SERVICE DATE
Dec 12, 2024

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-117

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 2025. Final overall rate changes for the test year ending December 31, 2025 are authorized consisting of an annual rate increase of $1,335,000, or 1.40 percent, for Wisconsin retail electric operations; an annual rate increase of $3,134,000, or 15.57 percent, for Wisconsin retail natural gas operations; and an annual increase of $1,097,000, or 10.85 percent, for Wisconsin retail water operations. The final overall rate changes are based on a return on equity (ROE) of 9.80 percent.

Introduction

On March 29, 2024, the applicant filed an application for authority to adjust its Wisconsin retail electric, natural gas, and water rates. (PSC REF#: 495138.)

The Commission issued a Notice of Proceeding on April 18, 2024. (PSC REF#: 498379.) The Commission's notice indicated that it would determine the actual level of the revenue requirement after reviewing the application and holding a hearing that was to be scheduled at a later date. In addition, the notice instructed any person desiring to become a party to file for intervention no later than 14 days from the date of service of the notice. The following organizations requested and were granted intervention, and therefore are parties in this docket:

Citizens Utility Board of Wisconsin (CUB), City of Superior, and Enbridge Energy, LP (Enbridge). (PSC REF#: 501774.)

On August 6, 2024, the Commission issued a Notice of Hearing. (PSC REF#: 511802.) Pursuant to due notice, on August 30, 2024, a party hearing was held virtually to receive testimony and technical information from the parties to the proceeding. (PSC REF#: 516584.)

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

On September 9, 2024, a public hearing was held in person and virtually for members of the general public. (PSC REF#: 516695.) The Commission's public hearing process involved the opportunity for members of the public to submit written comments through the Commission's website or at the public hearing, or to testify at the public hearing. The Commission received comments from 62 members of the public. (PSC REF#: 517585.)

The Commission considered this matter at its open meetings of October 31, 2024 and December 12, 2024.

Findings of Fact

1. The applicant is an investor-owned electric, natural gas, and water public utility as defined in Wis. Stat. § 196.01(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 tariff operating revenues of $95,034,054 for the test year ending

December 31, 2025, which results in an adjusted net operating income of $2,665,270, which is insufficient.

3. For Wisconsin retail electric operations, the estimated rate of return on average net investment rate base of $45,817,070 at current rates subject to the Commission's jurisdiction for the test year is 5.82 percent, which is insufficient.

4. A reasonable increase in operating revenue for the test year to produce a 7.94 percent return on the applicant's average net investment rate base for Wisconsin retail electric operations is $1,335,000.

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 tariff operating revenues of $20,133,193 for the test year ending December 31, 2025, which results in an adjusted net operating loss of $583,919, which is insufficient.

7. For the Wisconsin retail gas operations, the estimated rate of return on average net investment rate base of $21,368,660 at current rates subject to the Commission's jurisdiction for the test year is a negative 2.73 percent, which is insufficient.

8. A reasonable increase in operating revenue for the test year to produce a 7.94 percent return on the applicant's average net investment rate base for Wisconsin retail gas operations is $3,134,000.

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 tariff operating revenues of $10,109,100 for the test year ending December 31, 2025, which results in an adjusted net operating income of $2,108,499, which is insufficient.

11. For the Wisconsin retail water operations, the estimated rate of return on average net investment rate base of $36,601,239 at current rates subject to the Commission's jurisdiction for the test year is 5.76 percent, which is insufficient.

12. A reasonable increase in operating revenue for the test year to produce a 7.94 percent return on the applicant's average net investment rate base for Wisconsin retail water operations is $1,097,000.

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 embedded cost rate approved in the last rate case order for the 2005 Wisconsin Act 141 embedded credit calculations for the test year electric revenue requirement.

15. It is reasonable to remove the estimated water tower painting expense from the test year water revenue requirement and not authorize deferral accounting treatment at this time.

16. It is reasonable to include the percentage of industry association dues as set forth in Ex.-PSC-Griffin-2 in the test year electric, natural gas, and water revenue requirement consistent with past Commission practice.

17. It is reasonable for the applicant to continue to provide specific data in its initial data request responses in its next rate proceeding demonstrating the specific customer benefits

associated with payment of all association dues for which it intends to seek recovery in that proceeding.

18. It is reasonable to remove institutional or goodwill advertising expenses from the test year electric, natural gas, and water revenue requirement as proposed by Commission staff.

19. It is reasonable to exclude all Annual Incentive Plan compensation from the electric, natural gas, and water test year revenue requirements.

20. It is reasonable to exclude all Short-Term Incentive Plan compensation from the electric, natural gas, and water test year revenue requirements.

21. It is reasonable to remove accrued payroll from the electric, natural gas, and water test year revenue requirements.

22. It is reasonable for the 2025 wage increase for non-represented employees to be held to the inflation rate of 2.10 percent for the electric, natural gas, and water test year revenue requirements.

23. It is reasonable to remove four regular full-time employees from the electric, natural gas, and water test year revenue requirements.

24. It is reasonable to include all of the cost overruns related to docket 5820-CG-107 in the natural gas test year revenue requirement.

25. It is reasonable to amortize the Manufactured Gas Plant (MGP) costs incurred in 2022 to 2023 in the amount of $11,204,373 over a 10-year period of 2025 through 2034, for an annual amortization amount of $1,120,437.

26. It is reasonable to authorize carrying costs on the unamortized balance of the MGP costs at the applicant’s authorized long-term debt rate of 3.62 percent until December 31, 2026.

27. It is reasonable to return the tax reform liability of $492 associated with the Tax Cuts and Jobs Act (TCJA) authorized in docket 5-AF-101 over the 2025 test year.

28. 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 2025, or until the Commission authorizes a different amortization expense to be recorded.

29. It is reasonable to include the proposed 2025 customer service conservation (CSC) activities in the conservation budget.

30. A reasonable level of expensed conservation costs for retail electric operations is $1,025,437, which is comprised of $1,025,162 plus the overspent amount of $275.

31. A reasonable level of expensed conservation costs for retail natural gas operations is $306,399, which is comprised of $274,271 plus the overspent amount of $32,128.

32. It is reasonable to accept Commission staff’s uncontested electric, natural gas, and water revenue requirement adjustments.

33. A reasonable target level for the test year average common equity measured on a financial capital structure basis is 55.00 percent.

34. A reasonable financial capital structure for the test year consists of 54.88 percent common equity, 33.21 percent long-term debt, and 11.91 percent short-term debt.

35. A reasonable regulatory capital structure for the test year consists of 54.89 percent common equity, 33.25 percent long-term debt, and 11.87 short-term debt.

36. A reasonable rate of return on the applicant's common equity is 9.80 percent.

37. A reasonable rate for the applicant's short-term borrowing through commercial paper is 4.80 percent.

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

39. A reasonable weighted average composite cost of capital is 7.15 percent.

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

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

42. It is reasonable to accept the electric rate design proposed by Commission staff as adjusted for final revenue requirement.

43. It is reasonable to approve the electric fixed customer charges as proposed by the applicant and presented in Commission staff's rate design.

44. It is not reasonable or necessary to require the applicant to file a proposal for a new load market pricing (NLMP) tariff.

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

46. It is reasonable to consider the full range of natural gas COSS results, along with other factors, such as bill impacts, when designing natural gas rates and allocating revenue responsibility among the various customer classes.

47. It is reasonable to accept the natural gas revenue allocation proposed by Commission staff as adjusted for final revenue requirement.

48. It is reasonable to accept the natural gas rate design proposed by Commission staff as adjusted for final revenue requirement.

49. It is reasonable to approve the natural gas fixed customer charges as proposed by Commission staff.

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

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

52. It is reasonable to accept the water revenue allocation proposed by Commission staff as adjusted for final revenue requirement.

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

54. Energy conservation, renewable resources, or energy priorities listed in Wis. Stat. §§ 1.12 or 196.025 or their combination would not be cost-effective, technologically feasible, or environmentally sound alternatives to the changes authorized herein.

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

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 customers 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.

The applicant's small size, coupled with some unique characteristics of the applicant's service territory, present some challenges when setting its rates. The applicant's service territory is more likely than other Wisconsin households to have income below the poverty line, to face unemployment, or to experience both challenges. Further, the Climate and Economic Justice

Screening Tool (CEJST) maintained by the U.S. Council on Environmental Quality identifies two tracts in the applicant's service territory as Disadvantaged Communities, based on federal agency datasets measuring their burdens in eight categories: climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development.

The applicant is also unique because its earnings are extremely sensitive to the wholesale rates and fuel adjustment charged by its supplier. Purchased power costs represent approximately 83.60 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. To mitigate fluctuations in the applicant's earnings due to changes in the cost of purchased power, the applicant has historically been authorized to apply a Power Cost Adjustment to all of its retail bills pursuant to a Power Cost Adjustment Clause (PCAC). This adjustment permits increases or decreases in the cost of purchased power to be passed on directly to the customer. This average per kilowatt hour (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.

Applicable Standard of Review

The Commission's authority to establish utility rates and terms of service has a robust statutory foundation. Wisconsin Stat. §§ 196.03, 196.20, and 196.37 grant the Commission its general authority to establish utility rates and terms of service. Section 196.03 provides that any public utility rate "shall be reasonable and just and every unjust or unreasonable charge for such service is prohibited and declared unlawful." Under § 196.20, "no change in schedules which constitutes an increase in rates to consumers may be made except by order of the [C]ommission, after an investigation and opportunity for hearing." Under § 196.37, if the Commission finds rates to be "unjust, unreasonable, insufficient or unjustly discriminatory or preferential or otherwise unreasonable or unlawful, the [C]ommission shall determine and order reasonable rates . . . to be imposed, observed and followed in the future." The Commission's evaluation of the reasonableness of rates necessarily implicates numerous competing considerations, including reliability, conservation, financial health of the utility (capital structure and rate of return), customer affordability, and more. The Commission uses a traditional ratemaking process with a future test year. The process provides utilities with the ability to recover its forecasted costs in rates and the opportunity to earn an authorized return on common equity.

