatory Assets	---	---	---
Less: Contributions in Aid of Construction	---	---	---
Customer Advances	---	4,198	21,668
Accumulated Deferred Income Taxes	3,804,074	2,612,246	8,549,966
Regulatory Liabilities	---	---	---
Average Net Investment Rate Base	$45,130,557	$17,118,835	$35,128,195

Pro Forma Rate of Return

The net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2023, results in a rate of return on average net investment rate base of 4.28 percent for Wisconsin retail electric utility operations, 1.59 percent for Wisconsin retail natural gas utility operations, and 9.78 percent for Wisconsin retail water utility customers.

Financial Capital Structure

In determining the appropriate capital structure of the applicant, the Commission considers the impact on customer rates and the applicant's financial flexibility and creditworthiness at various levels of common equity in the applicant's capitalization. Based on the evidence in the record, the Commission finds that a reasonable financial capital structure consists of 55.07 percent common equity, 36.10 percent long-term debt, 8.83 percent short-term debt, and 1.53 percent debt equivalence for off-balance sheet obligations. The 55.00 percent common equity is higher than most of the other large IOUs, which is appropriate because the applicant's smaller size makes issuing debt and managing its capital structure more difficult.

In calculating capital structures, on a financial basis, the Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the applicant is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital. Adjustments for these off-balance sheet obligations are made by Standard and Poor's and other financial analysts when calculating various financial ratios, including the total debt to total capital ratio. Imputing debt for off-balance sheet obligations is not a common practice of other state utility commissions. The Commission is not obligated to adopt the risk assessment of an outside agency and will independently examine off-balance sheet obligations, based on this Commission's assessment of risk.

For the test year, the Commission finds it reasonable to impute $1,037,820 of debt equivalent consisting of operating leases.

Regulatory Capital Structure and Cost of Capital

In order to arrive at the common equity amount for the applicant's regulatory capital structure, Commission staff excluded non-utility property and life insurance for the employee incentive program plan. Consequently, a reasonable utility ratemaking capital structure for the purposes of establishing just and reasonable rates for the test year consists of 54.69 percent common equity, 36.41 percent long-term debt, and 8.91 percent short-term debt.

Short-Term Debt

The applicant's test-year capital structure contains $10,884,615 in short-term debt. A reasonable estimate of the applicant's average cost of short-term debt in the form of commercial paper for the test year is 3.63 percent.[2] The forecast is based on the average of the commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter and includes an administrative adder consistent with prior rate cases. This is a reasonable and objective method of determining the applicant's short-term debt costs.

Long-Term Debt

The embedded cost of long-term debt of 3.62 percent for the test year is reasonable.

Return on Common Equity

The principal factor used to determine the appropriate ROE is the investors' required return. Authorized returns less than the investors' required return would not compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of reasonable expectations. Unreasonably high returns would be unfair to utility consumers who ultimately pay for those returns.

[2] The applicant filed a short-term cost of debt rate at 1.00 percent, but noted in rebuttal testimony that this calculation was an oversight. As this was in error, the Commission finds it reasonable to accept the revised short-term cost of debt rate.

In reaching its determination as to the appropriate ROE, the Commission must balance the needs of investors with the needs of consumers, with due considerations to economic and financial conditions, along with public policy considerations.

When making this decision, the Commission exercises its legislative function in setting policy based upon its balancing of these factors. The law recognizes the great degree of discretion exercised by the Commission in making such decisions. The use of this discretion is also necessary because the investors' required return cannot be measured with precision.

Determining what ROE is appropriate is not a legal question, and making such determinations require a high degree of discretion and judgment, as it involves intertwined legal, factual, value and public policy determinations. Courts accord due weight consideration to the experience, technical competence, and specialized knowledge of the agency involved, as well as discretionary authority conferred upon it. Wis. Stat. § 227.57(10); *Tetra Tech EC, Inc. v. DOR*, 2018 WI 75, ¶ 84, 382 Wis.2d 496, 914 N.W.2d 21.

In this proceeding, the applicant requested to maintain its currently authorized 10.40 percent ROE. In direct testimony, the applicant stated that the Commission should consider setting the ROE at no lower than 10.20 percent if the Commission is resolved to lower the applicant's ROE. Commission staff recommended a point estimate of 10.00 percent be utilized in the revenue requirement calculation for the test year. CUB recommended an ROE of 9.00 percent but also supported a 10.00 percent ROE as an initial step toward that end while acknowledging the Commission's past deference to "gradualism" when considering large changes to the applicant's revenue requirement for the test year. The revenue impact for each

20 basis points change is approximately $81,000 for electric, $30,500 for natural gas, and $62,500 for water.

Commission staff provided testimony and financial modeling in this case regarding the equity return expected by investors in the applicant's common stock. Commission staff's analysis considered the current and expected interest rates, the expected investment risk associated with holding the applicant's securities during the test-year period, and the overall state of the economy. Commission staff noted that authorized returns granted by the Commission have declined since the applicant's last rate case. Commission staff's estimated range of 8.38 percent to 9.81 percent ROE was based on the current economic conditions but recommended a higher ROE be used in the revenue requirement calculation due to the risk associated with the smaller size of this utility.

The Commission finds that the models used to estimate the ROE in this case indicate that a reduction from the currently authorized 10.40 ROE is reasonable. The Commission has traditionally made gradual adjustments to the return, rather than large and sudden changes. In addition, the Commission has traditionally granted a higher ROE to the applicant due to the risk associated with its smaller size. The Commission also notes that the uncertain circumstances in this case point towards a more gradual approach. Given these considerations, the Commission finds that the balance is struck most reasonably in this proceeding by authorizing a ROE of 10.00 percent. An ROE of 10.00 percent is reasonable as it will provide sufficient returns to utility investors and maintain the financial integrity of the utility, without resulting in customer rates that are excessive. The authorized ROE reflects all of the financial factors that affect the applicant's cost of equity and as a result, it is not reasonable to identify a specific reduction attributable to any single factor.

Commissioner Nowak dissents.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for this test year are as follows:

	Amount	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$66,845,396	54.69%	10.00%	5.47%
Long-Term Debt	$44,500,000	36.41%	3.62%	1.32%
Short-Term Debt	$10,884,615	8.91%	3.63%	0.32%
Total Utility Capital	$122,230,011	100.00%		7.11%

The weighted average cost of capital of 7.11 percent is reasonable for the applicant for the test year. It generates an economic cost of capital of 9.24 percent and a pre-tax interest coverage ratio of 5.63 times.

