PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates	6690-UR-128

FINAL DECISION

This is the Final Decision on the application of Wisconsin Public Service Corporation (applicant) for authority to adjust electric and natural gas base rates for the 2025 and 2026 test years, and for approval of the applicant's 2025 Fuel Cost Plan. Final overall rate changes[1] for the test year ending December 31, 2025 are authorized consisting of a $55.1 million rate increase over currently authorized rates for retail electric operations, or 4.48 percent, and a $14.9 million rate increase over currently authorized rates for natural gas operations, or 3.75 percent, based on a 9.80 percent return on equity (ROE). Final overall rate changes for the test year ending December 31, 2026 are authorized consisting of a $85.1 million rate increase over currently authorized rates for retail electric operations, or 6.82 percent, and a $28.4 million rate increase over currently authorized rates for natural gas operations, or 6.81 percent, based on a 9.80 percent ROE.

Introduction

On April 12, 2024, the applicant filed an application requesting approval to adjust Wisconsin retail electric and natural gas rates base rates. (PSC REF#: 499073.)

[1] Changes reflected in the Final Decision reflect changes in the applicant's currently authorized revenue requirement and any difference from rates shown in the appendices is due to rounding.

On May 9, 2024, the Commission issued a Notice of Proceeding. (PSC REF#: 500855.) The notice advised that a hearing would be scheduled at a later date. The notice instructed those persons desiring to become a party to file for intervention no later than 14 days from the date of service. The following organizations and entities requested and were granted intervention and are therefore parties to this proceeding: Citizens Utility Board of Wisconsin (CUB); International Union of Operating Engineers Local 420 (IUOE); RENEW Wisconsin (RENEW); Roundy's Supermarkets, Inc. (Roundy's); Sierra Club; Vote Solar; Walmart Inc. (Walmart); and Wisconsin Industrial Energy Group (WIEG) (together with applicant, parties). (PSC REF#: 505901.)

On June 20, 2024, a Prehearing Conference Memorandum was issued making determinations consistent with the prehearing conference held on June 14, 2024. The memorandum established the issues, schedule and other facilitation matters for this proceeding pursuant to Wis. Admin. Code § PSC 2.04(4). (PSC REF#: 505901.) The issues for hearing were identified as follows:

A. Should the Commission grant in whole or in part the applicant's request for electric, and natural gas utility rate increases, and if so, under what terms and conditions?
   1. What is the applicant's revenue requirement for electric and natural gas service?
   2. What is the cost of service as related to each customer class?
   3. What is the appropriate rate design, including service rules, for each customer class?

On August 27, 2024, the Commission issued a Notice of Hearing. (PSC REF#: 515300.) Pursuant to due notice, on October 10, 2024, a public hearing was held in person and virtually for members of the general public. (PSC REF#: 522214.) The Commission's public hearing process involved the opportunity for members of the public to submit written comments through the Commission' web site or at the public hearing, or to testify at the public hearing. The Commission received comments from over 200 members of the public. (PSC REF#: 522477.)

A party hearing was held virtually on September 20, 2024, to receive testimony and technical information from the parties to the proceeding. (PSC REF#: 519364.)

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

The Commission considered this matter at its open meetings of November 7, 2024, and December 19, 2024.

Findings of Fact

1. The applicant is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a), providing electric and natural gas service to northcentral and northeast Wisconsin.

2. Currently authorized rates for the applicant's Wisconsin retail electric operations will produce total tariff operating revenues of $1,231.6 million and $1,247.3 million for the 2025 and 2026 test years, respectively. This results in a retail net operating income of $248.2 million and $223.2 million for 2025 and 2026, respectively, which is insufficient.

3. For the applicant's retail electric utility operations, the estimated rate of return on average net investment rate base of $3,638.0 million and $3,779.5 million at current rates for the 2025 and 2026 test years, is 6.82 percent and 5.91 percent, respectively, which is insufficient.

4. A reasonable increase to the applicant's Wisconsin retail electric operating revenues to produce a rate of return on the applicant's average net investment rate base of

7.93 percent and 8.02 percent in the 2025 and 2026 test years is $55.1 million and $85.1 million, respectively.

5. The applicant's filed electric operating income statement and net investment rate base for the 2025 and 2026 test years, as adjusted for Commission decisions, are reasonable.

6. Currently authorized rates for the applicant's natural gas utility operations will produce total tariff operating revenues of $398.2 million and $417.3 million for the 2025 and 2026 test years, respectively[2]. This results in a net operating income of $56.4 million and $51.4 million, respectively, which is insufficient.

7. For the applicant's natural gas utility operations, the estimated rate of return on average net investment rate base of $856.1 million and $907.3 million at current rates for the 2025 and 2026 test years, is 6.58 percent and 5.67 percent, respectively, which is insufficient.

8. A reasonable increase to the applicant's natural gas operating revenues to produce a rate of return on the applicant's average net investment rate base of 7.85 percent and 7.95 percent in the 2025 and 2026 test years is $14.9 million and $28.4 million, respectively.

9. The applicant's filed natural gas operating income statement and net investment rate base for the 2025 and 2026 test years, as adjusted for Commission decisions, are reasonable.

10. It is reasonable to exclude any costs associated with the U.S. Environmental Protection Agency requirements for Coal Combustion Residuals (CCR) from the 2025 and 2026 test year electric revenue requirements in this proceeding, and to not address the accounting treatment for any such costs at this time.

11. It is reasonable to accept Commission staff's uncontested fuel cost adjustments.

[2] The difference between the authorized rates and those shown in Appendices D and E result from the presentation of the timing of when the Act 141 credits are being applied.

12. It is reasonable to accept Commission staff's proposed adjustment to the West Riverside outage rate and use the Equivalent Forced Outage Rate (EFOR) from the Certificate of Public Convenience and Necessity (CPCN) for the West Riverside units.

13. It is reasonable to accept Commission staff's adjustment to monitored fuel costs to reflect the impact of Commission staff's adjustment to the electric sales forecast.

14. It is reasonable to include in fuel costs the impact of additional firm natural gas capacity costs for Fox Energy Center.

15. It is reasonable to reflect the revenue requirement impact of Commission staff's fuel cost update containing New York Mercantile Exchange (NYMEX) futures settlement prices as of October 15, 2024 for natural gas and heating oil, October 11, 2024 Argus spot coal prices, the October 8, 2024 Energy Information Administration (EIA) Short-term Energy Outlook (STEO) for highway diesel prices, and new fuel-related contracts to forecast the applicant's 2025 monitored fuel costs.

16. It is reasonable to set the applicant's 2025 Fuel Cost Plan level of monitored fuel costs at $285.7 million, or $24.42 per megawatt-hour (MWh), as shown in Appendix F.

17. It is reasonable to monitor the applicant's fuel costs using an annual bandwidth of plus or minus 2.0 percent, as provided in Wis. Admin. Code § PSC 116.06(3).

18. It is reasonable for the applicant to seek reconciliation of its 2025 fuel cost plan consistent with the requirements of Wis. Admin. Code ch. PSC 116.07.

19. It is reasonable for the applicant to file a 2026 fuel cost plan in 2025 consistent with the requirements of Wis. Admin. Code ch. PSC 116.

20. It is reasonable to accept Commission staff's electric sales forecast adjustments for the 2025 and 2026 test year electric revenue requirements.

21. It is reasonable to require the real time market pricing Midcontinent Independent System Operator, Inc. (MISO) transaction costs and new load market pricing MISO transaction costs be included in the 2025 and 2026 test year electric revenue requirements.

22. It is reasonable to accept Commission staff's natural gas sales forecast adjustments for the 2025 and 2026 test year natural gas revenue requirements.

23. It is reasonable to accept Commission staff's full-time equivalents (FTE) headcount adjustments for the applicant's part-time, seasonal, and non-represented employees for the 2025 and 2026 test year electric and natural gas revenue requirements. It is reasonable to accept the applicant's FTE forecast for represented FTE employees for the 2025 and 2026 test years.

24. It is not reasonable to authorize escrow or deferral accounting related to any changes between authorized and actual wages and headcount expenses.

25. It is reasonable to accept Commission staff's payroll adjustments for overtime hours for the 2025 and 2026 test year electric and natural gas revenue requirements.

26. It is reasonable that the wage percentage increase for non-represented employees and expiring collective bargaining contracts be held to 2.10 percent for the 2025 test year and 2.50 percent for the 2026 test year.

27. It is reasonable to accept Commission staff's adjustment related to the applicant's medical and dental expense associated with non-represented FTE adjustments for the 2025 and 2026 test year electric and natural gas revenue requirements.

28. It is reasonable to exclude all incentive compensation from the applicant's 2025 and 2026 test year electric and natural gas revenue requirements.

29. It is not reasonable to accept Commission staff's adjustment to the other expense line item included in operation and maintenance (O&M) Account – 921 Office Supplies and Expenses for the 2025 and 2026 test year electric and natural gas revenue requirements.

30. It is reasonable to accept the applicant's filed electric O&M maintenance expense forecast for Whitewater Generating Station (Whitewater) in the 2025 and 2026 test year electric revenue requirements.

31. It is reasonable to accept Commission staff's electric O&M maintenance expense adjustment for the Weston Power Plant, Hydro, Crane Creek Wind Park and Fox Energy Center plants.

32. It is reasonable for the applicant to recover a percentage of industry association dues consistent with past Commission practice in the 2025 and 2026 test year electric and natural gas revenue requirements.

33. It is reasonable for the applicant to provide specific data in its initial data request responses in its next rate proceeding demonstrating the specific customer benefits associated with payment of association dues for which the applicant intends to seek recovery in that proceeding.

34. It is reasonable to accept Commission staff's adjustment to advertising and economic development costs in the electric and natural gas revenue requirement for the 2025 and 2026 test years.

35. It is not necessary to require the applicant 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 advertising expenses for which it intends to seek recovery in that proceeding.

36. It is reasonable to require the applicant 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 Board of Director expenses for which it intends to seek recovery in that proceeding.

37. It is reasonable to accept the applicant's forestry management expense budget for inclusion in the 2025 and 2026 test year electric revenue requirements.

38. It is not necessary to require the applicant to escrow or defer the difference between authorized and actual forestry management expense.

39. It is reasonable to require the applicant to file annual forestry management reports containing the information detailed in this Final Decision no later than the first quarter of each year beginning in 2025 and ending in 2027.

40. It is reasonable to exclude all expenses associated with Leak Detection and Repair (LDAR) from the applicant's 2025 and 2026 test year natural gas revenue requirements.

41. It is reasonable for the Commission to take no action at this time to address the appropriate accounting treatment for future LDAR expenses.

42. It is reasonable to accept Commission staff's adjustments to the applicant's electric and natural gas utility plant in service and construction work in progress (CWIP) for the 2025 and 2026 test years.

43. It is reasonable for the applicant to defer the cost overruns for Paris Solar Generating and Battery Energy Storage System (Paris Solar and BESS) without any carrying costs, to a future rate proceeding.

44. It is reasonable to accept the applicant's proposal to amortize the regulatory liability balance associated with Paris Solar and BESS due to a change in the in-service date over one year (2025) and to require a true-up in the applicant's next rate proceeding.

45. It is reasonable for the applicant to defer the cost overruns for Darien Solar Generating and Battery Energy Storage System (Darien Solar and BESS) without any carrying costs, to a future rate proceeding.

46. It is reasonable for the applicant to defer the incremental revenue requirement impact arising from a change in the in-service date for the Darien Solar and BESS project, with carrying costs at the applicant's short term debt rate.

47. It is reasonable for the applicant to amortize the forecasted transmission escrow balance as proposed by the applicant for the 2025 and 2026 test year electric revenue requirements.

48. It is reasonable to include the amount of bad debt expense identified by the applicant in the 2025 and 2026 test year electric and natural gas revenue requirements, and to authorize escrow accounting treatment for bad debt expense over two years.

49. It is reasonable for the applicant to recover the undepreciated balance on Columbia Energy Center units 1 and 2 between June 1, 2026 (one day after the date of retirement) and December 31, 2026, using a 25-year levelized recovery period, with carrying costs at the applicant's authorized weighted average cost of capital.

50. It is reasonable for the applicant to submit additional analysis in in next rate proceeding of alternatives for addressing the remaining undepreciated balance for Columbia Energy Center units 1 and 2.

51. It is reasonable to require the applicant to sunset the levelized cost recovery approach on Columbia Energy Center units 1 and 2 on December 31, 2026, or as decided by the Commission in the applicant's next rate proceeding.

52. It is reasonable to require the applicant to defer the difference between the estimated and actual revenue requirement impact associated with retiring Columbia Energy Center units 1 and 2 resulting from changes in the units' May 31, 2026, retirement date.

53. It is reasonable for the applicant to amortize the acquisition costs related to the distribution-connected utility-owned solar generation and BESS projects and dedicated renewable energy resource (DRER) projects beginning in 2025 for 25 years, the estimated life of those facilities.

54. It is reasonable for the applicant to defer the costs associated with the Bring Your Own Device (BYOD) pilot program to the applicant's next rate proceeding.

55. It is reasonable for the applicant to continue to defer, with carrying costs at the applicant's short-term debt rate, any impacts of the Inflation Reduction Act of 2022 (IRA).

56. It is reasonable for the applicant to defer, with carrying costs at the applicant's authorized short-term debt rate, any impacts for the U.S Internal Revenue Service Revenue Procedure 2023-15 (IRS Revenue Procedure 2023-15) to the applicant's next rate proceeding.

57. It is reasonable for the applicant to defer, with carrying costs at the applicant's authorized short-term debt rate, the net impact of any loans or grant funds from programs through the U.S. Department of Energy (DOE) to the applicant's next rate proceeding.

58. The customer service conservation (CSC) activities proposed by the applicant for 2025 and 2026 are reasonable and consistent with the Commission's historical definition of CSC activities.

59. A reasonable estimate of escrowed conservation expense to be recorded for electric operations is $15.4 million and $16.3 million for the 2025 and 2026 test years, respectively.

60. A reasonable estimate of escrowed conservation expense to be recorded for natural gas operations is $6.2 million and $6.7 million for the 2025 and 2026 test years, respectively.

61. It is reasonable for the applicant to amortize all deferrals or escrows not separately discussed over a two-year period (2025 through 2026).

62. 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 G, for all items listed for 2025 and 2026 or until the Commission authorizes a different amortization expense to be recorded.

63. It is reasonable for the applicant to file a depreciation study for the Commission's approval no later than December 20, 2027.

64. It is reasonable to require the applicant and Commission staff in future rate proceedings to calculate revenue deficiencies by consistently rounding to four decimal places when represented as a number and two decimal places when shown as a percentage.

65. It is reasonable to require the applicant in future rate proceedings to present the second year of a two-year test year rate proceeding as a change from presently authorized rates.

66. It is reasonable for the applicant's Earnings Sharing Mechanism (ESM), as approved in docket 6690-UR-127, to remain in place until the applicant's next rate proceeding.

67. It is reasonable to accept all other Commission staff audit adjustments made to the applicant's filed electric and natural gas revenue requirements not contested by any party.

68. It is reasonable for the applicant to have $160 million for off-balance sheet obligations for 2025 and $154.7 million in off—balance sheet obligations for 2026.

69. An appropriate target level for the test-year average common equity measured on a financial capital structure basis is 53.00 percent for the 2025 and 2026 test years.

70. A reasonable financial capital structure for the 2025 test year consists of 53.00 percent common equity, 41.24 percent long-term debt, 2.88 percent short-term debt, and 2.87 percent debt equivalence for off-balance sheet obligations, including subsidiary debt. A reasonable financial capital structure for the 2026 test year consists of 53.00 percent common equity, 41.63 percent long-term debt, 2.93 percent short-term debt, and 2.44 percent debt equivalence for off-balance sheet obligations, including subsidiary debt.

71. It is reasonable to revise the applicant's dividend restriction based on the capital structure determinations in this proceeding, as set forth in the Opinion section of this Final Decision.

72. A reasonable regulatory capital structure for the 2025 test year consists of 54.39 percent common equity, 42.62 percent long-term debt, and 2.98 percent short-term debt. A reasonable regulatory capital structure for the 2026 test year consists of 54.17 percent common equity, 42.82 percent long-term debt, and 3.01 percent short-term debt.

73. A reasonable return on utility common stock equity is 9.80 percent for 2025 and 2026.

74. A reasonable interest rate for short-term borrowing through commercial paper is 4.72 percent for 2025 and 3.98 percent for 2026.

75. A reasonable average embedded cost for long-term debt is 4.43 percent for 2025 and 4.64 percent for 2026.

76. A reasonable weighted average composite cost of capital is 7.36 percent for 2025 and 7.41 percent for 2026.

77. It is reasonable to require the applicant to provide additional supporting information regarding the costs associated with the issuance of long-term debt forecasted but not issued in the test-years, the funds collected from customers associated with it, and Commission staff's proposal to defer the incremental impact associated with debt that is forecasted but not issued, to be returned to customers.

78. It is reasonable to consider the results of multiple electric cost-of-service study (COSS) models, for 2025 and 2026 revenue allocation and rate design.

79. It is reasonable to authorize the applicant's proposed changes to the customer classes in its electric COSS.

80. It is reasonable to adopt the electric revenue allocations for the 2025 and 2026 test years proposed by WIEG, modified to adjust the Electric Vehicle (EV) classes to zero percent, and as adjusted for final revenue requirement.

81. It is reasonable to accept the comprehensive electric rate design proposed by Commission staff in Ex.-PSC-Jurvich-1r and Ex.-PSC-Jurvich-2r, as adjusted for final revenue requirement and revenue allocation, for the 2025 and 2026 test years respectively.

82. It is reasonable to approve, with the modifications and conditions noted in this Final Decision, the applicant's proposal to create a BYOD demand response pilot.

83. It is reasonable to approve, with the modifications and conditions noted in this Final Decision, the applicant's proposal to close its COEV-R and WHEV-R tariffs to new customers and create an EV-R pilot program.

84. It is reasonable to authorize changes to the applicant's EV-C pilot program as noted in this Final Decision.

85. It is reasonable to adopt the rate design for the Cg-20 customer class proposed by Commission staff.

86. It is reasonable to increase the participation limit on the New Load Market Pricing (NLMP) Rider from 145.1 MW to 200 MW.

87. It is not reasonable to authorize at this time replacing the minimum incremental energy rate (IER) associated with the NLMP rider with a fixed adder.

88. It is not reasonable to authorize the applicant to fully phase in the Cp-1 High-Load Factor Credit at this time.

89. It is reasonable to require the applicant to conduct an analysis of the impacts and any unintended effects of fully phasing in the Cp-1 High-Load Factor Credit and to submit that analysis in its next rate proceeding.

90. It is reasonable for the applicant to add language clarifying its annual deadline for firm demand nominations to the Cp-I2 tariff.

91. It is reasonable to authorize the increased Renewable Pathway Premium rate from $0.00874 per kilowatt-hour (kWh) to $0.02518 per kWh for one-year subscriptions and from $0.00688 per kWh to $0.02331 per kWh for five-year subscriptions.

92. It is reasonable to accept the applicant's proposed minor administrative changes and clarifications to its electric rate sheets.

93. It is reasonable to require the applicant to investigate changes to its parallel generation tariffs proposed in this proceeding in a separate TE docket that shall be opened no later than April 1, 2025.

94. It is reasonable to increase the capacity cap on the PG-2B tariff from 1,000 kW to 5,000 kW.

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

96. It is reasonable to consider the results of multiple natural gas COSS models, for the 2025 and 2026 test year revenue allocation and rate design.

97. The natural gas revenue allocation for the 2025 and 2026 test years proposed by Commission staff in Ex.-PSC-Jurvich-3 and Ex.-PSC-Jurvich-4, respectively, as adjusted for final revenue requirement, are reasonable.

98. It is reasonable to accept the comprehensive natural gas rate design proposed by Commission staff in Ex.-PSC-Jurvich-3 and Ex.-PSC-Jurvich-4, as adjusted for final revenue requirement, for the 2025 and 2026 test years, respectively.

99. It is reasonable to approve the rate changes for natural gas service as shown in Appendices D and E.

100. It is reasonable to create a 12-month waiting period for Customer Requested Bill Due Date program customers who have fallen into arrears.

101. It is reasonable to accept the applicant's proposed updated definition of a Large Energy Customer under Wisconsin Act 141.

102. It is reasonable to eliminate the incremental deterrence component of the non-sufficient Funds (NSF) change and reconfigure the charge to consist of the administrative cost added to the average of the range of financial institution fees.

103. It is reasonable to consider the cost disparities between physical and remote disconnections and reconnections in a future rate proceeding.

104. It is reasonable to require the applicant to work with Commission staff on identifying and including additional reporting data for the Low Income Forgiveness Tariff (LIFT) program for inclusion in the initial filing for the applicant's next rate proceeding.

105. It is reasonable to approve tariff changes for electric and natural gas service consistent with the rates shown in Appendices B, C, D, and E.

106. Energy conservation, renewable resources, or energy priorities listed in Wis. Stat. §§ 1.12 or 196.025 and their combination would not be cost-effective, technically 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, 196.22, 196.37, 196.374, 196.395, 196.40, and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter this Final Decision authorizing the applicant to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B, C, D and E, and the fuel costs treatment set forth in Appendix F that are just and reasonable.

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

3. The Commission took official notice of and accepted into the record a October 23, 2024 quarterly process report, pursuant to Wis. Stat. § 227.45, and afforded all parties an adequate opportunity to respond.

4. The Commission's determinations in this matter are based on the specific facts presented in this application and are not precedential.

Opinion

Applicant and its Business

The applicant is an investor-owned electric and natural gas utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity, and in the purchase, distribution, and sale of natural gas in a service area of approximately 11,000 square miles in north central and northeastern Wisconsin and adjacent parts of upper Michigan. Cities that the applicant serves with retail electric service or natural gas service include Green Bay, Marinette, Oshkosh, Rhinelander, Sheboygan, Stevens Point, and Wausau in

Wisconsin and Menominee in Michigan. The applicant is an operating subsidiary of WEC Energy Group, a holding company based in Milwaukee, Wisconsin.

The applicant also sells electricity at wholesale rates to other utilities and electric cooperatives for resale. Federal Energy Regulatory Commission (FERC) regulates wholesale sales and rates. The applicant's wholesale rates, therefore, are not affected by this Final Decision. Similarly, the rates applicable to retail sales of electricity and natural gas to Michigan customers are not subject to the jurisdiction of this Commission and are not affected by this Final Decision.

The applicant's service territory presents unique challenges. As analyzed by CUB in this proceeding, 46 percent, or 39 out of the 85 census tracts served by the applicant, have a higher percentage of families with income below the poverty line, unemployment, or both, compared to statewide averages. These challenges appear especially significant in Brown County. Within the area served by the applicant 10 census tracts, largely within Brown County, have been identified as Disadvantaged Communities by the Climate and Economic Justice Screening Tool (CEJST), which, based on federal data sets, measures burdens in eight categories: climate change, energy, health, housing, legacy pollution, transportation, water and wastewater, and workforce development.

The Application

The applicant filed for approval of a 2025 Fuel Cost Plan pursuant to Wis. Admin. Code § PSC 116.03, an increase to electric and natural gas rates as described in the Revenue Requirement section below, and several new or modified tariff programs.

Intervenor and Public Participation

Stakeholder groups representing a broad variety of interests intervened, requested discovery, and provided testimony in this proceeding. Members of the public provided testimony and submitted more than 210 written comments, most of which were related to affordability of the applicant's service.

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 commission, 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 Metropolitan Sewerage Dist.,*141 Wis. 2d 10, 15, 414 N.W.2d 308 (Ct. App. 1987). It has set utility rates for more than 100 years. In ratemaking, the Commission exercises a legislative function. *Wis. Mfr. And Commerce v. Public Serv. Comm 'n (WMC),*94 Wis. 2d 314, 319, 319, 287 N.W.2d 844 (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 Pub. 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,[3] 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,"[4] Wis. Stat. § 196.37 does not

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

specify a standard of proof the Commission must find. 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 (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. v. Pub. Serv. Comm'n*, 94 Wis. 2d 314, 321, 287 N.W.2d 844 (Ct. App. 1979). This test requires only that there be 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, 644 N.W.2d 649 ("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. Pub. Serv. Comm'n of Wisconsin* noted in that case, the issue in the present docket is not one of a right, but one of legislative determinations. The applicant in the present docket does not have a right to the particular change in rates at issue and cannot prove they are 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 any specific burden or standard of proof—and, thus, there is no specific standard of proof that an applicant must satisfy.

Evidentiary Record

The applicant, other parties, and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates and rates for the applicant's 2025 and 2026 electric and natural gas utility operations. As noted above, members of the public provided testimony and submitted written comments. This evidence was accepted into the record. (PSC REF#: 524057.) Following the hearing, Sierra Club moved to strike certain evidence offered by the applicant. (PSC REF#: 518162.) The ALJ denied the motion and directed the applicant's re-filing of certain evidence. (PSC REF#: 520007.)

The Commission reviewed the received evidence which informed its decisions. During its discussion of record, the Commission identified additional evidence it wished to consider. Pursuant to Wis. Stat. § 227.45, the Commission accepted into the record for this proceeding a copy of the October 23, 2024 quarterly progress report filed with the Commission in docket 5-BS-255, and took official notice of the change of the in-service date for the Darien Solar and BESS. (PSC REF#: 523919.) The parties were provided an opportunity to rebut or offer countervailing evidence or contest the validity of the official notice by providing written comments in response to the Commission's Order. No comments were received.

Revenue Requirement

The applicant filed for separate 2025 and 2026 test years. The applicant concluded its current electric and natural gas rates were insufficient and proposed a base rate increase in 2025 and 2026. For Wisconsin retail electric rates for the 2025 test year, the applicant requested an 8.7 percent increase above 2024 authorized rates, and an incremental increase of approximately 4.9 percent for the 2026 test year. For natural gas rates for the 2025 test year, the applicant requested a 6.8 percent increase above 2024 authorized rates, and an incremental increase of approximately 3.7 percent for the 2026 test year. The applicant's requested rate increase reflects a 10.00 percent return on common stock equity.

The applicant claimed the main drivers impacting the electric revenue requirement for the 2025 and 2026 test years included the increased investments in rate base, significant inflation, higher capital costs due to increased interest rates since its last rate proceeding, and regulatory amortizations, including increases attributable to the transmission escrow. According to the applicant, the natural gas revenue requirement drivers included increased investments in rate base, significant inflation, regulatory amortizations, and higher capital costs.

Commission staff reviewed 2025 and 2026 test year filing information for both electric and natural gas operations. Based on its review, Commission staff determined that for 2025 and 2026 retail electric operations, the applicant would require an increase above currently authorized 2024 retail electric rates of 4.54 percent and 7.32 percent for the 2025 and 2026 test years, respectively. For 2025 and 2026 natural gas rates, Commission staff determined the applicant would require an increase above currently authorized 2024 natural gas rates of 3.22 percent and 6.27 percent for the 2025 and 2026 test years, respectively. Commission staff's proposed rate increase reflects a 9.65 percent return on common stock equity.

Income Statement

A public utility's obligation to serve is a condition of its franchise and is defined by statute. Wisconsin public utilities are required to furnish reasonably adequate service and facilities,[5] among other requirements. In setting just and reasonable utility rates, the

[5] Wis. Stat. § 196.03.

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 2025 and 2026 test years. The Commission sets this budget on a forward-looking basis, anticipating the services the utility will provide in the test year(s), and estimating the applicant's reasonable expenses[6] in order to determine the appropriate revenue requirement, or the total revenues the utility must collect from customers in the rates charged.

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." The USOA defines "extraordinary items" as gains and losses within the period (test year) that are significant, abnormal, significantly different from typical activities of the company, and not recurring. For such "extraordinary items", utilities are permitted to seek deferral accounting treatment.

In this proceeding, there were several requests or proposals presented by the parties for deferral or escrow accounting treatment. While the Commission finds that some of these requests have merit as will be discussed later in this Final Decision, the Commission notes that tracking all gains and losses with escrow or dollar-for-dollar treatment removes the incentive mechanisms provided by the future test year framework and negates its policy purpose. Such

[6] For many income statement items, reasonable expenses are estimated based on historic budget-to-actual or historic averages. This methodology is employed deliberately as it serves an important budget and risk balancing function by allowing both historic underspend and overspend to be incorporated into the test year on a rolling basis, thus smoothing out variances.

requests, and the risks associated therewith are also relevant to and intertwined with the other tasks the Commission undertakes in setting rates.

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 establishes a reasonable ROE. These parameters have a direct impact on customers' bills. The use of future test years and ratemaking mechanisms provide the state's utilities a reasonable opportunity to earn their authorized equity returns, even in the face of unexpected costs. These mechanisms include, for example, the use of relatively equity-rich capital structures for rate-setting purposes, authorization of 100 percent Allowance of Funds Used During Construction (AFUDC) or a current return on 50 percent of CWIP following Commission authorization of a Certificate of Authority (CA) or CPCN, and periodic adjustments to reflect changes in electric fuel costs that are outside a variance range. This ratemaking process affords reasonable opportunity for utilities to earn authorized returns, avoids Commission micromanagement of budgets, and sets proper incentives for utilities to manage business risk and seek efficiencies and innovations in order to capture the benefits of savings in between rate proceedings.

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 also informed by the unique characteristics of the applicants' service territory and the impact raising rates has on the customers the applicants serve, including households facing unemployment, low income, or high energy burden. These concerns must also be considered and balanced against providing the applicants a reasonable opportunity to earn a fair return.

In the evidentiary record assembled for this proceeding, a number of issues pertaining to the income statement were raised and are addressed separately below. 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.

Fuel Costs

Pursuant to Wis. Admin. Code § PSC 116.03, each of the five major investor-owned Wisconsin electric utilities must file a proposed fuel cost plan for each calendar year, known as the plan year, as part of a general rate proceeding, or if the applicant does not file a general rate proceeding, as a proceeding limited in scope to fuel cost. This fuel cost plan must include a calculation of certain fuel costs as described in Wis. Admin. Code § PSC 116.02, as well as the other information required by Wis. Admin. Code § PSC 116.03(2). After a hearing, the Commission approves the applicant's fuel cost plan and establishes the applicant's rates in accordance with the approved fuel cost plan as described in Wis. Admin. Code § PSC 116.03(3).

The fuel cost plan filed as part of the applicant's April 12, 2024 application to adjust electric and natural gas rates reflected a preliminary fuel cost estimate for the 2025 fuel plan year of $26.37 per MWh, which is a 3.0 percent decrease from the 2024 fuel cost plan approved by the Commission in docket 6690-UR-127. (PSC REF#: 487257.) Commission staff conducted an audit of the applicant's fuel costs, and Commission staff's adjustments consisted of updates for more recent information, corrections to modeling inputs and errors, and updates to non-modeled profiles and fixed costs.

The Commission finds that a reasonable estimate of the applicant's 2025 total company monitored fuel costs is $285.7 million which reflects the costs of generation and purchased energy, minus revenues from opportunity sales of energy and capacity. The 2025 monitored fuel costs divided by the 2025 estimate of native energy requirements of 11,698,814 MWh results in an average net monitored fuel cost of $24.42 per MWh, which is a 10.2 percent decrease from the 2024 fuel cost plan approved by the Commission in docket 6690-UR-127. Appendix F shows the monthly fuel costs to be used for monitoring purposes.

It is reasonable to monitor the applicant's fuel costs using a plus or minus 2.0 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3). Further, the applicant shall seek reconciliation of its 2025 fuel cost plan consistent with the requirements of Wis. Admin. Code ch. PSC 116; and the applicant shall file for its 2026 fuel cost plan in 2025 in accordance with Wis. Admin. Code ch. PSC 116.

Uncontested Fuel Adjustments

Commission staff and the applicant proposed various adjustments to the applicant's filed 2025 fuel costs that were not contested by any party. These adjustments included: (1) an increase of $2.2 million to reflect updated natural gas prices as of May 15, 2024; (2) a decrease of $0.616 million to reflect updated delivered coal, diesel, and heating oil prices as of mid-May 2024; (3) a decrease of $3.0 million to reflect updated planned outage schedules, EFORs, and Edgewater 5 operation extension; (4) an increase of $0.103 million to reflect transmission facility updates; (5) a decrease of $2.0 million to reflect Weston 4 and Elm Road gas co-firing limitations under existing air permits; and (6) a decrease of $4.2 million to reflect various back-end updates.

The Commission therefore finds it is reasonable to accept all of the uncontested monitored fuel adjustments to the applicant's 2025 fuel costs.

Impact of Electric Sales Adjustment on Monitored Fuel Costs

Commission staff proposed an adjustment to monitored fuel costs to reflect the impact of the proposed adjustment to the electric sales forecast on the applicant's native system requirement used in the fuel modeling. The impact of this adjustment was a $0.243 million increase to the applicant's 2025 fuel costs. In alignment with its overall positions regarding electric sales forecasting, CUB supported Commission's staff's adjustment and the applicant opposed the adjustment.

Consistent with the Commission's decision regarding the electric sales forecast, the Commission finds it reasonable to adjust the applicant's 2025 fuel costs to reflect the impact of the adjustment to the applicant's 2025 electric sales forecast.

West Riverside Outage Rate

The outage rate used in the modeling of the West Riverside units has been a contested issue in several previous fuel cost plans. West Riverside is majority owned and operated by Wisconsin Power and Light Company (WP&L). While the applicant itself does not own an interest in West Riverside, its sister utility, Wisconsin Electric Power Company (WEPCO), does hold a partial ownership interest. Since the applicant and WEPCO share modeling, the applicant's modeling results are impacted by the West Riverside operations.

The applicant proposed modeling West Riverside using an EFOR based on the historical actual outage rate. Commission staff typically uses a five-year historical average as the basis for forecasting EFOR. However, West Riverside went into service in May 2020, and does not have five years of historical data available. In addition, in its first few years, West Riverside experienced persistent operational and maintenance challenges, resulting in higher outage rates in its initial years than what would be considered normal operation. Due to the limited and unrepresentative historical outage data for West Riverside, Commission staff proposed an adjustment to use the EFOR from West Riverside's CPCN based on the expectation that the units would continue moving toward normal operations as recent issues become resolved. The impact of this adjustment was a $6,309 decrease to the applicant's 2025 fuel costs. CUB supported Commission staff's proposed adjustment.

In previous fuel plan years, the Commission has gradually reduced the authorized EFOR for West Riverside from the higher initial rates proposed by the utilities to the lower rate established in the CPCN. The Commission's Final Decision in docket 6680-UR-123, recognized the ongoing operational challenges at West Riverside and noted that the targeted EFOR should not be delayed indefinitely and in this instance authorized the use of 7.50 percent EFOR. (PSC REF#: 427760.) For the 2024 fuel cost plans, the Commission ordered WP&L in docket 6680-UR-124 (PSC REF#: 487254), WEPCO in docket 5-UR-110 (PSC REF#: 487244), and the applicant in docket 6690-UR-127 (PSC REF#: 487257), to use the EFOR from the CPCN for West Riverside.

Due to the continued limitation of the historical outage data available for West Riverside, and to remain consistent with previous decisions, the Commission finds it reasonable to continue to use the EFOR from the CPCN for West Riverside to model the applicant's 2025 fuel costs.

Fox Energy Center Gas Capacity Costs

The applicant proposed an additional adjustment to the 2025 fuel costs to account for additional firm gas capacity that had been procured for the Fox Energy Center after its initial filing. This adjustment was not contested by any party. The Commission finds it reasonable to include the additional gas capacity costs in the applicant's 2025 fuel costs.

NYMEX and Other Updates

Consistent with past Commission practice, Commission staff proposed a final update to the applicant's 2025 fuel costs to reflect updates to commodities (natural gas, heating oil, coal, and diesel) prices and contracts. Natural gas and heating oil prices were updated based on NYMEX futures as of October 15, 2024. Spot coal prices were updated based on October 11, 2024, Argus prices. Highway diesel prices were updated based on the October 8, 2024, EIA STEO. This information was included in a delayed exhibit filed by Commission staff. (PSC REF#: 522855.) These adjustments were not contested by any party and resulted in a decrease to the applicant's 2025 fuel costs by $15.4 million. The Commission finds it reasonable to accept these uncontested final adjustments to reflect updated commodities pricing.

Coal Combustion Residuals (CCR)

On May 8, 2024, the U.S. Environmental Protection Agency (EPA) published new regulations for CCR (a.k.a. coal ash) landfills and surface impoundments, which established new requirements for legacy CCR surface impoundments with an effective date of November 4, 2024. In its initial filing, the applicant included in Account 501 expenses of $0.600 million in 2025 and $25.0 million in 2026 for ash disposal costs related to compliance with the new EPA CCR regulations. The applicant's estimate of 2025 and 2026 CCR related expenses was presented as a single line item in Account 501. A more detailed breakdown of expenses, scope of work, timelines etc., was not available. The impact of the new regulations is still undetermined due to uncertainty regarding implementation and enforcement, potential delays from legal challenges, and the potential for the EPA to allow some site work to be deferred.