Rate setting is an area in which the Commission has special expertise. *Brookfield v. Milwaukee Metro. Sewerage Dist.*, 141 Wis. 2d 10, 15, 414 N.W.2d 308, 309 (Ct. App. 1987). It has set utility rates for more than 100 years. In ratemaking, the Commission exercises a legislative function. *Wisconsin Ass'n of Mfrs. and Commerce v. Public Serv. Comm'n (WMC)*, 94 Wis. 2d 314, 319, 287 N.W.2d 844, 846 (1979). "It is well established that the [Commission], in designing a rate structure that will enable a utility to recover the total revenue authorized, has wide discretion in determining the factors upon which it may base its precise rate schedule. . . . Rate-making agencies are not bound to any single regulatory formula; they are permitted to make the pragmatic adjustments, which may be called for by particular circumstances, unless their statutory authority plainly precludes this." *Id.* at 320, citing *City of West Allis v. Public Serv. Comm'n,* 42 Wis. 2d 569, 167 N.W.2d 401 (1969) (footnotes omitted). Determining whether rates are just and reasonable often requires a high degree of discretion, judgment, and technical analysis.

Such decisions involve intertwined legal, factual, and public policy determinations. The Commission, as fact finder, is charged with sifting through all of the information to reach a well-reasoned decision. In doing so, the Commission uses its experience, technical competence, and specialized knowledge to determine the credibility of each witness and the persuasiveness of highly technical evidence presented on each issue.

Wisconsin Stat. § 196.37, unlike a few provisions of Wis. Stat. ch. 196,[1] assigns no burden of proof to any party with respect to any determination that the Commission must make. While other sections of ch. 196 require certain determinations to be made only upon "clear and convincing evidence" or "a preponderance of the evidence,"[2] Wis. Stat. § 196.37 does not specify a standard of proof the Commission must apply. The applicable "standard of proof" by which the Commission makes its determinations is derived from Wis. Stat. § 227.57(6), which requires a court, in the event of a challenge to a Commission determination, to remand an agency's action back to the agency if its decision "depends on any finding of fact that is not supported by substantial evidence in the record." If later challenged in court, the Commission's factual findings "must be upheld on review if there is any credible and substantial evidence in the record upon which reasonable persons could rely to make the same findings." *Currie v. State Dep't of Indus., Labor & Human Relations, Equal Rights Div.*, 210 Wis. 2d 380, 386-87, 565 N.W.2d 253, 256-57 (Ct. App. 1997).

The substantial evidence test "is not weighing the evidence to determine whether a burden of proof test is met. Such tests are not applicable to administrative decisions." *Wisconsin Ass'n of Mfrs. & Commerce, Inc.*, 94 Wis. 2d at 321-22, . This test requires only that there be

[1] *See, e.g.* Wis. Stat. §§ 196.499(5)(am), 196.504(8), 196.54(2).
[2] *See, e.g.* Wis. Stat. §§ 196.499(5)(d), 96.64(2), 196.795(7)(c).

enough evidence for a finding to be reasonable. *Kitten v. State of Wis. Dept. of Workforce Dev.*, 2002 WI 54, ¶5, 252 Wis. 2d 561, 569, 644 N.W.2d 649, 652 ("Because this is a review of an administrative hearing, we will uphold the hearing examiner's findings of fact as long as they are supported by substantial evidence in the record. Wis. Stat. § 227.57(6)."). See *Wisconsin Ass'n of Mfrs. & Commerce*, 94 Wis. 2d at 322 ("When the issues basically involve a dispute over conflicting testimony and a reasonable [person] could be convinced by either side, it is within the administrative agency's province to weigh it and accept that which it finds more credible.") (citations omitted). Therefore, although administrative proceedings do observe the common-law rule that the "moving party" has the burden of proof, this rule is complied with by determining whether the applicant provided substantial evidence to support each of the Commission's determinations.

Thus, the burden carried by the applicant is not a burden of proof that exists with a legal standard of proof to be applied to the evidence, but is a burden of production and persuasion to provide substantial evidence upon which the Commission can rely when making its determinations. As the Court in *Clean Wisconsin, Inc. v. Public Serv. Comm'n of Wisconsin* noted, the issue in the present docket is not one of a right, but one of legislative determinations. *See* Nos. 2022AP1106, 2023AP120 (Wis. Ct. App. October 6, 2024) 2024 WL 4449699, ¶ 23. The applicant in the present docket does not have a right to the particular change in rates at issue and cannot prove it is entitled to such a change by a preponderance of the evidence. Instead, most of what the Commission must determine when considering such a request requires the Commission to weigh various aspects of the public interest and balance them to decide what appropriate and reasonable rates should be. Terms like "reasonable," "unreasonable," "insufficient," "unjustly discriminatory," or "preferential," are "not capable of definitive proof" and involve weighing different factors and considerations and applying public policy considerations to make a highly subjective determination.

The determinations the Commission must make in this proceeding are not subject to evidentiary standards meant for findings of fact, as the Commission must balance the facts it finds with policy considerations such as whether a proposed rate change is "reasonable" or "just." Under the substantial evidence test, the Commission only needs an evidentiary basis for its determinations; it does not need to find those determinations to the satisfaction of any specific burden or standard of proof—and, thus, there is no specific standard of proof that an applicant must satisfy.

Revenue Requirement

The applicant filed for a 2025 test year. The applicant concluded its current electric, natural gas, and water rates were insufficient and proposed a base rate increase in 2025. The applicant requested an overall increase in annual Wisconsin retail electric revenues of $2,031,000, or 2.17 percent over present revenues; an increase in annual Wisconsin retail natural gas revenues of $3,444,000, or 17.11 percent over present revenues; and an annual increase in annual Wisconsin retail water revenues of $1,817,000, or 17.97 percent over present revenues. The applicant's requested increases were based on a 10.00 percent return on common equity.

The applicant claimed the main drivers impacting the revenue requirements for the 2025 test year include larger capital additions in the gas infrastructure projects including the Hammond Avenue Gas Project approved in docket 5820-CG-107, a water main replacement project, and replacement of fleet vehicles. The applicant also cited increased operating expenses due to inflationary pressures, increased depreciation, and higher interest costs as factors contributing to its requested rate increases.

Commission staff reviewed 2025 test year filing information for electric, natural gas, and water operations. Based on its review, Commission staff determined that for 2025 electric operations, the applicant would require an increase above currently authorized 2023 electric rates of 1.29 percent. For 2025 natural gas rates, Commission staff determined the applicant would require an increase above currently authorized 2023 retail natural gas rates of 14.46 percent. For 2025 water rates, Commission staff determined the applicant would require an increase above currently authorized 2023 retail natural gas rates of 10.85 percent.

Income Statement

The applicant, Enbridge, CUB, City of Superior, and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates for the applicant's 2025 electric, natural gas, and water utility operations. Members of the public provided testimony and submitted more than 60 written comments, most of which were related to the affordability of the applicant's services.

A public utility's obligation to service is a condition of its franchise and is defined by statute. Wisconsin public utilities are required to furnish reasonably adequate service and facilities,[3] among other requirements. In setting just and reasonable utility rates, the Commission is tasked with first estimating the revenues that the applicant needs in order to recover its prudent costs to provide adequate service plus have a reasonable opportunity to earn a fair return in the test year 2025. The Commission sets this budget on a forward-looking basis,

[3] Wis. Stat. § 196.03.

estimating the anticipated expenses the applicant is likely to incur[4] and determining the appropriate revenue requirement, or the total revenues the utility must collect from customers in the rates it charges them. Commission decisions regarding certain finance parameters affect the estimated revenue requirement. For instance, the Commission establishes the applicant's capital structure, which sets the appropriate balance of equity and debt securities and sets a reasonable return on common equity (ROE). These parameters have a direct impact on customers' bills. The use of future test years and other financial and ratemaking mechanisms provide the state's utilities a reasonable opportunity to earn their authorized equity returns, even in the face of unexpected costs.

Decisions on the appropriate revenue requirement and finance parameters are interrelated and involve give and take to achieve overall rates that are just and reasonable. The Commission is not bound to any single regulatory formula, and is permitted to make the pragmatic adjustments which may be called for by particular circumstances. *Wisconsin Mfr. and Commerce v. Public Serv. Comm'n*, 94 Wis. 2d 314, 319, 320, 287 N.W. 2d 844 (1979) (citing City of West Allis. v. Public Serv. Comm'n, 42 Wis. 2d 569, 167 N.W.2d 491 (1969) (footnotes omitted). In this proceeding, the Commission's rate setting is informed by the size of the applicant and the unique characteristics of the applicant's service territory that were noted earlier. As a small utility, the applicant does not have a lot of flexibility in its budget. The applicant has not historically tended to over earn on its authorized ROE because it operates on tight margins. In setting a reasonable return on equity, the Commission recognizes this particular utility's unique

[4] Utilities experience budget variances, or unexpected costs and savings, throughout the test year. The Commission's Uniform System of Accounts (USOA) provides that "net income shall reflect all items of profit and loss within a period," meaning savings and costs are to be immediately recognized, with a few narrow exceptions related to certain items, including "extraordinary items".

exposure to macroeconomic risk of recession due to its higher concentration of commercial customers. In setting rates, the Commission is also informed by the impact raising rates has on the customers the applicant serves, including households facing unemployment, low income, or high energy burden. These concerns must be considered and balanced against providing the applicant a reasonable opportunity to earn a fair return.

The robust technical record and public participation helped inform the Commission's difficult task in balancing these often competing interests of the utility and its customers to arrive at a decision that is in the public interest. Significant issues pertaining to the income statement are addressed separately below.

Act 141 Embedded Credit Calculation

Commission staff initially made an adjustment to account for formula errors discovered in the applicant's 2005 Wisconsin Act 141 embedded credit calculations. The applicant noted that the embedded credit used for current revenues should be the rate that was approved in the last rate proceeding in docket 5820-UR-116, which was ($0.00245) and should be incorporated into the new proposed rates. After review, Commission staff agreed with the applicant that the embedded cost rate used in the calculation should be the rate that was approved with the last rate case order. The Commission finds it is reasonable for the applicant to use the rate authorized in docket 5820-UR-116.