Rate of Return on Rate Base

The 7.11 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of the applicant's average net investment rate base plus Construction Work In Progress (CWIP) for the test year is 85.91 percent of capital applicable primarily to utility operations, plus deferred investment tax credits.

This estimate reflects all appropriate Commission staff adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base. Accordingly, the rate of return on average Wisconsin retail electric, natural gas, and water utility net investment rate base, which is reasonable for the purpose of determining just and reasonable rates in this proceeding, is as follows:

	Retail Electric (%)	Retail Natural Gas (%)	Retail Water (%)
Cost of Capital	7.11	7.11	7.11
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	85.91	85.91	85.91
Percent Return Requirement Applicable to Net Investment Rate Base	8.28	8.28	8.28
Adjustment to Return Requirement to Provide Current Return on CWIP	---	---	---
Adjusted Percent Return Requirement on Net Investment Rate Base	8.28	8.28	8.28

Authorized Change in Revenue Requirement

On the basis of the findings in this Final Decision, a $2,481,000 increase in Wisconsin retail electric utility revenues, a $1,574,000 increase in Wisconsin natural gas utility revenues, and a $724,000 decrease in Wisconsin water utility revenues are reasonable for the purpose of determining just and reasonable rates in this proceeding and are computed as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)	Retail Water (000's)
Return Earned on Average Net Investment Rate Base at Present Rates	4.28%	1.59%	9.78%
Required Return on Average Net Investment Rate Base	8.28%	8.28%	8.28%
Average Net Investment Rate Base (000's)	$45,131	$17,119	$35,128
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	$1,805	$1,145	($527)
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes at a Combined Rate of 27.241% (000's)	$2,481	$1,574	($724)

Electric Cost of Service, Revenue Allocation, and Rates

Electric Cost of Service

The applicant, intervenors, and Commission staff testified and prepared electric COSS regarding the appropriate allocation of the expenses that make up the applicant's revenue requirement. Commission staff prepared its offered COSS using Commission staff's audited revenue requirement, which consisted of a 2.57 percent revenue deficiency. The applicant did not file an updated COSS including the results of Commission staff's audited revenue requirement as it disputed the specific aspects of Commission staff's proposed revenue requirement. Instead, it prepared COSS at different revenue requirements – 2.74 percent deficiency and 2.98 deficiency.[3] Enbridge filed a COSS at using a 2.74 percent deficiency. CUB did not file a COSS but commented that the applicant's originally filed electric COSS was directionally consistent with its preferred cost allocation approach.

Historically, the Commission has considered the results of multiple COSS approaches for the purposes of allocating revenue responsibility. For this proceeding, the COSS models presented in the record reflect differences in cost allocation approaches. The Commission recognizes that any COSS is not a precise reflection of cost causality, but rather depends heavily on the accuracy of the data and projections used and the many judgments of the person performing the study. The evidence in this proceeding supports a continuation of this practice, as no one COSS is capable of reflecting every equitable balance of costs imposed and benefits received for every customer class. As a result, the Commission finds that it is reasonable to

[3] The applicant ultimately supported its COSS at the 2.98 percent deficiency.

continue its long-standing practice of relying on multiple COSS models, as well as other factors such as customer bill impacts, when determining the final allocation of the revenue requirement.

Electric Revenue Allocation

The Commission generally uses electric COSS models and other information as a guide for determining the final revenue allocation. The testimony and exhibits in this case provide a robust record for the Commission to make a decision regarding which costs are appropriate to be recovered from each customer class. Wisconsin courts have long held that the Commission has wide discretion in determining the factors upon which it may base its rate decisions. Further, the Commission is not bound to any single regulatory formula; it is permitted to make pragmatic adjustments, which may be called for by particular circumstances, unless its statutory authority plainly precludes it. To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence, and specialized knowledge to identify a reasonable result, bearing in mind the various public policies that may be impacted by various ratemaking decisions. Wis. Stat. §§ 227.57(6), (8), and (10).

The applicant, intervenors, and Commission staff offered various revenue allocation proposals. The applicant and Commission staff provided testimony regarding the allocation of the forecasted electric test-year revenue deficiency. The applicant did not file an updated revenue allocation using Commission staff's audited revenue requirement, and instead offered a revenue allocation at the 2.98 percent deficiency level. Ultimately, the offered revenue allocations were directionally consistent and none included a revenue reduction for any specific rate class. However, the allocations differed in the magnitude of the class level revenue allocations. Commission staff proposed an electric revenue allocation that ranged from an allocation of 6.81 percent for the lighting service classes to a 1.21 percent increase for the large industrial class. Alternatively, Enbridge and the applicant offered revenue allocations that included a larger increase for residential and small commercial classes and a smaller increase for the large industrial class. CUB Commented that Commission staff's proposed revenue allocation was directionally similar to the applicant's originally filed revenue allocation, and the Commission could find it reasonable when adjusted for Commissions staff's overall audited revenue requirement deficiency.

Upon its review or the record in the proceeding, the Commission finds it reasonable to accept the revenue allocation proposed by the applicant. The Commission finds that this revenue allocation is supported by the COSS results, is consistent with the principles of gradualism and avoidance of rate shock, and will result in more accurate price signals for customers.

Chairperson Valcq dissents.

PCAC

The applicant's earnings are extremely sensitive to the wholesale rates and fuel adjustment charged by its supplier. Purchased power costs represent approximately 85.60 percent of the applicant's total operating expenses. Fluctuations in the applicant's earnings can result from changes in the wholesale demand-energy rate and fuel adjustment charged by ALLETE. In order to mitigate fluctuations in the applicant's earnings due to changes in the cost of purchased power, the Commission authorizes the applicant to continue to apply a Power Cost Adjustment to all of its retail bills. This adjustment permits increases or decreases in the cost of purchased power to be passed on directly to the customer. The applicant presumably makes no profit from applying this adjustment to its retail bills.

This Final Decision revises the PCAC to reflect the change in the base average cost of power (the "U" factor of the clause) for the test year. The PCAC is applicable each month and shall reflect the difference between monthly and test-period wholesale purchased power costs. The authorized rates, as shown in Appendix B, reflect the test-year PCAC factor. This average per kWh adjustment to a customer's retail electric bill represents expected changes in the wholesale cost of purchased power for the test year. The cost of purchased power used to compute this average adjustment is based upon rates set by ALLETE, which are effective on and after January 1 of the test year.

Electric Rate Design

The applicant and Commission staff provided comprehensive electric rate design proposals that include rates for all customer classes. The applicant did not update its electric rate design to reflect Commission staff's audited revenue requirement, whereas Commission staff prepared its electric rate design at the Commission staff audited revenue requirement. The applicant and Commission staff also developed revised residential and commercial 2005 Wisconsin Act 141 (Act 141) rate factors based on the applicant's required 2023 Act 141 contributions.