Due to the uncertainty of the impact of the new CCR regulations, Commission staff proposed excluding the impact of new CCR regulations from revenue requirement. Commission staff further proposed that once the costs associated with the new CCR regulations become more certain, if the costs involved meet deferral criteria, the applicants could file a request for deferral accounting treatment. The applicant did not offer objections to this approach.

In light of this uncertainty and absence of objection from the applicant, the Commission finds it reasonable to accept Commission staff's adjustment to remove the impact of new CCR regulations from 2025 and 2026 revenue requirements in this proceeding and to not address the accounting treatment for any such costs at this time.

Electric Sales Adjustment

Commission staff adjusted the electric sales revenue based on its forecasted customer growth rate and use per customer for the residential rate classes RG 1, RG-3 OTOU, and RG-5 OTOU. Commission staff used a four-year compound annual growth rate to forecast the average customer count and a five-year average was used to forecast the use per customer for the 2025 and 2026 test years. Using historical data that was provided by the applicant, the average customer count showed a strong linear growth rate for each of the residential rate classes therefore Commission staff chose to use a four-year compound annual growth rate for its forecast. The average use per customer can fluctuate from year to year therefore Commission staff chose to use a five-year average to forecast each test year. CUB supported Commission staff's proposed 2025 and 2026 electric sales revenue adjustments.

The applicant disagreed with Commission staff's residential growth adjustment and asserted that Commission staff's methodology was strictly backwards looking and did not take into consideration factors that may cause the test years to depart from historical trends. The applicant further argued that Commission staff's analysis failed to incorporate the important factors that are summarized in the applicant's testimony and as a result, stated that the Commission should select the applicant's as-filed forecast due to the more sophisticated, forward looking, and reasonable methodology it employed.

The Commission is not persuaded by the applicant's arguments. Commission staff's methodology utilizes a standard approach which not only looks at historical averages, but also adjusts sales for linear growth rates or compound annual growth rates. Based on the evidence in the record, the Commission finds it reasonable to accept Commission staff's electric sales adjustments for the 2025 and 2026 test years.

In addition to the adjustments discussed above for electric operations, Commission staff identified that when the applicant added Commission staff's adjustments to UI Planner two adjustments were inadvertently missed relating to the real time market pricing MISO transaction costs and NLMP MISO transaction costs resulting in Commission staff's revenue requirement to be understated by $0.311 million and $0.342 million for the electric sales for the 2025 and 2026 test years. Commission staff suggested that the Commission include both amounts in the final revenue requirement as the amounts were inadvertently excluded from staff's original numbers.

The Commission finds it reasonable to include real time market pricing MISO transaction costs and NLMP MISO transaction costs in the 2025 and 2026 test years revenue requirement.

Natural Gas Sales Adjustment

Commission staff proposed an adjustment to the gas sales RG-3 rate class, increasing the sales forecast by 2,594,367 therms for the 2025 test year and 3,535,158 therms for the 2026 test year. Additionally, Commission staff made an adjustment to the gas sales CG TL rate class, increasing the sales forecast by 3,530,086 therms for the 2025 test year and 5,572,179 therms for the 2026 test year. Commission staff's adjustment to the residential and large transportation rate classes result from higher customer count forecasts. The residential historical customer counts had a very strong linear growth rate. Therefore, Commission staff chose to use a linear forecast, based on the 2019 through 2023 period, to forecast the 2025 and 2026 test year totals. The large transportation historical customer counts had a strong growth rate. Commission staff identified that slowed growth, however, is likely. Therefore, Commission staff chose to take an average of the utility forecasted flat growth rate along with the Commission staff forecasted four-year compound annual growth rate, for years 2019 through 2023, to forecast the test year totals. Based on the adjustments discussed above and a NYMEX update, the natural gas sales revenue forecast had an overall increase of $2.2 million for the 2025 test year and an overall increase of $3.2 million for the 2026 test year.

CUB supported Commission staff's proposed 2025 and 2026 electric and natural gas sales revenue adjustments.

The applicant disagreed with Commission staff's methodology arguing that it was strictly backwards looking and did not take into consideration factors that may cause the test years to depart from historical trends. The applicant further argued that Commission staff's analysis failed to incorporate the important factors that are summarized in the applicant's testimony and as a result, stated that the Commission should select the applicant's as-filed forecast.

The Commission notes that here again, Commission staff utilized a standardized approach and did not look only at historic sales but also linear growth rates or compound annual growth rates. The Commission finds Commission staff's methodology reasonable and accepts its natural gas sales adjustments for the 2025 and 2026 test years.

Transmission Escrow

While the applicant forecasted the transmission escrow balance to be zero by the end of 2026, in the interest of gradualism, the applicant weighted 2026 more in terms of recovering the two-year forecast transmission expenses. Commission staff did not express any concerns with the applicant's request as the balance of the escrow is still forecasted to be zero at the end of 2026. The Commission finds that in the interest of gradualism the weighting requested by the applicant is reasonable. Therefore, the Commission finds it reasonable to amortize the forecasted transmission escrow balance as proposed by the applicant for the 2025 and 2026 test years.

O&M Maintenance Expense Adjustments

Commission staff proposed an adjustment to the O&M expenses for the Weston Power Plant, Hydro, Crane Creek Wind Park, and Fox Energy Center plants that was calculated using a three-year budget-to-actual analysis to adjust the applicant's test year budgets amounts to be consistent with the applicant's past maintenance spending. The 2025 maintenance adjustments resulted in a decrease of $0.304 million for Weston Power Plant, a decrease of $0.547 million for Hydro, a decrease of $0.287 million to Crane Creek Wind Park, and a decrease of $0.891 for Fox Energy Center maintenance. The 2026 maintenance adjustments include a decrease of $0.455 million for Weston Power Plant, a decrease of $0.550 million for Hydro, a decrease of $0.316 million to Crane Creek Wind Park, and a decrease of $0.960 million for Fox Energy maintenance. The applicant stated that although the applicant disagreed with Commission staff's methodology, the applicant was not contesting these reductions to plant O&M expense for the above-referenced plants.

Based on the evidence in the record, the Commission finds it reasonable to accept the O&M expense adjustments proposed by Commission staff for the plants listed above. The adjustments are based, in part, on historical data that the Commission finds to be reasonable.

In addition to the above plant adjustments, Commission staff also proposed the same budget-to-actual analysis adjustment for Whitewater which resulted in a decrease of $1.3 million and $1.4 million in 2025 and 2026. The applicant objected to Commission staff's methodology and stated that this adjustment could not be true of the Whitewater. The Commission approved the applicant's 50 percent acquisition on December 22, 2022, and the purchase closed on January 1, 2023. Therefore, the applicant observed that the budget-to-actual adjustment was not based on a three-year average but based on one year's operations.

Commission staff clarified that the adjustment was misclassified in direct testimony and the adjustment for the Whitewater and Commission staff's analysis was based on only one year:

2023. Commission staff identified that based on the additional information provided by the applicant, the Commission could find that the applicant's original budget for Whitewater is reasonable. Conversely, as the applicant only spent approximately 25 percent of the 2023 budget, the Commission could find that some or all Commission staff's adjustment could be considered reasonable.

The Commission finds that due to the timing of the Whitewater acquisition, a three-year budget-to-actual analysis is inapplicable and it is more reasonable to use the applicant's budget, which is informed by actual ownership experience and expenses. The Commission is not persuaded that the underspend of the prior budget warrants a reduction in the applicant's forecast given the limited information that was available to the applicant when that 2023 budget was estimated. Therefore, the Commission finds it reasonable to accept the applicant's filed electric O&M expense forecast for Whitewater in the 2025 and 2026 test years.

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 WP&L in docket 6680-UR-124 (PSC REF#: 487254) and Madison Gas and Electric (MGE) 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 intend to seek recovery.

In this proceeding, the applicant provided a 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-Probst-2, which included the applicant's 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 decreases of $0.484 million for electric operations and $0.129 million for natural gas operations for the 2025 test year, as well as decreases of $0.496 million for electric operations and $0.132 million for natural gas operations for the 2026 test year, pending Commission approval.

CUB stated that it is only appropriate to recover industry association dues if it can be shown that there are associated customer benefits. CUB argued that the applicant bears the burden of demonstrating the customer benefit and based upon the record in this proceeding, recommended that the Commission remove 100 percent of association dues from the test year revenue requirements. Vote Solar also argued that the applicant did not produce specific data demonstrating specific customer benefits.

The applicant testified that the Commission's historic practice of including a portion of industry association fees in rates is reasonable and justified. In addition, the applicant stated that the Commission's historical percentages are a fair reflection of the benefits to customers and should be maintained.

The Commission's directive, first directed in last year's rate proceedings to WP&L and MGE, was intended to be applicable to all investor-owned utilities, with the goal of gathering customer benefit information for future proceedings rather than making abrupt removals from revenue requirements. The applicant did provide some information but in the future the record would benefit from a more robust presentation by the applicant. The Commission finds that the information supplied did demonstrate that participation in the associations identified by the applicant 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 reasonable to allow inclusion of a percentage of industry associations dues consistent with past Commission practice, and as identified in Ex.-PSC-Probst-2, in the applicant's 2025 and 2026 electric and natural gas revenue requirements. Further, the Commission finds it reasonable to require the applicant to provide detailed information in its initial data request responses in its next rate proceeding demonstrating the specific customer benefits associated with payment of association dues for which the applicant intends to seek recovery.

Advertising and Economic Development Expenses

Per long-standing Commission practice, the Commission has disallowed promotional, institutional or good will advertising 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. Therefore, Commission staff removed the promotional advertising, institutional or goodwill advertising expenses and economic development expenses resulting in a decrease of $0.108 million for electric operations and $0.045 million for natural gas operations for the 2025 test year revenue requirement, as well as $0.110 million for electric operations and $0.046 million for natural gas operations for the 2026 test year requirement. Commission staff did not propose removing other advertising expenses where there was an associated customer benefit.

CUB and Vote Solar supported Commission staff's adjustment. Therefore, the Commission finds it reasonable and consistent with past practice to accept Commission staff's adjustment for promotional advertising, institutional or goodwill advertising expenses.

CUB stated that only those advertising expenses that provide a customer benefit should be allowed in rates and proposed that the applicant be required to provide specific data in its next rate proceeding demonstrating the specific customer benefits associated with advertising expenses for which it intends to seek recovery.

The Commission is not persuaded by CUB's argument that applicant be required to provide specific data in its next rate proceeding. The identification of which advertising expenses do or do not provide a customer benefit is readily ascertainable from the information the applicant has historically submitted on these expenses. The Commission finds no reason at this time to change its historic practices relating to the review of advertising expenses. Therefore, the Commission finds it is not necessary to require the applicant to provide specific data in its next rate proceeding demonstrating the customer benefit associated with advertising expenses for which it seeks recovery.

Account 921 – Office Supplies and Expense

Commission staff originally proposed an adjustment to the other expenses line item included in O&M Account 921 – Office Supplies and Expenses to limit the test year amounts to the three-year inflated average of actual expenses after accounting for a one-time amount included in the 2022 actual balance relating to an unwinding of a reserve adjustment. The applicant provided additional information regarding how the amounts were forecasted for the other expense line item included in O&M Account – 921 Office Supplies and Expenses. Based on this additional information, Commission staff withdrew the adjustment included in Adjustment 13. By removing Commission staff's adjustment, the revenue requirement would increase $0.893 million and $0.915 million in 2025 and 2026, respectively, for electric operations and $0.251 million and $0.257 million in 2025 and 2026, respectively, for natural gas.

The Commission agrees with the additional information provided by the applicant and finds it reasonable to remove Commission staff's adjustment for the other expense line item included in O&M Account – 921 Office Supplies and Expenses for the 2025 and 2026 test years.

Board of Director Costs

CUB identified that the applicant was seeking approximately $0.604 million and $1.0 million in Board of Directors fess for the 2025 and 2026 test years, respectively, and an additional $0.653 million and $0.671 million in Board of Directors Insurance for 2025 and 2026, respectively. CUB recommended the Commission require that the applicant provide specific data in its initial data request responses in its next rate proceeding, demonstrating the specific customer benefits associated with Board of Director costs (fees and insurance) for which it seeks recovery.

As the Commission has not historically examined these costs in detail, the Commission finds that it may be instructive for the Commission to see more detailed information regarding the nature and purpose of such costs. Therefore, the Commission finds it is reasonable to require the applicant to provide specific data in its initial data request response in its next rate proceeding demonstrating the specific customer benefits associated with Board of Director costs for which it seeks recovery.

Forestry Management Expense

The applicant requested a $3.9 million increase in forestry maintenance to improve reliability, reduce the frequency and duration of outages caused by the growing intensity and severity of storms in Wisconsin, and protect the electric distribution system from the Emerald Ash Borer infestation.

Commission staff proposed an adjustment to limit the test year forestry management amounts to the three-year inflated average of actual expenses pending the Commission's determination of the reasonableness of the applicant's request. This adjustment would have resulted in a decrease of $4.4 million and $4.5 million for the 2025 and 2026 test years electric revenue requirement, respectively.

The applicant provided information on historical forestry management miles, budget and actual spending and outage data. The projects identified for 2025 and 2026 and increased number of forestry maintenance miles trimmed in 2025 and 2026 are related to reducing the applicant's tree trimming cycle from 6 years on average to 4.8 years. The outages related to 'tree growing into primary' category has gone from being around 1 percent of the overall outages in the 2013 through 2017 period to 11 percent in 2023 and can be addressed with more frequent vegetation maintenance. ‘Tree Growing in the Primary’ are outages where trees within the applicant’s right of way make contact with the primary distribution lines due to growth. During the 2013 through 2017 period, the applicant saw fewer tree related outages in this category as its forestry management practices were on an optimal cycle by trimming 2,808 miles every year on an average. With the proposed funding increase, the applicant plans to trim 2,686 miles in 2025 and 2026 to shorten its trimming cycle. The applicant’s system has several thousand lesser miles of overhead distribution lines due to their System Modernization and Reliability Project approved by the Commission in docket 6690-CE-198 (PSC REF#: 187648.) Due to this change since the 2013 through 2017 period, the applicant can achieve their optimal forestry management cycle by managing lesser miles as compared to the 2013 through 2017 period. The applicant’s project selection methodology is based on addressing areas that are most overdue for forestry management to get back to its pre-2017 outage numbers.

The applicant proposed that to the extent the Commission is uncertain about the precise amount of spend in the test years, then it would be appropriate to authorize the applicant to escrow or defer differences in costs between the requested amounts and actual spend in the test years. According to the applicant, including the requested amounts in the revenue requirement subject to escrow or deferral accounting would allow the applicant to “true up” the amount spent in a future rate proceeding either through a refund to customers of any underspent amount, or collection from customers of any excess amounts spent through amortization of a regulatory asset. In this way customers would be held harmless. CUB argued the applicant is not entitled to ongoing dollar-for-dollar recovery of every cost.

The Commission finds the applicant's forestry management O&M increase to be reasonable. Based upon the record evidence, the Commission finds that the applicant made a sound case for the requested budgetary increase for forestry management. The Commission supports this funding request in full because the investment in better forestry management now will produce cost effective results and get the applicant on a shorter tree trimming cycle sooner. The increase in forestry management budget will expedite addressing tree related outages and reliability metrics in the applicant's service territory. Therefore, the Commission finds it reasonable to accept the applicant's forest management expense increase as proposed by the applicant for the 2025 and 2026 test years.

As the record supports the reasonableness of the forestry management proposed by the applicant, the Commission finds it is not reasonable to authorize the applicant to escrow or defer the difference between authorized and actual forestry management expense for the 2025 and 2026 test years. The Commission observes that escrow accounting treatment is generally limited to situations where costs and savings are bidirectionally volatile, and it is in the best interest of both the applicant and customers to smooth out the effects of those costs and savings to promote rate predictability and stability. As noted earlier in this Final Decision, tracking all gains and losses with escrow or dollar-for-dollar treatment removes the incentive mechanisms provided by the future test year framework and negates its policy purpose.

Forest Management Reporting

Commission staff recommended that should the Commission find the applicant's proposed forestry management expense to be reasonable, the Commission consider requiring the applicant to file annual forestry management reports, no later than the first quarter of each year beginning in 2025 and ending in 2027 and proposed a number of specific reporting requirements. The Commission believes that the estimation of individual project reliability metrices as proposed by Commission staff would be burdensome to the applicant and would not provide additional value in understanding the reliability improvements seen and instead finds that reporting on an assessment of reliability benefits would provide a more flexible reporting approach. Therefore, the Commission finds the following reporting conditions to be reasonable and requires the applicant to file annual forestry management reports no later than the first quarter of each year beginning in 2025 and ending in 2027 that include the following:

1. Number, identification, and trimming timeline for project.
2. Details of the progress made during the previous forestry maintenance season and the progress made to-date under this O&M item.
3. Comparison of total budgeted and actual annual cost.
4. Tree outage related data for individual projects for pre- and post-forestry maintenance period for the test years that includes outages by tree growing into primary, tree not growing into primary, and service line categories.
5. Tree outage related data for the applicant's system for pre- and post-forestry maintenance period for the test years that includes outages by tree growing into primary, tree not growing into primary, and service line categories.
6. Number of Emerald Ash Borer Infested hazard trees removed by project and cost for such hazard tree removal.
7. Report on assessment of reliability benefits.

Leak Detection and Repair

The applicant identified various expected impacts of the LDAR proposed rule[7] and based on an assumed effective date of March 1, 2025, included the associated compliance costs in its test year forecasts. In addition, the applicant identified that until the rule is finalized, the precise cost impact is difficult to estimate, and the Commission may view deferral as a preferable alternative to setting rates incorporating an estimate based on incomplete information.

Commission staff testified that the final language of the proposed amendments may change or may not be approved, changing any new requirements and noted it cannot be certain when the proposed rulemaking will reach its final publication or effective date. Given these uncertainties, Commission staff removed $3.7 million in the 2025 and 2026 test years natural gas revenue requirements pending the Commission's decision on the appropriateness of including the amount. Commission staff proposed that once the costs associated with the LDAR proposed rule become more certain, if the costs involved meet deferral criteria, the applicant could file a request for deferral accounting treatment.

CUB stated that Commission staff's adjustment is consistent with the Commission's past practice where costs associated with compliance requirements, such as the pending PHMSA rules, that are not yet finalized, or the impacts are not yet known, are removed from revenue requirements. CUB stated that if the Commission believes that it is highly likely the LDAR rules will go into effect during the test years in a state substantially similar to the currently amended draft, it may be reasonable to include some or all of the requested funds. CUB also identified that the Commission could consider whether to grant the entire request for both the 2025 and

[7] The US Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA's) notice of proposed rulemaking was published to the Federal Register on May 18, 2023. (Ex. PSC-Lindquist-1r.)

2026 test year or if the Commission believes that the evidence supports a conclusion that the effective date of the rules may be further in the future, it could grant the requested increase in annual expense for only the 2026 test year.

The applicant disagreed with Commission staff's adjustment and noted that the purpose of a forward-looking test year is to estimate costs that the utility will incur in the test year, or in the 2025 and 2026 test years in this docket.

Noting that the record indicates uncertainty around the timing of the rule in question, the Commission finds that it is premature to accept the applicant's proposed forecast due to the unknowns and finds that the applicant could file for a deferral later if needed. While the Commission remains open to flexibility, it acknowledges the unpredictability, especially with federal delays already extending over three years. Consistent with past practice, the Commission finds it reasonable to exclude all expenses relating to LDAR in the 2025 and 2026 test year natural gas revenue requirements. Further, if the program gains more certainty, the Commission finds it reasonable for the applicant to include an analysis of offsetting losses in gas supply forecasts noting that the applicant's request for investments in leak detection should logically reduce gas leaks, but no corresponding reduction was reflected in the gas supply forecast.

Commission staff also proposed that due to the uncertainty of the LDAR proposed rule, the Commission could consider deferral accounting treatment. Commission staff proposed that the applicant could file a request for deferral accounting treatment once the costs associated with the LDAR become more certain and those costs meet the deferral criteria. CUB asserted that deferral treatment could result in the 'pancaking' of significant deferred expenses on top of future distribution O&M and instead proposed escrow accounting treatment as an alternative to deferral accounting treatment.

The applicant stated that if the Commission chooses to delay including a specific estimate of these costs in rates, because the estimates are somewhat uncertain, then the Commission should authorize deferral accounting treatment now. In addition, the applicant stated that if the Commission believes that the LDAR rules will not go into effect in the test years—which is not supported by record evidence—then the appropriate mechanism would be to require the applicant to escrow differences in costs related to compliance with the LDAR rules if the applicant's forecast differs from actual expenses in 2025 or 2026.

The Commission finds it is not necessary to address the accounting treatment for future LDAR expenses at this time. However, this does not prevent the applicant from requesting deferral accounting treatment once the costs associated with the LDAR become more certain and if those costs meet the deferral criteria.

Employee Compensation

Full Time Equivalency Adjustment

Commission staff noted the number of regular full-time employees steadily declined between 2016 through 2022 with a slight increase in 2023. Accordingly, the regular FTEs for the applicant were maintained at the April 2024 levels which is in line with both the historic trend as well as a three-year linear trend. The above-described analysis resulted in an overall reduction of 47 FTEs for electric operations and 12 FTEs for natural gas operations; for a total decreased expense amount for the 2025 and 2026 test years of $7.1 million and $7.6 million, respectively. For part-time and seasonal employees, Commission staff used a three-year average to determine FTEs and an appropriate expense level per FTE; this adjustment resulted in a decreased expense amount for the 2025 and 2026 test years of $0.871 million and $1.0 million, respectively.

CUB indicated it opposed increased payroll expenses unless the applicant was able to demonstrate it can hire and retain staff and offered two recommendations if the Commission decided not to adopt Commission staff's FTE adjustments. First CUB proposed that FTEs should only be increased incrementally and suggested that restoring up to 25 percent of the FTEs may be reasonable. Second, CUB recommended that the expense associated with that incremental increase should be subject to escrow accounting for the 2025 and 2026 test years.

The applicant identified that in a tight labor market, its actual employee counts in 2023 and partial 2024 do not reflect the applicant's labor needs in 2025 and 2026, because it continues to struggle to attract, train, and retain employees. In addition, the applicant also disagreed with using a backward-looking three-year average for this category of costs for 2025 and 2026, citing that it understates the applicant's headcount and overtime costs. The applicant also disagreed with CUB's proposal of accepting only an incremental increase to FTEs.

IUOE agreed with the applicant and testified regarding the importance of increasing Union staffing levels and that headcount requirements should be forecasted by looking forward, not back. IUOE argued increasing customer counts, additional workloads related to LDAR and additional infrastructure hardening efforts all support increasing the in-house Union headcount.

The Commission finds it reasonable in this proceeding to reject Commission staff's adjustment to the regular represented FTEs, as those are less susceptible to seasonal fluctuations; and accepts only Commission staff's FTE reduction relating to the part-time, seasonal, and non-represented positions. The Commission finds this to be a balanced approach and consistent with the decision in the applicant's previous rate proceeding in docket 6690-UR-127 (PSC REF#: 455196), in which the Commission did not fully accept FTE adjustments due to labor market challenges. Further, the Commission does not find it necessary to require deferral or escrow accounting treatment for wage and headcount expenses as its decision on FTE adjustments negates the need for such treatment.

Overtime Hours

Commission staff adjusted overtime hours for electric and natural gas operations to reflect an average of overtime hours as well an average cost per hour. This adjustment resulted in a decreased expense amount for the 2025 and 2026 test years of $0.568 million and $0.850 million, respectively. CUB supported Commission staff's proposed payroll adjustment for overtime hours. The applicant disagreed with Commission staff's adjustments and argued that if the applicant cannot add employees and as seasonal work increases, the applicant will also need to rely on more part-time and seasonal employees, overtime, and contractors. The applicant asserted that using a three-year average for this category of costs for 2025 and 2026 understates its headcount and overtime costs.

The Commission finds that the overtime issue is tied into the above FTE decision and because of the Commission's decision on that item, finds the applicant's argument is less persuasive. Therefore, the Commission finds it reasonable to accept Commission staff's payroll adjustment related to overtime hours for the electric and natural gas 2025 and 2026 revenue requirement.

Inflation Rate for Non-Represented Employee Wages

Commission staff proposed an adjustment to the electric and natural gas operations wages for the non-represented, management, and executive employees to hold the wages to the level of inflation for the 2025 and 2026 test years. In instances where collective bargaining agreements expired, inflation was used for the escalation rate. The inflation rates used for the 2025 and 2026 test years were 2.10 percent and 2.50 percent, respectively. This adjustment resulted in a total decreased expense amount for the electric and natural gas operations for the 2025 and 2026 test years of $2.1 million and $1.6 million, respectively.

The applicant disagreed with the inflation rate used by Commission staff. The applicant provided examples of major nationwide surveys, recently ratified union contracts, and other competitors that project salary increases between 3.5 percent to 5.3 percent for 2025. In addition, IUOE agreed with the applicant that the figures used by Commission staff to predict future general wage increases were not reasonable.

The Commission finds based on long standing 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. Further, the Commission finds no record evidence to persuade a deviation from that practice. Therefore, the Commission finds it reasonable and consistent with past practice to use a 2.1 percent and 2.5 percent inflation rate for the wage increase for 2025 and 2026, respectively.

Medical and Dental Expenses

Commission staff removed a portion of the medical and dental expenses associated with Commission staff's head count labor adjustment which resulted in a decrease in revenue requirement of $0.687 million and $0.736 million in 2025 and 2026, respectively, for electric operations; and a decrease of $0.161 million and $0.173 million in 2025 and 2026, respectively, for natural gas operations. CUB supported removing a portion of the medical and dental expenses consistent with its position on FTEs. The applicant asserted the final revenue requirement should include appropriate medical and dental expenses to cover the applicant's entire workforce.

The Commission notes that medical and dental expenses directly tie to its decision on FTEs and as such, it is appropriate to adjust the amount of medical and dental expenses consistent with the FTE adjustment. Therefore, given the Commission only accepted the FTE reductions relating to the part-time, seasonal, and non-represented positions, the Commission also finds it reasonable to only accept Commission staff's adjustment related to the part-time, seasonal, and non-represented positions when calculating medical and dental expense for the applicant's 2025 and 2026 test year electric and natural gas operations revenue requirements.

Incentive Compensation

The applicant included both O&M labor and non-labor incentive compensation in the 2025 and 2026 test years. Commission staff removed all aspects of incentive compensation from the applicant's revenue requirement pending a Commission decision. This adjustment resulted in a decrease to O&M labor for the 2025 and 2026 test years of $6.1 million and $6.3 million, respectively. In addition, this adjustment resulted in a decrease to O&M non-labor for the 2025 and 2026 test years of $6.0 million and $6.2 million, respectively.

Commission staff practice is to exclude incentive plans from the revenue requirement when such plans are based primarily on financial results (e.g., prevailing stock price, earning per share, or achieving a specified net income or return on investment, etc.).

In the Commission's recent Final Decisions for Northern States Power Company-Wisconsin (NSPW) in docket 4220-UR-126, WP&L in docket 6680-UR-124, and Superior Water, Light and Power Company (SWLP) in docket 5820-UR-117 , the Commission found it was reasonable to exclude all short-term incentive plan compensation (STIP) for WP&L and all of the annual incentive plan compensation for NSPW and SWLP from the respective test year revenue requirements as those utilities did not provide sufficient information in the record to demonstrate that the non-financial goals provided customer benefit.

The applicant acknowledged that the Commission has not included incentive compensation in rates in prior cases. However, the applicant also stated that incentive compensation programs are an important aspect of the compensation package for both its represented and unrepresented employees, and therefore represent a legitimate cost of service and that many components of its incentive program provide direct customer benefit. CUB asserted that the information provided by the applicant in this proceeding is not substantially different from the WP&L STIP denied by the Commission in docket 6680-UR-124, so as to warrant a different treatment.

The Commission is not persuaded by the applicant's argument for the inclusion of incentive compensation costs. Similar to previous Commission decisions, where insufficient evidence of customer benefits led to disallowance, the Commission finds the information in this proceeding too high-level to demonstrate direct customer benefits. Therefore, the Commission finds it reasonable and consistent with past Commission practice to exclude all incentive compensation costs from the 2025 and 2026 test year revenue requirements.

Plant in Service and CWIP

Commission staff plant and CWIP adjustments were comprised of multiple components. First, Commission staff adjusted the 2023 balance to reflect year end actuals for plant in service, CWIP, and accumulated depreciation rather than the estimated 2023 year-end balances used by the applicant. Next after isolating discrete projects, Commission staff applied historic budget-to-actual percentages to the remaining 2024, 2025, and 2026 expenditures and plant additions, and applied a three-year average to determine 2024, 2025, and 2026 retirements. Budget-to-actual amounts and retirement averages were calculated using amounts from the most recent years where the utility filed a full rate proceeding; 2015, 2020, and 2023.

Commission staff's adjustments resulted in a $83.9 million reduction to the 2025 total company average electric plant in service, $79.6 million for Wisconsin retail; and a $16.0 million reduction to the average natural gas plant in service. The 2025 test-year average electric CWIP balance increased $0.220 million and the natural gas average CWIP balance increased $11.2 million. For 2026 there is a reduction of $121.5 million to the total company average plant in service for electric, $116.1 million for Wisconsin retail; and a $29.3 million reduction to the 2026 average natural gas plant in service. Additionally, due to the above plant adjustments, the electric 2026 test-year average CWIP balance increased $3.9 million and the natural gas average CWIP balance increased $8.2 million. CUB supported Commission staff's adjustment.

The applicant disagreed with Commission staff's methodology arguing that the budget-to-actual methodology does not always result in a lower than 100 percent factor and that the past performance against a forecasted amount is not indicative of the future. In addition, the applicant stated that Commission staff's budget-to-actual adjustment does not account for planning nuances.

The Commission finds that Commission staff's budget-to-actual approach is a standard methodology and consistent with prior rate proceedings. As such, the Commission does not find sufficient evidence in this instance to deviate from the budget-to-actual approach. Therefore, the Commission finds it reasonable to accept Commission staff's adjustments to the applicant's electric and natural gas plant in service and CWIP for the 2025 and 2026 test years.

Cost Overruns

Final project costs exceeding project estimates is not a new phenomenon, but the frequency and amount of such cost overruns have increased in recent years. In response, the Commission's processes have and will continue to evolve. This evolution can be seen in part, by the differing conditions imposed by the Commission's decisions authorizing construction projects. Historically, the Commission has required notification where project costs may exceed the estimated project costs by more than 10 percent. To better monitor and control project costs, the Commission has more recently imposed conditions setting a cap on project costs and requiring reporting as soon it is known that the cost estimates may be exceeded. The conditions imposed by the Commission have also varied depending upon whether the project is one that the utility is constructing pursuant to Wis. Stat. § 196.49 or § 196.491, or one that the utility may be acquiring from a developer under contract where the contracting parties presumably have a greater degree of control over price when negotiating a purchase, as opposed to undertaking a project directly.

Much of the discussion of cost overruns in this record involve project costs the applicants have stated were the result of "*force majeure*." Typically, *force majeure* events are those types of events that are beyond the knowledge or control of either party. *Shelter Forest Int'l Acquisition, Inc. v. COSCO Shipping (USA) Inc.*, 475 F.Supp.3d 1171, 1186 (D. Or. 2020). Such events, however, do not cover "unexpected difficulties and expense" unless those difficulties are "so extreme that a practical impossibility exists and resulting in a hardship so extreme as to be outside any reasonable contemplation of the parties." *Id.* The 7th Circuit Court of Appeals expounded on this in *Northern Indiana Public Service Co. v. Carbon County Coal Co.*, 799 F.2d 265 (7th Cir. 1986), where the Court observed:

> [a] force majeure clause is not intended to buffer a party against the normal risks of a contract. The normal risk of a fixed price contract is that the market price will change. If it rises, the buyer gains at the expense of the seller (except insofar as escalator provisions give the seller some protection); if it falls, as here, the seller gains at the expense of the buyer. The whole purpose of a fixed price contract is to allocate risks in this way. A force majeure clause interpreted to excuse the buyer from the consequences of the risk he expressly assumed would nullify a central term of the contract.

Id. at 275.

What does or does not constitute *force majeure*, however, depends upon how that term has been defined in the contract and that definition dictates the application, effect and scope of *force majeure*, and the Commission is not at liberty to interpret the contract in a manner which the parties never intended. *Allegiance Hillview, L.P. v. Range Texas Productioin, LLC*, 347 S.W.3d 855 (Tex App. 2011). It is also important to note that the definition can be amended by the contracting parties – making consideration by the Commission of what constitutes *force majeure* a moving target.

In addition to being guided by the conditions imposed by the Commission's authorizations and the contract terms agreed to by the parties, the Commission's review of cost overruns must also examine whether or not the actions of the applicants were reasonable and prudent. The applicants are entitled to earn a reasonable return upon the amount which has been prudently invested, and, in the absence of satisfactory proof to the contrary, it must be presumed that the investment was prudently made. *Waukesha Gas & Elec. Co. v. Railroad Comm.*, 181 Wis. 281, 194 N.W. 846,854-855 (1923). If there is any showing of imprudence on the record, the burden is on the utility to show that it was prudent. *See*, *Central Maine Power Co. v. PUC*, 156 ME 295, 163 A.2d 762, 36 PUR 3d 1, 7 (1954); *United Fuel Gas. Co. v. Railroad Comm*, 278 U.S. 322, 71 L.Ed. 390 at 398 (1928).

As the above illustrates, each project has its own unique set of circumstances that must be considered on a case-by-case basis. Before undertaking the specific review of each of five projects for which the applicants seek to include cost overruns in the 2025 and 2026 test year revenue requirements, the Commission notes the overarching challenges presented by reviewing cost overruns in rate cases after the projects or acquisitions have received Commission approval, and, in some instances, are already in-service. The Commission remains committed to and signals its intent to continue to look for ways to enhance the Commission's review and oversight of project costs – both at the time of project approval and throughout the construction process. What is clear from recent history, is that the construction market has changed. Supply chain and labor market challenges once attributed to the COVID pandemic that were unexpected at that time, are no longer abnormal occurrences and should be anticipated. The applicants' and the Commission's construction practices and procedures must also therefore change in light of these new market conditions.

Paris Solar Generating and Battery Energy Storage System

The applicant's acquisition of the Paris Solar and BESS was approved by the Commission's Final Decision, dated May 25, 2022, in docket 5-BS-254. Order Condition 7 stated:

> If it is discovered that the total project cost, including force majeure costs, may exceed the current estimate ($433 million), the applicants shall promptly notify the Commission as soon as they became aware of the possible change or cost increase.

(PSC REF#: 438529.)

On July 25, 2022, the applicant filed a *force majeure* notification for Paris Solar and BESS citing impacts caused by global supply chain events, labor market events, and module market and supply chain issues, which affected the vendor's major components and materials used in the Paris Solar Farm and BESS project. The applicant stated that it would not proceed with the BESS portion of the project until more definitive pricing was known.

The notice stated that the cost increases were prudently agreed to because those actions would enable the solar portion of the project to proceed without delays and would enable the common facilities to be constructed in an efficient and cost effective manner, and noted that avoiding the solar project delays would result in lower CO2 emissions and net benefits for customers through lower future energy and capacity costs.

On August 4, 2023, the applicant and the co-owners of the Paris Solar and BESS notified the Commission that they were proceeding with the BESS component of the project. The applicant and the co-owners negotiated a new contract price and guaranteed completion date for the BESS component. The applicant stated that the new cost of the BESS was prudently agreed to because it will allow the BESS component of the Paris project to proceed with a guaranteed in-service date and customers will still benefit from lower future energy and capacity costs, as well as decreased CO2 emissions. Furthermore, placing the BESS component in service as anticipated is necessary due to MISO's capacity accreditation methodology. The applicant notified the Commission on September 5, 2023, of additional cost increases that it attributed to implementation of the UFLPA which contributed to restrictions and delayed importation of modules causing increases in a variety of project costs. The Paris solar component is anticipated to be placed in service in December 2024. The BESS component is anticipated to be placed in service in June 2025.

Commission staff removed all revenue requirement impacts related to the cost overruns for the Paris Solar and BESS pending Commission authorization. This adjustment resulted in a decrease in applicant's electric operation by $2.4 million, $2.2 million for Wisconsin retail, and an increase of $ 0.028 in natural gas for the 2025 test year. For the 2026 test year, adjustment resulted in a decrease in applicant's electric operation by $2.9 million, $2.7 million for Wisconsin retail and an increase for natural gas of $0.035 million.