Water Tower Painting Expense

The applicant noted that the water tower installed in 2008 is being inspected with a full drain down in 2024 and is likely to require full internal and external coating in the next two years, pending the inspection report. The applicant further identified that the estimated cost of paint, painting staging, and enclosing work is projected to be between $800,000 and $1,000,000. Commission staff proposed an adjustment using the average of the applicant's estimated costs divided by the estimated useful life for water tower painting maintenance, in this case, 20 years. This resulted in an annual amount of $45,000 being included within the 2025 water revenue requirement. Amortizing the estimated total expense of upcoming water tower paintings over the average number of years between paintings has been standard Commission practice for water tower painting expenses. In response to Commission staff's proposal, the applicant ultimately requested approval to defer the water tower painting expenses when they occur and to amortize the recovery of the actual expenditure over 20 years.

The Commission notes that the water tower is in year 16 of its estimated 20-year useful life and that the record was not entirely clear as to when, within the remaining useful life, the water painting expenses would actually occur and what those expenses may be pending inspection. The Commission also observes that the applicant is routinely before it for a rate case every two years. Given the uncertainty of the project timeline and cost, and the frequency of the applicant coming before the Commission, the Commission finds it reasonable to remove the estimated water tower painting expense from the test year water revenue requirement. The Commission acknowledges the applicant's request for a deferral, but declines to authorize deferral accounting treatment at this time. The applicant can either pursue a separate deferral request when there is more certainty as to the timing and amount, or address this expense in a future rate proceeding.

Industry Association Dues

The Commission has historically allowed the recovery of association dues, to the extent that the activities of the association provide a benefit to customers. Certain industry associations engage in programs and activities, such as lobbying and advertising, that generally do not provide a benefit to customers. Where the amount of dues that provide a benefit to customers cannot be determined with precision, Commission staff has historically applied a recovery percentage to each association's dues that is intended to generally reflect the portion of activities of an association that could be considered to provide a benefit to customers based on review of the association's nonprofit tax return and/or websites.

In the Commission's Final Decisions for Wisconsin Power and Light Company in docket 6680-UR-124 (PSC REF#: 487254) and Madison Gas and Electric Company in docket 3270-UR-125 (PSC REF#: 487247), the Commission found it reasonable to require the utilities to provide specific data demonstrating the specific customer benefits associated with payment of all association dues for which they intended to seek recovery.

In this proceeding, the applicant provided a detailed list of the justification and customer benefit for each item of association dues and membership for which it sought recovery. Commission staff sponsored Ex.-PSC-Griffin-2, which included the applicant's detailed list of association dues along with its justification and customer benefit, and a summary of the industry association dues percentages the Commission has approved in the past. Commission staff removed 100 percent of the identified industry association dues from revenue requirement, which resulted in a decrease of $33,131 for electric operations, $47,131 for natural gas operations, and $4,635 for water operations for the 2025 test year, pending Commission approval.

The applicant objected to removal of all association dues given its size and limited resources. The applicant stated that it relies on contacts made through industry association membership to help it provide safe, reliable and competitive services. The applicant also clarified that it had already removed lobbying expenses in the information provided and maintained that the costs reflected in its request provide a direct benefit to its customers. The applicant requested that the Commission include all industry association dues in the test year electric, natural gas, and water revenue requirements.

CUB stated that it is only appropriate to recover industry association dues if it can be shown that there are associated customer benefits and argued that the record did not include evidence supporting recovery of these expenses. As such, CUB recommended that the Commission remove 100 percent of association dues from the test year revenue requirements.

The Commission appreciates the information provided by the applicant to support its request for recovery of association dues. The Commission finds that the information provided did demonstrate that participation in the associations does provide some customer benefits. The information supplied supports the Commission’s historic treatment which allows recovery of a percentage of the dues in light of such benefits. Therefore, the Commission finds it is reasonable to include the percentage of industry association dues as set forth in Ex.-PSC-Griffin-2 in the test year revenue requirement consistent with past Commission practice. As the additional detail about the benefits associated with the dues was helpful, the Commission finds it is reasonable for the applicant to continue to provide specific data in its initial data request responses in its next rate proceeding demonstrating the specific customer benefits associated with payment of all association dues for which it intends to seek recovery in that proceeding.

Advertising Expense

Commission staff removed institutional or goodwill advertising expenses, resulting in decreases of $12,315 for electric operations, $2,856 for natural gas operations, and $2,241 for water operations in the 2025 test year. Per long-standing Commission practice, the Commission has disallowed these expenses from rate recovery, which could include items such as name recognition, scholarships, sponsorships, economic development, etc., citing that the expenses provide no direct customer benefit. Commission staff did not propose removing advertising expenses for items other than institutional or goodwill where there was an associated customer benefit.

CUB recommended removing all advertising expenses unless the applicant provided sufficient evidence of customer benefit. The applicant stated that the majority of 2025 test year advertising expenses not related to institutional or goodwill advertising were for electric, gas, or water safety as well as to benefit the customer by providing information on low-income benefits and Focus on Energy information. The applicant asserted that such expenses provide a direct benefit to customers and should be included in the electric, natural gas, and water revenue requirements.

The Commission finds it reasonable and consistent with past practice to accept Commission staff's disallowance of institutional or goodwill advertising expenses. The Commission is not persuaded by CUB's argument that all advertising expenses should be disallowed, as the Commission finds that the record presented by the applicant demonstrated customer benefit for the costs other than those associated with institutional or goodwill advertising.

Employee Compensation

Annual Incentive Plan (AIP)

In accordance with past Commission practice for the applicant, Commission staff adjusted the 2025 test year revenue requirement to only include the portion of AIP compensation related to non-financial safety and reliability goals. The amount of AIP compensation associated with non-financial safety and reliability goals totaled $88,002, of which $58,960 was attributed to electric operations, $15,841 to natural gas operations, and $13,200 to water operations.

CUB did not oppose the inclusion of incentive compensation expenses provided there is sufficient evidence that the structure of the incentive compensation program produces customer benefits. CUB cited recent examples of instances where the Commission disallowed incentive compensation and stated its belief that the record in this docket did not include evidence demonstrating specific customer benefits related to the AIP, and recommended excluding the AIP dollars from the applicant's test year revenue requirements.

The Commission agrees with CUB. Similar to previous Commission decisions where insufficient evidence of customer benefits led to disallowance, the Commission finds the operational metrics information in this proceeding too high-level to demonstrate direct customer benefits. Therefore, the Commission finds it reasonable to exclude all AIP compensation from the test year revenue requirement, as the applicant did not provide sufficient information in the record to demonstrate how the non-financial goals provide a customer benefit. This approach is consistent with prior Commission decisions regarding AIPs.[5]

[5] *See, e.g.,* Final Decision, *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, docket 4220-UR-126 (Dec. 20, 2023) (PSC REF#: 487255).

Short-Term Incentive Plan (STIP)

The applicant identified a new STIP program available to all non-union employees not participating in the AIP that contains a mixture of financial and operational goals totaling $55,000. The applicant further identified that the STIP goals mirror the AIP financial and operational and values goals. Commission staff removed the entire STIP program amount pending the Commission's determination of how much, if any, should be included in the 2025 electric, natural gas, and water test year revenue requirements. In a recent Commission decision in docket 6680-UR-124 (PSC REF#: 487254), the Commission found it reasonable to exclude all STIP due to the absence of sufficient information demonstrating that the non-financial goals provided customer benefit.

CUB did not oppose the inclusion of incentive compensation expenses provided there is sufficient evidence that the structure of the incentive compensation program produces customer benefits. The applicant noted that the Commission has historically allowed the non-financial goals of incentive compensation to be included within the total revenue requirement and that this new plan should not be treated any different and requested the Commission to include the $16,500 non-financial piece of this plan.

The Commission observes that the applicant's STIP is new and is not that dissimilar to the STIP the Commission reviewed and addressed in docket 6680-UR-124. In that case, as here, the applicant has failed to provide sufficient detail regarding this new program or how the program would provide customer benefits. Therefore, the Commission finds it is reasonable to exclude all STIP compensation from the electric, natural gas and water test year revenue requirements, as there is not sufficient information in the record to demonstrate how the new STIP program provides customer benefits.

Accrued Payroll

Commission staff removed accrued payroll based on past Commission practice and noted that Commission staff payroll calculations are based on a full year's work, not the timing of when employees are paid.

The applicant identified that accrued payroll is the normal accounting book entry required based on the change of days from the last bi-weekly period in the respective calendar month/year. Without this entry, the applicant argued the payroll amounts would be under- or over-stated for the given year. The amounts relate to the estimated change from accrued days for the 2025 test year.

The Commission finds that Commission staff's adjustment addresses timing differences between work performed and payment. Therefore, the Commission determines it is reasonable to remove accrued payroll from the test year revenue requirement.

Inflation Rate for Non-Represented Employee Wages

Commission staff proposed an adjustment to the wages for the non-represented, management, and executive employees to hold the wages to the level of inflation for the 2025 test year. The inflation rate used for the 2025 test year was 2.10 percent. It has been longstanding Commission practice across all rate proceedings to use the inflation rate, as provided by Commission finance staff at the time of application filing, to determine the test year wage increase for non-union employees.

The applicant opposed the inflation rate used by Commission staff, arguing that it creates an inequity in compensation, leading to lower employee morale and higher turnover rates. The applicant stated that maintaining parity in salary increases between non-union and union employees is essential for regulated utilities to attract and retain a skilled workforce.

The Commission finds based on past practice that inflation rates are established at the date the rate proceeding application is filed, and once set, generally not updated for revenue requirement purposes. The Commission did not see any record evidence to support the applicant's claim that this historic practice has resulted in hiring or retention issues. Therefore, the Commission finds it is reasonable and consistent with past practice for the 2025 wage increase for non-represented employees to be held to the inflation rate of 2.10 percent for the test year electric, natural gas, and water revenue requirements.