In order to provide appropriate price signals to customers, maintain rate continuity, and achieve the goals of customer understanding and acceptance of rates, the Commission considered the COSS results, rate comparability, and customer bill impacts. Consistent with the directive on revenue allocation and for the prior stated reasons, the Commission finds the overall electric rate design proposed by the applicant, and as adjusted for the final revenue requirement, to be reasonable.

Chairperson Valcq dissents.

The authorized electric service rates appear in Appendix B. The Commission directs the applicant to file final form tariff sheets consistent with those rates.

Fixed Customer Charges

The applicant proposed changes to the fixed customer charges for all residential, commercial, and industrial rate classes, except for general service demand EC-3.[4] These proposed increases were consistent with the applicant's COSS, and they range from $2.00 per month for residential and general service classes (excluding EC-3) to $5.00 per month for large power classes.

To aid in the development of the record pertaining to fixed customer charges, Commission staff requested a basic customer cost analysis at Commission staff-adjusted levels. This request was consistent with recent rate case proceedings before the Commission where the Commission evaluated proposed changes to fixed customer charges and found it reasonable to continue discussion and analysis of changes to fixed customer charges.

Commission staff commented that in consideration for the evidence in the record, including COSS results, and due to the gradual nature of the applicant's proposal, it had included the applicant's proposed fixed customer charges in its offered electric rate design. CUB commented that it did not object to the proposed customer charges as they were supported by the range of COSS models under consideration in the proceeding.

For the reasons noted above, the decision to increase the customer charge is based on substantial evidence and represent a gradual shift in incorporating customer cost into fixed

[4] The applicant did not propose a rate increase to EC-3, as its COSS supported a decrease in revenue for EC-3, contrary to the overall COSS results.

customer rates. Therefore, the Commission finds it reasonable to authorize the electric fixed customer charges as proposed.

Commissioner Huebner dissents on the fixed customer charges for customer classes ER-1 and ER-TD.

Interruptible Rates

Testimony offered by Enbridge included a recommendation that the applicant submit a proposed interruptible rate in a TE docket no later than April 1, 2023. In its testimony, Enbridge noted that the applicant does not offer interruptible rate options, and since it procures all its power requirements and capacity is a factor in that allocation, interruptible load will help lower the capacity requirements and provide benefits to the system. The applicant responded that it would be willing to propose an interruptible rate as suggested by Enbridge. Therefore, the Commission finds it reasonable to direct the applicant to file for an interruptible rate option, as proposed by Enbridge, by April 1, 2023.

Natural Gas Cost of Service, Revenue Allocation, and Rates

Natural Gas Cost of Service

The applicant and Commission staff testified regarding natural gas cost of service issues and the appropriate allocation methods for allocating the plant and operating expenses that make up the applicant's revenue requirement.

The testimony in this proceeding covered the various COSS models and discussed the philosophical underpinnings of those models in detail. The Commission is not persuaded by the evidence that any of the proposed methods are unreasonable. As a result, the Commission finds that it is reasonable to continue its long-standing practice of relying on multiple models, as well as other factors such as customer bill impacts, when determining the final allocation of the revenue requirement.

Natural Gas Revenue Allocation and Rate Design

The applicant, CUB, and Commission staff agreed on Commission staff's proposed natural gas revenue allocation. The Commission finds it reasonable to authorize Commission staff's proposed natural gas revenue allocation as it is supported by the parties to this proceeding, and it provides for a gradual increase in natural gas revenue as compared to the overall revenue requirement.

Additionally, the applicant and Commission staff each offered a comprehensive natural gas rate design for Commission consideration, which included an increase to the monthly customer charge for each class, and the closure of the Coal Displacement rate, which has no customers under the rate. Based on an analysis of fixed customer costs produced by Commission staff's COSS models, results of the basic customer cost analysis provided by the applicant, and the applicant's gradual approach to developing its proposed customer charge rates, Commission staff's rate design included the applicants' proposed fixed customer charge increases.

Ultimately, in consideration of the evidence in the record, the Commission finds it reasonable to approve the Commission staff proposed natural gas rate design, including the increased fixed customer charges and closure of the Coal Displacement rate, as proposed. The authorized natural gas rates are included in Appendix C. The Commission directs the applicant to file final form tariff sheets consistent with those rates.

Water Cost of Service, Revenue Allocation, and Rate Design

Water Cost of Service

The applicant and Commission staff testified regarding water cost of service issues and the appropriate allocation methods for allocating the plant and operating expenses that make up the applicant's revenue requirement. Commission staff submitted for the record an analysis of the cost of supplying water for general service and for public fire protection service. Commission staff used the base-extra capacity cost allocation method for the analysis. Under this method, the operating expenses are allocated first to the service cost functions of extra-capacity maximum-day and maximum-hour demand, base, customer, and fire protection and then to each of the customer classes served. Summaries of such analyses are shown in Schedules 8 and 11 of Ex.-PSC-Fisher-1-r, Commission staff's proposal in the record in this proceeding. Appendix D shows customer class revenue requirements resulting from the cost analysis compared with water revenues at authorized rates. The Commission finds it reasonable to accept the water COSS prepared by Commission staff and agreed to by the applicant.

Water Revenue Allocation and Rate Design

The applicant and Commission staff agreed on Commission staff's proposed water revenue allocation and rate design. Therefore, the Commission finds it reasonable to approve Commission staff's proposed water rate design. Public fire protection charges to customers in the City of Superior will decrease by approximately than 1.22 percent, and the public fire protection charge to the Village of Superior will decrease by approximately 4.26 percent.

The authorized water rates as set forth in Appendix D are based on the cost of supplying various classes or types of service. Some typical water bills for residential, commercial, industrial, and public authority customers were computed using Schedule Mg-1 to compare existing rates with the new rates. That comparison is also set forth in Appendix D.

The overall decrease in annual water revenues is 6.39 percent, comprised of a 7.81 percent decrease in general service charges and a 1.29 percent decrease in fire protection charges. A typical residential customer's bill will decrease 8.21 percent (including public fire protection).

Order

1. This Final Decision takes effect one day after the date of service.

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2023, provided that the applicant files these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code §§ PSC 113.0406(1)(a), 134.13(1)(b), and 185.33(1)(f) by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

3. The authorized water rate decrease shall take effect on January 1, 2023. The applicant shall file this rate decrease and tariff provisions with the Commission and make them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 185.33(1)(f) by that date.