The applicant stated that if it did not accept the cost overruns, there would have been a potential delay of commercial operation of the needed generation resources. The applicant indicated that it and its co-owners aggressively negotiated the change orders, and that the ultimate costs reflect a good-faith, arm's length negotiation and resolution of significant and unexpected problems. The applicant stated it basically had two options: 1) accept the costs and continue with the projects; or 2) litigate the *force majeure* notices and potentially delay commercial operation.

CUB stated the cost should be disallowed because the applicant provided no additional information in the record regarding the cause of the cost overrun nor any steps it took to mitigate the magnitude of the costs. CUB stated that if approved, the Commission should direct that the applicant only be allowed recovery of the depreciation of the plant associated with the cost overruns.

The Commission notes that the Paris Solar and BESS project – which was authorized as a single project – is not yet fully in service. As noted previously, the BESS component is not anticipated to be in service until June 2025. Consistent with the Commission's handling of cost overruns for project not yet in service,[8] the Commission finds it is reasonable to exclude these cost overruns from the revenue requirement until the project's completion, at which point a full review of final costs could be conducted. The Commission prefers to review the reasonableness of the cost overruns and whether to allow recovery of some of all of such costs once the final total costs are known. Therefore, the Commission finds it reasonable for the applicant to defer the cost overruns associated with the Paris Solar and BESS, without any carrying costs, to a future rate proceeding.

In the Commission's Final Decision on Reopening in docket 6690-UR-127 (PSC REF#: 487257), the applicant was ordered to defer the incremental revenue requirement impact of the change to the in-service date for the Paris Solar and BESS project, with carrying costs at the applicant's short-term debt rate, to a future rate proceeding. The applicant identified that the forecasted regulatory liability associated with the deferral at the end of 2024 will be $6.9 million

[8] This determination is consistent with the Commission's initial handling of the project cost overruns for Badger Hollow II and the Ixonia LNG in the Final Decision on Reopening in docket 5-UR-110 (PSC REF#: 487244). *See also*, Final Decision, *Application for Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates*, Docket 6680-UR-124 (Dec. 20, 2023)(PSC REF#: 487254).

and the applicant proposed amortizing that liability over one year (2025) and requested a true up in its next rate proceeding for any difference. The Commission finds it reasonable to amortize the regulatory liability over one year (2025) and to require a true-up in the applicant's next rate proceeding.

Darien Solar and Battery Energy Storage System

The applicant's acquisition of the Darien Solar and BESS was approved by the Commission's Final Decision, dated January 31, 2023, in docket 5-BS-255.[9] Order Condition 6 stated:

> The Commission, consistent with its past practice, shall review in a future rate proceeding the recoverability of costs associated with the acquisition, O&M costs, and revenues associated with the project; provided, however, that in no event shall the recoverability of the acquisition costs exceed the estimated cost for each applicant specified in the application. If it is discovered or identified that the acquisition cost may exceed the estimated cost of $451 million, the applicants shall notify the Commission within 30 days of when it becomes aware of the possible cost increase.

The applicant's acquisition cost was identified as $67.7 million, excluding AFUDC.

On September 27, 2023, and October 18, 2023, the applicant filed *force majeure* notifications for Darien Solar and BESS citing impacts caused by implementation of UFLPA which contributed to restrictions and delayed importation of modules causing increases in a variety of related project costs, including:

- Contract staffing costs for additional mobilization and de-mobilization activities;
- Increased costs for project site and access road maintenance;
- Additional winter storage and snow removal costs; and,

[9] Final Decision, *Joint Application of Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Madison Gas and Electric Company for Approval to Acquire Owner Ownership Interest in Darien Solar Generating and Battery Energy Storage System*, docket 5-BS-255 (Jan. 31, 2023) (PSC REF#: 458394).

- Increase cost of spare modules.

The applicant stated that if it did not accept these costs, there would be a potential delay of commercial operation of the needed generation resources.

As the Commission has not approved the cost overruns, Commission staff removed all revenue requirement impacts related to the cost overruns pending Commission authorization. This adjustment resulted in a decrease in the applicant's electric operation by $0.370 million, $0.342 million for the Wisconsin retail and an increase of $0.003 million for natural gas in the 2025 test year; and a decrease in the applicant's electric operations by $0.362 million, $0.335 million for the Wisconsin retail and an increase for natural gas of $0.005 million for the 2026 test year.

The applicant stated there was no evidence in the record that the cost overruns were not accurate reflections of significant (and previously unknown) shifts in the market and respectfully asked the Commission to include the force majeure costs in its revenue requirement, reflecting applicant's prudent investment into these needed and Commission-approved projects. In addition, the applicant stated that even with added cost overruns the Darien Solar project remains competitive with the levelized costs for more recent solar projects.[10] When faced with force majeure notices from the developers, the applicant stated it had two choices: 1) accept the costs and continue with the projects; or 2) litigate the force majeure notices and potentially delay commercial operation of these needed generation resources.

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[10] The revised project cost estimate of $455.2 million is approximately a 24.5 percent increase over the cost authorized in the Final Decision. The revised estimated cost for the 250 MW solar facility, changes the cost per kW estimate to $1820.8 per kW, which would place this project among the most expensive utility-owned solar projects that the Commission has approved.

CUB stated the costs should be disallowed because the applicant provided no additional information in the record regarding the cause of the cost overruns nor identified any steps it took to mitigate the magnitude of the costs. CUB stated that if approved, the Commission should direct that the applicant only be allowed recovery of the depreciation of the plant associated with the cost overruns.

The Darien Solar and BESS was anticipated to be placed in service in December 2024. That date has changed. As noted previously, pursuant to Wis. Stat. § 227.45, the Commission accepted into the record for this proceeding a copy of the October 23, 2024, quarterly progress report filed with the Commission in docket 5-BS-255 and took official notice of the change of the in-service date for the Darien Solar and BESS. The new anticipated in-service date is now May 2025 for the solar component, with the in-service date for the BESS component under review.

Consistent with the treatment of the Paris Solar and BESS cost overruns as discussed above, the Commission finds it is reasonable to exclude the Darien Solar and BESS cost overruns from the revenue requirement until the project's completion, at which point a full review of final costs could be conducted. Thus, until the project is in service and the final cost overruns are known and can be analyzed by Commission staff, the Commission finds it reasonable for the applicant to defer the cost overruns associated with the Darien Solar and BESS, without any carrying costs, to a future rate proceeding. Additionally, consistent with the Paris Solar and BESS project, the Commission finds it reasonable to require the applicant to defer the incremental revenue requirement impact arising from a change in the in-service date for the Darien Solar and BESS project, with carrying costs at applicant's short-term debt rate, to a future rate proceeding.

Bad Debt Expense

The applicant identified that there were significant increases in bad debt expense related to increases in write-offs starting in 2022 due to the initial unwinding of the arrears balances associated with COVID -19. In addition, the applicant identified that customers have also experienced macroeconomic factors, such as significant inflation and higher gas prices, that have impeded a full recovery. This has attributed to arrearage levels that are still about 8 percent higher than pre-COVID. In addition, the applicant identified that the second factor responsible for the increase in arrears is the write-offs attributed to the LIFT. The LIFT program has shifted from approximately 2,500 active customers at any given time when the program started in 2021 to approximately 3,500 active customers based on 2024 data.

Commission staff stated that based on the lack of historical data for the LIFT program and the increased arrears balances, the Commission could find that the increase in bad debt expense is not unreasonable. Commission staff suggested the Commission may wish to continue monitoring the LIFT program as more historical data is available to determine if there are any trends or additional analysis that could be performed.

In addition, the applicant requested to recover the 2025 and 2026 forecasted bad debt balance over a two-year period (2025 through 2026). CUB recommended that the Commission direct that the LIFT deferral balance be amortized over a three- or four-year period instead of one year. The applicant opposed CUB's proposal, asserting that LIFT participation is expected to continue to grow and the forecasted balance should be recovered over a two-year period.

Based on the lack of historical data for the LIFT program and the increased arrears balances, the Commission finds it reasonable to include the bad debt expense as requested by the applicant the forecasted balance shall be recovered from customers over two years (2025 through 2026).

Columbia Energy Center

In the Commission's Final Decision in docket 6690-UR-127, the Commission included Order Condition 33 that stated, "the applicant shall complete an analysis of alternative recovery scenarios for generating units that will be retired prior to the end of their useful life." (PSC REF#: 455196.) The applicant declined to provide the analysis in the current rate proceeding, citing such analysis would be premature.

Columbia Units 1 and 2, which the applicant partially owns, are scheduled for retirement on May 31, 2026. As of June 1, 2026, the undepreciated book balance for Columbia Units 1 and 2 will be $239 million. The applicant requested Commission approval to transfer the plant's unamortized rate base balance to Account 182.2 (Unrecovered plant and regulatory study costs) of the Commission's USOA and to amortize the amount in Account 182.2 to Account 407 (Amortization of property losses, unrecovered plant and regulatory study costs) over the plant's remaining book life (17 years), with carrying cost set at the applicant's prevailing authorized weighted average cost of capital. Commission staff identified that the Commission could find the applicant's request to be reasonable as the request is consistent with prior Commission decisions related to the retirement generation assets.[11]

[11] Regarding Edgewater Unit 5 in its Final Decision in docket 6680-UR-123 (PSC REF#: 427760), Edgewater Unit 4 in its Final Decisions in docket 6680-AF-2018 (PSC REF#: 351927) and in docket 6680-UR-121

CUB stated it would be appropriate for the Commission to only allow a recovery of (depreciation) but not a recovery on (financing costs or return on investment), any undepreciated balances associated with plant taken out of service upon Columbias retirement as this strikes a more reasonable balance than asking customers to pay for everything including a generous shareholder return.

WIEG recommended the recovery of the remaining net book value of Columbia Units 1 and 2 on a levelized basis over a 25-year amortization period and utilizing securitization financing for at least the $178 million in remaining environmental costs. CUB argued that levelization itself does nothing to reduce the dollars recovered from customers absent a change to the financial parameters (e.g. return) applied to the levelized recovery. Asserting it increases the amount paid by customers, on a nominal dollar basis due to an increase in carrying costs and that extending the levelization period similarly adds to these carrying costs.

The applicant stated that the Commission should guard against reaching hasty conclusions about what it alleged would be "upsetting the ordinary approach to recovery" of utility assets, which is that its full costs, including a reasonable return on those costs, may be recovered from customers. The applicant stated that WP&L, the majority owner of the plant, has not made any commitments, beyond those in docket 6680-AF-107, on whether it will securitize these costs or assume the revenue requirement equivalent of securitization for them, which presumably would not occur until its next rate proceeding at the earliest. Until WP&L definitively identifies when Columbia will no longer use coal as a fuel source, the applicant stated that any such determination for the applicant's recovery of its portion of these costs would be premature. In

(PSCREF#: 355884), and Pulliam Units 5 and 6 and Weston Unit 1 in its Final Decision in docket 6690-UR-123 (PSC REF#: 226374) addition, the applicant stated that CUB made absolutely no showing justifying the proposal for disallowing a return on plant that was prudently acquired, and that has been used and useful in the provision of utility service. Further, the applicant argued that CUB has pointed to no precedent for doing so, and certainly has not identified any precedent for both disallowing a return on retired plant while simultaneously extending and levelizing recovery. The applicant additionally responded to the CUB proposal with legal argument alleging that it would represent an unconstitutional taking.

The Commission expresses disappointment at the applicant's reluctance to engage in an analysis of potential recovery alternatives for Columbia plant. While the Commission understands that it is not the majority owner, that does not mean that the applicant cannot conduct such an analysis as to how its share of the asset is going to be handled on its books. The Commission must also respond to the applicant's suggestion that adopting a non-traditional approach to addressing retired assets, such as the one proposed by CUB, would constitute an unconstitutional taking.[12] There are numerous examples, albeit in the context of settlement agreements or negotiations, where securitization and other innovative solutions to addressing early retirements have been proposed and accepted by the Commission.

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[12] The Takings Clause is found within the Fifth Amendment to the United States Constitution, which states:

> No person shall be held to answer for a capital, or otherwise infamous crime, unless on a presentment or indictment of a Grand Jury, except in cases arising in the land or naval forces, or in the militia, when in actual service in time of War or public danger; nor shall any person be subject for the same offense to be twice put in jeopardy of life or limb; nor shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty, or property, without due process of law; nor shall private property be taken for public use, without just compensation.

The Fifth Amendment is applied to the states via the Fourteenth Amendment.

There is an extensive line of cases which examine the intersection of the Takings Clause with proper utility regulation, most often via the rate setting function of regulatory bodies. The Supreme Court of the United States has observed that the core principle is that "the Constitution protects utilities from being limited to a charge for their property serving the public which is so 'unjust' as to be confiscatory." *Duquense Light Co. v. Barash*, 488 U.S. 299, 307, 109 S.Ct. 609, 615 (1989). Said another way, "[i]f the [authorized] rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments." *Id.* at 308.

The setting of utility rates, however, is a complicated undertaking informed by numerous interrelated decisions, which ultimately come together to determine the overall revenue requirement. The Supreme Court recognized this fact and observed that that,

> The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties. Errors to the detriment of one party may well be canceled out by countervailing errors or allowances in another part of the rate proceeding. The Constitution protects the utility from the net effect of the rate order on its property. Inconsistencies in one aspect of the methodology have no constitutional effect on the utility's property if they are compensated by countervailing factors in some other aspect.

Id. at 314. For this reason, it cannot be said that the Commission's determination on a single issue, in and of itself results in an unconstitutional taking, without knowing and analyzing *all* of the Commission's decisions in the rate case, each of which is necessary to produce the overall revenue requirement. It is the overall net effect of the total revenue requirement which must be so unjust as to be confiscatory before the Constitution is implicated.

In this instance, the Commission finds an alternative recovery mechanism strikes a more appropriate balance in the near term and directs the applicant to conduct a robust analysis of alternatives in its next rate proceeding. The Commission finds a modified approach using a 25-year levelized recovery period with a sunset clause ending December 31, 2026, to be reasonable as this would ensure the treatment is revisited in the applicant's next rate proceeding. Therefore, the Commission finds it reasonable to require the applicant as of June 1, 2026 (one day after date of scheduled retirement) and until December 31, 2026, to recover the applicant's share of any undepreciated balance for Columbia units 1 and 2 using a levelized approach over 25 years as proposed by WIEG, with carrying costs on the undepreciated balance at the applicant's authorized weighted cost of capital. In addition, the Commission finds it reasonable for the applicant to submit additional analysis in its next rate proceeding of alternatives for addressing the remaining undepreciated balance for Columbia units 1 and 2. This analysis is to include an amortization schedule in which the levelized and extend option does not result in additional costs to customers on the nominal basis.

Due to the potential change in the actual retirement date compared to the planned retirement date for Columbia Units 1 and 2, WIEG recommended the Commission include in its decision an order condition requiring the applicant to defer the revenue requirement impact of an earlier retirement date as a regulatory liability. Such an order condition is similar to one the Commission included in its Final Decision in docket 6680-UR-123 for the retirement of Edgewater 5 during the test year. (PSC REF#: 427760.) By including such an order condition in connection with Columbia 1 and 2, ratepayers will be protected should the utility decide to retire the plant prior to May 31, 2026.

The applicant agreed that it is prudent to allow for the possibility of changes in the retirement date, particularly since it is in the position of being a minority owner and that the deferral should be allowed whether the retirement date moves earlier or later. This would be identical to the way the Commission treated potential changes to the retirement date for WEPCO's Oak Creek Power Plant Units 5 and 6 in docket 5-UR-110. (PSC REF#: 455451.) Should the Commission wish to consider carrying costs, Commission staff recommended the short-term debt rate.

Consistent with the Commission's past practice when there is uncertainty in the retirement date of a plant, the Commission finds it reasonable to require the applicant to defer the difference between the estimated and actual revenue requirement impact associated with retiring Columbia units 1 and 2 resulting from changes in the units' May 31, 2026, retirement date.

Weston Power Plant

In this rate proceeding, the applicant sought approval to include in rates the costs to operate and maintain Weston Units 3 and 4, including sustaining capital expenditures and O&M costs incurred during the test years. The applicant also requested approval of its fuel cost plan for 2025, which included costs to test natural gas co-firing at Weston Unit 4 as well as the ongoing fuel costs to operate Weston Units 3 and 4.

Sierra Club offered multiple findings and recommendations relating to Weston Units 3 and 4 including early retirement, directing the applicant to conduct retirement planning to identify replacement resources for Weston Units 3 and 4, and requiring more robust long-term planning in future rate applications. Weston Units 3 and 4 have a total undepreciated balance of $767 million, including $285 million for the ReACT pollution control system at Weston Unit 3. The applicant stated that the Weston units provide customers capacity, reliability, and resiliency benefits and opposed Sierra Club's suggestions.

The Commission is not persuaded by Sierra Club's arguments. There is nothing in the record to rebut the presumption that the applicant is prudently operating the Weston units. Therefore, the Commission finds it reasonable to not require the applicant to conduct retirement planning to identify replacement resources for Weston Units 3 and 4.

Distribution-connected Utility-Owned Solar Generation and BESS Projects and DRER Projects

The applicant requested authorization to amortize the acquisition costs related to distribution-connected utility-owned solar generation and BESS projects and DRER projects beneath the CA threshold beginning in 2025 for 25 years, over the estimated life of those facilities. Commission staff identified that the Commission could find the applicant's request reasonable as it would align the amortization of the acquisition costs with the life of the asset.

The Commission concurs and finds it reasonable to authorize the amortization of the acquisition costs beginning in 2025 for 25 years since it would align the amortization of the acquisition costs with the life of the underlying assets.

Inflation Reduction Act

On August 16, 2022, the IRA was signed into law. In the Commission's Final Decision in docket 6690-UR-127 (PSC REF#: 455196), the Commission ordered the applicant to defer, with carrying costs at the applicant's short-term debt rate, any impacts of the Inflation Reduction Act. The applicant requested the Commission continue to authorize the applicant to defer the difference between tax credit projected, net of the sale discount, and those that are actually earned. The Commission finds it reasonable for the applicant to continue to defer, with carrying costs at the applicant's short-term debt rate, any impacts of the IRA which are currently unknown or unable to be estimated to include in the applicant's revenue requirement. Such a deferral ensures that both the applicant and customers are kept whole related to these tax benefits.

U.S. Internal Revenue Service (IRS) Revenue Procedure 2023-15

In April 2023, the IRS issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether certain expenditures to maintain, repair, replace or improve natural gas transmission and distribution property must be capitalized as improvements under the Internal Revenue Code for tax purposes. The applicant stated that it intends to adopt the new safe harbor method which would impact the applicant's deferred tax liabilities. At this time the precise impact on the applicant's deferred taxes has not been calculated and is not reflected in the 2025 or 2026 test year revenue requirement.

Commission staff proposed requiring the applicant to defer, with or without carrying costs, any impacts of the IRS Revenue Procedure 2023-15 to a future rate proceeding as a deferral would capture any cost increases or savings and would be consistent with the treatment authorized by the Commission related to the IRA discussed above. Should the Commission wish to consider carrying costs, Commission staff recommended the short-term debt rate.

The Commission finds it reasonable for the applicant to defer, with carrying costs at the short-term debt rate, any impacts of the IRS Revenue Procedure 2023-15 to a future rate proceeding. A deferral is appropriate because the impact on the applicant's deferred taxes is currently unknown or unable to be estimated to include in the applicant's revenue requirement. Such a deferral ensures that both the applicant and customers are kept whole.

U.S. Department of Energy (DOE) Loan or Grant Funds

The applicant identified that though its parent company, WEC Energy Group, that the applicant along with WEPCO are applying for DOE loans or grants, however, no amounts were in the applicant's 2025 or 2026 revenue requirement as no amounts have been awarded yet. The applicant proposed that if it is successful in obtaining either, it would plan to defer the net 2025 and 2026 impact until the next full rate proceeding. Commission staff stated the Commission could find this request reasonable and suggested requiring the applicant to defer, with or without carrying costs at the applicant's short term debt rate, the net impact of any loans or grant funds received to be addressed at the applicant's next full rate proceeding.

The Commission finds it reasonable for the applicant to defer, with carrying costs, at the applicant's short-term debt rate, the net impact of any loans or grant funds received to be addressed in the applicant's next full rate proceeding. A deferral is appropriate because it is currently unknown whether or not the applicant will be successful in securing any DOE loans or grants. Such a deferral ensures that both the applicant and customers are kept whole should any grant or loan be received in the future.

Bring Your Own Device

The applicant requested deferral accounting treatment for the BYOD pilot program. Commission staff did not have concerns with this request. The components of that program are discussed later in this Final Decision. The Commission finds the applicant's request for deferral accounting treatment related to the BYOD pilot program to be reasonable based on startup costs being unusual, infrequently recurring, and currently unknown or unable to be estimated to include in the applicant's revenue requirement.

Conservation

The applicant proposed electric and natural gas CSC activities for inclusion in its conservation budgets in this proceeding. In its Order in docket 5-BU-102 dated July 13, 2012, the Commission provided guidance regarding appropriate CSC activities. The Commission defined CSC activities as "those activities and services that a utility provides its customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus on Energy and federal and state energy programs." Based on this guidance, Commission staff reviewed the applicant's 2025 and 2026 proposed CSC activities and found them to be consistent with the Commission's definition of appropriate CSC activities. Based upon this record, the Commission finds the applicant's proposed CSC activities are appropriate for inclusion in the conservation budget.

The applicant proposed a total 2025 conservation budget of $21.6 million with $15.4 million allocated to electric operations and $6.2 million allocated to natural gas operations. Of the $15.4 million for electric operations, $13.1 million was for the applicant's required Focus on Energy (Focus) contribution and $2.3 million was for its CSC activities, including voluntary programs. Of the $6.2 million allocated for natural gas operations, $4.6 million was for the applicant's required Focus contribution and $1.6 million was for CSC activities, including voluntary programs.

The applicant proposed a total 2026 conservation budget of $23.0 million with $16.3 million allocated to electric operations and $6.7 million allocated to natural gas operations. Of the $16.3 million for electric operations, $13.9 million was for the applicant's required Focus contribution and $2.4 million was for its CSC activities, including voluntary programs. Of the $6.7 million allocated for natural gas operations, $5.0 million was for the applicant's required Focus contribution and $1.7 million was for CSC activities, including voluntary programs.

The Commission finds a reasonable level of expensed conservation costs recoverable in rates for the 2025 test year is $15.4 million for electric operations and $6.2 million for natural gas operations. The Commission finds a reasonable level of expensed conservation costs recoverable in rates for the 2026 test year is $16.3 million for electric operations and $6.7 million for natural gas operations. It is reasonable to direct the applicant to record the 2025 and 2026 expense amounts annually until they are superseded by a Commission order authorizing new conservation escrow accruals.

Amortization Periods for all other Deferrals and Escrows

The applicant sought Commission approval for continued deferral and escrow accounting treatment for several deferrals and escrows over a two-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 two-year period, 2025 through 2026, as identified in Appendix G.

Regulatory Amortizations

The Commission finds the regulatory asset and liability amortizations as reflected in Appendix G to be reasonable. The annual amortization expense amounts identified shall be recorded for 2025 and 2026, or until the Commission authorizes a different amortization amount to be recorded.

Depreciation Study

Based on past Commission practice, large investor-owned utilities had been completing depreciation studies every five years to update net book values and depreciation rates to reflect the current condition of older generation assets and to incorporate new generating assets recently put into service. In docket 6690-ER-104, Commission staff had identified that the applicant had not completed a depreciation study since 2011 and the Commission required the applicant to file a depreciation study by June 1, 2021. (PSC REF#: 401904.) On June 30, 2021, the applicant filed a depreciation study in docket 6690-DU-105 with the Commission requesting that the Commission certify depreciation rates for electric, natural gas, and common utility assets. The Commission issued its Final Decision in docket 6690-DU-105 on December 6, 2021, approving the proposed depreciation rates effective as of January 1, 2021. (PSC REF#: 426885.) In this proceeding, Commission staff recommended the Commission consider setting a date the applicant should file a new depreciation study for the Commission's approval.

The Commission finds it reasonable, in line with past Commission practice, to require the applicant to file a depreciation study in order to update net book values and depreciation rates, reflecting the status of older assets and incorporating new ones. Therefore, the Commission finds it reasonable to require the applicant to file a depreciation study for the Commission's approval no later than December 20, 2027.

Rounding Methodology

In Commission staff's revenue requirement, Commission staff consistently rounded to two decimal places for percentages, or four decimal places for numbers, in order to have consistent rounding calculations in order to have consistent rounding calculations. Another way to say this would be that percentages would be rounded to XX.XX percent. This is consistent with the Commission's decision in MGE's rate proceeding in docket 3270 UR-123 where in it is Final Decision (PSC REF#: 402247), the Commission found it reasonable to require the MGE to apply this consistent rounding in calculating revenue requirement deficiencies.

The Commission recognizes the need to establish a consistent rounding methodology prior to the start of rate proceedings in order to avoid changing standards mid-process. To be consistent across utilities, the Commission finds it reasonable to require the applicant and Commission staff, starting in its next rate proceeding and going forward, to calculate revenue deficiencies by consistently rounding to four decimal places when represented as a number and two decimal places when shown as a percentage.

Presentation of Revenue Deficiency in the Second Year of a Two-Year Test Year

The applicant identified that the 2026 test year impacts are shown as incremental or based on the applicant's requested revenue requirement and deficiency for the 2025 test year. Given the first year in a two-year test year rate proceeding has not been authorized, Commission staff has historically presented the revenue requirement and resulting deficiency based on presently authorized rates for both test years. In addition, historically the Commission has based its decisions regarding revenue requirement impacts based on using present authorized rates. As such, in this proceeding, Commission staff's proposed revenue requirement, revenue allocation, and rate design for the 2025 and 2026 test year revenue requirements were shown using 2024 authorized rates as the basis for the present rates presentation. Commission staff suggested the Commission consider identifying its preferred presentation for the second year in a two-year test year rate proceeding at either presently authorized rates consistent with Commission staff's presentation or as an incremental change to the calculated revenue deficiency for the first year as shown by the applicant.

The applicant stated that if the Commission is inclined to provide any specific direction as part of this proceeding, it should be clear that guidance is specific to Commission staff's presentation and should not dictate how utilities describe their own requested rate changes for the second year of a two-year rate proceeding. CUB stated the Commission should direct that both presentations be used, and consistently by both utility applicant and Commission staff.

The Commission notes how differing numbers in revenue allocation tables can create confusion and hinder clear comparisons. The Commission further notes that presenting the second year of a two-year test period with actual authorized rates, rather than projected rates, would provide a more accurate basis for decision-making. Given that the Commission has historically based its decisions regarding revenue requirement impacts based on using presently authorized rates, the Commission finds it reasonable to require the applicant to present the second year of a two-year test year rate proceeding as a change from presently authorized rates.

Other Uncontested Adjustments to Revenue Requirement

There were a number of other Commission staff adjustments to the applicant's filed electric and natural gas revenue requirements that were not contested by any party. The Commission finds those adjustments to be reasonable.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other adjustments not contested by the parties to arrive at the filed operating income statement are just and reasonable. Accordingly, per Commission decision, the electric and natural gas operation 2025 and 2026 test year operating income statements at present rates, which were updated, and which are considered reasonable for purposes of determination revenue requirements in this proceeding, are as follows:

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<u>2025 Test Year:</u>

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Revenues:			
Electric Sales Revenues	$ 1,294,065	$ 1,231,573	$ 398,206
Opportunity Sales	32,874	30,002	-
Other Operating Revenues	14,175	7,180	7,067
Total Operating Revenues	$ 1,341,114	$ 1,268,755	$ 405,273
O&M Expense:			
Fuel & Purchased Power	$ 362,424	$ 332,633	$ -
Purchased Gas	-	-	221,262
Other Production	89,216	82,205	-
Manufactured Gas Production	-	-	9,159
Gas Supply	-	-	1,875
Gas Storage	-	-	15,641
Transmission	183,815	176,940	(2,014)
Distribution	43,100	43,100	20,529
Customer Accounts	22,013	22,013	6,934
Customer Service	20,508	20,430	9,339
Sales Expense	-	-	-
Administrative & General	38,553	36,643	11,448
Total O&M Expense	$ 759,629	$ 713,964	$ 294,173
Depreciation, Decommissioning, & Amortizations	$ 219,531	$ 209,239	$ 37,355
Regulatory Amortizations	24,107	22,501	2,603
Taxes Other Than Income Taxes	50,038	47,729	4,942
Income Taxes	(14,991)	(13,631)	5,218
Deferred Income Taxes	39,581	37,878	4,644
Investment Tax Credits	3,010	2,881	(23)
Total Operating Expense	$ 1,080,905	$ 1,020,561	$ 348,912
Net Operating Income	$ 260,209	$ 248,194	$ 56,361

2026 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Revenues:			
Electric Sales Revenues	$ 1,311,979	$ 1,247,262	$ 417,332
Opportunity Sales	30,724	28,057	-
Other Operating Revenues	14,207	7,372	1,426
Total Operating Revenues	$ 1,356,910	$ 1,282,690	$ 418,758
O&M Expense:			
Fuel & Purchased Power	$ 394,929	$ 363,021	$ -
Purchased Gas	-	-	238,186
Other Production	79,042	72,888	-
Manufactured Gas Production	-	-	9,159
Gas Supply	-	-	1,928
Gas Storage	-	-	15,592
Transmission	212,109	205,383	(2,014)
Distribution	44,584	44,584	21,184
Customer Accounts	22,288	22,288	7,087
Customer Service	20,677	20,599	9,421
Sales Expense	-	-	-
Administrative & General	37,032	35,219	11,495
Total O&M Expense	$ 810,661	$ 763,982	$ 312,038
Depreciation, Decommissioning, & Amortizations	$ 223,660	$ 213,445	$ 39,951
Regulatory Amortizations	33,161	30,972	2,603
Taxes Other Than Income Taxes	52,001	50,071	5,542
Income Taxes	(38,220)	(36,431)	2,409
Deferred Income Taxes	41,904	40,254	4,795
Investment Tax Credits	(2,961)	(2,838)	(23)
Total Operating Expense	$ 1,120,206	$ 1,059,455	$ 367,315
Net Operating Income	$ 236,704	$ 223,235	$ 51,443

Summary of Average Net Investment Rate Base

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments reflected in the electric and natural gas average net investment rate bases are appropriate. Accordingly, the electric and natural gas 2025 and 2026 test year average net investment rate base, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2025 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Plant in Service	$ 6,703,865	$ 6,418,978	$ 1,457,029
Accumulated Depreciation	(2,046,227)	(1,943,340)	(405,196)
Net Plant	$ 4,657,638	$ 4,475,638	$ 1,051,832
Fuel Inventory	53,628	48,874	21,286
Materials and Supplies Inventory	64,832	61,573	10,359
Deferred Taxes	(962,118)	(922,966)	(223,465)
Customer Advances	(25,167)	(25,167)	(3,863)
Average Net Investment Rate Base	$ 3,788,813	$ 3,637,952	$ 856,149

2026 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Plant in Service	$ 6,897,594	$ 6,614,121	$ 1,544,163
Accumulated Depreciation	(2,061,023)	(1,960,343)	(433,810)
Net Plant	$ 4,836,571	$ 4,653,778	$ 1,110,354
Fuel Inventory	38,963	35,539	22,853
Materials and Supplies Inventory	64,817	61,590	10,359
Deferred Taxes	(684,977)	(946,199)	(232,444)
Customer Advances	(25,167)	(25,167)	(3,863)
Average Net Investment Rate Base	$ 3,930,208	$ 3,779,541	$ 907,259

Capital Structure

In making findings related to cost of capital and capital structure in this proceeding, the Commission must consider just and reasonable rates, the applicant's financial flexibility and creditworthiness, and its ability to attract new capital, among other principles. As a public utility, the applicant's financial strength and ability to attract capital at a reasonable cost is integral to providing a safe and reliable service. A weak financial position would increase the cost of debt and equity, which in turn would ultimately increase the overall revenue requirement borne by customers. The following table reflects the Commission's decision in this proceeding regarding the applicant's regulatory capital structure and cost of capital.

2025	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$2,942,423	54.39%	9.80%	5.33%
Long-Term Debt	$2,305,769	42.62%	4.43%	1.89%
Short-Term Debt	$161,302	2.98%	4.72%	0.14%
Total Utility Capital	$5,409,494	100.00%		7.36%

2026	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$3,336,020	54.17%	9.80%	5.31%
Long-Term Debt	$2,636,538	42.82%	4.64%	1.98%
Short-Term Debt	$185,489	3.01%	3.98%	0.12%
Total Utility Capital	$6,158,132	100.00%		7.41%

As seen in the tables above, a reasonable weighted average cost of capital is 7.36 percent for 2025 and 7.41 percent for 2026. It generates an economic cost of capital of 9.36 percent for 2025 and 9.40 percent for 2026. The applicant's pre-tax interest coverage ratios are 4.61 times in 2025 and 4.45 times in 2026.

Assessing the reasonableness of the applicant's capital structure depends upon three important principles. First, capital structure decisions must be based on the applicant's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for the applicant and the Commission to allow proper utility investment now and in the future. Third, it should support a dividend policy comparable to peer utility dividend practices as long as the applicant's common equity ratio does not decline below the approved target level.

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs if customers are to be protected. The identification of utility needs goes beyond foreseeable needs, and the applicant must have flexibility to finance both foreseen and unforeseen capital requirements.

The Commission's determination of an appropriate capital structure and cost of capital are interrelated, and in making such determinations the Commission must strike an appropriate balance between the needs of the applicant and those of its customers. The applicant, like other Wisconsin investor-owned utilities (IOUs), is making significant, capital-intensive investments to transition its generation fleet and to maintain a reliable infrastructure for customers. The financial integrity of the utility is an important factor in this transition so that it can attract the capital it needs. To date, the strong financial health of the applicant has resulted in its ability to make these significant investments. While these investments are necessary, the Commission must also balance the utility's financial health with the needs of its customers and the utility's obligation to serve customers at just and reasonable rates. The application in this proceeding included a request for a significant rate increase. 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 has broad discretion and authority to ensure that rates are just and reasonable. In the exercise of this authority, the Commission must establish a capital structure and cost of capital that strike an appropriate balance and is not bound to any single regulatory formula. The Commission is permitted to make pragmatic adjustments called for by particular circumstances, and to consider fundamental ratemaking principles such as gradualism. The Commission must make these decisions based upon the totality of the record before it.

Common Equity Ratio

In this proceeding, the applicant filed the financial capital structure requesting an increased common equity ratio of 53.50 percent, which represents an increase of 50 basis points over the approved financial capital structure in docket 6690-UR-127 (PSC REF#: 455196) of 53.00 percent. In conjunction with its determination on ROE as discussed below, the Commission finds that a 53.00 percent common equity ratio, measured on a financial basis, is reasonable. The 53.00 percent common equity ratio represents a continuation of the 53.00 percent common equity ratio authorized in the applicant's prior rate proceeding, docket 6690-UR-127.

To support the request for an increased equity layer, the applicant pointed to increases in borrowing costs over the last two years, and a large renewable energy capital plan that have placed upward pressure on the applicant's service rates while simultaneously decreasing the applicant's credit outlook. Conversely, CUB pointed out the potentially adverse rate payer impacts from allowing the applicant to increase their financial equity layer by an additional 50-basis points. The Commission is not persuaded that there is a sufficient basis for an increase or decrease of applicant's equity ratio. The Commission finds no compelling evidence demonstrating that a 50-basis point increase in financial equity is necessary to finance the applicant's capital needs. Maintaining a financial common equity ratio of 53.00 percent saves the applicant's customers approximately $1.735 million in 2025 and $1.96 million in 2026 compared to the equity layer increase proposed in the application. The Commission finds it reasonable to maintain the applicant's financial equity layer at 53.00 percent for both test years.

Off-Balance Sheet Obligations (OBO)

Off-balance-sheet financial obligations such as power purchase agreements and operating leases are viewed within the financial community as debt equivalents, which affect the borrowing power of the utility. Recognizing that off-balance-sheet obligations (OBO) affect the financial risks and credit ratings of the utility, the Commission includes imputed debt associated with OBOs in calculating the financial capital structure.[13] The imputed debt results in additional costs to ratepayers, because additional common equity is included in the regulatory capital structure to maintain the utility's target equity level from a credit perspective. If common equity is not added to restore the capitalization to its prior proportions, the cost of capital will be unaffected, but the financial leverage will increase and have a negative impact on the credit ratings of the utility. However, if additional common equity is added to restore the financial capital structure ratios, the financial leverage and credit ratings of the utility will remain the same and the cost of capital is increased.