Full-time Employee (FTE) Budget Adjustment

Commission staff reduced the 2025 regular FTE budget amounts, based on actual June 2024 headcount levels and trends over the previous 3 years, resulting in a revenue requirement reduction equivalent to 4 FTEs for a revenue requirement total of 81 FTEs. CUB supported Commission staff's proposed FTE budget reduction. The applicant stated that it maintains a very lean staff of 85 FTEs and a reduction of four FTEs is extremely detrimental to its operations, and all vacant positions were either posted, being re-posted due to lack of qualified applicants, or being posted in the near future.

The Commission acknowledges the applicant's concerns related to its small staff size but notes the applicant has been operating at or below the 81 FTE mark without reliability being impacted. Further, the Commission is simply authorizing a budget, not precluding the applicant from hiring more or fewer employees as needed to maintain service reliability and support its operations. Therefore, the Commission finds the applicant has not demonstrated the need for a higher headcount and therefore finds it reasonable to remove four FTEs from the electric, natural gas, and water test year revenue requirements.

Cost Overruns in Docket 5820-CG-107

The applicant's proposed project to replace natural gas distribution facilities was approved by Final Decision dated July 13, 2023 in docket 5820-CG-107 at a total cost of $2,059,070. Order Condition 3 stated, "If it is discovered that the total project cost, including *force majeure* costs, may exceed the estimated cost by more than 10 percent, the applicant shall notify the Commission within 30 days of when it becomes aware of the possible change or cost increase." (PSC REF#: 472750.) On September 28, 2023 and March 14, 2024, the applicant filed cost overrun notifications with the Commission and stated the overruns were due to the base bid coming in higher than originally budgeted, increased labor costs to expedite construction due to increasing winter weather, and relocating of gas meters and other activities that were not included in the original bid. (Ex.-PSC-Griffin-3.)

As the Commission had yet not approved the cost overruns, consistent with Commission practice which does not assume approvals or denial, Commission staff removed cost overruns of $355,542, which is a natural gas revenue requirement impact of approximately $32,141.

CUB was concerned given the scope of the project as well as the project timeline, which had a fairly quick turnaround between project application and project completion, and that the base bid came in over budget. Absent compelling evidence provided by the applicant demonstrating that it conducted all due diligence, and that these costs were truly unavoidable and reasonably foreseeable, CUB did not believe that customers should bear the costs of this project going over budget and supported the removal of the costs associated with the cost overruns from the test year revenue requirement.

The Commission recognizes CUB's concerns and affirms the importance of careful scrutiny of project cost overruns in order to protect customers from unreasonable costs. In this case, following careful review, the Commission recognizes and commends the applicant for its project management in the face of challenges with timeline compressions including tight construction windows, road construction coordination, weather, and federal pipeline safety compliance. The Commission finds that the applicant exercised due diligence and made efforts to minimize or mitigate cost increases. The Commission further notes the applicant provided timely notification of cost overruns and detailed cost breakdowns throughout the process. Therefore, the Commission finds it is reasonable to include the cost overruns related to docket 5820-CG-107 in the natural gas test year revenue requirement.

MGP

In 2001, the Wisconsin Department of Natural Resources identified the applicant as the party responsible for remediation of contamination found at a former manufactured gas plant (MGP) site operated by the applicant. In the applicant's prior rate case in docket 5820-UR-116, the applicant was authorized to amortize the MGP remediation costs over a 4-year period from 2023 through 2026, and authorized the applicant to defer additional costs incurred after December 31, 2021 until the applicant's next rate case. (PSC REF#: 455044.)

In this proceeding, the applicant sought Commission approval to amortize additional MGP costs incurred from 2022 through 2023 over a 10-year period of 2025 through 2034, in order to minimize the impact to customers. The applicant also requested that carrying costs be applied to any unamortized balance of the MGP remediation costs at the total cost of debt rate of 4.10 percent.

On a case-by-case basis, the Commission has adjusted the amortization period for MGP costs ranging from 4 years up to 10 years. In docket 4220-UR-118 (PSC REF#: 178198), the Commission found it reasonable to authorize a 10-year amortization period for Northern States Power Company-Wisconsin's Ashland site to help mitigate the rate shock of the large expense. The applicant argued its situation in this case was analogous. Given the small size of the utility, the MGP expense for the applicant is significant.

Based on prior Commission decisions regarding treatment of large MGP balances and the potential for customer rate shock in this instance, the Commission finds it reasonable to amortize the MGP costs incurred from 2022 to 2023 in the amount of $11,204,373 over a 10-year period from 2025 through 2034, for an annual amortization amount of $1,120,437.

Due to the deferred recovery of costs, the applicant requested carrying costs be applied to any unamortized balance of the remediation over ten years at the total cost of debt rate which it calculated to be 4.10 percent. Commission staff noted that the Commission has authorized carrying costs in some instances, and denied carrying costs in others.

While the Commission is inclined to authorize some carrying costs, it is not persuaded by the methodology the applicant used to arrive at its request or length of time proposed. Instead, the Commission finds it is more reasonable to authorize carrying costs at the long-term debt rate of 3.62 percent over 2 years ending December 31, 2026, which aligns with the applicant's next anticipated rate proceeding. Such an approach results in carrying costs being shared and is more equitable to the applicant's customers.

Tax Reform Liability

In its Final Decision in docket 5820-UR-116 (PSC REF#: 455044), the Commission required the applicant to conduct a final true-up of the regulatory liability balance associated with the TCJA authorized in docket 5-AF-101[6], in its next rate proceeding. In this proceeding the applicant reported a remaining regulatory liability balance of $492 and proposed returning the balance in 2025. The Commission finds the applicant's proposal to be reasonable.

Conservation Budget and Escrow Adjustment

The applicant proposed electric and natural gas CSC activities for inclusion in its conservation budget 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

[6] Order, dated May 24, 2018, (PSC REF#: 343223); Supplemental Order, dated August 7, 2019, (PSC REF#: 373697)

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 electric and natural gas CSC activities to be appropriate.

The reasonable level of expensed conservation costs recoverable in rates for the 2025 test year is $1,025,437 for electric utility operations and $306,399 for natural gas operations. The level of electric utility operations consists of forecasted conservation expenditures of $1,025,162 plus the amortization of the overspent amount of $275. The level for natural gas utility operations consists of forecasted conservation expenditures of $274,271 plus the amortization of the overspent amount of $32,128.

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 2025 test year was computed using the depreciation rates shown in Appendices E through H. These depreciation rates are effective on January 1, 2025, for computing the depreciation expense on the average investment for each plant account.

Amortization Periods for all other Deferrals and Escrows

The applicant sought Commission approval for continued deferral and escrow accounting treatment of several deferrals over a 2-year period, 2025 through 2026, which were not contested by any party and not listed separately as contested for a Commission decision. Therefore, consistent with past Commission practice, the Commission finds it reasonable for the applicant to continue deferral and escrow accounting treatment over the 2-year period, 2025 through 2026, as identified in Appendix I.

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 electric, natural gas, and water amortization expense amounts identified shall be recorded for 2025, 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 2025 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	$95,034,054	$20,133,193	$10,109,100
Other Operating Revenues	3,814,588	154,480	62,649
Total Operating Revenues	$98,848,642	$ 20,287,673	10,171,749
Operation and Maintenance Expenses			
Purchased Gas	-	$11,011,931	-
Other Purchased Gas Expense	-	2,716,969	-
Purchased Power	$80,367,915	-	-
Other Production	3,880	-	-
Source of Supply	-	-	230,367
Pumping	-	-	321,146
Water Treatment	-	-	819,460
Transmission Expenses	252,371	-	-
Distribution Expenses	1,656,980	2,196,219	1,627,103
Customer Accounts Expenses	1,031,124	786,632	443,475
Customer Service Expenses	1,336,736	483,162	35,493
Sales Promotion Expenses	-	-	-
Administrative and General Expenses	4,573,912	1,667,933	1,383,327
Total Operation and Maintenance Expenses	$89,222,918	$18,862,846	$4,860,371
Depreciation Expense	3,322,161	1,951,364	2,167,005
Amortization Expense	(67,998)	(100,118)	(59,616)
Taxes Other Than Income Taxes	3,369,891	431,500	643,800
State and Federal Income Taxes	49,000	(141,000)	107,000
Deferred Income Tax and Tax Credits	287,400	(133,000)	344,690
Total Operating Expenses	$96,183,372	$20,871,592	$8,063,250
Net Operating Income	$2,665,270	($583,919)	$2,108,499

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

2025 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	$97,488,733	$50,949,568	$72,832,217
Less: Accumulated Depreciation	49,410,564	28,472,991	28,385,271
Net Utility Plant	$48,078,169	$22,476,577	$44,446,946
Add: Gas in Storage	-	1,258,772	-
Materials and Supplies	1,310,939	536,293	1,132,174
Plant Acquisition Adjustment	-	-	-
Regulatory Assets	-	-	-
Less: Contributions in Aid of Construction	-	-	-
Customer Advances	-	1,587	20,760
Accumulated Deferred Income Taxes	3,572,038	2,901,395	8,957,121
Regulatory Liabilities	-	-	-
Average Net Investment Rate Base	$45,817,070	$21,368,660	$36,601,239

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 5.82 percent for Wisconsin retail electric utility operations, a negative 2.73 percent for Wisconsin retail natural gas utility operations, and 5.76 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 54.88 percent common equity, 33.21 percent long-term debt, and 11.91 percent short-term debt. The 55.00 percent target common equity is higher than most of the other large Wisconsin investor-owned utilities. The Commission finds a 55.00 percent target common equity is reasonable for the 2025 test year due to the applicant's smaller size, which makes issuing debt and managing its capital structure more difficult.