4. The applicant shall revise its existing rates and tariff provisions for electric, natural gas and water utility service, substituting the rate increases and tariff provisions that expand the terms of services, as shown in Appendices B, C, and D or as described in this Final

Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

5. The applicant shall prepare bill messages that properly identify the rates authorized in this Final Decision. The applicant shall provide the message to customers no later than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill messages with the Commission before it provides the message to customers.

6. The applicant shall discontinue escrow accounting for any over- or under-collection of credit card processing fees.

7. A true-up of the credit card processing fees is required in the next rate proceeding.

8. The applicant shall notify the Commission within 30 days of receiving confirmation of Husky's return to normal operations.

9. The applicant shall amortize the $201,465 regulatory liability associated with Husky over the two-year period of 2023 through 2024.

10. The applicant shall end the regulatory liability for water revenues from the Husky Superior Refinery (Husky) as of December 31, 2022.

11. A true-up of the regulatory liability associated with Husky is required in the next rate proceeding.

12. The applicant shall amortize the remaining $24,524 of the tax reform refunds associated with the TCJA authorized in docket 5-AF-101 over the two-year period of 2023-2024.

13. A true-up of the remaining tax reform refunds associated with the TCJA is required in the next rate proceeding.

14. The applicant shall amortize the deferred COVID-19 regulatory asset of $120,485 over the two-year period of 2023 through 2024.

15. A true-up of the deferred COVID-19 regulatory asset is required in the next rate proceeding.

16. The applicant shall amortize the bad debt expense of $325,000 over the two-year period of 2023 through 2024.

17. The applicant shall amortize the MGP costs of $1,559,906 over the four-year period of 2023 through 2026.

18. Any additional MGP costs incurred after December 31, 2021 shall be deferred until the applicant's next rate proceeding.

19. The applicant shall record annual conservation escrow accrual amounts for the 2023 test year of $863,550 for electric utility operations and $232,163 for natural gas operations. The applicant shall continue to record these expense amounts annually until they are superseded by a Commission order authorizing new conservation escrow accruals.

20. The applicant shall record amortization expenses consistent with Appendix I, for the 2023 test year, or until the Commission authorizes a different amortization expense to be recorded.

21. The applicant shall file a proposal for an interruptible rate option no later than April 1, 2023.

22. The applicant shall close its existing Coal Displacement rate service as proposed by the applicant.

23. The applicant shall file tariffs consistent with this Final Decision.

24. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 20th day of December, 2022.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:JAM:arw:dsa:DL: 01908808

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
4822 Madison Yards Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[5] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

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[5] *See Currier v. Wisconsin Dep't of Revenue,* 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

Docket 5820-UR-116

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN
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Docket 5820-UR-116

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Superior Water, Light and Power Company

Electric Revenue Summary for Test Year 2023

Rate Class, Sub-Class, and Descriptions		Present Revenue	Authorized Revenue	Revenue Change	Percent Change
Er-1	Residential Service	$12,712,294	$13,562,049	$849,755	6.68%
Er-TD	Residential Time-of-Day	$67,519	$72,088	$4,569	6.77%
Ed-1	Controlled Space Heating Service	$140,444	$149,429	$8,985	6.40%
Ew-1	Controlled Water Heating Service	$13,139	$13,993	$854	6.50%
	Total Residential	**$12,933,396**	**$13,797,559**	**$864,163**	**6.68%**
Ec-1	General Service	$3,436,825	$3,668,158	$231,333	6.73%
	Total Small Commercial	**$3,436,825**	**$3,668,158**	**$231,333**	**6.73%**
Ec-3	General Service Demand	$8,847,917	$8,922,159	$74,242	0.84%
Ec-5	General Service Time of Day	$1,790,564	$1,911,639	$121,075	6.76%
Ep-1	General Service Primary Voltage	$761,915	$804,898	$42,983	5.64%
	Total Medium Commercial	**$11,400,396**	**$11,638,696**	**$238,300**	**2.09%**
Ep-3	Large Power Time-of-Day	$11,937,175	$12,585,236	$648,062	5.43%
Ep-5	Large Industrial Time-of-Day	$51,650,329	$52,122,979	$472,650	0.92%
	Total Large Commercial and Industrial	**$63,587,504**	**$64,708,215**	**$1,120,712**	**1.76%**
El-1	Street Lighting Service	$304,015	$324,206	$20,191	6.64%
Ez-1	Sports Field Lighting Service	$12,674	$13,947	$1,273	10.04%
En-1	Night Watch Lighting Service	$74,386	$79,414	$5,029	6.76%
	Total Lighting	**$391,075**	**$417,567**	**$26,492**	**6.77%**
	Total Electric	**$91,749,196**	**$94,230,196**	**$2,481,000**	**2.70%**

Superior Water, Light and Power Company
Electric Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Residential Service (Er-1)			
Customer Charge			
Single Phase	$ 9.00	$ 11.00	per month
Energy Charge	$ 0.11500	$ 0.1384	per kWh
PCAC	$ 0.0170	$ -	per kWh
Residential Time-of-Day (Er-TD)			
Customer Charge			
Single Phase	$ 9.00	$ 11.00	per month
Energy Charge			
Summer On Peak	$ 0.1300	$ 0.1524	per kWh
Winter On Peak	$ 0.1380	$ 0.1604	per kWh
Off Peak	$ 0.0550	$ 0.0774	
PCAC	$ 0.0170	$ -	per kWh
Controlled Space Heating Service (Ed-1)			
Customer Charge	$ 5.00	$ 7.00	per month
Energy Charge	$ 0.0700	$ 0.0910	per kWh
PCAC	$ 0.0170	$ -	per kWh
Controlled Water Heating (Ew-1)			
Customer Charge	$ 5.00	$ 7.00	per month
Energy Charge	$ 0.08100	$ 0.0944	per kWh
PCAC	$ 0.0170	$ -	per kWh