In calculating capital structure, on a financial basis, the Commission has imputed debt associated with obligations not reported on balance sheets. Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate debt equivalent is necessary for the Commission to make an independent judgment regarding the applicant's

[13] Imputing debt for off-balance-sheet obligations is not a common practice of other state utility commissions. The Commission is not obligated to adopt the risk assessment of an outside rating agency and will independently examine off balance sheet obligations, based on its assessment of risk.

financial capital structure. This information is most readily available from the applicant and shall be provided as part of its next rate proceeding or rate settlement proceeding. The information shall include, at a minimum, all of the following information:

1. The minimum annual lease and Purchase Power Agreement (PPA) obligations.

2. The method of calculation along with the calculated amount of the debt equivalent.

3. Supporting documentation, including all reports, correspondence, and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent to the extent available, and publicly available documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds it reasonable to impute $160.7 million of debt equivalence for OBO in 2025 and $154.7 million of debt equivalence for 2026.

Incorporating the debt equivalences for OBO and other Commission determinations, the applicant's financial capital structure for 2025 will consist of 53.00 percent common equity, 41.24 percent long-term debt, 2.88 percent short-term debt, and 2.87 percent debt equivalence for OBO. For 2026, the applicant's financial capital structure will consist of 53.00 percent common equity, 41.63 percent long-term debt, 2.93 percent short-term debt, and 2.44 percent debt equivalence for OBO.

Dividend Restrictions

The Commission recognizes the need to protect customers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. It is reasonable that the applicant's dividend restriction shall match the dividend restrictions of the other Wisconsin jurisdictional operating utilities within the WEC holding company. The applicant shall not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 53.00 percent. The applicant shall not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual common equity ratio, on a financial basis, below the forecasted level of 53.00 percent.

Cost of Capital

Debt Cost Rates

Debt cost rates allow for the inclusion in revenue requirement for the recovery of an approximation of the costs the utility will pay for interest (and transactional costs as applicable) on long-term and short-term debt. Debt issuances and cost rates are forecasted along with interrelated capital parameters (e.g., capital budgeting, inflation) and may become asynchronous due to a variety of regulatory and exogenous factors. For example, forecasts made at the time of a utility's rate application with a regulatory Commission may differ from actual changes in interest rates that occur while the utility's Commission authorized rates are in effect.

Long-Term Debt

The Commission considered competing proposal from the applicant and Commission staff regarding the applicant's forecasted embedded cost of long-term debt in the test years. The applicant relied on a series of historical treasury and credit spreads when proposing their forecast, while Commission staff utilized a consensus forecast from the *Blue Chip Financial Forecasts* monthly publication, adjusted for the applicant's credit rating, for their proposal.

The Commission is persuaded by Commission staff's perspective and finds it reasonable to reduce the applicant's forecast for long-term debt to be issued in the test year by 75 basis points. Therefore, a reasonable estimate for the applicant's embedded cost of long-term debt is 4.43 percent on $2,305.8 million for 2025 and 4.64 percent on $2,636.5 million for 2026. However, the Commission declines to further reduce the applicant's forecast based on recent news of interest rate reductions by the Federal Reserve.

In this docket Commission staff reviewed the previous two rate proceedings filed by the applicant to determine whether the applicant had been accurately forecasting long term debt issuances. Commission staff noted that not all of the forecasted long-term debt issuances have been issued by the applicant. Commission staff recommended that the Commission consider a new order condition that would require the applicant to defer the incremental revenue requirement impact of any forecasted costs associated with the issuance of long-term debt that are not issued in the forecasted test year(s), to be returned to customers in its next rate proceeding. Commission staff recommended that this amount include carrying costs equal to the short-term debt rate. CUB agreed with Commission staff's proposal but recommended the carrying costs be set equal to Weighted Average Cost of Capital (WACC).

The Commission finds that Commission staff's proposal, and its potential implications, is not fully enough developed in the record and therefore does not accept Commission staff's proposal at this time. Instead the Commission finds it reasonable to require additional supporting information from the applicant, Commission staff, and intervenors regarding this proposal as a first step.

While considering the applicant's forecasting and issuing behavior for long-term debt, the Commission believes that additional information from the applicant is needed regarding any unintended consequences of Commission staff's proposed order condition to defer the applicant's rate collection for embedded debt financing costs associated with long-term debt that is forecasted, but not issued, in the test year for which it is forecasted. In the next rate proceeding the Commission will review this information before further considering Commission staff's proposal. Therefore, the Commission finds it is reasonable for the applicant, in its next rate proceeding, to provide additional supporting information regarding the costs associated with the issuance of long-term debt forecasted but not issued in the test-years, the funds collected from rate payers associated with it, and Commission staff's proposal to defer the incremental impact associated with debt that is forecasted but not issued, to be returned to customers.

Short-Term Debt

The applicant's filing in this proceeding forecasted a short-term debt cost rate of 4.67 percent on $154.9 million in 2025 and a cost rate of 3.99 percent on $172.4 million in 2026. Commission staff estimated short-term cost rates of 4.72 percent and 3.98 percent in 2025 and 2026, respectively.

The Commission finds a reasonable estimate of the applicant's average cost of short-term debt of 4.72 percent on $161.3 million for 2025 and 3.98 percent on $185.6 million for 2026.

Return on Common Equity

A principal factor used to determine the appropriate ROE is the investors' required return. Authorized returns of less than the investors' required return would fail to 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 the necessary level. Such 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 needs of investors with the needs of consumers, with due considerations to economic and financial conditions, along with public policy considerations.

The applicant, Commission staff, and multiple intervenors provided recommendations for the applicant's ROE in this docket. The applicant argued in favor of increasing its currently authorized ROE from 9.80 percent to 10.00 percent. CUB argued for a 9.30 percent ROE. Walmart argued that an ROE of 10.00 percent and 9.80 percent, respectively, was too high but did not provide a specific recommendation. Commission staff presented a range from 8.64 percent to 10.09 percent.

The Commission considered and weighed the evidence in this proceeding, which included national trends for ROEs for regulated electric and natural gas utilities, as well as the models used to estimate ROE. The Commission has traditionally made gradual, rather than dramatic, adjustments to ROE and considers both the needs of the shareholders and customers when making decisions on ROE. The Commission concludes, in light of the interrelated determinations made in this proceeding that maintaining an authorized return on common equity of 9.80 percent strikes a reasonable balance between the needs of investors with the needs of customers and considers gradualism in the broader context of this proceeding.

Earnings Sharing Mechanism (ESM)

The Commission may use a variety of tools, including earning sharing mechanisms (ESM), to ensure that the utility has sufficient capital and return on investment, while protecting customers from excessive utility profits. ESMs have been employed by the Commission in past proceedings as a means to balance the interests of the utility, its investors, and its customers. The applicant and other IOUs have voluntarily offered to have such mechanisms in place. The applicant has had an ESM since 2018, the applicant has an ESM. (PSC REF#: 330748,) Under the ESM currently in place from docket 6690-UR-127, the applicant retains the first 15 basis points if earnings above the authorized rate of ROE. The applicant and its customers split the next 60 basis points of earnings and customers will receive a full refund of all earnings above 75 basis points. Such mechanisms, which are in place for many other Wisconsin utilities, protect customers from paying excessive rates that would be unreasonable, while still providing shareholders the opportunity to earn a reasonable return on their investment. [14]

No party opposed continuation of the ESM. As a result, the Commission finds that it is reasonable for the applicant's ESM, as approved in docket 6690-UR-127, to remain in place until the applicant's next full rate proceeding. In determining earnings subject to the ESM, it is reasonable to measure the ROE on a Fuel Rules basis under Wis. Admin. Code ch. PSC 116. The ESM provides a balance that allows investors to benefit from an earned ROE that is above

[14] Final Decision, *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, Docket 4220-UR-125 (Wis. PSC Dec. 20, 2021) (PSC REF#: 427625); Final Decision, *Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates*, Docket 6680-UR-123 (Wis. PSC Dec. 22, 2021) (PSC REF#: 427760); Final Decision, *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas and Steam Rates,* Docket 5-UR-109 (Wis. PSC Dec. 19. 2019) (PSC REF#: 381305); Final Decision, *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Approval of Certain Accounting Treatment*, Docket 5-AF-107 (Wis. PSC Sept. 22, 2021) (PSC REF#: 421294).

the authorized 9.80 percent while protecting customers from bearing the cost of excessive overearning.

Rate of Return on Rate Base

The composite cost of capital must be translated into a rate of return that can 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 CWIP to capital applicable primarily to utility operations plus deferred investment tax credits for the 2025 and 2026 test years is 94.15 percent and 93.68 percent, respectively. These estimates reflect all appropriate Commission adjustments and are reasonable and just for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

2025 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Cost of Capital	7.36%	7.36%	7.36%
Ratio of Average Percent of Utility Investment Rate Base to Capital Applicable Primarily to Utility Operations	94.15%	94.15%	94.15%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Net Investment Rate Base	7.82%	7.82%	7.82%
Total Average CWIP Balances (000's)	454,781	454,781	19,976
Percent of CWIP Receiving Current Return	11.31%	11.31%	18.0%
Amount of CWIP Receiving Current Return (000's)	51,436	51,436	3,592
Current Earnings on CWIP Receiving Current Return at the Adjusted Cost of Capital	4,022	4,022	281
Average Net Investment Rate Base (000's)	3,788,813	3,637,952	856,149
Adjustment to Required Return to Provide a Return on CWIP	0.11%	0.11%	0.03%
Earnings on Regulatory Items at Specified Rate	-	-	-
Regulatory Items at Specified Rate	0.00%	0.00%	0.00%
Adjusted Required Return on Net Investment Rate Base	7.93%	7.93%	7.85%

<u>2026 Test Year:</u>

	Electric Total Co (000s)	Electric WI Jur (000s)	Natural Gas (000's)
Cost of Capital	7.41%	7.41%	7.41%
Ratio of Average Percent of Utility Investment Rate Base to Capital Applicable Primarily to Utility Operations	93.68%	93.68%	93.68%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Net Investment Rate Base	7.91%	7.91%	7.91%
Total Average CWIP Balances (000's)	887,538	887,538	68,012
Percent of CWIP Receiving Current Return	6.01%	6.01%	5.80%
Amount of CWIP Receiving Current Return (000's)	53,306	53,306	3,946
Current Earnings on CWIP Receiving Current Return at the Adjusted Cost of Capital	4,217	4,217	312
Average Net Investment Rate Base (000's)	3,930,208	3,779,541	907,259
Adjustment to Required Return to Provide a Return on CWIP	0.11%	0.11%	0.03%
Earnings on Regulatory Items at Specified Rate	-	-	-
Regulatory Items at Specified Rate	0.00%	0.00%	0.00%
Adjusted Required Return on Net Investment Rate Base	8.02%	8.02%	7.95%

Calculation of Deficiencies

On the basis of the findings in this Final Decision, a $55.1 million and $85.1 million increase in Wisconsin retail electric utility revenues are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively. For natural gas operations, a $14.9 million and $28.4 million increase in natural gas utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively, in this proceeding. These increases are computed as follows:

2025 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Adjusted Net Operating Income at Present Rates (000's)	$ 260,209	$ 248,194	$ 56,361
Average Net Investment Rate Base (000's)	3,788,813	3,637,952	856,149
Return on Average Net Investment Rate Base at Present Rates	6.87%	6.82%	6.58%
Required Return on Average Net Investment Rate Base	7.93%	7.93%	7.85%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.06%	1.10%	1.27%
Earnings Deficiency on Average Net Investment Rate Base (000's)	40,059	40,118	10,862
Tax Gross-up Factor	1.3744	1.3744	1.3744
Revised Revenue Deficiency (000's)	$ 55,058	$ 55,138	$ 14,929
Required Percentage Rate Increase	4.25%	4.48%	3.75%

2026 Test Year:

	Electric Total Co (000's)	Electric WI Jur (000's)	Natural Gas (000's)
Adjusted Net Operating Income at Present Rates (000's)	$ 236,704	$ 223,235	$ 51,443
Average Net Investment Rate Base (000's)	3,930,208	3,779,541	907,259
Return on Average Net Investment Rate Base at Present Rates	6.02%	5.91%	6.57%
Required Return on Average Net Investment Rate Base	8.02%	8.02%	7.95%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	2.00%	2.11%	2.28%
Earnings Deficiency on Average Net Investment Rate Base (000's)	78,525	79,909	20,664
Tax Gross-up Factor	1.3744	1.3744	1.3744
Revised Revenue Deficiency (000's)	107,924	109,826	28,401
	(27,115)	(24,732)	-
Adjusted Revenue Deficiency (000's)	$ 80,809	$ 85,095	$ 28,401
Required Percentage Rate Increase	6.16%	6.82%	6.81%

Electric Cost of Service, Revenue Allocation and Rates

2025 and 2026 Electric Cost of Service

The applicant, intervenors, and Commission staff provided testimony regarding electric cost of service and the appropriate allocation methods for allocating the plant and expenses that make up the applicant's revenue requirement for the 2025 and 2026 test years. The applicant proposed a COSS model that uses the applicant-preferred assumptions for COSS. At the request of Commission staff, the applicant prepared a range of COSS models for Commission consideration. These models covered a variety of different allocations including the 12-CP (coincident peak) and 4-CP production allocators, and demand/energy splits for production plant. The applicant prepared the COSS models to reflect Commission staff's audit adjusted revenue requirement.

The testimony in this proceeding covered the various COSS models and discussed the theoretical underpinnings of those models in detail. WIEG testified that it supported the 4-CP, 12-CP, and 75/25 COSS models as its preferred COSS approach. CUB testified that the 12-CP Capacity TOU and 12-CP Capacity Basic Customer models represented its preferred COSS approach.

No consensus was reached by the parties over the course of this proceeding regarding COSS methodologies. Furthermore, the Commission is not persuaded by the evidence that any of the proposed methods are unreasonable. The Commission's long-standing practice is to consider the results of several COSSs for the purposes of allocating test-year revenue responsibility. The evidence in this proceeding supports a continuation of this practice.

Therefore, the Commission finds it reasonable to consider the results of all COSSs in the record for the purposes of class revenue requirement allocation.

The applicant also testified that it added new customer classes to its electric class COSS representing its services for a dedicated renewable energy rider, and other renewable premiums, including energy for tomorrow and renewable pathways. The Commission finds it reasonable to authorize the applicant's proposed changes to the customer classes in its electric COSS to more accurately reflect its current array of customer classes.

Electric Revenue Allocation - 2025 Test Year

The applicant, CUB, WIEG, Walmart, and Commission staff provided testimony on electric revenue allocation for the 2025 test year. The applicant, WIEG, CUB, and Commission staff each provided a revenue allocation proposal. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement and recovered approximately $106.6 million, which translates to an increase of 8.66 percent over current retail electric tariff revenues. WIEG, CUB, and Commission staff offered alternative revenue allocations reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff proposed an alternative electric revenue allocation for the 2025 test year that recovers approximately $55.8 million, or 4.53 percent, above the applicant's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2025 test year at a 4.5 percent overall increase, which offered a lower allocation given to residential classes when compared to the revenue allocations proposed by the applicant and Commission staff. CUB proposed an electric revenue allocation for the 2025 test year at a 4.53 percent overall increase, which offered a lower allocation given to residential classes when compared to the revenue allocations proposed by the applicant, WIEG, and Commission staff, while allocating more to the Primary service classes.

Consistent with the determinations the Commission has made in previous rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to take into account the results of a number of different COSS in addition to other factors such as rate stability and bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the electric revenue allocation as proposed by WIEG with the modification of setting the allocation for EV-Res and EV-Com classes to 0 percent. The Commission finds that the modified revenue allocation offered by WIEG follows the directionality of the COSS models and promotes gradualism. The allocation is shown in Appendix B. The Commission finds that this allocation facilitates a reasonable approach to rate design shifts and results in a more equitable distribution among customer classes.

Electric Revenue Allocation - 2026 Test Year

The applicant, CUB, WIEG, Walmart, and Commission staff provided testimony on electric revenue allocation for the 2026 test year. The applicant, CUB, WIEG, and Commission staff each provided a revenue allocation proposal. The applicant and WIEG provided revenue allocations for 2026 using its 2025 proposed revenues as a starting point, while Commission staff and CUB used 2024 revenues. The applicant’s revenue allocation was based on the applicant’s originally filed test year revenue requirement. It recovered approximately $65.8 million, which translates to an increase of 4.88 percent over their proposed 2025 retail electric tariff revenues. CUB, WIEG, and Commission staff offered alternative revenue allocations reflecting

Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff's proposed electric revenue allocation for the 2026 test year recovers approximately $90.7 million, or 7.27 percent, above the applicant's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2026 test year at a 2.70 increase over the proposed 2025 test year revenue requirement, which offered a higher allocation given to residential classes and a lower allocation given to large industrial classes when compared to the revenue allocations proposed by Commission staff. CUB offered an electric revenue allocation proposal for the 2026 test year at a 7.25 percent overall increase, which offered a lower allocation given to residential classes when compared to the revenue allocations proposed by the applicant, WIEG, and Commission staff.

Consistent with the determinations the Commission has made in previous rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to take into account the results of a number of different COSS in addition to other factors such as rate stability and bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the electric revenue allocation as proposed by WIEG with the modification of setting the allocation for EV-Res and EV-Com classes to 0 percent. The Commission finds that the modified revenue allocation offered by WIEG follows the directionality of the COSS and promotes gradualism. The allocation is shown in Appendix C. The Commission finds that this allocation facilitates a reasonable approach to rate design shifts and results in a more equitable distribution among customer classes.

Electric Customer Rates and Tariff Changes

Overall Rate Design

The applicant proposed a comprehensive electric rate design that held customer charges constant for residential and small commercial, with changes to energy charges and demand charges to reflect the applicant's preferred revenue allocation and rate design. Commission staff used the same rate design structure proposed by the applicant and made changes to energy charges and demand charges to accomplish their preferred revenue allocation and rate structures following general rate design principles. No other parties proposed a complete rate design for all customer classes. Based on this record, the Commission finds it reasonable to approve the comprehensive rate design proposed by Commission staff, as adjusted for revenue requirement and revenue allocation decisions from the Commission. The authorized electric rates appear in Appendices B and C. The Commission directs the applicant to file final form tariff sheets consistent with those rates.

Through the rounds of written testimony, the applicant, intervening parties, and Commission staff discussed several rate design issues. The list of specific rate design items considered in this proceeding include:

- Development of a BYOD demand response pilot;
- Development of an EV-R pilot program;
- Adopting the proposed changes to the EV-C program;
- Modifying the rate structure of the Cg-20 class;
- Increasing the NLMP rider participation cap;
- Replacing the incremental energy rate for the NLMP with a fixed adder;

- Fully phasing-in the Cp-1 High-Load Factor Credit;
- Clarifying the annual firm demand nomination deadline;
- Expansion of one or more parallel generation tariffs;
- Adopting the proposed modifications to the standard net meter tariff (PG-2B); and
- Other miscellaneous tariff clarifications or alterations.

BYOD Demand Response Pilot

The applicant proposed to implement a BYOD demand response pilot program, an optional service available to residential electric customers served on schedules Rg-1, Rg-3, and Rg-5 with central air conditioning. Participating customers would provide the applicant with the ability to remotely control its devices during high electricity demand periods in order to reduce overall demand. The Commission previously approved a BYOD pilot for MGE, which has shown to be a generally successful program.[15]

Several parties provided commentary on the following aspects of the proposed BYOD program:

- Has the applicant provided sufficient detail to support their BYOD pilot program proposal?
- Is the proposed participation limit reasonable?
- Is the proposed implementation date reasonable?
- Should the Commission order the applicant to add a customer battery storage option in the proposed BYOD program?

[15] See Final Decision in docket 3270-UR-121 (PSC REF#: 295447)

The applicant did not provide detailed information on numerous aspects of the program as many program details are contingent on the chosen vendor and are thus presently unavailable, including details of what data will be collected following an event, how the applicant will ensure customer data security, the opt-out process, which device models will qualify, specifics regarding event communications, and what this program may cost to offer. The applicant stated it has no plan for vendor selection at this time, though it expects a vendor's ability to accommodate a variety of device models and its capacity for comprehensive data collection to be considered as key factors.

Commission staff stated that absent additional information, the Commission may wish to direct the applicant to file this proposal in a separate TE docket. Alternatively, should the Commission find that it is reasonable to approve the proposed BYOD program, Commission staff offered a number of reporting requirements for the Commission's consideration.

RENEW proposed requiring the applicant to select a vendor with the ability to expand the program to other clean energy technologies, like battery storage, in the future.

The applicant, Vote Solar, CUB, and RENEW provided testimony on the applicant's proposed participation limit of 3,000 devices for the proposed BYOD program. The applicant explained that it determined the initial subscription limit by scaling the initial Commission approved amount for MGE's BYOD program. As an initial step, the BYOD pilot tariff is limited to electric air conditioning, but it could be expanded in the future to incorporate additional technologies or devices once the applicant gains experience with such a pilot. Vote Solar proposed a capacity cap of 24,000, which he stated is scaled to the size of the applicant's service territory and sales.

The applicant requested an effective date of January 1, 2026, citing a one-year implementation timeline. The applicant explained the proposed timeline consists of three to four months for aggregation vendor selection, two months for contracting, three months to set up the aggregation vendor portal, and three months for initial customer outreach and enrollment. Outreach and enrollment are slated for the final three months, as the applicant intends to promote the program after it has selected the vendor. CUB expressed a desire for the program to be implemented before the 2025 cooling season but acknowledged the potential delays caused by awaiting Commission authorization. RENEW proposed the Commission accept the applicant's BYOD program with a bumped-up implementation date for the 2025 cooling season.

The applicant, CUB, RENEW, and Vote Solar provided testimony on the applicant's proposed BYOD program and the potential inclusion of customer battery storage as an option. RENEW and Vote Solar proposed expanding the BYOD program beyond smart thermostats to include customer-sited, behind-the-meter battery storage tariffs. The applicant argued that inclusion of customer battery storage as an option is premature, as the applicant should first evaluate the program before expanding it to other technologies.

Given the existing success of the MGE BYOD program, and this proposal's close adherence to the structure of that program, the Commission finds it reasonable to approve the program with modifications. The Commission finds it reasonable to scale the participation limit of the program to 24,000 devices on the basis that the higher cap would improve the cost effectiveness of the program. The Commission notes that the applicant's larger size warrants a higher participation limit than that approved for MGE. Additionally, the Commission finds it reasonable to authorize the applicant's proposed implementation date of January 1, 2026. While an earlier date might benefit some, as noted by the applicant, a 2025 date is not be feasible. The Commission does not find it reasonable to require the applicant to include a customer battery storage option in the proposed BYOD program at this time but does find it reasonable that exploration of expansion to other technologies occur with the status of those discussions to be reported to the Commission consistent with the reporting requirements discussed below.

The Commission finds it reasonable to require the applicant to submit a report containing the following information within one year of the effective date of the Final Decision in this docket:

- Details on the vendor that was selected, why said vendor was selected, and which vendors were not selected;
- Detailed information on all costs associated with offering this program under the chosen vendor;
- What data are available for collection under the chosen vendor;
- Details on how the chosen vendor will protect the privacy of participating customers;
- Anticipated benefits from offering this program and how those benefits will be measured;
- How participating customers will interact with the applicant and chosen vendor;
- Provide an updated tariff sheet with rates based on the costs associated with the chosen vendor;
- An anticipated timeline for when customers will be able to enroll on the program once a vendor is chosen; and

- Information on program evaluation including what entity will conduct an evaluation, what aspects of the program the applicant will evaluate and by what metrics, and the frequency throughout the year with which evaluations will occur.

In addition, the Commission finds that is reasonable to require the applicant to complete a statistical evaluation on the effectiveness of the BYOD program and provide those results to the Commission both within 18 months and within 24 months of the implementation date. At the 18 and 24-month points in the program, the evaluation shall identify the costs of the program, participation, and savings. As part of this evaluation, the applicant shall also report on its efforts to collaborate with interested stakeholders regarding potential modifications or extensions to the BYOD program.

Additionally, the applicant shall report on what other technologies a selected vendor can support, whether the vendor could support natural gas demand response programs, and report on how the BYOD program relates or applies to the applicant's implementation of FERC Order No. 2222.

Residential Electric Vehicle Proposal

The applicant proposed implementing an EV-R pilot program, an optional service available to residential electric customers with electric vehicles registered at their address. The program would provide an off-peak credit for any household use up to 600 kWh per month. The program would replace the applicant's current COEV-R and WHEV-R pilot programs. The applicant requested to close the COEV-R and WHEV-R programs, as monitoring individual EV charging use proved expensive, customer feedback indicated a desire for simpler plans with off-peak charging incentives without the fees of the current pilots, and many customers preferred to stay on their existing rate plans, which is not possible with the aforementioned programs. The applicant, RENEW, and Commission staff commented on the potential for this proposal to create a distinct and discriminatory customer class. Commission staff noted that the program may allow the potential for differential rates among similarly situated customers without a basis in those customers' usage characteristics or cost to serve, as the program does not use EV charging data. The applicant and RENEW both commented that the proposed program would not be discriminatory.

The applicant, CUB, RENEW, and Commission staff provided testimony on the applicant's proposed EV-R program, including the following topics:

- Is the proposed 600 kWh cap reasonable?
- Is the absence of a requirement to charge during designated off-peak times reasonable?
- Are the current plans for customer verification reasonable?
- What reporting requirements are reasonable should this program be authorized?
- Is it reasonable to direct the applicant to develop an EV charging pilot for multifamily housing?

The applicant proposed a 600 kWh per month usage cap, while also stating that the average monthly usage for EV charging is about 400 kWh per month. The applicant supported its 600 kWh proposal by stating that this proposal would help to prepare the program for the future and growing consumption of newer EVs. To align with the stated average usage of current EVs, Commission staff proposed a 400 kWh monthly cap.

The applicant, RENEW, and Commission staff commented on the program's lack of disincentives for charging during peak times beyond providing the credit for charging during off-peak times. Commission staff noted that the credit may not be a strong enough incentive to render the program's price signals effective and that the Commission could recommend that the applicant explore other mandatory off-peak charging windows and penalties for charging during peak times.

The applicant, RENEW, and Commission staff commented on the plan for verifying that a customer owns and uses an electric vehicle. The applicant noted that the customers alone would provide the details regarding their EVs that would determine eligibility. Commission staff commented that the reliance on self-reported EV registration details for eligibility verification could pose concerns. The applicant and RENEW commented that additional verification would be unnecessary and pose additional costs. Commission staff recommended various order conditions the Commission could consider should the Commission authorize the pilot program. RENEW noted support for Commission staff's proposed order conditions.

RENEW proposed the Commission direct the applicant to collaborate with NSPW, MGE, RENEW, and other stakeholders to develop a multifamily EV charging pilot. The pilot would address adoption challenges to multifamily housing and would draw from current similar pilots from NSPW and MGE. CUB commented in support of this proposal. The applicant noted that they may be open to developing additional multifamily EV charging offerings in the future but do not have sufficient information to commit to such a pilot now.

The Commission finds it reasonable to approve the applicant's EV-R program with modifications. As a threshold matter, the Commission does not find that the program creates a discriminatory rate class. It is appropriate for a utility to charge different rates for different customer classes where the differences are based upon unique characteristics and there is a system-wide benefit. Here, there can be no dispute that customers who own EVs have different usage due to the need to charge their vehicles. While there is not a specific requirement for a customer in this program to charge during off-peak, the Commission finds such a requirement is not necessary for approval of the program. The price signals are sufficient to incentivize the customer to charge during this time period. These price signals will not only help EV customers on the program, but all customers will benefit from managing the timing of increasing load from EV charging.

The Commission does find it reasonable, however, to modify the program in several ways. First, to align with the stated average usage of current EVs, the Commission concludes it is reasonable to require the applicant to modify the program's monthly cap to 400 kWh. Given the novel simplicity of the program, the Commission concludes it is reasonable to impose an enrollment cap of 7,500 customers and to limit the initial duration of the pilot program to two years. The pilot shall sunset on December 31, 2026 and continuation and/or modification may be considered in the applicant's next rate proceeding. The Commission approves the applicant's proposed verification method, as it finds that additional measures would cause additional administrative burden and detract from the program's simplicity. The Commission does not find it reasonable to require the applicant to develop an EV charging pilot for multifamily housing at this time, but does find it reasonable that this exploration occur with the status of those discussions to be reported to the Commission consistent with the reporting requirements discussed below.

The Commission finds it reasonable for the applicant to submit a report addressing the following within one year from the effective date of the Final Decision in this docket:

- Number of enrolled customers;
- Total amount of electricity sold, separated into the proposed TOU periods;
- Administrative budget and spending;
- Survey results regarding customer satisfaction;
- Aggregated usage data from participating customers;
- Amount of load shifted from on-peak to off-peak by participating customers;
- How frequently are participating customers using more energy than the maximum threshold for the credit;
- How frequently do customers not hit the maximum threshold for off-peak kWh;
- At what point in the billing cycle does the average customer begin to consume off-peak energy beyond the maximum threshold that qualifies for the credit;
- Estimated savings for participating customers;
- Details on how the applicant will protect the privacy of participating customers;
- Insights from collected data that can be used to inform future load management; and
- Information on the verification process with the Wisconsin Department of Transportation.

In addition to the reporting requirements noted above, the applicant shall also include in its report information on its collaboration with stakeholders regarding modifications and expansions to the program. The Commission also finds it reasonable to require the applicant to report on collaboration efforts in a follow up report in the applicant's next rate proceeding. Ultimately, the Commission finds these modifications and reporting conditions reasonably address any discriminatory concerns while maintaining the simplicity of the overall program design.

Given the Commission's authorization of the EV-R pilot program, as modified and conditioned by this Final Decision, the Commission finds it is reasonable to close to new customers the applicant's COEV-R and WHEV-R tariffs.

Commercial Electric Vehicle Proposal

The applicant proposed three changes to the existing EV-C program: increasing the minimum required EV charging installation size from 50 kW to 150 kW; removing the option for customers to purchase charging equipment directly from the applicant; and eliminating the program's pilot status and thus removing the 100 MW enrollment cap.

The applicant, RENEW, and Commission staff commented on the proposal to raise the minimum required commercial EV charging installation size from 50 kW to 150 kW. The applicant noted that the those falling in the 50 to 150 kW range are more likely to drop after two years, leading to a higher risk that their embedded cost allowance will not be recovered through incremental revenues. Commission staff did not raise concerns with raising the minimum installation size on its own but noted that doing so without providing a new tariff for customers in the 50 kW to 150 kW range may be worth discussion. RENEW commented in opposition of this proposal, as customers in the 50 to 150 kW range will be left without a tariff and that customers should not be deprived of rate choice.

The Commission finds it reasonable to increase the minimum required EV charging installation size from 50 kW to 150 kW, as customers in the 50 to 150 kW range are more likely to drop after two years, leading to a higher risk that their allowance will not be recovered through incremental revenues. To address the concerns about customers in the 50 to 150 kW range, the Commission directs the applicant to include, in its annual report for the EV-R program, reporting on its efforts to collaborate with stakeholders on the impacts associated with the change on the minimum size requirements.

The applicant, CUB, RENEW, and Commission staff commented on the proposal to remove the option for customers to purchase charging equipment directly from the applicant. The applicant cited a lack of customer interest as the impetus for this proposal. CUB and RENEW commented in support of this proposal. The Commission finds it reasonable to remove the option for customers to purchase charging equipment directly from the applicant given the demonstrated lack of interest from customers regarding this option.

The applicant, RENEW, and Commission staff commented on the applicant's proposal to remove the 100 MW enrollment cap, effectively eliminating the EV-C program's pilot status. Commission staff noted that the Commission may wish to maintain the program's pilot status if the increase in the minimum required EV charging installation size is enacted in order to better monitor the effects of said changes. RENEW commented in support of the proposal to remove the enrollment cap and eliminating the program's pilot status. The Commission finds it reasonable to remove the 100 MW enrollment cap from the program to allow for future growth. However, the Commission finds it reasonable for the program to maintain pilot status given the changes being enacted.

Cg-20 Rate Design

Walmart proposed altering the existing rate structure of the Cg-20 class by lowering energy charges and increasing demand-related charges. Walmart stated that this proposal would alter the cost recovery of the Cg-20 rates to more accurately reflect how those costs are incurred to the utility. The applicant responded by suggesting that any changes to the Cg-20 rate design should be made in moderation.

The Commission continues to believe gradualism is important in rate design. Large changes in demand-related charges, such as those proposed by Walmart, can have disparate impacts on customers depending on their load profile. As this rate class applies to a wide range of customers with varying load profiles, a large change could prove difficult to adjust to for certain customers. For this reason, the Commission finds it reasonable to approve the rate design for Cg-20 as proposed by Commission staff given its adherence to general rate design principles and more gradual application of changes.

Increasing the NLMP Rider Participation Cap to 200 MW

WIEG proposed an increase in the participation limit for its NLMP service from 145.1 MW to 200 MW to accommodate future growth. Commission staff did not raise concerns regarding the proposal. The applicant noted that expanding the participation cap would reduce both administrative burdens and any uncertainty for interested customers regarding the availability of the tariff. The Commission finds it reasonable to increase the participation limit on the NLMP Rider from 145.1 MW to 200 MW, as the adjustment would allow for future growth.

Replacing the NLMP Incremental Energy Rate with a Fixer Adder

WIEG proposed that the minimum Incremental Energy Rate (IER) be replaced with a fixed adder that more closely recognizes the NLMP Rider's non-locational marginal prices (LMP) pricing parameters. The applicant noted that the current IER is reasonable, as there have been few instances where LMPs have fallen below the current IER. The Commission finds that there was not sufficient evidence to support a change to the current structure of the NLMP tariff.

High-Load Factor Credit

Order Condition 17 in the Commission's Final Decision in docket 6690-UR-127[16] required the applicant to offer a high load factor credit for the Cp-1 class.

The applicant and WIEG proposed to implement the credit starting at the conclusion of this proceeding and fully phasing in after the conclusion of the applicant's next rate proceeding, allowing for a controlled introduction and monitoring of its effects. This phased approach helps mitigate potential risks and ensures that the credit aligns with the evolving needs of the utility and its customers. The applicant modeled this proposal off of an existing high load factor credit that is currently offered by NSPW, which the Commission had most recently reviewed in docket 4220-UR-125.[17] The Commission does not find it reasonable to fully phase in the High Load Factor Credit, as the applicant did not provide the robust analysis on customer impacts resulting from the credit that was requested in the prior rate proceeding, docket 6690-UR-127. Therefore, the Commission finds it reasonable to order the applicant to conduct a comprehensive analysis of the phase-in process to verify that no unintended effects arise from the credit. This analysis is to be completed by and presented in the next rate proceeding.

[16] See Final Decision in docket 6690-UR-127 (PSC REF#: 455196)
[17] See Final Decision in docket 4220-UR-125 (PSC REF#: 427625)

Firm Demand Nomination Deadline

The applicant proposed to set a new deadline of January 15 of each year for customers to submit any changes to its firm demand nominations and to add the language to implement this deadline to the Cp-I2 (Large Commercial and 14 Industrial-Interruptible Rider) rate schedules. The applicant noted that this change would facilitate its ability to obtain the necessary information for registering its forecasted amount of demand response load with MISO. No parties raised concerns with this proposal. The Commission finds it reasonable for the applicant to add language clarifying its annual deadline related to firm demand nominations.

Uncontested Rate Design Proposal

The applicant proposed increasing its Renewable Pathway Premium rate, raising the premium from $0.00874 per kWh to $0.02518 per kWh for one-year subscriptions, and from $0.00688 per kWh to $0.02331 per kWh for five-year subscriptions. Neither Commission staff nor any other parties raised any issues with this proposal. This proposed increase is based on updated data from the 2025 cost-of-service analysis and renewable facility costs. The Commission finds it reasonable to authorize the Renewable Pathway Premium rate increase.

Other Miscellaneous Tariff Clarifications or Alterations

The applicant proposed numerous other minor changes (other than pricing changes), including many minor administrative changes and clarifications. Upon review, Commission staff did not identify any specific concerns with the proposed miscellaneous tariff language revisions proposed by the applicant. The Commission finds it reasonable to approve the miscellaneous electric rate sheet changes as proposed by the applicant.