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 typically excludes items off-balance sheet debt like non-utility property and life insurance for the employee incentive program plan. However, in the current proceeding the applicant had no regulatory capital structure adjustments for off-balance sheet debt. Consequently, a reasonable utility ratemaking capital structure for the purposes of establishing just and reasonable rates for the test year consists of 54.89 percent common equity, 33.25 percent long-term debt, and 11.87 percent short-term debt.

Short-Term Debt

The applicant's test year capital structure contains $15,884,615 in short-term debt. Commission staff derived an estimate of the applicant's average cost of short-term debt in the form of commercial paper for the test year of 4.80 percent. 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. The applicant stated that if the Commission utilizes Commission staff's forecasted short-term borrowing cost estimate of 4.80 percent, then it requests including a 25-basis point adder per the intercompany lending agreement. This would result in an all-in short-term debt rate of 5.05 percent.

The Commission acknowledges Commission staff's methodology as being an objective way to determine the applicant's short-term debt costs and finds a short-term debt rate of 4.80 percent is reasonable. The Commission finds the use of an adder for a holding company intercompany lending agreement to be unreasonable.

Long-Term Debt

The applicant proposed an embedded cost of long-term debt of 3.62 percent for the test year. No party contested the proposed embedded cost of long-term debt rate. The Commission concurs and finds that a long-term debt rate of 3.62 percent is reasonable.

Return on Common Equity (ROE)

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.

In reaching its determination as to the appropriate ROE, the Commission must balance the impact to customers with the impacts to existing investors, 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. Wisconsin Dept. of Revenue*, 2018 WI 75, ¶ 84, 382 Wis.2d 496, 564-65, 914 N.W.2d 21, 54.

In this proceeding, the applicant requested to maintain its currently authorized 10.00 percent ROE and stated that a return of 10.00 percent would facilitate appropriate investment in the utility and help maintain the applicant's current credit metrics. Commission staff recommended a point estimate of 9.65 percent be utilized in the revenue requirement calculation for the test year. CUB recommended an ROE of 9.50 percent, stating it acknowledged the Commission's past deference to "gradualism" when considering large changes to the applicant's revenue requirement for the test year. CUB also identified the applicant's unique exposure to macroeconomic risks due to its high concentration of commercial customers. The revenue impact for each 20-basis points change was approximately $75,000 for electric, $35,000 for natural gas, and $60,000 for water.

Commission staff provided testimony and financial modeling 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 8.74 percent to 9.34 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 applicant.

The Commission finds that the models used to estimate the ROE in this case indicate that a reduction from the currently authorized 10.00 ROE is reasonable. The Commission has traditionally made gradual adjustments to the return, rather than large and sudden changes, and notes that the applicant's authorized ROE was also reduced by 40 basis points in its previous rate proceeding. 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 surrounding the applicant's pending acquisition 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 an ROE of 9.80 percent. An ROE of 9.80 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.

Accordingly, the Commission finds the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate which are considered reasonable and just for setting rates in this proceeding are as follows:

	Amount	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$73,463,068	54.89%	9.80%	5.38%
Long-Term Debt	$44,500,000	33.25%	3.62%	1.20%
Short-Term Debt	$15,884,615	11.87%	4.80%	0.57%
Total Utility Capital	$133,847,683	100.01%		7.15%

The weighted average cost of capital of 7.15 percent is reasonable for the applicant for the test year. It generates an economic cost of capital of 9.16 percent and a pre-tax interest coverage ratio of 5.18 times.

The Commission also considered a suggestion by CUB to harmonize the standard language used in final decision financial tables. The Commission appreciates this suggestion, acknowledges its potential merit, and prefers to continue discussion as a general administrative matter rather than institute changes in this Final Decision.

Rate of Return on Rate Base

The 7.15 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) to capital applicable primarily to utility operations, plus deferred investment tax credits is 90.03 percent for the test year.

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	7.15	7.15	7.15
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	90.03	90.03	90.03
Percent Return Requirement Applicable to Net Investment Rate Base	7.94	7.94	7.94
Adjustment to Return Requirement to Provide Current Return on CWIP	-	-	-
Adjusted Percent Return Requirement on Net Investment Rate Base	7.94	7.94	7.94

Authorized Change in Revenue Requirement

On the basis of the findings in this Final Decision, a $1,335,000 increase in Wisconsin retail electric utility revenues, a $3,134,000 increase in Wisconsin natural gas utility revenues, and a $1,097,000 increase 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	5.82%	-2.73%	5.76%
Required Return on Average Net Investment Rate Base	7.94%	7.94%	7.94%
Average Net Investment Rate Base (000's)	$45,817	$21,369	$36,601
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	$971	$2,280	$798
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes at a Combined Rate of 27.241% (000's)	$1,335	$3,134	$1,097

Electric Cost of Service, Revenue Allocation, and Rates

Electric Cost of Service

The applicant, CUB, Enbridge, and Commission staff provided testimony regarding COSS and 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 1.29 percent revenue deficiency. The applicant did not file an updated COSS including the results of Commission staff's audited revenue requirement. Instead, it prepared COSS at a revenue requirement deficiency of 2.10 percent and Enbridge filed a COSS using the Commission staff-proposed 1.29 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, as was Commission staff's electric COSS.

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 specific 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 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 from doing so. 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, CUB, Enbridge, 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 2.10 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 0.15 percent increase for the large commercial class to 4.70 percent for the lighting service classes. 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. However, CUB noted that the Commission should consider limiting class-level revenue increases to 2.0 to 2.5 times the overall utility increase. Upon its review of the record, the Commission finds it reasonable to accept the revenue allocation proposed by Commission staff as adjusted for final revenue requirement. 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.

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 rate factors based on the applicant's required 2025 Wisconsin Act 141 contributions. Commission staff's rate design was supported by one of the intervenors, CUB.

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 Commission staff, and as adjusted for the final revenue requirement, to be reasonable.

The authorized electric service rates appear in Appendix B. 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. 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 and commercial classes except for the EC-5, EP-1, EP-3, and Ep-5 classes. These proposed increases were consistent with the applicant's COSS, and they range from $1.00 per month for residential and $2.00-$3.00 for the commercial classes (excluding EC-5).

To aid in the development of the record pertaining to fixed customer charges, the applicant filed a basic bill impact customer cost analysis as requested by Commission staff in previous dockets. Commission staff also performed a basic bill impact customer cost analysis. This 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 represents a gradual shift in incorporating customer cost into fixed charges. The applicant did not propose a rate increase to EC-5, or the EP classes, as its COSS supported a decrease in revenue for all of these classes. Therefore, the Commission finds it reasonable to authorize the electric fixed customer charges as proposed by the applicant and presented in Commission staff's offered rate design.

New Load Market Pricing Rate

Testimony offered by Enbridge included a recommendation that the applicant submit a proposed NLMP rate in a TE docket no later than June 1, 2025. In its testimony, Enbridge noted that the applicant does not offer NLMP rate options, though they are commonly offered throughout the state. The applicant stated that it would be willing to propose a NLMP rate in collaboration with Enbridge or others, but would prefer not to do so on a specific timeline. Commission staff recommended that any consideration of a NLMP tariff be taken up in a separate proceeding.

The Commission finds that the applicant is voluntarily willing to work on this, and that given the complexity involved, allowing the applicant and Enbridge to proceed without an ordered timeline is appropriate. Therefore, the Commission finds it reasonable not to require the applicant to file for an NLMP rate at this time.

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 longstanding 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 that Commission staff's proposed natural gas revenue allocation is reasonable, with the applicant supporting either its allocation or the Commission staff allocation, and CUB supporting the Commission staff allocation or a new 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.

Natural Gas Fixed Charges

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. Commission staff proposed increases to the monthly customer charge for each class based on an analysis of the fixed customer costs produced by Commission staff's COSS models and the results of the basic consumer cost analysis provided by the applicant. While the Commission may have found that the applicant's proposed rates were reasonable, Commission staff's allocation and rate proposal were more moderate, adhering to the principal of gradualism in ratemaking. 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 Commission staff increased fixed customer charges 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 (PFP) 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.

The applicant accepted Commission staff's proposal and it was not contested by any party in this proceeding. Therefore, the Commission finds it reasonable to accept the water COSS prepared by Commission staff and agreed to by the applicant. Customer class revenue requirements resulting from the cost analysis compared with water revenues at authorized rates can be found in Appendix D.

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. PFP charges to customers in the City of Superior will increase by approximately 11.05 percent, and the PFP charge to the Village of Superior will increase by approximately 7.74 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 increase in annual water revenues is 10.85 percent, comprised of an 11.28 percent increase in general service charges and a 9.33 percent increase in PFP charges. A typical residential customer's bill will increase 9.64 percent, including PFP.

Lead Service Lines

The Commission's position on lead service aligns with that of public health officials around the world: there is no safe level of lead in drinking water. While there is state and federal financial assistance available for communities to assist in the replacement of service lines containing lead, in this case, state law does not allow the applicant to access many of the funds. While water quality is a critical component to the provision of safe drinking water, it is not something that the Commission directly regulates. The Commission finds it appropriate that

Wisconsin utilities and communities work diligently to remove lead from drinking water systems. The Commission expects the applicant to work with Commission staff, the Department of Natural Resources, and the City of Superior to produce a plan for the replacement of any service lines that contain lead.

Affordability of Utility Service

CUB and the City of Superior raised concerns related to utility service affordability and emphasized during the course of the proceeding that affordability and consideration of energy burden must remain a top priority. Many members of the public raised similar concerns.

The Commission acknowledges that affordability is a serious issue. In making its decisions, the Commission must balance these concerns with the needs of the utility to collect sufficient revenue to provide reliable service. The Commission finds that the revenue requirement, including finance parameters, and rates authorized in the present proceeding, taken in their totality, strike a reasonable balance and protect customers from unreasonable costs. The Commission notes that the applicant does have an arrears management program authorized by the Commission in dockets 5820-TE-101, 5820-TW-101, and 5820-TG-101. The Commission encourages the applicant to look for ways to improve access to and awareness of the program so that customers can to take advantage of this program as well as other state resources that may provide assistance.