SSuperior Water, Light and Power Company
Electric Rates

Rate Schedule	Present Rates	Authorized Rates	Units
General Service (Ec-1)			
Customer Charge			
Single Phase	$ 11.00	$ 13.00	per month
Three Phase	$ 16.00	$ 18.00	per month
Energy Charge	$ 0.1126	$ 0.1374	per kWh
PCAC	$ 0.0170	$ -	per kWh
General Service Demand (Ec-3)			
Customer Charge			
Single Phase	$ 17.00	$ 17.00	per month
Three Phase	$ 28.00	$ 28.00	per month
Distribution Demand Charge	$ 2.00	$ 3.00	per kW
Billed Demand Charge	$ 8.00	$ 9.00	per kW
Energy Charge	$ 0.0710	$ 0.0853	per kWh
PCAC	$ 0.0170	$ -	per kWh
General Service Time-of-Day (Ec-5)			
Customer Charge	$ 205.00	$ 210.00	per month
Distribution Demand Charge	$ 2.00	$ 3.00	per kW
Billed Demand Charge			
Winter	$ 10.00	$ 11.50	per kW
Summer	$ 9.00	$ 10.50	per kW
Energy Charge			
Winter On-Peak	$ 0.0740	$ 0.0936	per kWh
Summer On-Peak	$ 0.0700	$ 0.0896	per kWh
Off-Peak	$ 0.0500	$ 0.0695	per kWh
PCAC	$ 0.0170	$ -	per kWh

Superior Water, Light and Power Company
Electric Rates

Rate Schedule	Present Rates		Authorized Rates		Units
General Service Primary Voltage (Ep-1)					
Customer Charge	$	75.00	$	80.00	per month
Distribution Demand Charge	$	2.00	$	3.00	per kW
Billed Demand Charge	$	8.00	$	9.00	per kW
Energy Charge	$	0.0659	$	0.0834	per kWh
PCAC	$	0.0170	$	-	per kWh
Large Power Time-of-Day (Ep-3)					
Customer Charge	$	205.00	$	210.00	per month
Distribution Demand Charge	$	2.00		$3.00	per kW
Billed Demand Charge					
Winter	$	10.00	$	11.00	per kW
Summer	$	9.00	$	10.00	per kW
Energy Charge					
Winter On-Peak	$	0.0701	$	0.0889	per kWh
Summer On-Peak	$	0.0672	$	0.0860	per kWh
Off-Peak	$	0.0452	$	0.0640	per kWh
PCAC	$	0.0170	$	-	per kWh
Act 141 LEU Credit			$	0.00245	per kWh
Large Industrial Time-of-Day Service (Ep-5)					
Customer Charge	$	600.00	$	605.00	per month
Distribution Demand Charge	$	2.00	$	3.00	per kW
Billed Demand Charge					
Winter	$	11.35	$	12.35	per kW
Summer	$	11.35	$	12.35	per kW
Energy Charge					
Winter On-Peak	$	0.0621	$	0.0781	per kWh
Summer On-Peak	$	0.0581	$	0.0741	per kWh
Off-Peak	$	0.0387	$	0.0547	per kWh
PCAC	$	0.0170	$	-	per kWh

Superior Water, Light and Power Company
Electric Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Street Lighting Service (EL-1)			
Overhead			
3,500 Lumen LED change to 6,000 LED	$ 10.03	$ 11.00	per month
8,500 Lumen LED change to 13,000 LED	$ 12.69	$ 13.50	per month
150 W HPS	$ 11.21	$ 12.50	per month
250 W HPS	$ 13.00	$ 13.89	per month
250 W MV	$ 13.77	$ 15.00	per month
400 W MV	$ 17.90	$ 19.25	per month
Ornamental			
Customer Charge	$ 13.00	$ 13.50	per month
Signal Lighting			
Customer Charge	$ 28.00	$ 28.00	per month
Energy Charge	$ 0.0600	$ 0.0857	per kWh
PCAC	$ 0.0170	$ -	per kWh
Sports Field Lighting (Ez-1)			
Customer Charge	$ 22.00	$ 25.00	per month
Energy Charge	$ 0.1000	$ 0.1405	per kWh
PCAC	$ 0.0170	$ -	per kWh
Night Watch Lighting (En-1)			
Overhead			
6,630 Lumen LED	$ 9.80	$ 11.80	per month
150 W HPS	$ 13.35	$ 15.50	per month
250 W HPS	$ 13.95	$ 15.95	per month
400 W MV	$ 22.80	$ 24.20	per month
Pole Charge	$ 6.50	$ 8.25	per month
Energy Charge	$ -	$ -	per kWh
PCAC	$ 0.0170	$ -	per kWh
Miscellaneous			
Average Base Cost of Power	$ 0.0642	$ 0.0812	per kWh
Act 141 Energy Factor			
Residential		$ 0.00331	per kWh
Commercial		$ 0.00245	per kWh
Embedded Cost Allowances			
Energy Only Classes	$ 356.00	$ 303.27	per customer
Demand Classes	$ 31.00	$ 36.84	per kW
Street Lighting	$ 12.00	$ 9.89	per lamp

SUPERIOR WATER, LIGHT AND POWER COMPANY
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2023

Residential Service Rg-1: Single Phase

Monthly kWh Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
100	$22.20	$24.84	$2.64	11.89%
500	$75.00	$80.20	$5.20	6.93%
577	**$85.16**	**$90.86**	**$5.69**	**6.68%**
750	$108.00	$114.80	$6.80	6.30%
1,000	$141.00	$149.40	$8.40	5.96%
1,500	$207.00	$218.60	$11.60	5.60%
2,500	$339.00	$357.00	$18.00	5.31%
4,000	$537.00	$564.60	$27.60	5.14%

General Service Ec-1: Single Phase

kWh Use	Present Rates	Proposed Rates	Change	Change
500	$75.80	$81.70	$5.90	7.78%
1,000	$140.60	$150.40	$9.80	6.97%
1,284	**$177.41**	**$189.42**	**$12.02**	**6.77%**
2,000	$270.20	$287.80	$17.60	6.51%
3,000	$399.80	$425.20	$25.40	6.35%
4,000	$529.40	$562.60	$33.20	6.27%
5,000	$659.00	$700.00	$41.00	6.22%
6,000	$788.60	$837.40	$48.80	6.19%

General Service Ec-1: Three Phase

kWh Use	Present Rates	Proposed Rates	Change	Change
500	$80.80	$86.70	$5.90	7.30%
1,000	$145.60	$155.40	$9.80	6.73%
1,284	**$182.41**	**$194.42**	**$12.02**	**6.59%**
2,000	$275.20	$292.80	$17.60	6.40%
3,000	$404.80	$430.20	$25.40	6.27%
4,000	$534.40	$567.60	$33.20	6.21%
5,000	$664.00	$705.00	$41.00	6.17%
6,000	$793.60	$842.40	$48.80	6.15%