Expansion of One or More Parallel Generation Tariffs

Vote Solar proposed the following:

- Require the applicant to make at least one tariff available to all qualifying facilities (QFs), including renewable generators up to 80 MW, permitting the QF to interconnect in parallel, self-supply, and receive unbundled supplemental, backup and maintenance power at nondiscriminatory prices.
- That the utility must also purchase all electricity put to the utility by QFs up to 5 MW at the utility's full avoided cost prices.
- The avoided energy and capacity prices under the parallel generation tariffs be raised to a level equivalent to what the utility's rate-based generation costs ratepayers for equivalent energy and capacity contribution. Alternatively, the Commission should cap the amount of cost of the utility's own generation included in the authorized revenue requirement to the LMP and CONE-times-accredited-capacity values in the parallel generation tariffs.
- The capacity value established in multi-year contracts with QFs be set for the term of the legally enforceable obligation or contract and not reset annually based on revised MISO CONE calculations and accreditations.
- The existing $0.00 placeholder for avoided transmission be replaced by an avoided transmission value of either $0.01209/kWh, based on the utility's marginal cost of service calculation and consistent with the Commission's prior practice, or $0.0133/kWh based on the coincidence of solar production to the American Transmission Company LLC (ATC) 12CP hours that drive Schedule 9

network service charges plus an additional increment per kilowatt hour to reflect the avoided costs under the ATC Schedule 26, Schedule 26-A, and Schedules 7 and 8 that are based on electricity withdrawals from the transmission system.

RENEW requested to expand the tariff to larger QFs and proposed the following:

- Order the applicant to review ATC schedules and charges, review its own QF
- invoices, and propose actual buyback rates to replace the $0 "placeholder" value in the applicant's parallel generation tariffs.
- Allow parties and Commission staff to investigate the issues with the avoided cost parallel generation rates identified in this docket, for parties to provide testimony and evidence to inform a Commission decision on, reconciling the differences between the costs to the utility of rate-based generation and the avoided costs paid to customers under the Parallel Generation tariffs.

The Commission notes that the parallel generation tariffs are highly technical and require a more robust analysis than is possible within the limited timeline of this rate proceeding. Thus, the Commission finds it reasonable to direct the applicant to address the proposed changes in a TE docket to be opened by Commission staff by April 1, 2025.

Proposed Modifications to the PG-2B Tariff

RENEW proposed to increase the capacity cap on the PG-2B tariff from 1,000 kW to 5,000 kW, noting that raising the capacity cap would bring the applicant in-line with other Wisconsin utilities and provide Wisconsin businesses with opportunities to meet their sustainability and energy independence goals. Vote Solar and WIEG supported RENEW's proposal. The Commission finds it reasonable to increase the capacity cap on the PG-2B tariff from 1,000 kW to 5,000 kW as it allows a greater number of customers to benefit from the program and aligns the tariff with similar offerings from other Wisconsin utilities.

Natural Gas Cost of Service, Revenue Allocation and Rates

2025 and 2026 Natural Gas Cost of Service

The applicant, CUB, WIEG, and Commission staff provided testimony regarding natural gas cost-of-service methodology. The applicant prepared two natural gas COSS: COSS A, and COSS B. COSS A and COSS B were prepared using parameters established by Commission staff, and they reflect Commission staff's audit adjustments. The applicant supported the use of multiple COSS models, recognizing a spectrum of allocation positions. Commission staff and CUB supported the use of multiple COSS models. While WIEG commented that neither COSS allocates certain costs consistent with Commission direction nor uses unweighted coincidental peak demand as is consistent with other utilities, WIEG ultimately supported the Commission's use of multiple COSS models.

The Commission's long-standing practice is to consider the results of several COSS for the purposes of allocating test-year revenue responsibility. The evidence in this proceeding supports a continuation of this practice. Therefore, the Commission finds it reasonable to consider the results of all COSS in the record for the purposes of class revenue requirement allocation for the 2025 and 2026 test years.

Natural Gas Revenue Allocation-2025 Test Year

The applicant, CUB, WIEG and Commission staff provided testimony on the natural gas revenue allocation for the 2025 test year. The applicant, CUB, and Commission staff provided comprehensive revenue allocation proposals. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement. It recovers approximately $26.8 million, which translates to an increase of 6.73 percent over current retail revenues. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff developed natural gas rates for the 2025 test year that recover approximately $12.7 million, or 3.25 percent, above the applicant's revenue at present rates. CUB offered a natural gas revenue allocation proposal for the 2025 test year at a 3.25 percent overall increase, which offered a lower allocation given to residential classes when compared to the revenue allocations proposed by the applicant and Commission staff.

Consistent with the determinations the Commission has made in previous rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to consider the results of a number of different COSS in addition to other factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the natural gas revenue allocation initially proposed by Commission staff, as shown in Ex.-PSC-Jurvich-3, and as adjusted for the final revenue requirement, as shown in Appendix D. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Natural Gas Revenue Allocation-2026 Test Year

The applicant, CUB, WIEG, and Commission staff provided testimony on the natural gas revenue allocation for the 2026 test year. The applicant, CUB, and Commission staff provided comprehensive revenue allocation proposals. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement. It recovers approximately $42.9 million, which translates to an increase of 10.31 percent over current retail revenues. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff also developed natural gas rates for the 2026 test year that recover approximately $25.9 million, or 6.26 percent, above the applicant's revenue at present rates. CUB offered a natural gas revenue allocation proposal for the 2026 test year at a 6.27 percent overall increase, which offered a lower allocation given to residential classes when compared to the revenue allocations proposed by the applicant and Commission staff.

Consistent with the determinations the Commission has made in previous rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to consider the results of a number of different COSS in addition to other factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the natural gas revenue allocation initially proposed by Commission staff, as adjusted for the final revenue requirement, and as shown in Ex.-PSC-Jurvich-4, and shown in Appendix E. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Overall Natural Gas Rate Design 2025 and 2026 Test Years

The applicant and Commission staff provided comprehensive natural gas rate design proposals that include rates for all customer classes. Commission staff largely preserved the rate design proposed by the applicant and made adjustments to distribution rates to achieve the offered revenue allocation. The Commission generally chooses one of the comprehensive natural gas rate design proposals in addition to making separate decisions on specific rate design sub-issues. The Commission finds that the rate design proposed by Commission staff in Ex. -PSC-Jurvich-3 and Ex.-PSC-Jurvich-4, as modified by the Commission determinations in the above sections of this Final Decision, is reasonable.

Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed by Commission staff in Ex.-PSC-Jurvich-3 and Ex.-PSC-Jurvich-4 for the 2025 and 2026 test years, adjusted for final revenue requirement. The authorized rates appear in Appendices D and E.

The applicant's authorized rates as set forth in Appendices D and E are based on the cost of supplying natural gas service to the various service rate classes and other rate setting goals, including gradualism in ratemaking. A summary of the revenue rate impacts on a service rate class basis is shown in Appendices D and E. The percentage rate change to any individual customer will not necessarily equal the overall percentage change to the associated service rate class, but rather it will depend on the specific usage level of the customer. Appendices D and E also show some typical natural gas bills for the applicant's residential service, comparing existing rates with new rates, including the cost of natural gas.

Natural Gas Customer Rates and Tariff Changes

The applicant proposed the following tariff changes: modifying the Customer Requested Bill Due Date Program's approach to customers with arrears and changing the definition of a Large Energy Customer under Wisconsin Act 141. These changes are discussed individually below.

Customer Requested Bill Due Date Program

The Customer Requested Bill Due Date program allows customers to request a due date for payment on their bills, with those who are 60 days in arrears automatically removed from the program. Currently, those customers can return upon making payment arrangements with the applicant. The applicant proposed to change this, creating a 12-month waiting period before customers can return to the program wherein, they must remain in good standing. The applicant noted that this has been implemented across WEC utilities and that allowing customers to return to the program requires significant manual intervention across multiple departments.

The Commission finds it reasonable to create a 12-month waiting period for Customer Requested Bill Due Date program customers who have fallen into arrears, as the change reduces administrative burden and aligns the applicant with comparable utilities.

Large Energy Customer Definition Under Wisconsin Act 141

The applicant requested to define a Large Energy Customer as all of the customer's facilities in its service territory that share the same federal employer identification number, as it notes this definition is more accurate to statute and aligns with the definition used by WEPCO Gas Operations and Wisconsin Gas LLC. Currently, the applicant considers each facility separately, even if it shares a federal employment identification number with another. No party opposed the applicant's proposed definition. The Commission concurs and finds it reasonable to alter the current definition of a Large Energy Customer as proposed by the applicant.

Electric and Natural Gas Tariff Changes

NSF Charges

Commission staff requested the applicant to break down the components of its NSF charge. The applicant responded that it was comprised of the applicant's administrative cost, financial institution fees, and an incremental deterrence component. Commission staff proposed two alternative charges, both of which eliminate the incremental deterrence fee: the administrative cost added to the highest financial institution fee assessed to the applicant of $12.74 or the administrative cost added to the average of the range of financial institution fees of $7.24. The Commission concludes that eliminating the incremental difference component and setting the charge based on administrative cost plus the average financial institution fee provides a balanced and reasonable solution for the NSF charge structure. Therefore, the Commission finds it reasonable to eliminate the incremental deterrence component of the NSF charge and reconfigure the charge to consist of the administrative cost added to the average of the range of financial institution fees resulting in a rate of $7.24.

Reconnection/Disconnection Charges

Commission staff presented analysis on the cost disparities between physical and remote disconnections and reconnections. Commission staff noted that this disparity may warrant further examination in a future proceeding, particularly as the remote capabilities of the Advanced Metering Infrastructure (AMI) devices and deployment of those devices continue to expand. Given the increasing deployment of AMI and the growing capacities of AMI technology, the Commission finds it reasonable to require the applicant to consider cost disparities between physical and remote disconnections and reconnections in a future proceeding.

Affordability and Low Income Forgiveness Tariff

CUB 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. 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.

In docket 6690-UR-127, the Commission directed the applicant to work with CUB and other interested parties on development alternative low-income assistance programs. In docket 6690-UR-127, the Commission also authorized the applicant to extend its LIFT and directed that it provide additional details regarding the program in a separate tariff docket filing. In this proceeding, CUB proposed that the Commission require the applicant to provide, as part of its initial filings in its next rate proceeding, additional reporting data about the LIFT program. Specifically, CUB recommended including the following additional reporting data for the LIFT program:

- Number of customers who enroll in LIFT;
- Number and percentage of customers who successfully complete the program;
- Number and percentage of customers who are unsuccessful in completing a LIFT payment plan who are ultimately disconnected for non-payment;
- Number of unique customers who participate in LIFT over time, with particular attention paid to any customer who goes through more than one forgiveness cycle;

- Forgiveness dollars credited to customers and other fees avoided by customers; and
- Revenue collected from LIFT participants.

The applicant acknowledged that Commission staff continues to evaluate the performance of the LIFT program based on the applicant's ongoing reporting and will continue to work with Commission staff to continue ongoing reporting, which may include the additional information that CUB proposed.

The Commission recognizes that there is an active docket for the applicant's LIFT program, docket 5-TU-100, wherein the applicant is working with Commission staff to develop performance metrics and reporting requirements. In addition, there are ongoing and evolving discussions with the applicant, Commission staff and stakeholders occurring as part of the investigation of the applicant's development of alternative low-income assistance programs in docket 6690-UI-101 that have included discussion and review of the LIFT program. The Commission strongly encourages the applicant prioritize this work, be responsive to Commission staff and the parties involved, and move as quickly as possible toward a solution to address customers' affordability challenges.

The Commission notes the lack of historical data for the LIFT program and the need for continued analysis on the performance and effectiveness of the LIFT program as it relates to the financial impacts on the applicant's revenue requirement. Therefore, the Commission finds it reasonable to establish additional metrics and reporting requirements for the LIFT program to be provided by the applicant as part of its initial filing for its next rate proceeding. The Commission finds it reasonable to require the applicant to work with Commission staff on identifying and including additional reporting data for the LIFT program for inclusion in the initial filing for the applicant's next rate proceeding.

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 file 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) and 134.13(1)(b) 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. By January 1, 2026, the applicant shall revise its existing rates and tariff provisions for both electric and natural gas utility service for 2026, substituting the rate modifications and tariff provisions that expand the terms of services 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 may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B, C, D, and E 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.

4. The applicant shall prepare a bill message that properly identifies 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 message with the Commission before it provides the message to customers.

5. The applicant shall file electric and natural gas tariffs consistent with this Final Decision.

6. The electric fuel costs in Appendix F shall be used for monitoring the applicant's 2025 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

7. All 2025 fuel costs shall be monitored using a plus or minus 2.0 percent tolerance band pursuant to Wis. Admin. Code § PSC 116.06(3).

8. The applicant shall seek reconciliation of its 2025 fuel cost plan consistent with the requirements of Wis. Admin. Code § PSC 116.07.

9. The applicant shall file a 2026 fuel cost plan in 2025 consistent with the requirements of Wis. Admin. Code ch. PSC 116.

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

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

12. The applicant shall file an annual forestry management report, no later than the first quarter of each year beginning in 2025 and ending in 2027. This report should include the following information: 1) Number, identification, and trimming timeline for project; (2) Details of the progress made during the previous forestry maintenance season and the progress made to

date under this O&M item; (3) Comparison of total budgeted and actual annual cost; (4) Tree outage related data for individual projects for pre- and post-forestry maintenance period for the test years that includes outages by tree growing into primary, tree not growing into primary, and service line categories; (5) Tree outage related data for the applicant's system for pre- and post-forestry maintenance period for the test years that includes outages by tree growing into primary, tree not growing into primary, and service line categories; (6) Number of Emerald Ash Borer Infested hazard trees removed by project and cost for such hazard tree removal; (7) Report on assessment of reliability benefits.

13. The applicant shall defer the cost overruns for Paris Solar and BESS without any carrying costs to a future rate proceeding.

14. The applicant shall amortize the regulatory liability balance associated with Paris Solar and BESS due to a change in in-service date over one year (2025) and require a true-up in the applicant's next rate proceeding.

15. The applicant shall defer the cost overruns for Darien Solar and BESS without any carrying costs to a future rate proceeding.

16. The applicant shall defer the incremental revenue requirement impact arising from the change in service date for the Darien Solar and BESS project, with carrying costs at the applicant's short term debt rate.

17. The applicant shall levelize recovery of the undepreciated balance on Columbia units 1 and 2 from June 1, 2026, to December 31, 2026, using a 25-year recovery period, with carrying costs at the applicant's weighted average cost of capital.

18. The applicant shall submit additional analysis of alternatives for addressing the remaining undepreciated balance for Columbia units 1 and 2 in the applicant's next rate proceeding.

19. The applicant shall defer the difference between the estimated and actual revenue requirement impact associated with any change in the date of retirement for Columbia units 1 and 2.

20. The applicant shall amortize the acquisition costs related to the distribution-connected utility-owned solar generation and BESS projects and DRER projects beginning in 2025 for 25 years, the estimated life of those facilities.

21. The applicant shall defer the costs associated with the BYOD pilot program to the applicant's next rate proceeding.

22. The applicant shall continue to defer, with carrying costs at the applicant's short-term debt rate, any impacts of the IRA.

23. The applicant shall defer, with carrying costs at the applicant's authorized short-term debt rate, any impacts for the IRS Revenue Procedure 2023-15.

24. The applicant shall defer, with carrying costs at the applicant's authorized short-term debt rate, the net impact of any loans or grant funds from programs through the DOE.

25. The applicant shall record annual conservation escrow expense for retail electric operations of $15.4 million and 16.3 million in 2025 and 2026, respectively. The conservation escrow expense amount shall continue to be recorded until a new rate order is issued by the Commission authorizing a different amount to be recorded.

26. The applicant shall record annual conservation escrow expense for natural gas operations of $6.2 million and $6.7 million in 2025 and 2026, respectively. The conservation escrow expense amount shall continue to be recorded until a new rate order is issued by the Commission authorizing a different amount to be recorded.

27. The applicant shall record amortization expenses consistent with Appendix G, in all material effects, for 2025 and 2026, or until the Commission authorizes a different amortization expense to be recorded.

28. The applicant shall file a depreciation study for the Commission's approval no later than December 20, 2027.

29. The applicant shall calculate revenue deficiencies by consistently rounding to four decimal places when represented as a number and two decimal places when shown as a percentage when calculating revenue requirement deficiencies.

30. The applicant shall present the second year of a two-year test year rate proceeding as a change from presently authorized rates.

31. The applicant is authorized to retain 100.00 percent of the first 15 basis points of earnings above its ROE. The applicant will return to customers an amount equal to 50 percent of earnings between 15+ and 75 basis points above its ROE. The applicant will return to customers 100.00 percent of earnings exceeding 75+ basis points above its ROE. The ROE should be measured in the same manner as earnings defined by "Excess revenues" in Wis. Admin. Code. Ch. PSC 116 (Fuel Rules ROE).

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

33. The applicant shall submit, in its next rate proceeding application, detailed information regarding all off balance-sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at a minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

34. The applicant may not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis to fall below the test-year authorized level of 53.00 percent in 2025 and 2026. The applicant shall not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual common equity ratio, on a financial basis, below the forecasted level of 53.00 percent.

35. The applicant shall submit, in its next rate proceeding, supporting information regarding the costs associated with the issuance of long-term debt forecasted but not issued in the forecasted test year(s), the funds collected from customers associated with it, and Commission staff's proposal to defer the increment impact associated with debt that is forecasted but not issued, to be returned to customers.

36. The applicant shall offer a BYOD demand response pilot program, as modified and conditioned by this Final Decision.

37. The applicant shall close its existing COEV-R and WHEV-R programs to new customers and shall offer an EV-R pilot program, as modified and conditioned by this Final Decision.

38. The applicant shall file a report on the EV-R pilot containing the information identified in this Final Decision one year from the effective date of this Final Decision.

39. The applicant shall report on its EV-R collaboration efforts regarding potential EV tariff adjustments, pilot program modifications, and expansion possibilities, with its first report to be filed one year from the effective date of this Final Decision, and a second report filed as part of the applicant's next rate proceeding.

40. The applicant shall implement changes to its EV-C pilot program, as modified by this Final Decision.

41. The applicant shall adopt the rate design for the Cg-20 customer class proposed by Commission staff.

42. The applicant shall increase the participation limit on the NLMP Rider from 145.1 MW to 200 MW.

43. The applicant shall conduct an analysis to submit in its next rate proceeding of the impacts and any unintended effects on customers resulting from fully phasing in the Cp-1 High-Load Factor Credit.

44. The applicant shall add language clarifying its annual deadline for firm demand nominations to the Cp-I2 tariff.

45. The applicant shall increase the Renewable Pathway Premium rate consistent with the discussion in this Final Decision.

46. The applicant shall implement the proposed minor administrative changes and clarifications to its electric rate sheets consistent with the discussion in this Final Decision.

47. The applicant shall investigate changes to its parallel generation tariffs proposed in this proceeding in a separate TE docket that shall be opened no later than April 1, 2025.

48. The applicant shall increase the capacity cap on the PG-2B tariff from 1,000 kW to 5,000 kW.

49. The applicant shall implement the comprehensive natural gas rate design proposed by Commission staff, as modified and conditioned by this Final Decision.

50. The applicant shall create a 12-month waiting period for Customer Requested Bill Due Date program customers who have fallen into arrears.

51. The applicant shall alter the current definition of a Large Energy Customer under Wisconsin Act 141 consistent with Commission's discussion.

52. The applicant shall eliminate the incremental deterrence component of the NSF change and reconfigure the charge to consist of the administrative cost added to the average of the range of financial institution fees ($7.24).

53. The applicant shall consider the cost disparities between physical and remote disconnections and reconnections in a future proceeding.

54. The applicant shall work with Commission staff on identifying and including additional reporting data for the LIFT program for inclusion in the initial filing for the applicant's next rate proceeding.

55. The requirements in prior Commission orders that are not expressly addressed in this Final Decision remain in effect and are not superseded by this Final Decision.

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

57. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 19th day of December, 2024.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:DAP:dsa:arw DL:02038340

Attachments

See attached Notice of Rights

Docket 6690-UR-128

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.[18] 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

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

Docket 6690-UR-128

APPENDIX A

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Docket 6690-UR-128

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Electric Revenue Yield - Test Year 2025

Rate Schedule	Booked Energy MWh	Revenue Yield in 2025 With Present Rates	Revenue Yield in 2025 With Authorized Rates	Percent Change in 2025 Over Current	Cost of Service Revenue Requirement	
Rg1	2,910,821	$474,160,587	$505,942,354	6.70%		
Rg3-OTOU	72,788	$10,103,863	$10,784,150	6.73%		
Rg5-OTOU	21,220	$3,224,807	$3,438,006	6.61%		
Rg RR	3,453	$493,468	$523,724	6.13%		
Total Residential & Farm	3,008,283	$487,982,725	$520,688,234	6.70%		
Cg1	823,664	$116,344,007	$123,684,909	6.31%		
Cg1 RR	15	$2,608	$2,628	0.76%		
Cg3-OTOU	100,015	$12,786,542	$12,900,027	0.89%		
Total Small General Secondary	923,695	$129,133,157	$136,587,564	5.77%		
Total Small Customer Class	**3,931,977**	**$617,115,882**	**$657,275,797**	**6.51%**		
Cg5	246,333	$29,575,920	$29,892,031	1.07%		
Cg5 RR	0	$0	$0	0.00%		
Total Medium Customer Class	**246,333**	**$29,575,920**	**$29,892,031**	**1.07%**		
Cg-20	2,789,371	$278,739,391	$290,597,108	4.25%		
Cg-20RR	55,995	$5,650,570	$5,898,004	4.38%		
Cp-Secondary	750,931	$67,018,182	$67,253,918	0.35%		
Cp-Primary	1,125,910	$87,317,350	$89,158,020	2.11%		
Cp-Transmission	1,013,885	$69,683,967	$69,466,110	-0.31%		
Cp-Secondary RR	72,857	$6,202,694	$6,264,021	0.99%		
Cp-Primary RR	114,761	$8,923,311	$9,089,761	1.87%		
Cp-Transmission RR	171,510	$12,488,734	$12,549,854	0.49%		
NLMP	380,288	$15,707,999	$15,707,999	0.00%		
RTMP	377,736	$19,907,469	$20,223,568	1.59%		
Total Large Customer Class	**6,853,246**	**$571,639,668**	**$586,208,362**	**2.55%**		
Ls-1	38,100	$12,984,978	$13,077,602	0.71%		
Total Street Lighting & Other	**38,100**	**$12,984,978**	**$13,077,602**	0.71%		
COEV-R	0	$24,776	$24,776	0.00%		
WHEV-R	0	$724	$724	0.00%		
EV-C	0	$25,728	$25,728	0.00%		
Total EV Customer Class	0	$51,228	$51,228	0.00%		
Naturewise-Residential		$67,408	$67,408	0.00%		
Naturewise-C&I		$28,824	$28,824	0.00%		
Automatic transfer switch		$85,056	$85,056	0.00%		
Parallel generation		$24,086	$24,086	0.00%		
Total Misc Customer Class	0	$205,373	$205,373	0.00%		
Total Wisconsin Retail	**11,069,656**	**$1,231,573,050**	**$1,286,710,393**	**4.48%**	**$1,286,711,313**	-$920

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
Residential Flat Rate - Rg1							
Customer charge							
Single PH per day	152,050,788	$0.58915	$89,580,722	152,050,788	$0.58915	$89,580,722	0.00%
Energy charge	2,910,380,753	$0.13213	$384,548,609	2,910,380,753	$0.14305	$416,329,967	8.26%
Fuel cost adjustment	2,910,380,753	$0.00000	$0	2,910,380,753	$0.00000	$0	0.00%
Other							
Other	2,910,380,753	$0.00000	$0	2,910,380,753	$0.00000	$0	0.00%
Revenue sharing	2,910,380,753	$0.00000	$0	2,910,380,753	$0.00000	$0	0.00%
Act 141 capped credits	297,485	-$0.00227	-$675	297,485	-$0.00179	-$532	-21.15%
Act 141 capped contribution	297,485	$0.00062	$185	297,485	$0.00062	$185	0.00%
Total Revenue: Residential Flat Rate - Rg1			**$474,128,841**			**$505,910,341**	
Residential Small Optional 2TOU - Rg3							
Customer charge							
Single PH per day	2,319,996	$0.58915	$1,366,826	2,319,996	$0.58915	$1,366,826	0.00%
Energy charge							
On-peak	19,598,856	$0.24122	$4,727,636	19,598,856	$0.26000	$5,095,703	7.79%
Off-peak	53,189,189	$0.07538	$4,009,401	53,189,189	$0.08125	$4,321,622	7.79%
Fuel cost adjustment							
Adjustment	72,788,045	$0.00000	$0	72,788,045	$0.00000	$0	0.00%
Other							
Other	72,788,045	$0.00000	$0	72,788,045	$0.00000	$0	0.00%
Revenue sharing	72,788,045	$0.00000	$0	72,788,045	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00179	$0	-21.15%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 2TOU - Rg3			**$10,103,863**			**$10,784,150**	
Residential Small Optional 3TOU - Rg5							
Customer charge							
Single PH per day	909,672	$0.58915	$535,933	909,672	$0.58915	$535,933	0.00%
Energy charge							
On-peak	3,301,069	$0.30152	$995,338	3,301,069	$0.32500	$1,072,847	7.79%
Shoulder	6,040,176	$0.13213	$798,088	6,040,176	$0.14305	$864,047	8.26%
Off-peak	11,879,109	$0.07538	$895,447	11,879,109	$0.08125	$965,178	7.79%
Fuel cost adjustment							
Adjustment	21,220,354	$0.00000	$0	21,220,354	$0.00000	$0	0.00%
Other							
Other	21,220,354	$0.00000	$0	21,220,354	$0.00000	$0	0.00%
Revenue sharing	21,220,354	$0.00000	$0	21,220,354	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00179	$0	-21.15%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 3TOU - Rg5			**$3,224,807**			**$3,438,006**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
Residential Response Rewards - RgRR							
Customer charge							
Single PH per day	131,879	$0.58915	$77,697	131,879	$0.58915	$77,697	0.00%
Energy charge							
On-peak	789,264	$0.26458	$208,824	789,264	$0.28521	$225,106	7.80%
Off-peak	2,642,548	$0.06784	$179,276	2,642,548	$0.07313	$193,250	7.79%
Critical peak	21,254	$1.30198	$27,672	21,254	$1.30198	$27,672	0.00%
Fuel cost adjustment							
Adjustment	3,453,066	$0.00000	$0	3,453,066	$0.00000	$0	0.00%
Other							
Other	3,453,066	$0.00000	$0	3,453,066	$0.00000	$0	0.00%
Revenue sharing	3,453,066	$0.00000	$0	3,453,066	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00179	$0	-21.15%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Response Rewards - RgRR			**$493,468**			**$523,724**	
Residential Charger Only EV - COEV-R							
Fixed service and administration charge							
Bundled service per month	1,093	$20.00000	$21,862	1,093	$20.00000	$21,862	0.00%
Pre-paid service per month	364	$8.00000	$2,915	364	$8.00000	$2,915	0.00%
Energy charge							
On-peak (summer)	8,811	$0.25145	$2,216	8,811	$0.26091	$2,299	3.76%
On-peak (non-summer)	8,811	$0.13786	$1,215	8,811	$0.14305	$1,260	3.76%
Intermediate-peak (summer)	13,217	$0.13786	$1,822	13,217	$0.14305	$1,891	3.76%
Intermediate-peak (non-summer)	13,217	$0.13786	$1,822	13,217	$0.14305	$1,891	3.76%
Off-peak (summer)	198,249	$0.06223	$12,336	198,249	$0.06223	$12,336	0.00%
Off-peak (non-summer)	198,249	$0.06223	$12,336	198,249	$0.06223	$12,336	0.00%
Fuel cost adjustment	440,553	$0.00000	$0	440,553	$0.00000	$0	0.00%
Other							
Other	440,553	$0.00000	$0	440,553	$0.00000	$0	0.00%
Total Revenue: Residential Charger Only EV - COEV-R			**$56,523**			**$56,789**	
Residential Whole Home EV - WHEV-R							
Fixed service and administration charge							
Bundled service per month	32	$20.00000	$638	32	$20.00000	$638	0.00%
Pre-paid service per month	11	$8.00000	$85	11	$8.00000	$85	0.00%
Total Revenue: Residential Whole Home EV - WHEV-R			**$724**			**$724**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Commercial Electric Vehicle EV-C							
Fixed service and administration charge							
Bundled-single port, per month per port A	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port B	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port C	96	$25.00000	$2,400	96	$25.00000	$2,400	0.00%
Bundled-dual port, per month per port A	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port B	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port C	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Pre-paid-single port, per month per port A	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port B	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port C	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-dual port, per month per port A	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port B	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port C	0	$2.00000	$0	0	$2.00000	$0	0.00%
Total Revenue: Commercial Electric Vehicle EV-C			**$25,728**			**$25,728**	
General Secondary Flat Rate - Cg1 (<50 kW)							
Customer charge							
Single PH per day	12,604,575	$0.90840	$11,449,996	12,604,575	$0.90840	$11,449,996	0.00%
Three PH per day	4,495,251	$1.45350	$6,533,847	4,495,251	$1.45350	$6,533,847	0.00%
Energy charge	823,664,357	$0.11945	$98,386,707	823,664,357	$0.12835	$105,717,320	7.45%
Fuel cost adjustment	823,664,357	$0.00000	$0	823,664,357	$0.00000	$0	0.00%
Other							
Other	823,664,357	$0.00000	$0	823,664,357	$0.00000	$0	0.00%
Revenue sharing	823,664,357	$0.00000	$0	823,664,357	$0.00000	$0	0.00%
Act 141 capped credits	16,076,484	-$0.00236	-$37,941	16,076,484	-$0.00172	-$27,652	-27.12%
Act 141 capped contribution	16,076,484	$0.00071	$11,397	16,076,484	$0.00071	$11,397	0.00%
Total Revenue: General Secondary Flat Rate - Cg1 (<50 kW)			**$116,344,007**			**$123,684,909**	
General Secondary Flat Rate Response Rewards - Cg1RR							
Customer charge							
Single PH per day	0	$0.90840	$0	0	$0.90840	$0	0.00%
Three PH per day	379	$1.45350	$551	379	$1.45350	$551	0.00%
Energy charge							
On-peak	5,847	$0.22566	$1,319	5,847	$0.22798	$1,333	1.03%
Off-peak	9,500	$0.06541	$621	9,500	$0.06608	$628	1.02%
Critical peak	98	$1.17680	$116	98	$1.17680	$116	0.00%
Fuel cost adjustment							
Adjustment	15,445	$0.00000	$0	15,445	$0.00000	$0	0.00%
Other							
Other	15,445	$0.00000	$0	15,445	$0.00000	$0	0.00%
Revenue sharing	15,445	$0.00000	$0	15,445	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00172	$0	-27.12%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg1RR			**$2,608**			**$2,628**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Secondary Small Optional TOU - Cg3OTOU							
Customer charge							
Single PH per day	1,683,750	$0.90840	$1,529,519	1,683,750	$0.90840	$1,529,519	0.00%
Three PH per day	127,627	$1.45350	$185,506	127,627	$1.45350	$185,506	0.00%
Energy charge							
On-peak	27,701,547	$0.22894	$6,341,992	27,701,547	$0.23128	$6,406,814	1.02%
Off-peak	72,313,224	$0.06541	$4,730,008	72,313,224	$0.06608	$4,778,458	1.02%
		$0.95875					
Fuel cost adjustment							
Adjustment	100,014,771	$0.00000	$0	100,014,771	$0.00000	$0	0.00%
Other							
Other	100,014,771	$0.00000	$0	100,014,771	$0.00000	$0	0.00%
Revenue sharing	100,014,771	$0.00000	$0	100,014,771	$0.00000	$0	0.00%
Act 141 capped credits	334,129	-$0.00236	-$789	334,129	-$0.00172	-$575	-27.12%
Act 141 capped contribution	334,129	$0.00091	$305	334,129	$0.00091	$305	0.00%
Total Revenue: General Secondary Small Optional TOU - Cg3OTOU			**$12,786,542**			**$12,900,027**	
General Secondary Flat Rate - Cg5 (50 < kW > 100)							
Customer charge							
Single PH per day	143,259	$2.07120	$296,718	143,259	$2.07120	$296,718	0.00%
Three PH per day	496,528	$3.31400	$1,645,493	496,528	$3.31400	$1,645,493	0.00%
Energy charge	246,332,884	$0.11225	$27,650,866	246,332,884	$0.11351	$27,961,246	1.12%
Fuel cost adjustment	246,332,884	$0.00000	$0	246,332,884	$0.00000	$0	0.00%
Other							
Other	246,332,884	$0.00000	$0	246,332,884	$0.00000	$0	0.00%
Revenue sharing	246,332,884	$0.00000	$0	246,332,884	$0.00000	$0	0.00%
Act 141 capped credits	8,954,287	-$0.00236	-$21,132	8,954,287	-$0.00172	-$15,401	-27.12%
Act 141 capped contribution	8,954,287	$0.00044	$3,975	8,954,287	$0.00044	$3,975	0.00%
Total Revenue: General Secondary Flat Rate - Cg5 (50 < kW > 100)			**$29,575,920**			**$29,892,031**	
General Secondary Flat Rate Response Rewards - Cg5RR							
Customer charge							
Single PH per day	0	$2.07120	$0	0	$2.07120	$0	0.00%
Three PH per day	0	$3.31400	$0	0	$3.31400	$0	0.00%
Energy charge							
On-peak	0	$0.17988	$0	0	$0.18172	$0	1.02%
Off-peak	0	$0.06541	$0	0	$0.06608	$0	1.02%
Critical peak	0	$1.17256	$0	0	$1.17256	$0	0.00%
Fuel cost adjustment							
Adjustment	0	$0.00000	$0	0	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Revenue sharing	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00172	$0	-27.12%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg5RR			**$0**			**$0**	

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	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Commercial and Industrial Demand - Cg20 (100-1000 kW)							
Customer charge							
Secondary	1,305,410	$3.05750	$3,991,292	1,305,410	$3.05750	$3,991,292	0.00%
Primary	7,366	$5.58900	$41,167	7,366	$5.58900	$41,167	0.00%
Energy charge							
On-peak	970,687,032	$0.07278	$70,646,602	970,687,032	$0.08	$74,723,488	5.77%
Off-peak	1,818,684,400	$0.04282	$77,876,066	1,818,684,400	$0.04528	$82,350,030	5.74%
Demand charge							
On-peak (summer)	2,641,887	$18.44900	$48,740,172	2,641,887	$18.89600	$49,921,095	2.42%
On-peak (non-summer)	4,824,100	$11.99200	$57,850,612	4,824,100	$12.28200	$59,249,601	2.42%
Standby	6,243	$2.25100	$14,053	6,243	$2.25100	$14,053	0.00%
Customer maximum	9,228,786	$2.39900	$22,139,858	9,228,786	$2.457	$22,675,127	2.42%
Fuel cost adjustment							
Adjustment	2,789,371,433	$0.00000	$0	2,789,371,433	$0.00000	$0	0.00%
Other							
Energy limiter		$0.18847	-$1,857,972		$0.19649	-$1,857,972	4.26%
Primary discount			-$98,726			-$98,726	
Other	2,789,371,433	$0.00000	$0	2,789,371,433	$0.00000	$0	0.00%
Revenue sharing	2,789,371,433	$0.00000	$0	2,789,371,433	$0.00000	$0	0.00%
Act 141 capped credits	299,508,191	-$0.00236	-$706,839	299,508,191	-$0.00172	-$515,154	-27.12%
Act 141 capped contribution	299,508,191	$0.00034	$103,107	299,508,191	$0.00034	$103,107	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20 (100-1000 kW)			**$278,739,391**			**$290,597,108**	
Commercial and Industrial Demand - Cg20RR (100-1000 kW)							
Customer charge							
Secondary	9,616	$3.05750	$29,400	9,616	$3.05750	$29,400	0.00%
Primary	1,265	$5.58900	$7,070	1,265	$5.58900	$7,070	0.00%
Energy charge							
On-peak	18,951,318	$0.05337	$1,011,432	18,951,318	$0.05645	$1,069,802	5.77%
Off-peak	35,084,055	$0.03854	$1,352,139	35,084,055	$0.04075	$1,429,675	5.73%
Critical peak	1,959,780	$0.45365	$889,054	1,959,780	$0.47983	$940,361	5.77%
Demand charge							
On-peak (summer)	60,867	$13.83700	$842,215	60,867	$14.17200	$862,606	2.42%
On-peak (non-summer)	112,122	$8.99400	$1,008,421	112,122	$9.21200	$1,032,864	2.42%
Standby	0	$2.25100	$0	0	$2.25100	$0	0.00%
Customer maximum	220,817	$2.39900	$529,740	220,817	$2.45700	$542,547	2.42%
Fuel cost adjustment							
Adjustment	55,995,153	$0.00000	$0	55,995,153	$0.00000	$0	0.00%
Other							
Primary discount			-$10,664			-$10,664	
Other	55,995,153	$0.00000	$0	55,995,153	$0.00000	$0	0.00%
Revenue sharing	55,995,153	$0.00000	$0	55,995,153	$0.00000	$0	0.00%
Act 141 capped credits	4,032,509	-$0.00236	-$9,517	4,032,509	-$0.00172	-$6,936	-27.12%
Act 141 capped contribution	4,032,509	$0.00032	$1,279	4,032,509	$0.00032	$1,279	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20RR (100-1000 kW)			**$5,650,570**			**$5,898,004**	