Order

1. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2025, 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.

2. 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.

3. 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.

4. The applicant shall continue to provide specific data in its initial data request responses in its next rate proceeding demonstrating the specific customer benefits associated with payment of all association dues for which it intends to seek recovery in that proceeding.

5. The applicant shall amortize the MGP costs incurred in 2022 to 2023 in the amount of $11,204,373 over the 10-year period of 2025 through 2034. The amortization shall include carrying costs at the authorized long-term debt rate of 3.62 percent until December 31, 2026.

6. The applicant shall record conservation escrow expense amounts of $1,025,437 for electric operations and $306,399 for natural gas operations for the 2025 test year. The

applicant shall continue to record these expense amounts until the Commission authorizes different conservation escrow accruals.

7. All authorized amortizations shall begin on January 1, 2025, or as of the effective date of this Final Decision, whichever is later.

8. The annual amortization expense amounts itemized in Appendix I shall be recorded for all items listed for 2025 or until the Commission authorizes a different amortization expense to be recorded.

9. The applicant shall maintain a long-term range of 50.00 to 55.00 percent for its common equity ratio, on a financial basis.

10. The applicant shall submit a 10-year financial forecast in its next rate proceeding.

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

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

13. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 12th day of December, 2024.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:EJG:jlt:DL:02038330

Attachments

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.[7] 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

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

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN
(Not a party but must be served per Wis. Stat. § 227.53)
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Docket 5820-UR-117

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Superior Water, Light & Power
ELECTRIC RETAIL REVENUE ALLOCATION SUMMARY
TEST YEAR ENDED DECEMBER 31, 2025

RATE CLASS		PRESENT REVENUES	AUTHORIZED REVENUES	REVENUE CHANGE	PERCENT CHANGE
ER1	Residential Service	$13,411,031	$14,053,345	$642,314	4.79%
ERTD	Residential Optional Time-of-Day Service	$85,141	$88,662	$3,521	4.14%
ED-1	Controlled Space Heating Service	$140,046	$147,437	$7,391	5.28%
EW-1	Controlled Water Heating Service	$12,019	$12,662	$643	5.35%
	TOTAL RESIDENTIAL	$13,648,237	$14,302,106	$653,869	4.79%
EC-1	General Service	$3,279,298	$3,315,590	$36,292	1.11%
	TOTAL GENERAL SERVICE	$3,279,298	$3,315,590	$36,292	1.11%
EC-3	General Service Demand (25-500 kW)	$8,645,474	$8,688,865	$43,391	0.50%
EC-5	General Service Time-of-Day (25-500 kW)	$1,745,323	$1,747,510	$2,187	0.13%
EP-1	General Service Primary Voltage	$858,964	$864,431	$5,467	0.64%
	TOTAL SMALL COMMERCIAL & INDUSTRIAL	$11,249,348	$11,300,806	$51,458	0.46%
EP-3	Large Power Time-of-Day Service (500-0 kW)	$11,1238,518	$11,169,053	$30,535	0.27%
EP-5	Large Industrial Time-of-Day Service (>10000 kW)	$55,325,668	$55,852,128	$526,460	0.95%
	TOTAL LARGE COMMERCIAL & INDUSTRIAL	$66,464,186	$67,021,181	$556,995	0.84%
EL-1	Street Lighting Service	$319,225	$334,885	$15,660	4.91%
EZ-1	Sports Field Lighting Service	$2,599	$2,716	$117	4.50%
EN-1	Night Watch Lighting Service	$70,749	$74,383	$3,635	5.14%
	TOTAL LIGHTING SERVICE	$392,573	$411,984	$19,412	4.94%
TOTAL ELECTRIC RETAIL REVENUE		**$95,034,054**	**$96,359,576**	**$1,335,000**	**1.40%**

Superior Water, Light and Power Company

Electric Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Residential Service (Er-1)			
Customer Charge			
Single Phase	$ 11.00	$ 12.00	per month
Energy Charge	$ 0.1384	$ 0.1393	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Residential Time-of-Day (Er-TD)			
Customer Charge			
Single Phase	$ 11.00	$ 12.00	per month
Energy Charge			
Winter On Peak	$ 0.1524	$ 0.1514	per kWh
Summer On Peak	$ 0.1604	$ 0.1598	per kWh
Off Peak	$ 0.0774	$ 0.0760	
PCAC	$ - 0.0046	$ -	per kWh
Controlled Space Heating Service (Ed-1)			
Customer Charge	$ 7.00	$ 8.00	per month
Energy Charge	$ 0.0910	$ 0.0837	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Controlled Water Heating (Ew-1)			
Customer Charge	$ 7.00	$ 8.00	per month
Energy Charge	$ 0.0944	$ 0.0906	per kWh
PCAC	$ - 0.0046	$ -	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	$ 13.00	$ 15.00	per month
Three Phase	$ 18.00	$ 20.00	per month
Energy Charge	$ 0.1374	$ 0.1325	per kWh
PCAC	$ - 0.0046	$ -	per kWh
General Service Demand (Ec-3)			
Customer Charge			
Single Phase	$ 17.00	$ 20.00	per month
Three Phase	$ 28.00	$ 30.00	per month
Distribution Demand Charge	$ 3.00	$ 3.00	per kW
Billed Demand Charge	$ 9.00	$ 9.00	per kW
Energy Charge	$ 0.0853	$ 0.0809	per kWh
PCAC	$ - 0.0046	$ -	per kWh
General Service Time-of-Day (Ec-5)			
Customer Charge	$ 210.00	$ 210.00	per month
Distribution Demand Charge	$ 3.00	$ 3.00	per kW
Billed Demand Charge			
Winter	$ 11.50	$ 11.50	per kW
Summer	$ 10.50	$ 10.50	per kW
Energy Charge			
Winter On-Peak	$ 0.0936	$ 0.0893	per kWh
Summer On-Peak	$ 0.0896	$ 0.0856	per kWh
Off-Peak	$ 0.0695	$ 0.0646	per kWh
PCAC	$ - 0.0046	$ -	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	$ 80.00	$ 80.00	per month
Distribution Demand Charge	$ 3.00	$ 3.00	per kW
Billed Demand Charge	$ 9.00	$ 9.00	per kW
Energy Charge	$ 0.0834	$ 0.0786	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Large Power Time-of-Day (Ep-3)			
Customer Charge	$ 210.00	$ 210.00	per month
Distribution Demand Charge	$ 3.00	$3.00	per kW
Billed Demand Charge			
Winter	$ 11.00	$ 11.00	per kW
Summer	$ 10.00	$ 10.00	per kW
Energy Charge			
Winter On-Peak	$ 0.0889	$ 0.0893	per kWh
Summer On-Peak	$ 0.0860	$ 0.0856	per kWh
Off-Peak	$ 0.0640	$ 0.0646	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Act 141 LEU Credit		$ 0.00265	per kWh
Large Industrial Time-of-Day Service (Ep-5)			
Customer Charge	$ 605.00	$ 605.00	per month
Distribution Demand Charge	$ 3.00	$ 3.00	per kW
Billed Demand Charge			
Winter	$ 12.35	$ 12.35	per kW
Summer	$ 12.35	$ 12.35	per kW
Energy Charge			
Winter On-Peak	$ 0.0781	$ 0.0735	per kWh
Summer On-Peak	$ 0.0741	$ 0.0684	per kWh
Off-Peak	$ 0.0547	$ 0.0516	per kWh
PCAC	$ - 0.0046	$ -	per kWh

Superior Water, Light and Power Company
Electric Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Street Lighting Service (EL-1)			
Overhead			
6,000 Lumen LED	$ 11.00	$ 11.75	per month
13,000 Lumen LED	$ 13.50	$ 14.25	per month
150 W HPS	$ 12.50	$ 13.25	per month
250 W HPS	$ 13.89	$ 14.70	per month
250 W MV	$ 15.00	$ 15.75	per month
400 W MV	$ 19.25	$ 20.00	per month
Ornamental			
100 W MV	$ 13.50	$ 14.50	per month
Signal Lighting			
2 W MV	$ 28.00	$ 29.00	per month
Energy Charge	$ 0.0857	$ 0.0857	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Sports Field Lighting (Ez-1)			
Customer Charge	$ 25.00	$ 26.00	per month
Energy Charge	$ 0.1405	$ 0.1422	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Night Watch Lighting (En-1)			
Overhead			
6,630 Lumen LED	$ 11.80	$ 12.35	per month
150 W HPS	$ 15.50	$ 15.85	per month
250 W HPS	$ 15.95	$ 16.30	per month
400 W MV	$ 24.20	$ 24.55	per month
Pole Charge	$ 8.25	$ 8.60	per month
Energy Charge	$ -	$ -	per kWh
PCAC	$ - 0.0046	$ -	per kWh
Miscellaneous			
Average Base Cost of Power	$ 0.0642	$ 0.0765	per kWh
Act 141 Energy Factor			
Residential		$ 0.00325	per kWh
Commercial		$ 0.00265	per kWh
Embedded Cost Allowances			
Energy Only Classes	$ 303.27	$ 194.20	per customer
Demand Classes	$ 36.84	$ 69.04	per kW
Street Lighting	$ 9.89	$ 5.14	per lamp
Insufficient Funds (NSF) Cost	$ 20.00		
Reconnection Costs			
Normal Business Hours	$ 50.00		
Outside Business Hours	$ 100.00		

Superior Water, Light & Power
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

Residential Service Rg-1: Single Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$24.38	$25.93	$1.55	6.36%
500	$77.90	$81.65	$3.75	4.81%
750	$111.35	$116.48	$5.13	4.60%
1,000	$144.80	$151.30	$6.50	4.49%
1,500	$211.70	$220.95	$9.25	4.37%
2,500	$345.50	$360.25	$14.75	4.27%
4,000	$546.20	$569.20	$23.00	4.21%
48	**$17.43**	**$18.69**	**$1.26**	**7.25%**