* Values in bold represent class average usage

Superior Water, Light and Power Company

Gas Revenue Summary for Test Year 2023

Rate Schedule		Present Revenue without Cost of Gas	Cost of Gas Revenue	Total Present Revenue	Authorized Revenue without Cost of Gas	Cost of Gas Revenue	Total Authorized Revenue	Revenue Change	Percent Change with Cost of Gas	Percent Change without Cost of Gas
GR-1	Residential Service	$ 4,608,975	$ 7,124,407	$ 11,733,382	$ 5,551,102	$ 7,090,313	$ 12,641,415	$ 908,033	7.7%	19.7%
	Total Residential Service	**$ 4,608,975**	**$ 7,124,407**	**$ 11,733,382**	**$ 5,551,102**	**$ 7,090,313**	**$ 12,641,415**	**$ 908,033**	**7.7%**	**19.7%**
GC-1	Small Commerical - Firm System Sales	$ 1,546,396	$ 3,567,337	$ 5,113,733	$ 1,859,355	$ 3,562,420	$ 5,421,775	$ 308,042	6.0%	19.9%
GI-1	Small Commerical - Interruptible System Sales	$ 142,658	$ 420,919	$ 563,577	$ 160,688	$ 429,038	$ 589,726	$ 26,149	4.6%	18.3%
	Total Small Commerical Service	**$ 1,689,054**	**$ 3,988,256**	**$ 5,677,310**	**$ 2,020,043**	**$ 3,991,458**	**$ 6,011,501**	**$ 334,191**	**5.9%**	**19.8%**
GL-1	Large Commerical - Firm System Sales	$ 568,786	$ 1,953,581	$ 2,522,367	$ 698,270	$ 1,966,232	$ 2,664,502	$ 142,135	5.6%	25.0%
GI-6	Large Commerical - Interruptible System Sales	$ 222,361	$ 1,036,825	$ 1,259,186	$ 268,884	$ 1,055,588	$ 1,324,472	$ 65,286	5.2%	29.4%
TSP	Large Commerical - Interruptible Transport (GI-6)	$ 395,168	$ -	$ 395,168	$ 519,666	$ -	$ 519,666	$ 124,498	31.5%	31.5%
PFI	Partial Firm-Interruptible Service	$ 5,160	$ -	$ 5,160	$ 5,160	$ -	$ 5,160	$ -	0.0%	0.0%
	Total Large Commercial Service	**$ 1,191,475**	**$ 2,990,406**	**$ 4,181,881**	**$ 1,491,980**	**$ 3,021,820**	**$ 4,513,800**	**$ 331,919**	**7.9%**	**27.9%**
	Total Revenue	**$ 7,489,504**	**$ 14,103,069**	**$ 21,592,573**	**$ 9,063,125**	**$ 14,103,591**	**$ 23,166,716**	**$ 1,574,143**	**7.3%**	**21.0%**

Superior Water, Light and Power Company

Gas Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Residential Service - GR-1			
Customer Charge	$7.25	$10.00	per month
Distribution Charge	$ 0.3245	$ 0.3779	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Small Commerical - Firm System Sales - GC-1			
Customer Charge	$15.00	$18.00	per month
Distribution Charge	$ 0.2305	$ 0.2811	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Small Commerical - Interruptible System Sales - GI-1			
Customer Charge	$135.00	$150.00	per month
Distribution Charge	$ 0.1658	$ 0.1894	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Firm System Sales - GL-1			
Customer Charge	$160.00	$175.00	per month
Distribution Charge	$ 0.1489	$ 0.1894	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Interruptible System Sales - GI-6			
Customer Charge	$430.00	$450.00	per month
Distribution Charge	$ 0.0914	$ 0.1153	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Interruptible Transport (GI-6) - TSR			
Customer Charge	$430.00	$430.00	per month
Additional Meter Charge	$25.00	$25.00	per month
Distribution Charge	$ 0.0914	$ 0.1153	per therm
Partial Firm-Interruptible Service - PFI			
Customer Charge	$430.00	$430.00	per month
Distribution Charge			
Firm Contract Load	$ 0.1489	$ 0.1894	per month
Interruptible Load	$ 0.0914	$ 0.1153	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Base Average Cost of Gas			
Commodity Rate Charge (Comm)	$ 0.2974	$ 0.5550	per therm
Peak Day Demand Charge (D1)	$ 0.0630	$ 0.0861	per therm
Annual Demand Charge (D2)	$ 0.0325	$ 0.0488	per therm
Act 141 Distribution Rate*			
Residential	$ 0.00863	$ 0.00720	per therm
Commercial	$ 0.01243	$ 0.00910	per therm

*Act 141 distribution rates are included in the above distribution service charges.

SUPERIOR WATER, LIGHT AND POWER COMPANY
RESIDENTIAL BILL COMPARISON
TEST YEAR ENDED DECEMBER 31, 2023

Residential Service (GR-1) - System Supply - Summer

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 7.25	$ 10.00	$ 2.75	37.9%
10	$ 16.72	$ 20.01	$ 3.28	19.6%
20	$ 26.20	$ 30.01	$ 3.82	14.6%
24	$ 29.98	$ 34.02	$ 4.03	13.4%
40	$ 45.14	$ 50.03	$ 4.89	10.8%
50	$ 54.61	$ 60.03	$ 5.42	9.9%
75	$ 78.30	$ 85.05	$ 6.76	8.6%
100	$ 101.98	$ 110.07	$ 8.09	7.9%
200	$ 196.70	$ 210.13	$ 13.43	6.8%
300	$ 291.43	$ 310.20	$ 18.77	6.4%
500	$ 480.89	$ 510.34	$ 29.45	6.1%

Residential Service (GR-1) - System Supply - Non-Summer

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 7.25	$ 10.00	$ 2.75	37.9%
10	$ 17.58	$ 20.87	$ 3.28	18.7%
20	$ 27.92	$ 31.74	$ 3.82	13.7%
30	$ 38.25	$ 42.60	$ 4.35	11.4%
40	$ 48.58	$ 53.47	$ 4.89	10.1%
50	$ 58.92	$ 64.34	$ 5.42	9.2%
75	$ 84.75	$ 91.51	$ 6.76	8.0%
100	$ 110.59	$ 118.68	$ 8.09	7.3%
127	$ 138.49	$ 148.02	$ 9.53	6.9%
200	$ 213.92	$ 227.35	$ 13.43	6.3%
300	$ 317.26	$ 336.03	$ 18.77	5.9%
500	$ 523.94	$ 553.39	$ 29.45	5.6%