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	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Cp Large C&I (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	38,106	$21.86300	$833,122	38,106	$21.86300	$833,122	0.00%
Customer charge per day-primary voltage	18,731	$25.51230	$477,870	18,731	$25.51230	$477,870	0.00%
Customer charge per day-transmission voltag	3,088	$58.29040	$179,981	3,088	$58.29040	$179,981	0.00%
Energy charge-secondary voltage							
On-peak	383,306,492	$0.06872	$26,340,822	383,306,492	$0.06843	$26,229,663	-0.42%
Off-peak	367,624,489	$0.04042	$14,859,382	367,624,489	$0.04025	$14,796,886	-0.42%
Energy charge-primary voltage							
On-peak	545,518,970	$0.06671	$36,391,570	545,518,970	$0.06642	$36,233,370	-0.43%
Off-peak	580,391,373	$0.03924	$22,774,557	580,391,373	$0.03907	$22,675,891	-0.43%
Energy charge-transmission voltage							
On-peak	450,412,897	$0.06587	$29,668,697	450,412,897	$0.06559	$29,542,582	-0.43%
Off-peak	563,472,490	$0.03875	$21,834,559	563,472,490	$0.03858	$21,738,769	-0.44%
Demand charge-secondary voltage							
Peak (summer)	424,318	$20.23500	$8,586,069	424,318	$20.49600	$8,696,816	1.29%
Peak (non-summer)	758,012	$11.24200	$8,521,567	758,012	$11.38700	$8,631,479	1.29%
Intermediate (summer)	14,969	$15.17600	$227,174	14,969	$15.37200	$230,108	1.29%
Intermediate (non-summer)	24,203	$8.43200	$204,078	24,203	$8.54000	$206,692	1.28%
Variable interruptible (summer)	141,804	$12.19600	$1,729,437	141,804	$12.45700	$1,766,448	2.14%
Variable interruptible (non-summer)	279,212	$7.22200	$2,016,466	279,212	$7.36700	$2,056,952	2.01%
Customer maximum	1,921,599	$2.20900	$4,244,812	1,921,599	$2.26400	$4,350,500	2.49%
Demand charge-primary voltage							
Peak (summer)	629,935	$19.78500	$12,463,267	629,935	$20.04000	$12,623,901	1.29%
Peak (non-summer)	1,132,663	$10.99200	$12,450,230	1,132,663	$11.13300	$12,609,935	1.28%
Intermediate (summer)	4,904	$14.83900	$72,774	4,904	$15.03000	$73,711	1.29%
Intermediate (non-summer)	695	$8.24400	$5,726	695	$8.35000	$5,800	1.29%
Variable interruptible (summer)	138,325	$11.74600	$1,624,765	138,325	$12.00100	$1,660,038	2.17%
Variable interruptible (non-summer)	258,977	$6.97200	$1,805,590	258,977	$7.11300	$1,842,106	2.02%
Customer maximum	3,001,035	$1.92600	$5,779,993	3,001,035	$1.92600	$5,779,993	0.00%
Demand charge-transmission voltage							
Peak (summer)	106,498	$19.76200	$2,104,614	106,498	$19.76500	$2,104,934	0.02%
Peak (non-summer)	219,749	$10.97900	$2,412,623	219,749	$10.98100	$2,413,063	0.02%
Intermediate (summer)	134,763	$14.82200	$1,997,462	134,763	$14.82400	$1,997,732	0.01%
Intermediate (non-summer)	275,594	$8.23400	$2,269,238	275,594	$8.23600	$2,269,789	0.02%
Variable interruptible (summer)	359,357	$11.72300	$4,212,746	359,357	$11.72600	$4,213,825	0.03%
Variable interruptible (non-summer)	695,437	$6.95900	$4,839,546	695,437	$6.96100	$4,840,937	0.03%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	2,890,726,711	$0.00000	$0	2,890,726,711	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	1,800,000	$0.50000	$900,000	1,800,000	$0.50000	$900,000	0.00%
Power factor discount			-$217,836			-$217,836	
Other	2,890,726,711	$0.00000	$0	2,890,726,711	$0.00000	$0	0.00%
Load factor credit	419,402,975	-$0.00500	-$2,097,015	419,402,975	-$0.00500	-$2,097,015	0.00%
Act 141 capped credits	2,663,123,376	-$0.00236	-$6,284,971	2,663,123,376	-$0.00172	-$4,580,572	-27.12%
Act 141 capped contribution	2,663,123,376	$0.00030	$790,581	2,663,123,376	$0.00030	$790,581	0.00%
Total Revenue: Cp Large C&I (> 1,000 kW)			**$224,019,499**			**$225,878,048**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Cp Large C&I Response Rewards (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	3,480	$21.86300	$76,074	3,480	$21.86300	$76,074	0.00%
Customer charge per day-primary voltage	2,542	$25.51230	$64,858	2,542	$25.51230	$64,858	0.00%
Customer charge per day-transmission voltag	726	$58.29040	$42,341	726	$58.29040	$42,341	0.00%
Energy charge-secondary voltage							
On-peak	36,741,195	$0.05097	$1,872,699	36,741,195	$0.05132	$1,885,558	0.69%
Off-peak	34,331,772	$0.03597	$1,234,914	34,331,772	$0.03623	$1,243,840	0.72%
Critical peak	1,784,026	$0.43328	$772,983	1,784,026	$0.43622	$778,228	0.68%
Energy charge-primary voltage							
On-peak	51,498,197	$0.04948	$2,548,131	51,498,197	$0.04982	$2,565,640	0.69%
Off-peak	58,663,711	$0.03492	$2,048,537	58,663,711	$0.03516	$2,062,616	0.69%
Critical peak	4,599,345	$0.42058	$1,934,393	4,599,345	$0.42343	$1,947,501	0.68%
Energy charge-transmission voltage							
On-peak	70,398,748	$0.04886	$3,439,683	70,398,748	$0.04919	$3,462,914	0.68%
Off-peak	95,669,458	$0.03449	$3,299,640	95,669,458	$0.03472	$3,321,644	0.67%
Critical peak	5,441,978	$0.41531	$2,260,108	5,441,978	$0.41812	$2,275,400	0.68%
Demand charge-secondary voltage							
Peak (summer)	58,727	$15.17600	$891,235	58,727	$15.37200	$902,746	1.29%
Peak (non-summer)	103,336	$8.43200	$871,331	103,336	$8.54000	$882,492	1.28%
Intermediate (summer)	1,359	$11.38200	$15,466	1,359	$11.52900	$15,665	1.29%
Intermediate (non-summer)	2,964	$6.32400	$18,743	2,964	$6.40500	$18,983	1.28%
Customer maximum	203,372	$2.20900	$449,249	203,372	$2.26400	$460,434	2.49%
Demand charge-primary voltage							
Peak (summer)	72,404	$14.83900	$1,074,403	72,404	$15.03000	$1,088,232	1.29%
Peak (non-summer)	127,358	$8.24400	$1,049,940	127,358	$8.35000	$1,063,440	1.29%
Intermediate (summer)	0	$11.12900	$0	0	$11.27300	$0	1.29%
Intermediate (non-summer)	0	$6.18300	$0	0	$6.26300	$0	1.29%
Customer maximum	262,412	$1.92600	$505,406	262,412	$1.92600	$505,406	0.00%
Demand charge-transmission voltage							
Peak (summer)	106,649	$14.82200	$1,580,752	106,649	$14.82400	$1,580,965	0.01%
Peak (non-summer)	189,484	$8.23400	$1,560,213	189,484	$8.23600	$1,560,592	0.02%
Intermediate (summer)	0	$11.11700	$0	0	$11.11800	$0	0.01%
Intermediate (non-summer)	0	$6.17600	$0	0	$6.17700	$0	0.02%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	359,128,431	$0.00000	$0	359,128,431	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	611,998	$0.50000	$305,999	611,998	$0.50000	$305,999	0.00%
Power factor discount			-$5,031			-$5,031	
Other	359,128,431	$0.00000	$0	359,128,431	$0.00000	$0	0.00%
Revenue sharing	359,128,431	$0.00000	$0	359,128,431	$0.00000	$0	0.00%
Act 141 capped credits	147,537,265	-$0.00236	-$348,188	147,537,265	-$0.00172	-$253,764	-27.12%
Act 141 capped contribution	147,537,265	$0.00034	$50,864	147,537,265	$0.00034	$50,864	0.00%
Total Revenue: Cp Large C&I Response Rewards (> 1,000 kW)			**$27,614,739**			**$27,903,636**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
General Primary Service - New Load Market Pricing (NLMP)							
Customer charge							
Scheduling per day, Secondary	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Scheduling per day, Primary	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Scheduling per day, Transmission	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Energy charge							
Hourly LMP	380,287,940	$0.03148	$11,970,662	380,287,940	$0.03148	$11,970,662	0.00%
Embedded cost adder	380,287,940	$0.00050	$190,144	380,287,940	$0.00050	$190,144	0.00%
Demand charge							
Peak (summer)	428,357	$0.01559	$6,678	428,357	$0.01559	$6,678	0.00%
Transmission demand	428,357	$8.25000	$3,533,946	428,357	$8.25000	$3,533,946	0.00%
Total Revenue: General Primary Service - New Load Market Pricing (NLMP)			**$15,707,999**			**$15,707,999**	
General Primary Service - Real-Time Market Pricing (RTMP)							
Customer charge							
Scheduling per month	84	$1,000.000	$84,000	84	$1,000.000	$84,000	0.00%
Energy charge							
Hourly LMP	377,736,280	$0.03252	$12,285,042	377,736,280	$0.03252	$12,285,042	0.00%
Embedded cost adder	377,736,280	$0.00550	$2,077,550	377,736,280	$0.00550	$2,077,550	0.00%
Demand charge							
Transmission demand	1,089,995	$5.01000	$5,460,877	1,089,995	$5.30000	$5,776,976	5.79%
Total Revenue: General Primary Service - Real-Time Market Pricing (RTMP)			**$19,907,469**			**$20,223,568**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Ls-1 Lighting Service							
Company Owned							
Sodium Vapor							
5,670 Lumens (70W)	2,556	$18.11000	$46,289	2,556	$20.23000	$51,708	11.71%
9,000 Lumens (100W) (Closed)	189,660	$17.87000	$3,389,224	189,660	$17.98000	$3,410,087	0.62%
14,000 Lumens (150W) (Closed)	141,123	$20.02000	$2,825,282	141,123	$20.15000	$2,843,628	0.65%
27,000 Lumens (250W) (Closed)	82,759	$24.26000	$2,007,733	82,759	$24.42000	$2,020,975	0.66%
45,000 Lumens (400W)	6,180	$32.52000	$200,974	6,180	$32.74000	$202,333	0.68%
9,000 Lumens (100W) - Area	57,123	$15.74000	$899,116	57,123	$15.85000	$905,400	0.70%
14,000 Lumens (150W) - Area	10,031	$18.59000	$186,476	10,031	$18.72000	$187,780	0.70%
27,000 Lumens (250W) - Directional	5,091	$29.65000	$150,948	5,091	$29.84000	$151,915	0.64%
45,000 Lumens (400W) - Directional (Close	25,899	$36.27000	$939,357	25,899	$36.51000	$945,572	0.66%
Metal Halide							
8,500 Lumens (150W)	456	$28.60000	$13,042	456	$28.79000	$13,128	0.66%
26,000 Lumens (350W)	180	$31.46000	$5,663	180	$31.67000	$5,701	0.67%
36,000 Lumens (400W) - (Closed)	36	$33.36000	$1,201	36	$33.58000	$1,209	0.66%
26,000 Lumens (350W) - Directional	1,356	$35.27000	$47,826	1,356	$35.51000	$48,152	0.68%
36,000 Lumens (400W) - Directional (Close	4,584	$37.37000	$171,304	4,584	$37.62000	$172,450	0.67%
110,000 Lumens (1000W) - Directional	1,836	$54.10000	$99,328	1,836	$54.46000	$99,989	0.67%
LED							
Class B Low Output Security	0	$13.34000	$0	0	$13.43000	$0	0.67%
Class C Low Output Roadway	18,540	$14.77000	$273,836	18,540	$14.87000	$275,690	0.68%
Class D Med Output Roadway	20,628	$18.35000	$378,524	20,628	$18.46000	$380,793	0.60%
Class E High Output Roadway	19,884	$22.88000	$454,946	19,884	$23.03000	$457,929	0.66%
Class G Med Output Flood	0	$26.69000	$0	0	$26.87000	$0	0.67%
Class H High Output Flood	0	$32.41000	$0	0	$32.63000	$0	0.68%
Class H Med Output Post Top	0	$23.83000	$0	0	$23.99000	$0	0.67%
Class K Med Output Post Top	0	$27.64000	$0	0	$27.83000	$0	0.69%
Class M Med Output Post Top	0	$31.46000	$0	0	$31.67000	$0	0.67%
Customer Owned (closed)							
Sodium Vapor							
9,000 Lumens (100W)	1,476	$12.89000	$19,026	1,476	$12.98000	$19,158	0.70%
14,000 Lumens (150W)	7,908	$14.94000	$118,146	7,908	$15.04000	$118,936	0.67%
27,000 Lumens (250 W)	7,668	$18.79000	$144,082	7,668	$18.92000	$145,079	0.69%
45,000 Lumens (400W)	1,368	$22.89000	$31,314	1,368	$23.04000	$31,519	0.66%
Metal Halide							
8,500 Lumens (150W)	48	$17.89000	$859	48	$18.01000	$864	0.67%
26,000 Lumens (350W)	0	$22.09000	$0	0	$22.24000	$0	0.68%
Common							
Wood Poles	70,812	$5.24000	$371,055	70,812	$5.28000	$373,887	0.76%
Fiberglass Poles 25' / 20'	264	$8.73000	$2,305	264	$8.79000	$2,321	0.69%
Fiberglass Poles 30' / 25'	384	$11.28000	$4,332	384	$11.36000	$4,362	0.71%
Fiberglass Poles 35' / 30'	288	$14.13000	$4,069	288	$14.23000	$4,098	0.71%
Fiberglass Poles 40' / 35'	0	$23.49000	$0	0	$23.65000	$0	0.68%
Spans	83,508	$2.32000	$193,739	83,508	$2.34000	$195,409	0.86%
Excess Footage - Mast Arm	27,348	$0.24000	$6,564	27,348	$0.24000	$6,564	0.00%
Fuel cost adjustment	38,099,601	$0.00000	$0	38,099,601	$0.00000	$0	0.00%
Other							
Other	38,099,601	$0.00000	$0	38,099,601	$0.00000	$0	0.00%
Revenue sharing	38,099,601	$0.00000	$0	38,099,601	$0.00000	$0	0.00%
Act 141 capped credits	3,976,368	-$0.00236	-$9,384	3,976,368	-$0.00172	-$6,839	-27.12%

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Act 141 capped contribution	3,976,368	$0.00196	$7,806	3,976,368	$0.00196	$7,806	0.00%
Total Revenue: Ls-1 Lighting Service			**$12,984,978**			**$13,077,602**	

Electric Rate Design - Test Year 2025
Wisconsin Public Service Corporation

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Nature Wise							
NAT-R per 100 kWh block	52,786	$1.27700	$67,408	52,786	$1.27700	$67,408	0.00%
NAT-C per 100 kWh block	22,571	$1.27700	$28,824	22,571	$1.27700	$28,824	0.00%
Total Revenue: Nature Wise			**$96,232**			**$96,232**	
Automatic Transfer Switch ATS							
Customer charge							
Option 1 per month	216	$236.000	$50,976	216	$236.000	$50,976	0.00%
Option 2 per month	48	$710.000	$34,080	48	$710.000	$34,080	0.00%
Total Revenue: Automatic Transfer Switch ATS			**$85,056**			**$85,056**	
Parallel Generation							
Customer Charge per day (Pg-2A)	7,535	$0.65750	$4,954	7,535	$0.65750	$4,954	0.00%
Customer Charge per day (Pg-2B)	29,097	$0.65750	$19,131	29,097	$0.65750	$19,131	0.00%
Total Revenue: Parallel Generation			**$24,086**			**$24,086**	

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Rg1 -- Residential Service			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
Energy Charge - Base	$0.13213	$0.14305	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg3 -- Residential Service 2TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.24122	$0.26000	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.07538	$0.08125	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg5 -- Residential Service 3TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.30152	$0.32500	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Shoulder Peak Energy Charge - Base	$0.13213	$0.14305	per kWh
Off-Peak Energy Charge - Base	$0.07538	$0.08125	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
RgRR -- Residential Response Rewards			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.26458	$0.28521	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.30198	$1.30198	per kWh
Off-Peak Energy Charge - Base	$0.06784	$0.07313	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1 -- General Secondary Service			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
Energy Charge - Base	$0.11945	$0.12835	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1RR -- General Secondary Service Response Rewards			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.22566	$0.22798	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17680	$1.17680	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06608	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cg3 -- General Secondary Service - Optional TOU			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.22894	$0.23128	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06608	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5 -- General Secondary Service - Flat			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
Energy Charge - Base	$0.11225	$0.11351	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5RR -- General Secondary Service - Response Rewards			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
On-Peak Energy Charge - Base	$0.17988	$0.18172	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17256	$1.17256	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06608	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cg20 -- Commercial and Industrial Demand			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.07278	$0.07698	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.04282	$0.04528	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$18.449	$18.896	per kW
On-Peak Demand Charge - Base (Non-summer)	$11.992	$12.282	per kW
Standby Demand - Base	$2.251	$2.251	per kW
Customer Demand Charge	$2.399	$2.457	per kW
Energy Limiter	$0.18847	$0.19649	per kWh
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand
Cg20RR -- Commercial and Industrial Demand - Response Rewards			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.05337	$0.05645	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$0.45365	$0.47983	per kWh
Off-Peak Energy Charge - Base	$0.03854	$0.04075	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$13.83700	$14.17200	per kW
On-Peak Demand Charge - Base (Non-summer)	$8.99400	$9.21200	per kW
Standby Demand - Base	$2.25100	$2.25100	per kW
Customer Demand Charge	$2.39900	$2.45700	per kW
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Naturewise (NAT)			
NAT-R	$1.27700	$1.27700	per 100 kWh block
NAT-C	$1.27700	$1.27700	per 100 kWh block
Automatic Transfer Switch (ATS)			
Customer Charge - Total	$236.00000	$236.00000	per Month
Customer Charge - Maintenance	$710.00000	$710.00000	per Month
Parallel Generation			
Customer Charge (Pg-2A)	$0.65750	$0.65750	per Day
Customer Charge (Pg-2B)	$0.65750	$0.65750	per Day
COEV-R -- Residential Electric Vehicle Charger Only			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
Energy charge			
On-peak (summer)	$0.25145	$0.26091	per kWh
On-peak (non-summer)	$0.13786	$0.14305	per kWh
Intermediate-peak (summer)	$0.13786	$0.14305	per kWh
Intermediate-peak (non-summer)	$0.13786	$0.14305	per kWh
Off-peak (summer)	$0.06223	$0.06223	per kWh
Off-peak (non-summer)	$0.06223	$0.06223	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
WHEV-R -- Residential Electric Vehicle Whole Home			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
EV-C -- Electric Vehicle Commercial			
Fixed service and administration charge			
Bundled-single port A	$24.00000	$24.00000	per Month, per Port
Bundled-single port B	$24.00000	$24.00000	per Month, per Port
Bundled-single port C	$25.00000	$25.00000	per Month, per Port
Bundled-dual port A	$26.00000	$26.00000	per Month, per Port
Bundled-dual port B	$26.00000	$26.00000	per Month, per Port
Bundled-dual port C	$26.00000	$26.00000	per Month, per Port
Pre-paid-single port A	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port B	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port C	$4.00000	$4.00000	per Month, per Port
Pre-paid-dual port A	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port B	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port C	$2.00000	$2.00000	per Month, per Port
Renewable Pathway Pilot			
One year subscription	$0.00874	$0.02173	per kWh
Five year subscription	$0.00688	$0.01986	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cp -- Large Commercial and Industrial			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.06872	$0.06843	per kWh
On-Peak Energy Charge - Base (Primary)	$0.06671	$0.06642	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.06587	$0.06559	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.04042	$0.04025	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.03924	$0.03907	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.03875	$0.03858	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$20.235	$20.496	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$19.785	$20.040	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$19.762	$19.765	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$11.242	$11.387	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$10.992	$11.133	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$10.979	$10.981	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$15.176	$15.372	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$14.839	$15.030	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$14.822	$14.824	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$8.432	$8.540	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$8.244	$8.350	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$8.234	$8.236	per kW
On-Peak Demand Charge - Summer Variable Int (Secondary)	$12.196	$12.457	per kW
On-Peak Demand Charge - Summer Variable Int (Primary)	$11.746	$12.001	per kW
On-Peak Demand Charge - Summer Variable Int (Transmission)	$11.723	$11.726	per kW
On-Peak Demand Charge - Non-summer Variable Int (Secondary)	$7.222	$7.367	per kW
On-Peak Demand Charge - Non-summer Variable Int (Primary)	$6.972	$7.113	per kW
On-Peak Demand Charge - Non-summer Variable Int (Transmission)	$6.959	$6.961	per kW
Customer Demand Charge (Secondary)	$2.209	$2.264	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW
Interruptible Demand Credit - Summer (Secondary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Primary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Transmission)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Non-Summer (Secondary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Primary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Transmission)	$4.02000	$4.02000	per kW
Load Factor Credit	($0.00500)	($0.00500)	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
CpRR -- Large Commercial and Industrial Response Rewards			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.05097	$0.05132	per kWh
On-Peak Energy Charge - Base (Primary)	$0.04948	$0.04982	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.04886	$0.04919	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base (Secondary)	$0.43328	$0.43622	per kWh
Critical Peak Energy Charge - Base (Primary)	$0.42058	$0.42343	per kWh
Critical Peak Energy Charge - Base (Transmission)	$0.41531	$0.41812	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.03597	$0.03623	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.03492	$0.03516	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.03449	$0.03472	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$15.176	$15.372	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$14.839	$15.030	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$14.822	$14.824	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$8.432	$8.540	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$8.244	$8.350	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$8.234	$8.236	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$11.382	$11.529	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$11.129	$11.273	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$11.117	$11.118	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$6.324	$6.405	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$6.183	$6.263	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$6.176	$6.177	per kW
Customer Demand Charge (Secondary)	$2.209	$2.264	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
New Load Market Pricing (NLMP)			
Scheduleing Charge	$6.00000	$6.00000	per Day
Transmission Demand	$8.25000	$8.25000	per kW
Embedded Cost Adder	$0.00050	$0.00050	per kWh
Real Time Market Pricing (RTMP)			
Scheduling Charge	$1,000.00	$1,000.00	per Month
Embedded Cost Adder	$0.00550	$0.00550	per kWh
Transmission Demand	$5.01000	$5.30000	per kW

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Ls1 Lighting Service			
Company Owned			
Sodium Vapor			
5,670 Lumens (70W)	$18.11000	$20.23000	per Month
9,000 Lumens (100W) (Closed)	$17.87000	$17.98000	per Month
14,000 Lumens (150W) (Closed)	$20.02000	$20.15000	per Month
27,000 Lumens (250W) (Closed)	$24.26000	$24.42000	per Month
45,000 Lumens (400W)	$32.52000	$32.74000	per Month
9,000 Lumens (100W) - Area	$15.74000	$15.85000	per Month
14,000 Lumens (150W) - Area	$18.59000	$18.72000	per Month
27,000 Lumens (250W) - Directional	$29.65000	$29.84000	per Month
45,000 Lumens (400W) - Directional (Closed)	$36.27000	$36.51000	per Month
Metal Halide			
8,500 Lumens (150W)	$28.60000	$28.79000	per Month
26,000 Lumens (350W)	$31.46000	$31.67000	per Month
36,000 Lumens (400W) - (Closed)	$33.36000	$33.58000	per Month
26,000 Lumens (350W) - Directional	$35.27000	$35.51000	per Month
36,000 Lumens (400W) - Directional (Closed)	$37.37000	$37.62000	per Month
110,000 Lumens (1000W) - Directional	$54.10000	$54.46000	per Month
LED			
Class B Low Output Security	$13.34000	$13.43000	per Month
Class C Low Output Roadway	$14.77000	$14.87000	per Month
Class D Med Output Roadway	$18.35000	$18.46000	per Month
Class E High Output Roadway	$22.88000	$23.03000	per Month
Class G Med Output Flood	$26.69000	$26.87000	per Month
Class H High Output Flood	$32.41000	$32.63000	per Month
Class H Med Output Post Top	$23.83000	$23.99000	per Month
Class K Med Output Post Top	$27.64000	$27.83000	per Month
Class M Med Output Post Top	$31.46000	$31.67000	per Month
Customer Owned (Closed)			
Sodium Vapor			
9,000 Lumens (100W)	$12.89000	$12.98000	per Month
14,000 Lumens (150W)	$14.94000	$15.04000	per Month
27,000 Lumens (250 W)	$18.79000	$18.92000	per Month
45,000 Lumens (400W)	$22.89000	$23.04000	per Month
Metal Halide			
8,500 Lumens (150W)	$17.89000	$18.01000	per Month
26,000 Lumens (350W)	$22.09000	$22.24000	per Month
Common			
Wood Poles	$5.24000	$5.28000	per Month
Fiberglass Poles 25' / 20'	$8.73000	$8.79000	per Month
Fiberglass Poles 30' / 25'	$11.28000	$11.36000	per Month
Fiberglass Poles 35' / 30'	$14.13000	$14.23000	per Month
Fiberglass Poles 40' / 35'	$23.49000	$23.65000	per Month
Spans	$2.32000	$2.34000	per Month
Excess Footage - Mast Arm	$0.24000	$0.24000	per Month per Foot
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Embedded Credits for Line Extensions			
Rg1, Rg3, & Rg5	$1,371	$1,859	per Customer
Cg1, Cg3, & Cg5	$2,603	$2,869	per Customer
Cg20 & Cp	$60.47	$67.84	per kW
Act 141 Costs Embedded in Base Rates			
Rg1, Rg3, & Rg5	$0.00227	$0.00179	per kWh
Cg1, Cg3, & Cg5	$0.00236	$0.00172	per kWh
Cg20 & Cp	$0.00236	$0.00172	per kWh
Standard Street Lighting	$0.00236	$0.00172	per kWh

Comparison of Bills for Residential

A	B	C	D	E	F	G
Rg1						
	Typical Bills					
Monthly Use	**Current Rates**		**Authorized 2025**		**Authorized 2025 Change**	
(kWh)	**Monthly**	**Annual**	**Monthly**	**Annual**	**Monthly %**	**Monthly $**
350	$64.17	$770.04	$67.99	$815.88	5.95%	$3.82
450	$77.38	$928.56	$82.29	$987.48	6.35%	$4.91
550	$90.59	$1,087.08	$96.60	$1,159.20	6.63%	$6.01
660	**$105.13**	**$1,261.56**	**$112.33**	**$1,347.96**	**6.85%**	**$7.20**
750	$117.02	$1,404.24	$125.21	$1,502.52	7.00%	$8.19
1,000	$150.05	$1,800.60	$160.97	$1,931.64	7.28%	$10.92
2,000	$282.18	$3,386.16	$304.02	$3,648.24	7.74%	$21.84
3,000	$414.31	$4,971.72	$447.07	$5,364.84	7.91%	$32.76

Electric Revenue Yield - Test Year 2026

Rate Schedule	Booked Energy MWh	Revenue Yield in 2026 With Current Rates	Revenue Yield in 2026 With Authorized 2026 Rates	Percent Change in 2026	Cost of Service Revenue Requirement
Rg1	2,940,901	$479,060,923	$525,785,514	9.75%	
Rg3-OTOU	69,101	$9,592,024	$10,488,801	9.35%	
Rg5-OTOU	20,886	$3,174,027	$3,478,705	9.60%	
Rg RR	3,449	$493,166	$535,092	8.50%	
Total Residential & Farm	3,034,337	$492,320,139	$540,288,112	9.74%	
Cg1	826,203	$116,747,360	$127,093,773	8.86%	
Cg1 RR	15	$2,617	$2,690	2.79%	
Cg3-OTOU	100,323	$12,830,218	$13,246,286	3.24%	
Total Small General Secondary	926,542	$129,580,195	$140,342,749	8.31%	
Total Small Customer Class	**3,960,879**	**$621,900,334**	**$680,630,861**	**9.44%**	
Cg5	247,092	$29,671,980	$30,582,248	3.07%	
Cg5 RR	0	$0	$0	0.00%	
Total Medium Customer Class	**247,092**	**$29,671,980**	**$30,582,248**	**3.07%**	
Cg-20	2,797,969	$279,553,160	$296,341,125	6.01%	
Cg-20RR	56,168	$5,666,582	$5,993,519	5.77%	
Cp-Secondary	761,317	$67,881,275	$69,886,962	2.95%	
Cp-Primary	1,141,474	$88,526,422	$92,317,562	4.28%	
Cp-Transmission	1,027,925	$70,643,226	$71,473,882	1.18%	
Cp-Secondary RR	73,865	$6,280,637	$6,432,989	2.43%	
Cp-Primary RR	116,348	$9,042,903	$9,197,530	1.71%	
Cp-Transmission RR	173,882	$12,660,693	$12,732,038	0.56%	
NLMP	455,679	$20,670,556	$20,670,556	0.00%	
RTMP	377,736	$21,524,416	$22,385,512	4.00%	
Total Large Customer Class	**6,982,364**	**$582,449,870**	**$607,431,677**	**4.29%**	
Ls-1	38,418	$12,984,978	$13,456,790	3.63%	
Total Street Lighting & Other	**38,418**	**$12,984,978**	**$13,456,790**	3.63%	
COEV-R	0	$24,776	$24,776	0.00%	
WHEV-R	0	$724	$724	0.00%	
EV-C	0	$25,728	$25,728	0.00%	
Total EV Customer Class	0	$51,228	$51,228	0.00%	
Naturewise-Residential		$66,060	$66,060	0.00%	
Naturewise-C&I		$28,247	$28,247	0.00%	
Automatic transfer switch		$85,056	$85,056	0.00%	
Parallel generation		$24,020	$24,020	0.00%	
Total Misc Customer Class	0	$203,383	$203,383	0.00%	
Total Wisconsin Retail	**11,228,753**	**$1,247,261,774**	**$1,332,356,187**	**6.82%**	**$1,332,356,434**