Residential Service Rg-1: Three Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
100	$13.38	$13.93	$0.55	4.11%
500	$66.90	$69.65	$2.75	4.11%
750	$100.35	$104.48	$4.13	4.11%
1,000	$133.80	$139.30	$5.50	4.11%
1,500	$200.70	$208.95	$8.25	4.11%
2,500	$334.50	$348.25	$13.75	4.11%
4,000	$535.20	$557.20	$22.00	4.11%
48	**$6.43**	**$6.69**	**$0.26**	**4.11%**

* Values in bold represent class average usage

Superior Water, Light & Power
DETAILED BILL IMPACT ANALYSIS: RESIDENTIAL & GENERAL SERVICE
TEST YEAR ENDED DECEMBER 31, 2025

General Service Gs-1: Single Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$51.90	$53.30	$1.40	2.70%
1,000	$96.80	$98.60	$1.80	1.86%
2,000	$186.60	$189.20	$2.60	1.39%
3,000	$276.40	$279.80	$3.40	1.23%
4,000	$366.20	$370.40	$4.20	1.15%
5,000	$456.00	$461.00	$5.00	1.10%
6,000	$545.80	$551.60	$5.80	1.06%
95	**$15.57**	**$16.65**	**$1.08**	**6.91%**

General Service Gs-1: Three Phase

Monthly	Monthly Bills		Authorized Increase	
kWh	Current Rates	Proposed Rates	$ Amount	% Change
500	$44.90	$45.30	$0.40	0.89%
1,000	$89.80	$90.60	$0.80	0.89%
2,000	$179.60	$181.20	$1.60	0.89%
3,000	$269.40	$271.80	$2.40	0.89%
4,000	$359.20	$362.40	$3.20	0.89%
5,000	$449.00	$453.00	$4.00	0.89%
6,000	$538.80	$543.60	$4.80	0.89%
95	**$8.57**	**$8.65**	**$0.08**	**0.89%**

* Values in bold represent class average usage

Superior Water, Light, and Power Company
Gas Revenue Summary for Test Year 2025

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	$ 5,508,081	$ 5,622,564	$ 11,130,645	$ 7,130,046	$ 5,623,255	$ 12,753,301	$ 1,622,656	14.6%	29.5%
	Total Residential Service	**$ 5,508,081**	**$ 5,622,564**	**$ 11,130,645**	**$ 7,130,046**	**$ 5,623,255**	**$ 12,753,301**	**$ 1,622,656**	**14.6%**	**29.5%**
GC-1	Small Commerical - Firm System Sales	$ 1,860,604	$ 2,815,199	$ 4,675,803	$ 2,610,495	$ 2,817,525	$ 5,428,020	$ 752,217	16.1%	40.4%
GI-1	Small Commerical - Interruptible System Sales	$ 167,295	$ 332,603	$ 499,898	$ 232,930	$ 332,604	$ 565,534	$ 65,636	13.1%	39.2%
	Total Small Commerical Service	**$ 2,027,899**	**$ 3,147,802**	**$ 5,175,701**	**$ 2,843,425**	**$ 3,150,129**	**$ 5,993,554**	**$ 817,853**	**15.8%**	**40.3%**
GL-1	Large Commerical - Firm System Sales	$ 687,043	$ 1,550,426	$ 2,237,469	$ 947,247	$ 1,552,738	$ 2,499,985	$ 262,516	11.7%	38.2%
GI-6	Large Commerical - Interruptible System Sales	$ 249,736	$ 684,641	$ 934,377	$ 351,978	$ 687,112	$ 1,039,090	$ 104,713	11.2%	41.9%
TSP	Large Commerical - Interruptible Transport (GI-6)	$ 655,001	$ -	$ 655,001	$ 981,253	$ -	$ 981,253	$ 326,252	49.8%	49.8%
PFI	Partial Firm-Interruptible Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%	0.0%
	Total Large Commercial Service	**$ 1,591,780**	**$ 2,235,067**	**$ 3,826,847**	**$ 2,280,478**	**$ 2,239,850**	**$ 4,520,328**	**$ 693,481**	**18.1%**	**43.6%**
	Total Revenue	**$ 9,127,760**	**$ 11,005,433**	**$ 20,133,193**	**$ 12,253,949**	**$ 11,013,234**	**$ 23,267,183**	**$ 3,133,990**	**15.6%**	**34.3%**

Superior Water, Light, and Power Company
Gas Rates

Rate Schedule	Present Rates	Authorized Rates	Units
Residential Service - GR-1			
Customer Charge	$10.00	$11.50	per month
Distribution Charge	$ 0.3779	$ 0.5143	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Small Commerical - Firm System Sales - GC-1			
Customer Charge	$18.00	$28.00	per month
Distribution Charge	$ 0.2811	$ 0.3917	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Small Commerical - Interruptible System Sales - GI-1			
Customer Charge	$150.00	$220.00	per month
Distribution Charge	$ 0.1894	$ 0.2699	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Firm System Sales - GL-1			
Customer Charge	$175.00	$245.00	per month
Distribution Charge	$ 0.1894	$ 0.2682	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Interruptible System Sales - GI-6			
Customer Charge	$450.00	$750.00	per month
Distribution Charge	$ 0.1153	$ 0.1670	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Large Commerical - Interruptible Transport (GI-6) - TSR			
Customer Charge	$450.00	$750.00	per month
Additional Meter Charge	$25.00	$25.00	per month
Distribution Charge	$ 0.1153	$ 0.1670	per therm
Partial Firm-Interruptible Service - PFI			
Customer Charge	$450.00	$450.00	per month
Distribution Charge			
Firm Contract Load	$ 0.1894	$ 0.2682	per month
Interruptible Load	$ 0.1153	$ 0.1670	per therm
Gas Supply Acquisition Charge - System Supply Service	$ 0.0190	$ 0.0190	per therm
Base Average Cost of Gas			
Commodity Rate Charge (Comm)	$ 0.5550	$ 0.3872	per therm
Peak Day Demand Charge (D1)	$ 0.0861	$ 0.1075	per therm
Annual Demand Charge (D2)	$ 0.0488	$ 0.0609	per therm
Act 141 Distribution Rate*			
Residential	$ 0.00720	$ 0.00884	per therm
Commercial	$ 0.00910	$ 0.01212	per therm

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

SUPERIOR WATER, LIGHT, & POWER
RESIDENTIAL BILL COMPARISON
TEST YEAR ENDED DECEMBER 31, 2025

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

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 10.00	$ 11.50	$ 1.50	15.0%
10	$ 18.45	$ 21.31	$ 2.86	15.5%
20	$ 26.90	$ 31.13	$ 4.23	15.7%
17	$ 24.36	$ 28.18	$ 3.82	15.7%
40	$ 43.80	$ 50.75	$ 6.96	15.9%
50	$ 52.25	$ 60.57	$ 8.32	15.9%
75	$ 73.37	$ 85.10	$ 11.73	16.0%
100	$ 94.50	$ 109.64	$ 15.14	16.0%
200	$ 178.99	$ 207.77	$ 28.78	16.1%
300	$ 263.49	$ 305.91	$ 42.42	16.1%
500	$ 432.49	$ 502.19	$ 69.70	16.1%

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

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 10.00	$ 11.50	$ 1.50	15.0%
10	$ 19.53	$ 22.39	$ 2.86	14.7%
20	$ 29.05	$ 33.28	$ 4.23	14.6%
30	$ 38.58	$ 44.17	$ 5.59	14.5%
40	$ 48.10	$ 55.06	$ 6.96	14.5%
50	$ 57.63	$ 65.95	$ 8.32	14.4%
75	$ 81.44	$ 93.17	$ 11.73	14.4%
100	$ 105.25	$ 120.39	$ 15.14	14.4%
131	$ 134.78	$ 154.15	$ 19.37	14.4%
200	$ 200.50	$ 229.28	$ 28.78	14.4%
300	$ 295.75	$ 338.17	$ 42.42	14.3%
500	$ 486.25	$ 555.95	$ 69.70	14.3%

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

Annual Therm Use	AnnualBill Present Rates	Monthly Bill Proposed Rates	Amount Change	Percent Change
0	$ 10.00	$ 11.50	$ 1.50	15.0%
60	$ 66.40	$ 76.09	$ 9.68	14.6%
100	$ 214.01	$ 245.65	$ 31.64	14.8%
200	$ 308.01	$ 353.29	$ 45.28	14.7%
300	$ 402.02	$ 460.94	$ 58.92	14.7%
400	$ 496.03	$ 568.59	$ 72.56	14.6%
500	$ 590.04	$ 676.24	$ 86.20	14.6%
750	$ 825.05	$ 945.35	$ 120.30	14.6%
888	$ 954.78	$ 1,093.91	$ 139.12	14.6%
1000	$ 1,060.07	$ 1,214.47	$ 154.40	14.6%
1250	$ 1,295.09	$ 1,483.59	$ 188.50	14.6%
1500	$ 1,530.11	$ 1,752.71	$ 222.60	14.5%

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

		Cost of Service		Authorized Rates		
Customer Class	Revenue at Present Rates	Revenue Required	Increase over Present Rates	Revenue	Increase over Present Rates	Percent of Cost of Service
Residential	$4,442,649	$4,898,704	10.27%	$4,902,087	10.34%	100.07%
Multifamily Residential	$547,689	$593,162	8.30%	$595,393	8.71%	100.38%
Commercial	$1,594,265	$1,727,823	8.38%	$1,725,676	8.24%	99.88%
Industrial	$1,112,248	$1,336,721	20.18%	$1,335,529	20.07%	99.91%
Public Authority	$144,887	$156,149	7.77%	$154,082	6.35%	98.68%
Inter-Dept	$4,511	$5,128	13.67%	$5,191	15.06%	101.23%
Irrigation	$44,218	$62,784	41.99%	$62,817	42.06%	100.05%
Private Fire Protection	$161,160	$161,160	0.00%	$161,160	0.00%	100.00%
Public Fire Protection	$2,057,473	$2,264,469	10.06%	$2,264,745	10.07%	100.01%
Total	$10,109,100	$11,206,100	10.85%	$11,206,679	10.86%	100.01%
Fire Protection						
City of Superior	$2,011,297	$2,214,720	10.11%	$2,214,996	10.13%	100.01%
Private Fire Protection	$161,160	$161,160	0.00%	$161,160	0.00%	100.00%
Village of Superior	$46,176	$49,749	7.74%	$49,749	7.74%	100.00%
Total	$2,218,633	$2,425,629	9.33%	$2,425,905	9.34%	100.01%
Total - General Service and Public Fire Protection						
City of Superior	$9,901,764	$10,995,191	11.04%	$10,995,770	11.05%	100.01%
Private Fire Protection	$161,160	$161,160	0.00%	$161,160	0.00%	100.00%
Village of Superior	$46,176	$49,749	7.74%	$49,749	7.74%	100.00%
Total	$10,109,100	$11,206,100	10.85%	$11,206,679	10.86%	100.01%