Residential Service (GR-1) - System Supply - Annual Total

Annual Therm Use	AnnualBill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 87.00	$ 120.00	$ 33.00	37.9%
50	$ 137.99	$ 173.66	$ 35.67	25.8%
100	$ 188.98	$ 227.32	$ 38.34	20.3%
200	$ 290.97	$ 334.65	$ 43.68	15.0%
300	$ 392.95	$ 441.97	$ 49.02	12.5%
400	$ 494.93	$ 549.29	$ 54.36	11.0%
500	$ 596.92	$ 656.62	$ 59.70	10.0%
750	$ 851.87	$ 924.92	$ 73.05	8.6%
905	$ 1,009.95	$ 1,091.27	$ 81.33	8.1%
1000	$ 1,106.83	$ 1,193.23	$ 86.40	7.8%
1250	$ 1,361.79	$ 1,461.54	$ 99.75	7.3%
1500	$ 1,616.75	$ 1,729.85	$ 113.10	7.0%

Superior Water, Light and Power Company
Comparison of Revenue
at
Present Rates and Authorized Rates

Customer Class	Revenue at Present Rates	Authorized Rates: Revenue	Authorized Rates: Increase over Present Rates
Residential	$4,922,960	$4,467,513	-9.25%
Multifamily Residential	$646,417	$599,570	-7.25%
Commercial	$1,767,496	$1,648,140	-6.75%
Industrial	$1,423,868	$1,359,635	-4.51%
Public Authority	$155,712	$145,566	-6.52%
Inter-Dept	$4,798	$4,474	-6.76%
Public Fire Protection	$2,125,385	$2,098,006	-1.29%
Total	$11,046,636	$10,322,905	-6.55%
Public Fire Protection			
City of Superior	$2,077,157	$2,051,832	-1.22%
Village of Superior	$48,228	$46,174	-4.26%
Total	$2,125,385	$2,098,006	-1.29%
Other Sales Revenue			
Private Fire Protection	$106,152	$106,152	0.00%
Other Water Sales	$175,932	$175,932	0.00%
Total	$282,084	$282,084	0.00%
Total Sales Revenues	$11,328,720	$10,604,989	-6.39%

MG-1: GENERAL SERVICE - METERED			
Meter Size	Existing Rates	Proposed Rates	Percent Change
5/8"	$ 18.25	$ 18.25	0.00%
3/4"	$ 18.25	$ 18.25	0.00%
1"	$ 28.00	$ 28.00	0.00%
1 1/4"	$ -	$ -	0.00%
1 1/2"	$ 45.00	$ 45.00	0.00%
2"	$ 70.00	$ 70.00	0.00%
3"	$ 110.00	$ 110.00	0.00%
4"	$ 160.00	$ 160.00	0.00%
6"	$ 280.00	$ 280.00	0.00%
8"	$ 415.00	$ 415.00	0.00%
10"	$ 595.00	$ 595.00	0.00%
12"	$ 775.00	$ 775.00	0.00%

MG-1: GENERAL SERVICE - METERED			
Volume Blocks (CCF)	Existing Rates	Proposed Rates	Percent Change
First 20	$ 6.74	$ 5.66	-16.02%
Next 480	$ 5.32	$ 5.09	-4.32%
Next 500	$ 4.97	$ 4.75	-4.43%
Over 1,000	$ 4.00	$ 3.82	-4.50%

F-1: PUBLIC FIRE			
Meter Size	Existing Rates	Proposed Rates	Percent Change
5/8"	$ 13.00	$ 12.54	-3.54%
3/4"	$ 13.00	$ 12.54	-3.54%
1"	$ 30.00	$ 31.35	4.50%
1 1/4"	$ -	$ -	
1 1/2"	$ 65.00	$ 62.71	-3.52%
2"	$ 100.00	$ 101.00	1.00%
3"	$ 190.00	$ 188.00	-1.05%
4"	$ 325.00	$ 313.00	-3.69%
6"	$ 650.00	$ 626.00	-3.69%
8"	$ 1,050.00	$ 1,003.00	-4.48%
10"	$ 1,550.00	$ 1,505.00	-2.90%
12"	$ 2,100.00	$ 2,006.00	-4.48%

F-2: VILLAGE OF SUPERIOR			
Municipal Charge	Existing Charge	Proposed Charge	Percent Change
Annually	$ 48,228	$ 46,174	-4.26%
Monthly	$ 4,019	$ 3,848	-4.26%

UPF-1: PRIVATE FIRE			
Connection Size	Existing Rates	Proposed Rates	Percent Change
2-inch	$ 14.00	$ 14.00	0.00%
3-inch	$ 26.00	$ 26.00	0.00%
4-inch	$ 45.00	$ 45.00	0.00%
6-inch	$ 90.00	$ 90.00	0.00%
8-inch	$ 142.00	$ 142.00	0.00%
10-inch	$ 215.00	$ 215.00	0.00%
12-inch	$ 285.00	$ 285.00	0.00%
14-inch	$ 355.00	$ 355.00	0.00%
16-inch	$ 430.00	$ 430.00	0.00%

Superior Water, Light and Power Company

Customer Water Bill Comparison at Present and Authorized Rates

			Monthly			Monthly Including Public Fire Protection		
Customer Type	Meter Size	Volume (100 Cubic Feet)	Bills at Old Rates	Bills at New Rates	Percent Change	Bills at Old Rates	Bills at New Rates	Percent Change
Small Residential	5/8"	2	$ 31.73	$ 29.57	-6.81%	$ 44.73	$ 42.11	-5.86%
Average Residential	5/8"	4	$ 45.21	$ 40.89	-9.56%	$ 58.21	$ 53.43	-8.21%
Large Residential	5/8"	6	$ 58.69	$ 52.21	-11.04%	$ 71.69	$ 64.75	-9.68%
Large Residential	5/8"	8	$ 72.17	$ 63.53	-11.97%	$ 85.17	$ 76.07	-10.68%
Large Residential	5/8"	10	$ 85.65	$ 74.85	-12.61%	$ 98.65	$ 87.39	-11.41%
Multifamily Residential	5/8"	12	$ 99.13	$ 86.17	-13.07%	$ 112.13	$ 98.71	-11.97%
Multifamily Residential	5/8"	16	$ 126.09	$ 108.81	-13.70%	$ 139.09	$ 121.35	-12.75%
Multifamily Residential	5/8"	20	$ 153.05	$ 131.45	-14.11%	$ 166.05	$ 143.99	-13.29%
Multifamily Residential	5/8"	24	$ 174.33	$ 151.81	-12.92%	$ 187.33	$ 164.35	-12.27%
Commercial	5/8"	15	$ 119.35	$ 103.15	-13.57%	$ 132.35	$ 115.69	-12.59%
Commercial	1"	100	$ 588.40	$ 548.40	-6.80%	$ 618.40	$ 579.75	-6.25%
Commercial	2"	250	$ 1,428.40	$ 1,353.90	-5.22%	$ 1,528.40	$ 1,454.90	-4.81%
Commercial	4"	500	$ 2,848.40	$ 2,716.40	-4.63%	$ 3,173.40	$ 3,029.40	-4.54%
Industrial	1"	500	$ 2,716.40	$ 2,584.40	-4.86%	$ 2,746.40	$ 2,615.75	-4.76%
Industrial	1 1/2"	750	$ 3,975.90	$ 3,788.90	-4.70%	$ 4,040.90	$ 3,851.61	-4.68%
Industrial	4"	2,000	$ 9,333.40	$ 8,911.40	-4.52%	$ 9,658.40	$ 9,224.40	-4.49%
Industrial	6"	4,000	$ 17,453.40	$ 16,671.40	-4.48%	$ 18,103.40	$ 17,297.40	-4.45%
Public Authority	5/8"	5	$ 51.95	$ 46.55	-10.39%	$ 64.95	$ 59.09	-9.02%
Public Authority	3/4"	15	$ 119.35	$ 103.15	-13.57%	$ 132.35	$ 115.69	-12.59%
Public Authority	1"	100	$ 588.40	$ 548.40	-6.80%	$ 618.40	$ 579.75	-6.25%
Public Authority	1 1/2"	200	$ 1,137.40	$ 1,074.40	-5.54%	$ 1,202.40	$ 1,137.11	-5.43%