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
Residential Flat Rate - Rg1							
Customer charge							
Single PH per day	153,622,309	$0.58915	$90,506,583	153,622,309	$0.58915	$90,506,583	0.00%
Energy charge	2,940,460,997	$0.13213	$388,523,112	2,940,460,997	$0.14802	$435,247,037	12.03%
Fuel cost adjustment	2,940,460,997	$0.00000	$0	2,940,460,997	$0.00000	$0	0.00%
Other							
Other	2,940,460,997	$0.00000	$0	2,940,460,997	$0.00000	$0	0.00%
Revenue sharing	2,940,460,997	$0.00000	$0	2,940,460,997	$0.00000	$0	0.00%
Act 141 capped credits	297,485	-$0.00227	-$675	297,485	-$0.00178	-$530	-21.59%
Act 141 capped contribution	297,485	$0.00062	$185	297,485	$0.00062	$185	0.00%
Total Revenue: Residential Flat Rate - Rg1			**$479,029,205**			**$525,753,276**	
Residential Small Optional 2TOU - Rg3							
Customer charge							
Single PH per day	2,202,470	$0.58915	$1,297,585	2,202,470	$0.58915	$1,297,585	0.00%
Energy charge							
On-peak	18,606,022	$0.24122	$4,488,145	18,606,022	$0.26730	$4,973,390	10.81%
Off-peak	50,494,743	$0.07538	$3,806,294	50,494,743	$0.08353	$4,217,826	10.81%
Fuel cost adjustment							
Adjustment	69,100,765	$0.00000	$0	69,100,765	$0.00000	$0	0.00%
Other							
Other	69,100,765	$0.00000	$0	69,100,765	$0.00000	$0	0.00%
Revenue sharing	69,100,765	$0.00000	$0	69,100,765	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00178	$0	-21.59%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 2TOU - Rg3			**$9,592,024**			**$10,488,801**	
Residential Small Optional 3TOU - Rg5							
Customer charge							
Single PH per day	895,348	$0.58915	$527,494	895,348	$0.58915	$527,494	0.00%
Energy charge							
On-peak	3,249,088	$0.30152	$979,665	3,249,088	$0.33689	$1,094,585	11.73%
Shoulder	5,945,063	$0.13213	$785,521	5,945,063	$0.14802	$879,988	12.03%
Off-peak	11,692,051	$0.07538	$881,347	11,692,051	$0.08353	$976,637	10.81%
Fuel cost adjustment							
Adjustment	20,886,202	$0.00000	$0	20,886,202	$0.00000	$0	0.00%
Other							
Other	20,886,202	$0.00000	$0	20,886,202	$0.00000	$0	0.00%
Revenue sharing	20,886,202	$0.00000	$0	20,886,202	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00178	$0	-21.59%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Small Optional 3TOU - Rg5			**$3,174,027**			**$3,478,705**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Residential Response Rewards - RgRR							
Customer charge							
Single PH per day	132,263	$0.58915	$77,923	132,263	$0.58915	$77,923	0.00%
Energy charge							
On-peak	788,261	$0.26458	$208,558	788,261	$0.29320	$231,118	10.82%
Off-peak	2,639,191	$0.06784	$179,048	2,639,191	$0.07518	$198,414	10.82%
Critical peak	21,227	$1.30198	$27,637	21,227	$1.30198	$27,637	0.00%
Fuel cost adjustment							
Adjustment	3,448,679	$0.00000	$0	3,448,679	$0.00000	$0	0.00%
Other							
Other	3,448,679	$0.00000	$0	3,448,679	$0.00000	$0	0.00%
Revenue sharing	3,448,679	$0.00000	$0	3,448,679	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00178	$0	-21.59%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Response Rewards - RgRR			**$493,166**			**$535,092**	
Residential Charger Only EV - COEV-R							
Fixed service and administration charge							
Bundled service per month	1,093	$20.00000	$21,862	1,093	$20.00000	$21,862	0.00%
Pre-paid service per month	364	$8.00000	$2,915	364	$8.00000	$2,915	0.00%
Energy charge							
On-peak (summer)	8,803	$0.25145	$2,213	8,803	$0.26997	$2,377	7.37%
On-peak (non-summer)	8,803	$0.13786	$1,214	8,803	$0.14802	$1,303	7.37%
Intermediate-peak (summer)	13,205	$0.13786	$1,820	13,205	$0.14802	$1,955	7.37%
Intermediate-peak (non-summer)	13,205	$0.13786	$1,820	13,205	$0.14802	$1,955	7.37%
Off-peak (summer)	198,069	$0.06223	$12,325	198,069	$0.06223	$12,325	0.00%
Off-peak (non-summer)	198,069	$0.06223	$12,325	198,069	$0.06223	$12,325	0.00%
Fuel cost adjustment	440,154	$0.00000	$0	440,154	$0.00000	$0	0.00%
Other							
Other	440,154	$0.00000	$0	440,154	$0.00000	$0	0.00%
Total Revenue: Residential Charger Only EV - COEV-R			**$56,494**			**$57,015**	
Residential Whole Home EV - WHEV-R							
Fixed service and administration charge							
Bundled service per month	32	$20.00000	$638	32	$20.00000	$638	0.00%
Pre-paid service per month	11	$8.00000	$85	11	$8.00000	$85	0.00%
Total Revenue: Residential Whole Home EV - WHEV-R			**$724**			**$724**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Commercial Electric Vehicle EV-C							
Fixed service and administration charge							
Bundled-single port, per month per port A	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port B	96	$24.00000	$2,304	96	$24.00000	$2,304	0.00%
Bundled-single port, per month per port C	96	$25.00000	$2,400	96	$25.00000	$2,400	0.00%
Bundled-dual port, per month per port A	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port B	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Bundled-dual port, per month per port C	240	$26.00000	$6,240	240	$26.00000	$6,240	0.00%
Pre-paid-single port, per month per port A	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port B	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-single port, per month per port C	0	$4.00000	$0	0	$4.00000	$0	0.00%
Pre-paid-dual port, per month per port A	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port B	0	$2.00000	$0	0	$2.00000	$0	0.00%
Pre-paid-dual port, per month per port C	0	$2.00000	$0	0	$2.00000	$0	0.00%
Total Revenue: Commercial Electric Vehicle EV-C			**$25,728**			**$25,728**	
General Secondary Flat Rate - Cg1 (<50 kW)							
Customer charge							
Single PH per day	12,674,725	$0.90840	$11,513,720	12,674,725	$0.90840	$11,513,720	0.00%
Three PH per day	4,520,267	$1.45350	$6,570,208	4,520,267	$1.45350	$6,570,208	0.00%
Energy charge	826,203,230	$0.11945	$98,689,976	826,203,230	$0.13196	$109,025,778	10.47%
Fuel cost adjustment	826,203,230	$0.00000	$0	826,203,230	$0.00000	$0	0.00%
Other							
Other	826,203,230	$0.00000	$0	826,203,230	$0.00000	$0	0.00%
Revenue sharing	826,203,230	$0.00000	$0	826,203,230	$0.00000	$0	0.00%
Act 141 capped credits	16,076,484	-$0.00236	-$37,941	16,076,484	-$0.00170	-$27,330	-27.97%
Act 141 capped contribution	16,076,484	$0.00071	$11,397	16,076,484	$0.00071	$11,397	0.00%
Total Revenue: General Secondary Flat Rate - Cg1 (<50 kW)			**$116,747,360**			**$127,093,773**	
General Secondary Flat Rate Response Rewards - Cg1RR							
Customer charge							
Single PH per day	0	$0.90840	$0	0	$0.90840	$0	0.00%
Three PH per day	382	$1.45350	$555	382	$1.45350	$555	0.00%
Energy charge							
On-peak	5,865	$0.22566	$1,323	5,865	$0.23412	$1,373	3.75%
Off-peak	9,529	$0.06541	$623	9,529	$0.06786	$647	3.75%
Critical peak	99	$1.17680	$116	99	$1.17680	$116	0.00%
Fuel cost adjustment							
Adjustment	15,492	$0.00000	$0	15,492	$0.00000	$0	0.00%
Other							
Other	15,492	$0.00000	$0	15,492	$0.00000	$0	0.00%
Revenue sharing	15,492	$0.00000	$0	15,492	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00170	$0	-27.97%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg1RR			**$2,617**			**$2,690**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Secondary Small Optional TOU - Cg3OTOU							
Customer charge							
Single PH per day	1,693,123	$0.90840	$1,538,033	1,693,123	$0.90840	$1,538,033	0.00%
Three PH per day	128,338	$1.45350	$186,540	128,338	$1.45350	$186,540	0.00%
Energy charge							
On-peak	27,786,934	$0.22894	$6,361,541	27,786,934	$0.23751	$6,599,675	3.74%
Off-peak	72,536,124	$0.06541	$4,744,588	72,536,124	$0.06786	$4,922,301	3.75%
		$0.95875					
Fuel cost adjustment							
Adjustment	100,323,058	$0.00000	$0	100,323,058	$0.00000	$0	0.00%
Other							
Other	100,323,058	$0.00000	$0	100,323,058	$0.00000	$0	0.00%
Revenue sharing	100,323,058	$0.00000	$0	100,323,058	$0.00000	$0	0.00%
Act 141 capped credits	334,129	-$0.00236	-$789	334,129	-$0.00170	-$568	-27.97%
Act 141 capped contribution	334,129	$0.00091	$305	334,129	$0.00091	$305	0.00%
Total Revenue: General Secondary Small Optional TOU - Cg3OTOU			**$12,830,218**			**$13,246,286**	
General Secondary Flat Rate - Cg5 (50 < kW > 100)							
Customer charge							
Single PH per day	144,059	$2.07120	$298,374	144,059	$2.07120	$298,374	0.00%
Three PH per day	499,295	$3.31400	$1,654,665	499,295	$3.31400	$1,654,665	0.00%
Energy charge	247,092,183	$0.11225	$27,736,098	247,092,183	$0.11591	$28,640,455	3.26%
Fuel cost adjustment	247,092,183	$0.00000	$0	247,092,183	$0.00000	$0	0.00%
Other							
Other	247,092,183	$0.00000	$0	247,092,183	$0.00000	$0	0.00%
Revenue sharing	247,092,183	$0.00000	$0	247,092,183	$0.00000	$0	0.00%
Act 141 capped credits	8,954,287	-$0.00236	-$21,132	8,954,287	-$0.00170	-$15,222	-27.97%
Act 141 capped contribution	8,954,287	$0.00044	$3,975	8,954,287	$0.00044	$3,975	0.00%
Total Revenue: General Secondary Flat Rate - Cg5 (50 < kW > 100)			**$29,671,980**			**$30,582,248**	
General Secondary Flat Rate Response Rewards - Cg5RR							
Customer charge							
Single PH per day	0	$2.07120	$0	0	$2.07120	$0	0.00%
Three PH per day	0	$3.31400	$0	0	$3.31400	$0	0.00%
Energy charge							
On-peak	0	$0.17988	$0	0	$0.18662	$0	3.75%
Off-peak	0	$0.06541	$0	0	$0.06786	$0	3.75%
Critical peak	0	$1.17256	$0	0	$1.17256	$0	0.00%
Fuel cost adjustment							
Adjustment	0	$0.00000	$0	0	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Revenue sharing	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00236	$0	0	-$0.00170	$0	-27.97%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Flat Rate Response Rewards - Cg5RR			**$0**			**$0**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Commercial and Industrial Demand - Cg20 (100-1000 kW)							
Customer charge							
Secondary	1,312,671	$3.05750	$4,013,492	1,312,671	$3.05750	$4,013,492	0.00%
Primary	7,407	$5.58900	$41,397	7,407	$5.58900	$41,397	0.00%
Energy charge		$0.00000					
On-peak	973,679,090	$0.07278	$70,864,364	973,679,090	$0.07532	$73,337,509	3.49%
Off-peak	1,824,290,335	$0.04282	$78,116,112	1,824,290,335	$0.04431	$80,834,305	3.48%
Demand charge							
On-peak (summer)	2,650,969	$18.44900	$48,907,725	2,650,969	$20.08	$53,231,190	8.84%
On-peak (non-summer)	4,837,938	$11.99200	$58,016,548	4,837,938	$13.05200	$63,144,761	8.84%
Standby	6,261	$2.25100	$14,094	6,261	$2.25100	$14,094	0.00%
Customer maximum	9,228,786	$2.39900	$22,139,858	9,228,786	$2.61	$24,087,131	8.80%
Fuel cost adjustment							
Adjustment	2,797,969,425	$0.00000	$0	2,797,969,425	$0.00000	$0	0.00%
Other							
Energy limiter		$0.18847	-$1,857,972		$0.19979	-$1,857,972	6.01%
Primary discount			-$98,726			-$98,726	
Other	2,797,969,425	$0.00000	$0	2,797,969,425	$0.00000	$0	0.00%
Revenue sharing	2,797,969,425	$0.00000	$0	2,797,969,425	$0.00000	$0	0.00%
Act 141 capped credits	299,508,191	-$0.00236	-$706,839	299,508,191	-$0.00170	-$509,164	-27.97%
Act 141 capped contribution	299,508,191	$0.00034	$103,107	299,508,191	$0.00034	$103,107	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20 (100-1000 kW)			**$279,553,160**			**$296,341,125**	
Commercial and Industrial Demand - Cg20RR (100-1000 kW)							
Customer charge							
Secondary	9,669	$3.05750	$29,562	9,669	$3.05750	$29,562	0.00%
Primary	1,272	$5.58900	$7,110	1,272	$5.58900	$7,110	0.00%
Energy charge							
On-peak	19,009,734	$0.05337	$1,014,549	19,009,734	$0.05523	$1,049,908	3.49%
Off-peak	35,192,199	$0.03854	$1,356,307	35,192,199	$0.03988	$1,403,465	3.48%
Critical peak	1,965,820	$0.45365	$891,794	1,965,820	$0.46946	$922,874	3.49%
Demand charge							
On-peak (summer)	61,075	$13.83700	$845,098	61,075	$15.06000	$919,793	8.84%
On-peak (non-summer)	112,444	$8.99400	$1,011,322	112,444	$9.78900	$1,100,715	8.84%
Standby	0	$2.25100	$0	0	$2.25100	$0	0.00%
Customer maximum	220,817	$2.39900	$529,740	220,817	$2.61000	$576,332	8.80%
Fuel cost adjustment							
Adjustment	56,167,753	$0.00000	$0	56,167,753	$0.00000	$0	0.00%
Other							
Primary discount			-$10,664			-$10,664	
Other	56,167,753	$0.00000	$0	56,167,753	$0.00000	$0	0.00%
Revenue sharing	56,167,753	$0.00000	$0	56,167,753	$0.00000	$0	0.00%
Act 141 capped credits	4,032,509	-$0.00236	-$9,517	4,032,509	-$0.00170	-$6,855	-27.97%
Act 141 capped contribution	4,032,509	$0.00032	$1,279	4,032,509	$0.00032	$1,279	0.00%
Total Revenue: Commercial and Industrial Demand - Cg20RR (100-1000 kW)			**$5,666,582**			**$5,993,519**	

Electric Rate Design - Test Year 2026
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Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
Cp Large C&I (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	38,106	$21.86300	$833,122	38,106	$21.86300	$833,122	0.00%
Customer charge per day-primary voltage	18,731	$25.51230	$477,870	18,731	$25.51230	$477,870	0.00%
Customer charge per day-transmission voltage	3,088	$58.29040	$179,981	3,088	$58.29040	$179,981	0.00%
Energy charge-secondary voltage							
On-peak	388,608,049	$0.06872	$26,705,145	388,608,049	$0.06442	$25,034,131	-6.26%
Off-peak	372,709,147	$0.04042	$15,064,904	372,709,147	$0.03789	$14,121,950	-6.26%
Energy charge-primary voltage							
On-peak	553,059,903	$0.06671	$36,894,626	553,059,903	$0.06253	$34,582,836	-6.27%
Off-peak	588,414,361	$0.03924	$23,089,380	588,414,361	$0.03678	$21,641,880	-6.27%
Energy charge-transmission voltage							
On-peak	456,649,823	$0.06587	$30,079,524	456,649,823	$0.06175	$28,198,127	-6.25%
Off-peak	571,274,967	$0.03875	$22,136,905	571,274,967	$0.03632	$20,748,707	-6.27%
Demand charge-secondary voltage							
Peak (summer)	430,084	$20.23500	$8,702,755	430,084	$24.01800	$10,329,764	18.70%
Peak (non-summer)	768,593	$11.24200	$8,640,520	768,593	$13.34300	$10,255,333	18.69%
Intermediate (summer)	15,173	$15.17600	$230,263	15,173	$18.01400	$273,323	18.70%
Intermediate (non-summer)	24,541	$8.43200	$206,926	24,541	$10.00700	$245,577	18.68%
Variable interruptible (summer)	143,731	$12.19600	$1,752,945	143,731	$15.97900	$2,296,680	31.02%
Variable interruptible (non-summer)	283,111	$7.22200	$2,044,628	283,111	$9.32300	$2,639,445	29.09%
Customer maximum	1,921,599	$2.20900	$4,244,812	1,921,599	$2.29100	$4,402,383	3.71%
Demand charge-primary voltage							
Peak (summer)	638,480	$19.78500	$12,632,321	638,480	$23.48300	$14,993,419	18.69%
Peak (non-summer)	1,148,475	$10.99200	$12,624,034	1,148,475	$13.04600	$14,983,001	18.69%
Intermediate (summer)	4,971	$14.83900	$73,762	4,971	$17.61200	$87,546	18.69%
Intermediate (non-summer)	704	$8.24400	$5,806	704	$9.78500	$6,891	18.69%
Variable interruptible (summer)	140,202	$11.74600	$1,646,810	140,202	$15.44400	$2,165,276	31.48%
Variable interruptible (non-summer)	262,594	$6.97200	$1,830,805	262,594	$9.02600	$2,370,173	29.46%
Customer maximum	3,001,035	$1.92600	$5,779,993	3,001,035	$1.92600	$5,779,993	0.00%
Demand charge-transmission voltage							
Peak (summer)	107,945	$19.76200	$2,133,215	107,945	$23.16000	$2,500,014	17.19%
Peak (non-summer)	222,821	$10.97900	$2,446,355	222,821	$12.86700	$2,867,041	17.20%
Intermediate (summer)	136,595	$14.82200	$2,024,610	136,595	$17.37000	$2,372,654	17.19%
Intermediate (non-summer)	279,448	$8.23400	$2,300,971	279,448	$9.65000	$2,696,669	17.20%
Variable interruptible (summer)	364,240	$11.72300	$4,269,990	364,240	$15.12100	$5,507,678	28.99%
Variable interruptible (non-summer)	705,157	$6.95900	$4,907,187	705,157	$8.84700	$6,238,523	27.13%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	2,930,716,250	$0.00000	$0	2,930,716,250	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	1,800,000	$0.50000	$900,000	1,800,000	$0.50000	$900,000	0.00%
Power factor discount			-$217,836			-$217,836	
Other	2,930,716,250	$0.00000	$0	2,930,716,250	$0.00000	$0	0.00%
Load factor credit	419,402,975	-$0.00500	-$2,097,015	419,402,975	-$0.00500	-$2,097,015	0.00%
Act 141 capped credits	2,663,123,376	-$0.00236	-$6,284,971	2,663,123,376	-$0.00170	-$4,527,310	-27.97%
Act 141 capped contribution	2,663,123,376	$0.00030	$790,581	2,663,123,376	$0.00030	$790,581	0.00%
Total Revenue: Cp Large C&I (> 1,000 kW)			**$227,050,922**			**$233,678,406**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Cp Large C&I Response Rewards (> 1,000 kW)							
Customer charge							
Customer charge per day-secondary voltage	3,480	$21.86300	$76,074	3,480	$21.86300	$76,074	0.00%
Customer charge per day-primary voltage	2,542	$25.51230	$64,858	2,542	$25.51230	$64,858	0.00%
Customer charge per day-transmission voltage	726	$58.29040	$42,341	726	$58.29040	$42,341	0.00%
Energy charge-secondary voltage							
On-peak	37,249,323	$0.05097	$1,898,598	37,249,323	$0.04832	$1,799,887	-5.20%
Off-peak	34,806,578	$0.03597	$1,251,993	34,806,578	$0.03410	$1,186,904	-5.20%
Critical peak	1,808,698	$0.43328	$783,673	1,808,698	$0.41068	$742,796	-5.22%
Energy charge-primary voltage							
On-peak	52,210,413	$0.04948	$2,583,371	52,210,413	$0.04690	$2,448,668	-5.21%
Off-peak	59,475,025	$0.03492	$2,076,868	59,475,025	$0.03310	$1,968,623	-5.21%
Critical peak	4,662,954	$0.42058	$1,961,145	4,662,954	$0.39864	$1,858,840	-5.22%
Energy charge-transmission voltage							
On-peak	71,372,357	$0.04886	$3,487,253	71,372,357	$0.04631	$3,305,254	-5.22%
Off-peak	96,992,559	$0.03449	$3,345,273	96,992,559	$0.03269	$3,170,687	-5.22%
Critical peak	5,517,240	$0.41531	$2,291,365	5,517,240	$0.39364	$2,171,806	-5.22%
Demand charge-secondary voltage							
Peak (summer)	59,525	$15.17600	$903,348	59,525	$18.01400	$1,072,280	18.70%
Peak (non-summer)	104,779	$8.43200	$883,494	104,779	$10.00700	$1,048,520	18.68%
Intermediate (summer)	1,359	$11.38200	$15,466	1,359	$13.51100	$18,358	18.70%
Intermediate (non-summer)	2,964	$6.32400	$18,743	2,964	$7.50500	$22,243	18.67%
Customer maximum	203,372	$2.20900	$449,249	203,372	$2.29100	$465,925	3.71%
Demand charge-primary voltage							
Peak (summer)	73,389	$14.83900	$1,089,016	73,389	$17.61200	$1,292,523	18.69%
Peak (non-summer)	129,136	$8.24400	$1,064,594	129,136	$9.78500	$1,263,592	18.69%
Intermediate (summer)	0	$11.12900	$0	0	$13.20900	$0	18.69%
Intermediate (non-summer)	0	$6.18300	$0	0	$7.33900	$0	18.70%
Customer maximum	262,412	$1.92600	$505,406	262,412	$1.92600	$505,406	0.00%
Demand charge-transmission voltage							
Peak (summer)	108,099	$14.82200	$1,602,239	108,099	$17.37000	$1,877,675	17.19%
Peak (non-summer)	192,129	$8.23400	$1,581,990	192,129	$9.65000	$1,854,044	17.20%
Intermediate (summer)	0	$11.11700	$0	0	$13.02800	$0	17.19%
Intermediate (non-summer)	0	$6.17600	$0	0	$7.23800	$0	17.20%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	364,095,147	$0.00000	$0	364,095,147	$0.00000	$0	0.00%
Other							
Standby	0	$3.50000	$0	0	$3.50000	$0	0.00%
Substation transformer capacity	620,464	$0.50000	$310,232	620,464	$0.50000	$310,232	0.00%
Power factor discount			-$5,031			-$5,031	
Other	364,095,147	$0.00000	$0	364,095,147	$0.00000	$0	0.00%
Revenue sharing	364,095,147	$0.00000	$0	364,095,147	$0.00000	$0	0.00%
Act 141 capped credits	147,537,265	-$0.00236	-$348,188	147,537,265	-$0.00170	-$250,813	-27.97%
Act 141 capped contribution	147,537,265	$0.00034	$50,864	147,537,265	$0.00034	$50,864	0.00%
Total Revenue: Cp Large C&I Response Rewards (> 1,000 kW)			**$27,984,234**			**$28,362,558**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Primary Service - New Load Market Pricing (NLMP)							
Customer charge							
Scheduling per day, Secondary	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Scheduling per day, Primary	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Scheduling per day, Transmission	365	$6.00000	$2,190	365	$6.00000	$2,190	0.00%
Energy charge							
Hourly LMP	455,678,690	$0.03554	$16,196,694	455,678,690	$0.03554	$16,196,694	0.00%
Embedded cost adder	455,678,690	$0.00050	$227,839	455,678,690	$0.00050	$227,839	0.00%
Demand charge							
Peak (summer)	512,904	$0.01559	$7,996	512,904	$0.01559	$7,996	0.00%
Transmission demand	512,904	$8.25000	$4,231,457	512,904	$8.25000	$4,231,457	0.00%
Total Revenue: General Primary Service - New Load Market Pricing (NLMP)			**$20,670,556**			**$20,670,556**	
General Primary Service - Real-Time Market Pricing (RTMP)							
Customer charge							
Scheduling per month	84	$1,000.000	$84,000	84	$1,000.000	$84,000	0.00%
Energy charge							
Hourly LMP	377,736,280	$0.03680	$13,901,989	377,736,280	$0.03680	$13,901,989	0.00%
Embedded cost adder	377,736,280	$0.00550	$2,077,550	377,736,280	$0.00550	$2,077,550	0.00%
Demand charge							
Transmission demand	1,089,995	$5.01000	$5,460,877	1,089,995	$5.80000	$6,321,974	15.77%
Total Revenue: General Primary Service - Real-Time Market Pricing (RTMP)			**$21,524,416**			**$22,385,512**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Ls-1 Lighting Service							
Company Owned							
Sodium Vapor							
5,670 Lumens (70W)	2,556	$18.11000	$46,289	2,556	$22.75000	$58,149	25.62%
9,000 Lumens (100W) (Closed)	189,660	$17.87000	$3,389,224	189,660	$18.50000	$3,508,710	3.53%
14,000 Lumens (150W) (Closed)	141,123	$20.02000	$2,825,282	141,123	$20.73000	$2,925,480	3.55%
27,000 Lumens (250W) (Closed)	82,759	$24.26000	$2,007,733	82,759	$25.12000	$2,078,906	3.54%
45,000 Lumens (400W)	6,180	$32.52000	$200,974	6,180	$33.67000	$208,081	3.54%
9,000 Lumens (100W) - Area	57,123	$15.74000	$899,116	57,123	$16.30000	$931,105	3.56%
14,000 Lumens (150W) - Area	10,031	$18.59000	$186,476	10,031	$19.25000	$193,097	3.55%
27,000 Lumens (250W) - Directional	5,091	$29.65000	$150,948	5,091	$30.70000	$156,294	3.54%
45,000 Lumens (400W) - Directional (Closec	25,899	$36.27000	$939,357	25,899	$37.55000	$972,507	3.53%
Metal Halide							
8,500 Lumens (150W)	456	$28.60000	$13,042	456	$29.61000	$13,502	3.53%
26,000 Lumens (350W)	180	$31.46000	$5,663	180	$32.57000	$5,863	3.53%
36,000 Lumens (400W) - (Closed)	36	$33.36000	$1,201	36	$34.54000	$1,243	3.54%
26,000 Lumens (350W) - Directional	1,356	$35.27000	$47,826	1,356	$36.52000	$49,521	3.54%
36,000 Lumens (400W) - Directional (Closec	4,584	$37.37000	$171,304	4,584	$38.69000	$177,355	3.53%
110,000 Lumens (1000W) - Directional	1,836	$54.10000	$99,328	1,836	$56.01000	$102,834	3.53%
LED							
Class B Low Output Security	0	$13.34000	$0	0	$13.81000	$0	3.52%
Class C Low Output Roadway	18,540	$14.77000	$273,836	18,540	$15.29000	$283,477	3.52%
Class D Med Output Roadway	20,628	$18.35000	$378,524	20,628	$19.00000	$391,932	3.54%
Class E High Output Roadway	19,884	$22.88000	$454,946	19,884	$23.69000	$471,052	3.54%
Class G Med Output Flood	0	$26.69000	$0	0	$27.63000	$0	3.52%
Class H High Output Flood	0	$32.41000	$0	0	$33.55000	$0	3.52%
Class H Med Output Post Top	0	$23.83000	$0	0	$24.67000	$0	3.52%
Class K Med Output Post Top	0	$27.64000	$0	0	$28.62000	$0	3.55%
Class M Med Output Post Top	0	$31.46000	$0	0	$32.57000	$0	3.53%
Customer Owned (closed)							
Sodium Vapor							
9,000 Lumens (100W)	1,476	$12.89000	$19,026	1,476	$13.35000	$19,705	3.57%
14,000 Lumens (150W)	7,908	$14.94000	$118,146	7,908	$15.47000	$122,337	3.55%
27,000 Lumens (250 W)	7,668	$18.79000	$144,082	7,668	$19.45000	$149,143	3.51%
45,000 Lumens (400W)	1,368	$22.89000	$31,314	1,368	$23.70000	$32,422	3.54%
Metal Halide							
8,500 Lumens (150W)	48	$17.89000	$859	48	$18.52000	$889	3.52%
26,000 Lumens (350W)	0	$22.09000	$0	0	$22.87000	$0	3.53%
Common							
Wood Poles	70,812	$5.24000	$371,055	70,812	$5.42000	$383,801	3.44%
Fiberglass Poles 25' / 20'	264	$8.73000	$2,305	264	$9.04000	$2,387	3.55%
Fiberglass Poles 30' / 25'	384	$11.28000	$4,332	384	$11.68000	$4,485	3.55%
Fiberglass Poles 35' / 30'	288	$14.13000	$4,069	288	$14.63000	$4,213	3.54%
Fiberglass Poles 40' / 35'	0	$23.49000	$0	0	$24.32000	$0	3.53%
Spans	83,508	$2.32000	$193,739	83,508	$2.40000	$200,419	3.45%
Excess Footage - Mast Arm	27,348	$0.24000	$6,564	27,348	$0.25000	$6,837	4.17%
Fuel cost adjustment	38,418,475	$0.00000	$0	38,418,475	$0.00000	$0	0.00%
Other							
Other	38,418,475	$0.00000	$0	38,418,475	$0.00000	$0	0.00%
Revenue sharing	38,418,475	$0.00000	$0	38,418,475	$0.00000	$0	0.00%
Act 141 capped credits	3,976,368	-$0.00236	-$9,384	3,976,368	-$0.00170	-$6,760	-27.97%
Act 141 capped contribution	3,976,368	$0.00196	$7,806	3,976,368	$0.00196	$7,806	0.00%
Total Revenue: Ls-1 Lighting Service			**$12,984,978**			**$13,456,790**	

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026

Electric Rate Design - Test Year 2026
Wisconsin Public Service Corporation

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Nature Wise							
NAT-R per 100 kWh block	51,730	$1.27700	$66,060	51,730	$1.27700	$66,060	0.00%
NAT-C per 100 kWh block	22,120	$1.27700	$28,247	22,120	$1.27700	$28,247	0.00%
Total Revenue: Nature Wise			**$94,307**			**$94,307**	
Automatic Transfer Switch ATS							
Customer charge							
Option 1 per month	216	$236.000	$50,976	216	$236.000	$50,976	0.00%
Option 2 per month	48	$710.000	$34,080	48	$710.000	$34,080	0.00%
Total Revenue: Automatic Transfer Switch ATS			**$85,056**			**$85,056**	
Parallel Generation							
Customer Charge per day (Pg-2A)	7,516	$0.65750	$4,942	7,516	$0.65750	$4,942	0.00%
Customer Charge per day (Pg-2B)	29,017	$0.65750	$19,079	29,017	$0.65750	$19,079	0.00%
Total Revenue: Parallel Generation			**$24,020**			**$24,020**	

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Rg1 -- Residential Service			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
Energy Charge - Base	$0.13213	$0.14802	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg3 -- Residential Service 2TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.24122	$0.26730	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.07538	$0.08353	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg5 -- Residential Service 3TOU			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.30152	$0.33689	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Shoulder Peak Energy Charge - Base	$0.13213	$0.14802	per kWh
Off-Peak Energy Charge - Base	$0.07538	$0.08353	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
RgRR -- Residential Response Rewards			
Customer Charge - Single Phase-Year	$0.58915	$0.58915	per Day
Customer Charge - Single Phase-Seasonal	$1.17830	$1.17830	per Day
On-Peak Energy Charge - Base	$0.26458	$0.29320	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.30198	$1.30198	per kWh
Off-Peak Energy Charge - Base	$0.06784	$0.07518	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1 -- General Secondary Service			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
Energy Charge - Base	$0.11945	$0.13196	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg1RR -- General Secondary Service Response Rewards			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.22566	$0.23412	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17680	$1.17680	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06786	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cg3 -- General Secondary Service - Optional TOU			
Customer Charge - Single Phase-Year	$0.90840	$0.90840	per Day
Customer Charge - Single Phase-Seasonal	$1.81680	$1.81680	per Day
Customer Charge - Three Phase-Year	$1.45350	$1.45350	per Day
Customer Charge - Three Phase-Seasonal	$2.90700	$2.90700	per Day
On-Peak Energy Charge - Base	$0.22894	$0.23751	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06786	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5 -- General Secondary Service - Flat			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
Energy Charge - Base	$0.11225	$0.11591	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Cg5RR -- General Secondary Service - Response Rewards			
Customer Charge - Single Phase-Year	$2.07120	$2.07120	per Day
Customer Charge - Single Phase-Seasonal	$4.14250	$4.14250	per Day
Customer Charge - Three Phase-Year	$3.31400	$3.31400	per Day
Customer Charge - Three Phase-Seasonal	$6.62790	$6.62790	per Day
On-Peak Energy Charge - Base	$0.17988	$0.18662	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$1.17256	$1.17256	per kWh
Off-Peak Energy Charge - Base	$0.06541	$0.06786	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cg20 -- Commercial and Industrial Demand			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.07278	$0.07532	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.04282	$0.04431	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$18.449	$20.080	per kW
On-Peak Demand Charge - Base (Non-summer)	$11.992	$13.052	per kW
Standby Demand - Base	$2.251	$2.251	per kW
Customer Demand Charge	$2.399	$2.610	per kW
Energy Limiter	$0.18847	$0.19979	per kWh
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand
Cg20RR -- Commercial and Industrial Demand - Response Rewards			
Customer Charge - Single Phase	$3.05750	$3.05750	per Day
Customer Charge - Three Phase	$5.58900	$5.58900	per Day
On-Peak Energy Charge - Base	$0.05337	$0.05523	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base	$0.45365	$0.46946	per kWh
Off-Peak Energy Charge - Base	$0.03854	$0.03988	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Summer)	$13.83700	$15.06000	per kW
On-Peak Demand Charge - Base (Non-summer)	$8.99400	$9.78900	per kW
Standby Demand - Base	$2.25100	$2.25100	per kW
Customer Demand Charge	$2.39900	$2.61000	per kW
Primary Discount-Metering Primary Service	1.10%	1.10%	Discount
Primary Discount-Metering Transmission Service	2.00%	2.00%	Discount
Primary Discount-Delivery Primary Service	$0.36000	$0.36000	per kW of customer max demand
Primary Discount-Delivery Transmission Service	$0.55000	$0.55000	per kW of customer max demand

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Naturewise (NAT)			
NAT-R	$1.27700	$1.27700	per 100 kWh block
NAT-C	$1.27700	$1.27700	per 100 kWh block
Automatic Transfer Switch (ATS)			
Customer Charge - Total	$236.00000	$236.00000	per Month
Customer Charge - Maintenance	$710.00000	$710.00000	per Month
Parallel Generation			
Customer Charge (Pg-2A)	$0.65750	$0.65750	per Day
Customer Charge (Pg-2B)	$0.65750	$0.65750	per Day
COEV-R -- Residential Electric Vehicle Charger Only			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
Energy charge			
On-peak (summer)	$0.25145	$0.26997	per kWh
On-peak (non-summer)	$0.13786	$0.14802	per kWh
Intermediate-peak (summer)	$0.13786	$0.14802	per kWh
Intermediate-peak (non-summer)	$0.13786	$0.14802	per kWh
Off-peak (summer)	$0.06223	$0.06223	per kWh
Off-peak (non-summer)	$0.06223	$0.06223	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
WHEV-R -- Residential Electric Vehicle Whole Home			
Fixed service and administration charge			
Bundled service	$20.00000	$20.00000	per Month
Pre-paid service	$8.00000	$8.00000	per Month
EV-C -- Electric Vehicle Commercial			
Fixed service and administration charge			
Bundled-single port A	$24.00000	$24.00000	per Month, per Port
Bundled-single port B	$24.00000	$24.00000	per Month, per Port
Bundled-single port C	$25.00000	$25.00000	per Month, per Port
Bundled-dual port A	$26.00000	$26.00000	per Month, per Port
Bundled-dual port B	$26.00000	$26.00000	per Month, per Port
Bundled-dual port C	$26.00000	$26.00000	per Month, per Port
Pre-paid-single port A	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port B	$4.00000	$4.00000	per Month, per Port
Pre-paid-single port C	$4.00000	$4.00000	per Month, per Port
Pre-paid-dual port A	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port B	$2.00000	$2.00000	per Month, per Port
Pre-paid-dual port C	$2.00000	$2.00000	per Month, per Port
Renewable Pathway Pilot			
One year subscription	$0.02173	$0.02173	per kWh
Five year subscription	$0.01986	$0.01986	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cp -- Large Commercial and Industrial			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.06872	$0.06442	per kWh
On-Peak Energy Charge - Base (Primary)	$0.06671	$0.06253	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.06587	$0.06175	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.04042	$0.03789	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.03924	$0.03678	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.03875	$0.03632	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$20.235	$24.018	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$19.785	$23.483	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$19.762	$23.160	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$11.242	$13.343	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$10.992	$13.046	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$10.979	$12.867	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$15.176	$18.014	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$14.839	$17.612	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$14.822	$17.370	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$8.432	$10.007	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$8.244	$9.785	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$8.234	$9.650	per kW
On-Peak Demand Charge - Summer Variable Int (Secondary)	$12.196	$15.979	per kW
On-Peak Demand Charge - Summer Variable Int (Primary)	$11.746	$15.444	per kW
On-Peak Demand Charge - Summer Variable Int (Transmission)	$11.723	$15.121	per kW
On-Peak Demand Charge - Non-summer Variable Int (Secondary)	$7.222	$9.323	per kW
On-Peak Demand Charge - Non-summer Variable Int (Primary)	$6.972	$9.026	per kW
On-Peak Demand Charge - Non-summer Variable Int (Transmission)	$6.959	$8.847	per kW
Customer Demand Charge (Secondary)	$2.209	$2.291	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW
Interruptible Demand Credit - Summer (Secondary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Primary)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Summer (Transmission)	$8.03900	$8.03900	per kW
Interruptible Demand Credit - Non-Summer (Secondary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Primary)	$4.02000	$4.02000	per kW
Interruptible Demand Credit - Non-Summer (Transmission)	$4.02000	$4.02000	per kW
Load Factor Credit	($0.00500)	($0.00500)	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
CpRR -- Large Commercial and Industrial Response Rewards			
Customer Charge - Secondary	$21.86300	$21.86300	per Day
Customer Charge - Primary	$25.51230	$25.51230	per Day
Customer Charge - Transmission	$58.29040	$58.29040	per Day
On-Peak Energy Charge - Base (Secondary)	$0.05097	$0.04832	per kWh
On-Peak Energy Charge - Base (Primary)	$0.04948	$0.04690	per kWh
On-Peak Energy Charge - Base (Transmission)	$0.04886	$0.04631	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Critical Peak Energy Charge - Base (Secondary)	$0.43328	$0.41068	per kWh
Critical Peak Energy Charge - Base (Primary)	$0.42058	$0.39864	per kWh
Critical Peak Energy Charge - Base (Transmission)	$0.41531	$0.39364	per kWh
Off-Peak Energy Charge - Base (Secondary)	$0.03597	$0.03410	per kWh
Off-Peak Energy Charge - Base (Primary)	$0.03492	$0.03310	per kWh
Off-Peak Energy Charge - Base (Transmission)	$0.03449	$0.03269	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Peak (Secondary)	$15.176	$18.014	per kW
On-Peak Demand Charge - Summer Peak (Primary)	$14.839	$17.612	per kW
On-Peak Demand Charge - Summer Peak (Transmission)	$14.822	$17.370	per kW
On-Peak Demand Charge - Non-summer Peak (Secondary)	$8.432	$10.007	per kW
On-Peak Demand Charge - Non-summer Peak (Primary)	$8.244	$9.785	per kW
On-Peak Demand Charge - Non-summer Peak (Transmission)	$8.234	$9.650	per kW
On-Peak Demand Charge - Summer Intermediate (Secondary)	$11.382	$13.511	per kW
On-Peak Demand Charge - Summer Intermediate (Primary)	$11.129	$13.209	per kW
On-Peak Demand Charge - Summer Intermediate (Transmission)	$11.117	$13.028	per kW
On-Peak Demand Charge - Non-summer Intermediate (Secondary)	$6.324	$7.505	per kW
On-Peak Demand Charge - Non-summer Intermediate (Primary)	$6.183	$7.339	per kW
On-Peak Demand Charge - Non-summer Intermediate (Transmission)	$6.176	$7.238	per kW
Customer Demand Charge (Secondary)	$2.209	$2.291	per kW
Customer Demand Charge (Primary)	$1.926	$1.926	per kW
Customer Demand Charge (Transmission)	$0.000	$0.000	per kW
Substation Transformer Capacity	$0.50000	$0.50000	per kVA
Standby	$3.50000	$3.50000	per kW

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
New Load Market Pricing (NLMP)			
Scheduleing Charge	$6.00000	$6.00000	per Day
Transmission Demand	$8.25000	$8.25000	per kW
Embedded Cost Adder	$0.00050	$0.00050	per kWh
Real Time Market Pricing (RTMP)			
Scheduling Charge	$1,000.00	$1,000.00	per Month
Embedded Cost Adder	$0.00550	$0.00550	per kWh
Transmission Demand	$5.01000	$5.80000	per kW