Authorized Water Rates

MG-1: GENERAL SERVICE - METERED			
Meter Size	Existing Rates	Proposed Rates	Percent Change
5/8"	$ 18.25	$ 20.00	9.59%
3/4"	$ 18.25	$ 20.00	9.59%
1"	$ 28.00	$ 33.00	17.86%
1 1/4"	$ -	$ -	0.00%
1 1/2"	$ 45.00	$ 56.00	24.44%
2"	$ 70.00	$ 86.00	22.86%
3"	$ 110.00	$ 143.00	30.00%
4"	$ 160.00	$ 221.00	38.13%
6"	$ 280.00	$ 402.00	43.57%
8"	$ 415.00	$ 618.00	48.92%
10"	$ 595.00	$ 903.00	51.76%
12"	$ 775.00	$ 1,188.00	53.29%

MG-1: GENERAL SERVICE - METERED			
Volume Blocks (CCF)	Existing Rates	Proposed Rates	Percent Change
Mg-1R - Residenital			
First 20	$ 5.66	$ 6.27	10.78%
Next 480	$ 5.09	$ 6.27	23.18%
Next 500	$ 4.75	$ 6.27	32.00%
Over 1,000	$ 3.82	$ 6.27	64.14%
Mg-1MF - Multifamily and Mg-1NR - Nonresidential			
First 20	$ 5.66	$ 6.04	6.71%
Next 480	$ 5.09	$ 5.29	3.93%
Next 500	$ 4.75	$ 4.95	4.21%
Over 1,000	$ 3.82	$ 4.67	22.25%
Mg-1IR - Irrigation			
First 20	$ 5.66	$ 6.20	9.54%
Next 480	$ 5.09	$ 6.20	21.81%
Next 500	$ 4.75	$ 6.20	30.53%
Over 1,000	$ 3.82	$ 6.20	62.30%

F-1: PUBLIC FIRE PROTECTION			
Meter Size	Existing Rates	Proposed Rates	Percent Change
5/8"	$ 12.54	$ 13.50	7.66%
3/4"	$ 12.54	$ 13.50	7.66%
1"	$ 31.35	$ 33.80	7.81%
1 1/4"	$ -	$ -	
1 1/2"	$ 62.71	$ 68.00	8.44%
2"	$ 101.00	$ 109.00	7.92%
3"	$ 188.00	$ 203.00	7.98%
4"	$ 313.00	$ 338.00	7.99%
6"	$ 626.00	$ 676.00	7.99%
8"	$ 1,003.00	$ 1,082.00	7.88%
10"	$ 1,505.00	$ 1,622.00	7.77%
12"	$ 2,006.00	$ 2,163.00	7.83%

UPF-1: PRIVATE FIRE PROTECTION			
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%

F-2: VILLAGE OF SUPERIOR			
Municipal Charge	Existing Charge	Proposed Charge	Percent Change
Annually	$ 46,176	$ 49,749	7.74%
Monthly	$ 3,848	$ 4,146	7.74%

Superior Water, Light and Power Company

Customer Water Bill Comparison at Present and Authorized Rates

Customer Type	Meter Size	Volume (100 Cubic Feet)	Monthly Bills at Old Rates	Monthly Bills at New Rates	Monthly Percent Change	Monthly Including Public Fire Protection Bills at Old Rates	Monthly Including Public Fire Protection Bills at New Rates	Monthly Including Public Fire Protection Percent Change
Small Residential	5/8"	2	$ 29.57	$ 32.54	10.04%	$ 42.11	$ 46.04	9.33%
Average Residential	5/8"	4	$ 40.89	$ 45.08	10.25%	$ 53.43	$ 58.58	9.64%
Large Residential	5/8"	6	$ 52.21	$ 57.62	10.36%	$ 64.75	$ 71.12	9.84%
Large Residential	5/8"	8	$ 63.53	$ 70.16	10.44%	$ 76.07	$ 83.66	9.98%
Large Residential	5/8"	10	$ 74.85	$ 82.70	10.49%	$ 87.39	$ 96.20	10.08%
Multifamily Residential	5/8"	12	$ 86.17	$ 92.48	7.32%	$ 98.71	$ 105.98	7.37%
Multifamily Residential	5/8"	16	$ 108.81	$ 116.64	7.20%	$ 121.35	$ 130.14	7.24%
Multifamily Residential	5/8"	20	$ 131.45	$ 140.80	7.11%	$ 143.99	$ 154.30	7.16%
Multifamily Residential	5/8"	24	$ 151.81	$ 161.96	6.69%	$ 164.35	$ 175.46	6.76%
Commercial	5/8"	15	$ 103.15	$ 110.60	7.22%	$ 115.69	$ 124.10	7.27%
Commercial	1"	100	$ 548.40	$ 577.00	5.22%	$ 579.75	$ 610.80	5.36%
Commercial	2"	250	$ 1,353.90	$ 1,423.50	5.14%	$ 1,454.90	$ 1,532.50	5.33%
Commercial	4"	500	$ 2,716.40	$ 2,881.00	6.06%	$ 3,029.40	$ 3,219.00	6.26%
Industrial	1"	500	$ 2,584.40	$ 2,693.00	4.20%	$ 2,615.75	$ 2,726.80	4.25%
Industrial	1 1/2"	750	$ 3,788.90	$ 3,953.50	4.34%	$ 3,851.61	$ 4,021.50	4.41%
Industrial	4"	2,000	$ 8,911.40	$10,026.00	12.51%	$ 9,224.40	$10,364.00	12.35%
Industrial	6"	4,000	$16,671.40	$19,547.00	17.25%	$17,297.40	$20,223.00	16.91%
Public Authority	5/8"	5	$ 46.55	$ 50.20	7.84%	$ 59.09	$ 63.70	7.80%
Public Authority	3/4"	15	$ 103.15	$ 110.60	7.22%	$ 115.69	$ 124.10	7.27%
Public Authority	1"	100	$ 548.40	$ 577.00	5.22%	$ 579.75	$ 610.80	5.36%
Public Authority	1 1/2"	200	$ 1,074.40	$ 1,129.00	5.08%	$ 1,137.11	$ 1,197.00	5.27%

Superior Water, Light and Power Company
Schedule of Electric Depreciation Rates
Effective January 1, 2025

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%
372	Leased Property 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	6.67%
397	Communication Equip	5.00%

Superior Water, Light and Power Company
Schedule of Gas Depreciation Rates
Effective January 1, 2025

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%
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, 2025

Account Number	Account Title	Depreciation Rate
	SOURCE OF SUPPLY PLANT	
312	Collecting and Impounding Reservoirs	1.50%
313	Lake, River, and Other Intakes	1.43%
314	Wells and Springs	2.20%
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	Sand or Other Media Filtration 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	
390	Structures and Improvements	5.88%
391	Office Furniture and Equipment	5.88%
392	Transportation Equipment	UNIT
394	Tools, Shop and Garage Equipment	5.88%
395	Laboratory Equipment	5.88%
396	Power Operated Equipment	6.67%
397	Communication Equipment	10.00%
397.1	SCADA Equipment	5.88%
398	Miscellaneous Equipment	5.88%

Superior Water, Light and Power Company
Schedule of Common Depreciation Rates
Effective January 1, 2025

Account Number	Account Title	Deprec. Rate
	INTANGIBLE PLANT	
303	Miscellaneous intangible plant	10.00%
	GENERAL PLANT	
390	Structures and Improvements	2.78%
391	Office Furniture and Equipment	5.00%
392	Transportation Equipment	25.00%
393	Stores Equipment	5.00%
394	Tools, Shop and Garage	4.00%
395	Equipment Laboratory Equipment	5.00%
396	Power Operated Equip	6.67%
397	Communication Equipment	5.00%
398	Miscellaneous Equipment	5.00%

Superior Water, Light and Power Company
5820-UR-117
Amortization of Regulated Assets and Liabilities
Test Year 2025

	PSCW Escrow Authorization	Amortization Period	Test Year 2025 Amortization Amount Electric	Gas	Water	Estimated Balance at 12/31/2025 Electric	Gas	Water
Manufactured Gas Plant (MGP) Costs	5820-UR-116	2023 - 2034	$ -	$ 2,020,556	$ -	$ -	$ 10,984,055	$ -
Conservation Escrow		2025 - 2026	1,025,437	306,399	-	(275)	(32,128)	-
Credit Card Fees	5820-UR-116	2025 - 2026	17,687	15,420	12,245	17,687	15,420	12,245
Tax Reform	5-AF-101	2025	-	(462)	-	-	-	-
Husky Superior Refinery	5820-UR-115	2025 - 2026	-	-	(86,495)	-	-	(86,495)
Bad Debt	5820-TE-101 5820-TG-101 5820-TW-101	2025 - 2026	(120,000)	(97,500)	(32,500)	(120,000)	(97,500)	(32,500)
AMI Loss Over Recovery	5820-UR-114	2025 - 2026	(67,998)	(100,118)	(59,616)	(67,998)	(100,118)	(59,616)
			$ 855,126	$ 2,144,295	$ (166,366)	$ (170,586)	$ 10,769,730	$ (166,366)