Superior Water, Light and Power Company
Schedule of Electric Depreciation Rates
Effective January 1, 2023

Account Number	Account Title	Deprec. Rate
	TRANSMISSION PLANT	
353	Station Equipment	2.50%
354	Towers & Fixtures	1.83%
355	Poles & Fixtures	3.14%
356	Overhead Conductors & Devices	2.63%
359	Roads & Trails	2.50%
	DISTRIBUTION PLANT	
361	Structures and Improvements	1.96%
362	Station Equipment	2.63%
364	Poles, Towers & Fixtures	4.12%
365	Overhead Conductors & Devices	4.67%
366	Underground Conduit	1.91%
367	Underground Conductors & Devices	4.17%
368	Line Transformers	3.13%
369	Services	6.67%
370	Meters	5.00%
371	Installation on Customer Premises	6.67%
373	Street Lighting & Signal Systems	6.00%
	GENERAL PLANT	
391	Office Furniture and Equipment	5.00%
392	Transportation Equip	25.00%
393	Stores Equipment	5.00%
394	Tools, Shop & Garage Equip	4.00%
395	Lab Equip	5.00%
396	Power Operated Equip	UNIT
397	Communication Equip	5.00%

Superior Water, Light and Power Company
Schedule of Gas Depreciation Rates
Effective January 1, 2023

Account Number	Account Title	Deprec. Rate
	TRANSMISSION PLANT	
366	Structures and improvements	2.74%
367	Mains	2.74%
369	Measuring and Reg. St. Equipment	5.25%
370	Communication equipment	8.33%
	DISTRIBUTION PLANT	
375	Structures and Improvements	1.67%
376	Mains	2.74%
378	Measuring and Reg. St. Equip. - General	5.25%
379	Measuring and Reg. St. Equip. - City Gate	5.00%
380	Services	4.71%
381	Meters	5.00%
383	House Regulators	3.33%
385	Industrial Measuring and Reg. St. Equipment	3.03%
	GENERAL PLANT	
391	Office Furniture and Equipment	5.00%
391.1	Computer Equipment	25.00%
394	Tools, Shop and Garage Equipment	4.00%
395	Laboratory Equipment	4.00%
397	Communication Equipment	5.00%

Superior Water, Light and Power Company
Schedule of Water Depreciation Rates
Effective January 1, 2023

Account Number	Account Title	Deprec. Rate
	SOURCE OF SUPPLY PLANT	
312	Collecting and Impounding Reservoirs	1.50%
313	Lake, river, and other intakes	1.43%
314	Wells and Springs	2.22%
316	Supply Mains	1.43%
	PUMPING PLANT	
321	Structures and Improvements	2.50%
325	Electric Pumping Equipment	3.33%
328	Other Pumping Equipment	5.00%
	WATER TREATMENT PLANT	
331	Structures and Improvements	2.22%
332	Water Treatment Equipment	2.33%
	TRANSMISSION AND DISTRIBUTION PLANT	
342	Distribution Reservoirs and Standpipes	1.90%
343	Transmission and Distribution Mains	1.10%
345	Services	3.85%
346	Meters	5.00%
348	Hydrants	5.50%
	GENERAL PLANT	
391	Office Furniture and Equipment	5.88%
394	Tools, Shop and Garage Equipment	5.88%
395	Laboratory Equipment	5.88%
397	Communication Equipment	10.00%
397.1	Communication Equipment - SCADA	5.88%

Superior Water, Light and Power Company
Schedule of Common Depreciation Rates
Effective January 1, 2023

Account Number	Account Title	Deprec. Rate
	INTANGIBLE PLANT	
303	Miscellaneous intangible plant	10.00%
303.1	Miscellaneous intangible plant	6.67%
	GENERAL PLANT	
390	Structures and Improvements	2.78%
391	Office Furniture and Equipment	9.09%
391.1	Computer Equipment	25.00%
392	Transportation Equipment	UNIT
393	Stores Equipment	5.00%
394	Tools, Shop and Garage Equipment	5.88%
395	Laboratory Equipment	5.00%
396	Power Operated Equip	UNIT
397	Communication Equipment	8.33%
398	Miscellaneous Equipment	5.00%

Amortization of Regulated Assets and Liabilities
5820-UR-116
Amortization of Regulated Assets and Liabilities
Test Year 2023

	PSC Escrow Authorization	Amoritization Period	Year 2023 Amortization Amount			Balance at 12/31/2023 Deferral Balance (Gross of Tax)		
			Electric	Gas	Water	Electric	Gas	Water
Manufactured Gas Plant Costs		2023 - 2026		519,969			1,559,906	
Tax Reform	5-AF-101	2023 - 2024	(14,031)	(7,910)	(2,583)	(14,031)	(7,910)	(2,583)
Husky Superior Refinery	5820-UR-115	2023 - 2024			(201,465)			(201,465)
Bad Debt	5820-TE-101, 5820-TG-101, 5820-TW-101	2023 - 2024	(157,300)	(127,075)	(40,625)	157,300	127,075	40,625
COVID-19	5-AF-101	2023 - 2024	51,809	21,687	46,989	51,809	21,687	46,989
			$ (119,522)	$ 406,671	$ (197,684)	$ 195,078	$ 1,700,758	$ (116,434)