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Ls1 Lighting Service			
Company Owned			
Sodium Vapor			
5,670 Lumens (70W)	$18.11000	$22.75000	per Month
9,000 Lumens (100W) (Closed)	$17.87000	$18.50000	per Month
14,000 Lumens (150W) (Closed)	$20.02000	$20.73000	per Month
27,000 Lumens (250W) (Closed)	$24.26000	$25.12000	per Month
45,000 Lumens (400W)	$32.52000	$33.67000	per Month
9,000 Lumens (100W) - Area	$15.74000	$16.30000	per Month
14,000 Lumens (150W) - Area	$18.59000	$19.25000	per Month
27,000 Lumens (250W) - Directional	$29.65000	$30.70000	per Month
45,000 Lumens (400W) - Directional (Closed)	$36.27000	$37.55000	per Month
Metal Halide			
8,500 Lumens (150W)	$28.60000	$29.61000	per Month
26,000 Lumens (350W)	$31.46000	$32.57000	per Month
36,000 Lumens (400W) - (Closed)	$33.36000	$34.54000	per Month
26,000 Lumens (350W) - Directional	$35.27000	$36.52000	per Month
36,000 Lumens (400W) - Directional (Closed)	$37.37000	$38.69000	per Month
110,000 Lumens (1000W) - Directional	$54.10000	$56.01000	per Month
LED			
Class B Low Output Security	$13.34000	$13.81000	per Month
Class C Low Output Roadway	$14.77000	$15.29000	per Month
Class D Med Output Roadway	$18.35000	$19.00000	per Month
Class E High Output Roadway	$22.88000	$23.69000	per Month
Class G Med Output Flood	$26.69000	$27.63000	per Month
Class H High Output Flood	$32.41000	$33.55000	per Month
Class H Med Output Post Top	$23.83000	$24.67000	per Month
Class K Med Output Post Top	$27.64000	$28.62000	per Month
Class M Med Output Post Top	$31.46000	$32.57000	per Month
Customer Owned (Closed)			
Sodium Vapor			
9,000 Lumens (100W)	$12.89000	$13.35000	per Month
14,000 Lumens (150W)	$14.94000	$15.47000	per Month
27,000 Lumens (250 W)	$18.79000	$19.45000	per Month
45,000 Lumens (400W)	$22.89000	$23.70000	per Month
Metal Halide			
8,500 Lumens (150W)	$17.89000	$18.52000	per Month
26,000 Lumens (350W)	$22.09000	$22.87000	per Month
Common			
Wood Poles	$5.24000	$5.42000	per Month
Fiberglass Poles 25' / 20'	$8.73000	$9.04000	per Month
Fiberglass Poles 30' / 25'	$11.28000	$11.68000	per Month
Fiberglass Poles 35' / 30'	$14.13000	$14.63000	per Month
Fiberglass Poles 40' / 35'	$23.49000	$24.32000	per Month
Spans	$2.32000	$2.40000	per Month
Excess Footage - Mast Arm	$0.24000	$0.25000	per Month per Foot
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Public Service Corporation
Present and Authorized Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Embedded Credits for Line Extensions			
Rg1, Rg3, & Rg5	$1,859	$1,978	per Customer
Cg1, Cg3, & Cg5	$2,869	$3,049	per Customer
Cg20 & Cp	$68	$72.72	per kW
Act 141 Costs Embedded in Base Rates			
Rg1, Rg3, & Rg5	$0.00179	$0.00178	per kWh
Cg1, Cg3, & Cg5	$0.00172	$0.00170	per kWh
Cg20 & Cp	$0.00172	$0.00170	per kWh
Standard Street Lighting	$0.00172	$0.00170	per kWh

Comparison of Bills for Residential

A	B	C	D	E	F	G

Rg1

Monthly Use (kWh)	Typical Bills					
	Current Rates		Authorized 2026		Authorized 2026 Change	
	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
350	$64.17	$770.04	$69.73	$836.76	8.66%	$5.56
450	$77.38	$928.56	$84.53	$1,014.36	9.24%	$7.15
550	$90.59	$1,087.08	$99.33	$1,191.96	9.65%	$8.74
660	**$105.13**	**$1,261.56**	**$115.61**	**$1,387.32**	**9.97%**	**$10.48**
750	$117.02	$1,404.24	$128.93	$1,547.16	10.18%	$11.91
1,000	$150.05	$1,800.60	$165.94	$1,991.28	10.59%	$15.89
2,000	$282.18	$3,386.16	$313.96	$3,767.52	11.26%	$31.78
3,000	$414.31	$4,971.72	$461.98	$5,543.76	11.51%	$47.67

Wisconsin Public Service Corporation
PSCW Adjusted Change of Total Revenue Dollar Amounts between Current and Final Revenue
for the test year ended December 31, 2025

Sales Customers - All	Average Customer Counts	Total Therms	Current Rates 2025 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2025 Total Revenues	Final 2025 Gas Revenues	Final 2025 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Residential Sales Service	309,567	259,066,731	$ 232,768,773	$ 123,710,277	$ 109,058,496	$ 238,701,403	$ 123,710,277	$ 114,991,126	$ 5,932,630	2.55%
Residential Sales Service - Seasonal	1,337	1,163,990	$ 1,317,188	$ 561,058	$ 756,130	$ 1,343,845	$ 561,058	$ 782,787	$ 26,657	2.02%
Firm Commercial/Industrial Standard 0 to 2000 therms	18,767	18,649,664	$ 16,294,544	$ 9,161,312	$ 7,133,232	$ 16,721,621	$ 9,161,312	$ 7,560,309	$ 427,077	2.62%
Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms	28	29,886	$ 29,566	$ 12,748	$ 16,818	$ 30,249	$ 12,748	$ 17,501	$ 683	2.31%
Firm Commercial/IndustrialSmall 2001 to 20000 therms	14,935	87,774,730	$ 61,398,743	$ 41,829,060	$ 19,569,683	$ 63,171,794	$ 41,829,060	$ 21,342,734	$ 1,773,051	2.89%
Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms	4	25,099	$ 16,932	$ 10,334	$ 6,598	$ 17,439	$ 10,334	$ 7,105	$ 507	2.99%
Firm Commercial/Industrial Medium 20001 to 200000 therms	1,305	58,614,262	$ 37,069,382	$ 27,229,336	$ 9,840,046	$ 38,728,167	$ 27,229,336	$ 11,498,831	$ 1,658,785	4.47%
Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Commercial/Industrial Large Over 200000 therms	25	11,668,936	$ 6,128,470	$ 4,905,459	$ 1,223,011	$ 6,429,143	$ 4,905,459	$ 1,523,684	$ 300,673	4.91%
Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Medium 20001 to 200000 therms	13	1,916,081	$ 996,231	$ 728,360	$ 267,871	$ 1,048,922	$ 728,360	$ 320,562	$ 52,691	5.29%
Interruptible Commercial/Industrial Large 200001 to 2400000 therms	1	248,755	$ 122,744	$ 82,748	$ 39,996	$ 129,476	$ 82,748	$ 46,728	$ 6,732	5.48%
Interruptible Commercial/Industrial Super Large Over 2400000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Medium 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Large Over 200000 therms	2	15,354,017	$ 5,649,571	$ 4,912,766	$ 736,805	$ 6,021,140	$ 4,912,766	$ 1,108,374	$ 371,569	6.58%
Commercial/Industrial Electric Generation Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 1 1 to 3,000 therms	22	362,134	$ 250,004	$ 136,240	$ 113,764	$ 250,115	$ 136,240	$ 113,875	$ 111	0.04%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	438,552	$ 280,307	$ 170,319	$ 109,988	$ 280,395	$ 170,319	$ 110,076	$ 88	0.03%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	529,396	$ 311,116	$ 217,678	$ 93,438	$ 311,167	$ 217,678	$ 93,489	$ 51	0.02%
CSR TSL-IG2T	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
CSR TSL-IG4T	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
PWRDEPT	8	21,726,595	$ 10,088,141	$ 7,311,716	$ 2,776,425	$ 10,685,623	$ 7,311,716	$ 3,373,907	$ 597,482	5.92%
PWRDEPT FIRM	-	779,095	$ 382,030	$ 282,692	$ 99,338	$ 403,765	$ 282,692	$ 121,073	$ 21,735	5.69%
Total - Sales Customers - All	346,013	478,347,923	$ 373,103,742	$ 221,262,103	$ 151,841,639	$ 384,274,264	$ 221,262,103	$ 163,012,161	$ 11,170,522	2.99%

Transportation Customers - All	Average Customer Counts	Total Therms	Current Rates 2025 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2025 Total Revenues	Final 2025 Gas Revenues	Final 2025 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/IndustrialSmall 0 to 20000 therms	167	2,472,870	$ 459,115	$ -	$ 459,115	$ 482,610	$ -	$ 482,610	$ 23,495	5.12%
Commercial/Industrial Medium 20001 to 200000 therms	542	42,105,561	$ 5,406,567	$ -	$ 5,406,567	$ 6,147,623	$ -	$ 6,147,623	$ 741,056	13.71%
Commercial/Industrial Large 200000 to 2400000 therms	223	150,945,383	$ 10,826,661	$ -	$ 10,826,661	$ 13,096,788	$ -	$ 13,096,788	$ 2,270,127	20.97%
Commercial/Industrial Super Large Over 2400000 therms	24	134,817,253	$ 5,816,559	$ -	$ 5,816,559	$ 6,213,645	$ -	$ 6,213,645	$ 397,086	6.83%
Commercial/Industrial Extra Super Large Over 15000000 therms	6	159,106,315	$ 4,069,840	$ -	$ 4,069,840	$ 4,387,844	$ -	$ 4,387,844	$ 318,004	7.81%
CSR TSL-IG4T	1	9,297,700	$ 207,744	$ -	$ 207,744	$ 218,170	$ -	$ 218,170	$ 10,426	5.02%
PWRDEPT	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
PWRDEPT FIRM	0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Power Generation Contracted Service	1	64,435,516	$ 440,793	$ -	$ 440,793	$ 440,793	$ -	$ 440,793	$ -	0.00%
Total - Transportation Customers - All	964	563,180,598	$ 27,227,279	$ -	$ 27,227,279	$ 30,987,473	$ -	$ 30,987,473	$ 3,760,194	13.81%

Note1: Gas Costs are priced at Final base rates under both current Gas Revenues and Final 2025 Gas Revenues.

Wisconsin Public Service Corporation
PSCW Adjusted Change of Total Revenue Dollar Amounts between Current and Final Revenue
for the test year ended December 31, 2025

All Customers - All	Average Customer Counts	Total Therms	Current Rates 2025 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2025 Total Revenues	Final 2025 Gas Revenues	Final 2025 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Residential Sales Service	309,567	259,066,731	$ 232,768,773	$ 123,710,277	$ 109,058,496	$ 238,701,403	$ 123,710,277	$ 114,991,126	$ 5,932,630	2.55%
Residential Sales Service - Seasonal	1,337	1,163,990	$ 1,317,188	$ 561,058	$ 756,130	$ 1,343,845	$ 561,058	$ 782,787	$ 26,657	2.02%
Firm Commercial/Industrial Standard 0 to 2000 therms	18,767	18,649,664	$ 16,294,544	$ 9,161,312	$ 7,133,232	$ 16,721,621	$ 9,161,312	$ 7,560,309	$ 427,077	2.62%
Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms	28	29,886	$ 29,566	$ 12,748	$ 16,818	$ 30,249	$ 12,748	$ 17,501	$ 683	2.31%
Firm Commercial/IndustrialSmall 2001 to 20000 therms	14,935	87,774,730	$ 61,398,743	$ 41,829,060	$ 19,569,683	$ 63,171,794	$ 41,829,060	$ 21,342,734	$ 1,773,051	2.89%
Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms	4	25,099	$ 16,932	$ 10,334	$ 6,598	$ 17,439	$ 10,334	$ 7,105	$ 507	2.99%
Firm Commercial/Industrial Medium 20001 to 200000 therms	1,305	58,614,262	$ 37,069,382	$ 27,229,336	$ 9,840,046	$ 38,728,167	$ 27,229,336	$ 11,498,831	$ 1,658,785	4.47%
Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Commercial/Industrial Large Over 200000 therms	25	11,668,936	$ 6,128,470	$ 4,905,459	$ 1,223,011	$ 6,429,143	$ 4,905,459	$ 1,523,684	$ 300,673	4.91%
Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Medium 20001 to 200000 therms	13	1,916,081	$ 996,231	$ 728,360	$ 267,871	$ 1,048,922	$ 728,360	$ 320,562	$ 52,691	5.29%
Interruptible Commercial/Industrial Large 200001 to 2400000 therms	1	248,755	$ 122,744	$ 82,748	$ 39,996	$ 129,476	$ 82,748	$ 46,728	$ 6,732	5.48%
Interruptible Commercial/Industrial Large Over 2400000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Medium 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Large Over 200000 therms	2	15,354,017	$ 5,649,571	$ 4,912,766	$ 736,805	$ 6,021,140	$ 4,912,766	$ 1,108,374	$ 371,569	6.58%
Commercial/Industrial Electric Generation Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 1 1 to 3,000 therms	22	362,134	$ 250,004	$ 136,240	$ 113,764	$ 250,115	$ 136,240	$ 113,875	$ 111	0.04%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	438,552	$ 280,307	$ 170,319	$ 109,988	$ 280,395	$ 170,319	$ 110,076	$ 88	0.03%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	529,396	$ 311,116	$ 217,678	$ 93,438	$ 311,167	$ 217,678	$ 93,489	$ 51	0.02%
Commercial/IndustrialSmall 0 to 20000 therms	167	2,472,870	$ 459,115	$ -	$ 459,115	$ 482,610	$ -	$ 482,610	$ 23,495	5.12%
Commercial/Industrial Medium 20001 to 200000 therms	542	42,105,561	$ 5,406,567	$ -	$ 5,406,567	$ 6,147,623	$ -	$ 6,147,623	$ 741,056	13.71%
Commercial/Industrial Large 200000 to 2400000 therms	223	150,945,383	$ 10,826,661	$ -	$ 10,826,661	$ 13,096,788	$ -	$ 13,096,788	$ 2,270,127	20.97%
Commercial/Industrial Super Large Over 2400000 therms	24	134,817,253	$ 5,816,559	$ -	$ 5,816,559	$ 6,213,645	$ -	$ 6,213,645	$ 397,086	6.83%
Commercial/Industrial Extra Super Large Over 15000000 therms	6	159,106,315	$ 4,069,840	$ -	$ 4,069,840	$ 4,387,844	$ -	$ 4,387,844	$ 318,004	7.81%
CSR TSL-IG4T	1	9,297,700	$ 207,744	$ -	$ 207,744	$ 218,170	$ -	$ 218,170	$ 10,426	5.02%
PWRDEPT	8	21,726,595	$ 10,088,141	$ 7,311,716	$ 2,776,425	$ 10,685,623	$ 7,311,716	$ 3,373,907	$ 597,482	5.92%
PWRDEPT FIRM	0	779,095	$ 382,030	$ 282,692	$ 99,338	$ 403,765	$ 282,692	$ 121,073	$ 21,735	5.69%
Power Generation Contracted Service	1	64,435,516	$ 440,793	$ -	$ 440,793	$ 440,793	$ -	$ 440,793	$ -	0.00%
Total - All Customers - All	346,977	1,041,528,521	$ 400,331,021	$ 221,262,103	$ 179,068,918	$ 415,261,737	$ 221,262,103	$ 193,999,634	$ 14,930,716	3.73%

Note1: Gas Costs are priced at Final base rates under both current Gas Revenues and Final 2025 Gas Revenues.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2025

Residential Service and Commercial FST (0 to 2,000 therms annually) Service

2025 Final Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5589	$ 1.1178	$ 0.5589	NA	$ 0.5589
Enhanced Telemetry Service	$ -	$ -	$ -		$ 0.1973
Transportation Administrative	$ -	$ -	$ -	NA	$ 0.9205
Daily Demand Charge	$ -		$ -	NA	$ -
Distribution Margin per therm	$ 0.1609	$ 0.1609	$ 0.1609	NA	$ 0.1609
Competitive Supply Margin	$ 0.0370	$ 0.0370	$ 0.0370	NA	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	$ 0.0007
Peak Day Margin	$ 0.0015	$ 0.0015	$ 0.0015	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.2001	$ 0.2001	$ 0.2001	NA	$ 0.1616
Peak Demand	$ 0.1160	$ 0.1160	$ 0.1160	NA	$ -
Annual Demand	$ 0.0159	$ 0.0159	$ 0.0159	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ 0.3615	$ 0.3615	$ 0.3615	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	$ 0.4934	NA	$ -
Total Rate	$ 0.6935	$ 0.6935	$ 0.6935	NA	$ 0.1616
Act 141 Surcharge Rate	$ 0.0074	$ 0.0074	$ 0.0068	NA	$ 0.0074

NA = Not Available

2024 Current Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5589	$ 1.1178	$ 0.5589	NA	$ 0.5589
Enhanced Telemetry Service	$ -	$ -	$ -		$ 0.1973
Transportation Administrative	$ -	$ -	$ -	NA	$ 0.9205
Daily Demand Charge	$ -		$ -	NA	$ -
Distribution Margin per therm	$ 0.1491	$ 0.1491	$ 0.1491	NA	$ 0.1491
Competitive Supply Margin	$ 0.0271	$ 0.0271	$ 0.0271	NA	$ -
Daily Balancing Margin	$ 0.0003	$ 0.0003	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.1772	$ 0.1772	$ 0.1772	NA	$ 0.1494
Peak Demand	$ 0.1160	$ 0.1160	$ 0.1160	NA	$ -
Annual Demand	$ 0.0159	$ 0.0159	$ 0.0159	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ 0.3615	$ 0.3615	$ 0.3615	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	$ 0.4934	NA	$ -
Total Rate	$ 0.6706	$ 0.6706	$ 0.6706	NA	$ 0.1494
Act 141 Surcharge Rate	$ 0.0067	$ 0.0067	$ 0.0064	NA	$ 0.0075

NA = Not Available

Final Change in Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ -	$ -	$ -	NA	$ -
Enhanced Telemetry Service					
Transportation Administrative	$ -	$ -	$ -	NA	$ -
Daily Demand Charge	$ -	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.0118	$ 0.0118	$ 0.0118	NA	$ 0.0118
Competitive Supply Margin	$ 0.0099	$ 0.0099	$ 0.0099	NA	$ -
Daily Balancing Margin	$ 0.0004	$ 0.0004	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0008	$ 0.0008	$ 0.0008	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.0229	$ 0.0229	$ 0.0229	NA	$ 0.0122
Peak Demand	$ -	$ -	$ -	NA	$ -
Annual Demand	$ -	$ -	$ -	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ -	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ -	$ -	$ -	NA	$ -
Total Rate	$ 0.0229	$ 0.0229	$ 0.0229	NA	$ 0.0122
Act 141 Surcharge Rate	$ 0.0007	$ 0.0007	$ 0.0004	NA	$ (0.0001)

NA = Not Available

CG-FS Commercial Industrial Small 2,001 to 20,000 Therms Annually

2025 Final Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.9863	$ 1.9726	NA	NA	$ 0.9863
Enhanced Telemetry Service		$ -			$ 0.1973
Transportation Administrative	$ -	$ -	NA	NA	$ 0.9205
Daily Demand Charge	$ -		NA	NA	$ -
Distribution Margin per therm	$ 0.1427	$ 0.1427	NA	NA	$ 0.1427
Competitive Supply Margin	$ 0.0370	$ 0.0370	NA	NA	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	NA	NA	$ 0.0007
Peak Day Margin	$ 0.0015	$ 0.0015	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.1819	$ 0.1819	NA	NA	$ 0.1434
Peak Demand	$ 0.1160	$ 0.1160	NA	NA	$ -
Annual Demand	$ 0.0159	$ 0.0159	NA	NA	$ -
Balancing	$ -	$ -			
Commodity	$ 0.3615	$ 0.3615	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	NA	NA	$ -
Total Rate	$ 0.6753	$ 0.6753	NA	NA	$ 0.1434
Act 141 Surcharge Rate	$ 0.0068	$ 0.0068	NA	NA	$ 0.0068

NA = Not Available

2024 Current Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.9863	$ 1.9726	NA	NA	$ 0.9863
Enhanced Telemetry Service		$ -			$ 0.1973
Transportation Administrative	$ -	$ -	NA	NA	$ 0.9205
Daily Demand Charge	$ -		NA	NA	$ -
Distribution Margin per therm	$ 0.1336	$ 0.1336	NA	NA	$ 0.1336
Competitive Supply Margin	$ 0.0271	$ 0.0271	NA	NA	$ -
Daily Balancing Margin	$ 0.0003	$ 0.0003	NA	NA	$ 0.0003
Peak Day Margin	$ 0.0007	$ 0.0007	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.1617	$ 0.1617	NA	NA	$ 0.1339
Peak Demand	$ 0.1160	$ 0.1160	NA	NA	$ -
Annual Demand	$ 0.0159	$ 0.0159	NA	NA	$ -
Balancing	$ -	$ -			
Commodity	$ 0.3615	$ 0.3615	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	NA	NA	$ -
Total Rate	$ 0.6551	$ 0.6551	NA	NA	$ 0.1339
Act 141 Surcharge Rate	$ 0.0064	$ 0.0064	NA	NA	$ 0.0064

NA = Not Available

Final Change in Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ -	$ -	NA	NA	$ -
Enhanced Telemetry Service					$ -
Transportation Administrative	$ -	$ -	NA	NA	$ -
Daily Demand Charge	$ -	$ -	NA	NA	$ -
Distribution Margin per therm	$ 0.0091	$ 0.0091	NA	NA	$ 0.0091
Competitive Supply Margin	$ 0.0099	$ 0.0099	NA	NA	$ -
Daily Balancing Margin	$ 0.0004	$ 0.0004	NA	NA	$ 0.0004
Peak Day Margin	$ 0.0008	$ 0.0008	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.0202	$ 0.0202	NA	NA	$ 0.0095
Peak Demand	$ -	$ -	NA	NA	$ -
Annual Demand	$ -	$ -	NA	NA	$ -
Balancing			NA	NA	
Commodity	$ -	$ -	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ -	$ -	NA	NA	$ -
Total Rate	$ 0.0202	$ 0.0202	NA	NA	$ 0.0095
Act 141 Surcharge Rate	$ 0.0004	$ 0.0004	NA	NA	$ 0.0004

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2025

CG-{FM,IM} Commercial Industrial Medium 20,001 to 200,000 Therms Annually

	2025 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	$ 4.9315	$ 9.8630	$ 4.9315	$ 4.9315	$ 4.9315	$ 4.9315	$ 9.8630	$ 4.9315	$ 4.9315	$ 4.9315	$ -	$ -	$ -	$ -	$ -
Enhanced Telemetry Service	$ 0.1973	$ 0.3946	$ 0.1973	$ 0.1973	$ 0.1973	$ 0.1973	$ 0.3946	$ 0.1973	$ 0.1973	$ 0.1973	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ 0.9205	$ -	$ -	$ -	$ -	$ 0.9205	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1169	$ 0.1169	$ 0.1169	$ 0.1169	$ 0.1169	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0172	$ 0.0172	$ 0.0172	$ 0.0172	$ 0.0172
Competitive Supply Margin	$ 0.0370	$ 0.0370	$ 0.0370	$ 0.0370	$ -	$ 0.0271	$ 0.0271	$ 0.0271	$ 0.0271	$ -	$ 0.0099	$ 0.0099	$ 0.0099	$ 0.0099	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0015	$ 0.0015	$ -	$ -	$ -	$ 0.0007	$ 0.0007	$ -	$ -	$ -	$ 0.0008	$ 0.0008	$ -	$ -	$ -
Other Margin															
Total All Margin Rates	$ 0.1561	$ 0.1561	$ 0.1546	$ 0.1546	$ 0.1176	$ 0.1278	$ 0.1278	$ 0.1271	$ 0.1271	$ 0.1000	$ 0.0283	$ 0.0283	$ 0.0275	$ 0.0275	$ 0.0176
Peak Demand	$ 0.1160	$ 0.1160	$ -	$ -	$ -	$ 0.1160	$ 0.1160	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0159	$ 0.0159	$ 0.0159	$ 0.0159	$ -	$ 0.0159	$ 0.0159	$ 0.0159	$ 0.0159	$ -	$ -	$ -	$ -	$ -	$ -
Balancing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Commodity	$ 0.3615	$ 0.3615	$ 0.3615	$ 0.3615	$ -	$ 0.3615	$ 0.3615	$ 0.3615	$ 0.3615	$ -	$ -	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	$ 0.3774	$ 0.3774	$ -	$ 0.4934	$ 0.4934	$ 0.3774	$ 0.3774	$ -	$ -	$ -	$ -	$ -	$ -
Total Rate	$ 0.6495	$ 0.6495	$ 0.5320	$ 0.5320	$ 0.1176	$ 0.6212	$ 0.6212	$ 0.5045	$ 0.5045	$ 0.1000	$ 0.0283	$ 0.0283	$ 0.0275	$ 0.0275	$ 0.0176
Act 141 Surcharge Rate	$ 0.0068	$ 0.0068	$ 0.0068	$ 0.0068	$ 0.0068	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004

NA = Not Available

NA = Not Available

NA = Not Available

CG-{FL,IL} Commercial Industrial Large 200,001 to 2,400,000 Therms Annually

	2025 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	$ 21.3698	$ 42.7396	NA	$ 21.3698	$ 21.3698	$ 21.3698	$ 42.7396	NA	$ 21.3698	$ 21.3698	$ -	$ -	NA	$ -	$ -
Enhanced Telemetry Service	$ 0.1973	$ 0.3946		$ 0.1973	$ 0.1973	$ 0.1973	$ 0.3946		$ 0.1973	$ 0.1973	$ -	$ -	NA	$ -	$ -
Transportation Administrative	$ -	$ -	NA	$ -	$ 0.9205	$ -	$ -	NA	$ -	$ 0.9205	$ -	$ -	NA	$ -	$ -
Daily Demand Charge	$ 0.1548	$ 0.1548	NA	$ 0.1548	$ 0.1548	$ 0.1475	$ 0.1475	NA	$ 0.1475	$ 0.1475	$ 0.0073	$ 0.0073	NA	$ 0.0073	$ 0.0073
Distribution Margin per therm	$ 0.0625	$ 0.0625	NA	$ 0.0625	$ 0.0625	$ 0.0484	$ 0.0484	NA	$ 0.0484	$ 0.0484	$ 0.0141	$ 0.0141	NA	$ 0.0141	$ 0.0141
Competitive Supply Margin	$ 0.0370	$ 0.0370	NA	$ 0.0370	$ -	$ 0.0271	$ 0.0271	NA	$ 0.0271	$ -	$ 0.0099	$ 0.0099	NA	$ 0.0099	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	NA	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	NA	$ 0.0003	$ 0.0003	$ 0.0004	$ 0.0004	NA	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0015	$ 0.0015	NA	$ -	$ -	$ 0.0007	$ 0.0007	NA	$ -	$ -	$ 0.0008	$ 0.0008	NA	$ -	$ -
Other Margin															
Total All Margin Rates	$ 0.1017	$ 0.1017	NA	$ 0.1002	$ 0.0632	$ 0.0765	$ 0.0765	NA	$ 0.0758	$ 0.0487	$ 0.0252	$ 0.0252	NA	$ 0.0244	$ 0.0145
Peak Demand	$ 0.1160	$ 0.1160	NA	$ -	$ -	$ 0.1160	$ 0.1160	NA	$ -	$ -	$ -	$ -	NA	$ -	$ -
Annual Demand	$ 0.0159	$ 0.0159	NA	$ 0.0159	$ -	$ 0.0159	$ 0.0159	NA	$ 0.0159	$ -	$ -	$ -	NA	$ -	$ -
Balancing	$ -	$ -		$ -	$ -	$ -	$ -		$ -	$ -					
Commodity	$ 0.3615	$ 0.3615	NA	$ 0.3615	$ -	$ 0.3615	$ 0.3615	NA	$ 0.3615	$ -	$ -	$ -	NA	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4934	$ 0.4934	NA	$ 0.3774	$ -	$ 0.4934	$ 0.4934	NA	$ 0.3774	$ -	$ -	$ -	NA	$ -	$ -
Total Rate	$ 0.5951	$ 0.5951	NA	$ 0.4776	$ 0.0632	$ 0.5699	$ 0.5699	NA	$ 0.4532	$ 0.0487	$ 0.0252	$ 0.0252	NA	$ 0.0244	$ 0.0145
Act 141 Surcharge Rate	$ 0.0068	$ 0.0068	NA	$ 0.0068	$ 0.0068	$ 0.0064	$ 0.0064	NA	$ 0.0064	$ 0.0064	$ 0.0004	$ 0.0004	NA	$ 0.0004	$ 0.0004

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2025

CG-SL Commercial Industrial Super Large 2,400,001 to 15,000,000 Therms Annually

	2025 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	NA	NA	NA	$ 121.8411	$ 121.8411	NA	NA	NA	$ 121.8411	$ 121.8411	NA	NA	NA	$ -	$ -
Enhanced Telemetry Service				$ 0.1973	$ 0.1973				$ 0.1973	$ 0.1973					$ -
Transportation Administrative	NA	NA	NA	$ -	$ 0.9205	NA	NA	NA	$ -	$ 0.9205	NA	NA	NA	$ -	$ -
Daily Demand Charge	NA	NA	NA	$ 0.1100	$ 0.1100	NA	NA	NA	$ 0.1000	$ 0.1000	NA	NA	NA	$ 0.0100	$ 0.0100
Distribution Margin per therm	NA	NA	NA	$ 0.0314	$ 0.0314	NA	NA	NA	$ 0.0294	$ 0.0294	NA	NA	NA	$ 0.0020	$ 0.0020
Competitive Supply Margin	NA	NA	NA	$ 0.0370	$ -	NA	NA	NA	$ 0.0271	$ -	NA	NA	NA	$ 0.0099	$ -
Daily Balancing Margin	NA	NA	NA	$ 0.0007	$ 0.0007	NA	NA	NA	$ 0.0003	$ 0.0003	NA	NA	NA	$ 0.0004	$ 0.0004
Peak Day Margin	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -
Other Margin															
Total All Margin Rates	NA	NA	NA	$ 0.0691	$ 0.0321	NA	NA	NA	$ 0.0568	$ 0.0297	NA	NA	NA	$ 0.0123	$ 0.0024
Peak Demand	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -
Annual Demand	NA	NA	NA	$ 0.0159	$ -	NA	NA	NA	$ 0.0159	$ -	NA	NA	NA	$ -	$ -
Balancing				$ -					$ -						
Commodity	NA	NA	NA	$ 0.3615	$ -	NA	NA	NA	$ 0.3615	$ -	NA	NA	NA	$ -	$ -
Total Natural Gas Rate Per Therm	NA	NA	NA	$ 0.3774	$ -	NA	NA	NA	$ 0.3774	$ -	NA	NA	NA	$ -	$ -
Total Rate	NA	NA	NA	$ 0.4465	$ 0.0321	NA	NA	NA	$ 0.4342	$ 0.0297	NA	NA	NA	$ 0.0123	$ 0.0024
Act 141 Surcharge Rate	NA	NA	NA	$ 0.0068	$ 0.0068	NA	NA	NA	$ 0.0064	$ 0.0064	NA	NA	NA	$ 0.0004	$ 0.0004

CG-IEGL Commercial Industrial Interruptible Electric Generation Large Over 200,000 Therms Annually

	2025 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	NA	NA	$ 249.0000	NA	$ 249.0000	NA	NA	$ 249.0000	NA	$ 249.0000	NA	NA	$ -	NA	$ -
Enhanced Telemetry Service			$ 0.1973		$ 0.1973			$ 0.1973		$ 0.1973					
Transportation Administrative	NA	NA	$ -	NA	$ 0.9205	NA	NA	$ -	NA	$ 0.9205	NA	NA	$ -	NA	$ -
Daily Demand Charge	NA	NA	$ 0.0720	NA	$ 0.0720	NA	NA	$ 0.0720	NA	$ 0.0720	NA	NA	$ -	NA	$ -
Distribution Margin per therm	NA	NA	$ 0.0363	NA	$ 0.0363	NA	NA	$ 0.0129	NA	$ 0.0129	NA	NA	$ 0.0234	NA	$ 0.0234
Competitive Supply Margin	NA	NA	$ 0.0070	NA	$ -	NA	NA	$ 0.0066	NA	$ -	NA	NA	$ 0.0004	NA	$ -
Daily Balancing Margin	NA	NA	$ 0.0007	NA	$ 0.0007	NA	NA	$ 0.0003	NA	$ 0.0003	NA	NA	$ 0.0004	NA	$ 0.0004
Peak Day Margin	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -
Other Margin															
Total All Margin Rates	NA	NA	$ 0.0440	NA	$ 0.0370	NA	NA	$ 0.0198	NA	$ 0.0132	NA	NA	$ 0.0242	NA	$ 0.0238
Peak Demand	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -
Annual Demand	NA	NA	$ 0.0159	NA	$ -	NA	NA	$ 0.0159	NA	$ -	NA	NA	$ -	NA	$ -
Balancing			$ -					$ -							
Commodity	NA	NA	$ 0.3615	NA	$ -	NA	NA	$ 0.3615	NA	$ -	NA	NA	$ -	NA	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ 0.3774	NA	$ -	NA	NA	$ 0.3774	NA	$ -	NA	NA	$ -	NA	$ -
Total Rate	NA	NA	$ 0.4214	NA	$ 0.0370	NA	NA	$ 0.3972	NA	$ 0.0132	NA	NA	$ 0.0242	NA	$ 0.0238
Act 141 Surcharge Rate	NA	NA	$ 0.0068	NA	$ 0.0068	NA	NA	$ 0.0064	NA	$ 0.0064	NA	NA	$ 0.0004	NA	$ 0.0004

NA = Not Available

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2025

CG-XSL Commercial Industrial Extra Super Large Over 15,000,000 Therms Annually

2025 Final Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	NA	NA	$ 1,100.0000	$ 1,100.0000	$ 1,100.0000
Enhanced Telemetry Service			$ 0.1973	$ 0.1973	$ 0.1973
Transportation Administrative	NA	NA	$ -	$ -	$ 0.9205
Daily Demand Charge	NA	NA	$ 0.0475	$ 0.0475	$ 0.0475
Distribution Margin per therm	NA	NA	$ 0.0094	$ 0.0094	$ 0.0094
Competitive Supply Margin	NA	NA	$ 0.0370	$ 0.0370	$ -
Daily Balancing Margin	NA	NA	$ 0.0007	$ 0.0007	$ 0.0007
Peak Day Margin	NA	NA	$ -	$ -	$ -
Other Margin					
Total All Margin Rates	NA	NA	$ 0.0471	$ 0.0471	$ 0.0101
Peak Demand	NA	NA	$ -	$ -	$ -
Annual Demand	NA	NA	$ 0.0159	$ 0.0159	$ -
Balancing	NA	NA	$ -	$ -	
Commodity	NA	NA	$ 0.3615	$ 0.3615	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ 0.3774	$ 0.3774	$ -
Total Rate	NA	NA	$ 0.4245	$ 0.4245	$ 0.0101
Act 141 Surcharge Rate	NA	NA	$ 0.0068	$ 0.0068	$ 0.0068

NA = Not Available

2024 Current Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	NA	NA	$ 1,000.0000	$ 1,000.0000	$ 1,000.0000
Enhanced Telemetry Service			$ 0.1973	$ 0.1973	$ 0.1973
Transportation Administrative	NA	NA	$ -	$ -	$ 0.9205
Daily Demand Charge	NA	NA	$ 0.0450	$ 0.0450	$ 0.0450
Distribution Margin per therm	NA	NA	$ 0.0093	$ 0.0093	$ 0.0093
Competitive Supply Margin	NA	NA	$ 0.0271	$ 0.0271	$ -
Daily Balancing Margin	NA	NA	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	NA	NA	$ -	$ -	$ -
Other Margin					
Total All Margin Rates	NA	NA	$ 0.0367	$ 0.0367	$ 0.0096
Peak Demand	NA	NA	$ -	$ -	$ -
Annual Demand	NA	NA	$ 0.0159	$ 0.0159	$ -
Balancing	NA	NA	$ -	$ -	
Commodity	NA	NA	$ 0.3615	$ 0.3615	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ 0.3774	$ 0.3774	$ -
Total Rate	NA	NA	$ 0.4141	$ 0.4141	$ 0.0096
Act 141 Surcharge Rate	NA	NA	$ 0.0064	$ 0.0064	$ 0.0064

Final Change in Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	NA	NA	$ 100.0000	$ 100.0000	$ 100.0000
Enhanced Telemetry Service					$ -
Transportation Administrative	NA	NA	$ -	$ -	$ -
Daily Demand Charge	NA	NA	$ 0.0025	$ 0.0025	$ 0.0025
Distribution Margin per therm	NA	NA	$ 0.0001	$ 0.0001	$ 0.0001
Competitive Supply Margin	NA	NA	$ 0.0099	$ 0.0099	$ -
Daily Balancing Margin	NA	NA	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	NA	NA	$ -	$ -	$ -
Other Margin					
Total All Margin Rates	NA	NA	$ 0.0104	$ 0.0104	$ 0.0005
Peak Demand	NA	NA	$ -	$ -	$ -
Annual Demand	NA	NA	$ -	$ -	$ -
Balancing					
Commodity	NA	NA	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ -	$ -	$ -
Total Rate	NA	NA	$ 0.0104	$ 0.0104	$ 0.0005
Act 141 Surcharge Rate	NA	NA	$ 0.0004	$ 0.0004	$ 0.0004

NA = Not Available

IG-SOS Interruptible Agricultural Seasonal Opportunity Sales

2025 Final Rates

Rates - Description	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5000	$ -	$ -	NA	NA
Enhanced Telemetry Service	$ 0.1973	$ -	$ -		
Transportation Administrative	$ -	$ -	$ -	NA	NA
Daily Demand Charge	$ -			NA	NA
Distribution Margin per therm	$ 0.2616	$ 0.2133	$ 0.1389	NA	NA
Competitive Supply Margin	$ 0.0370	$ 0.0370	$ 0.0370	NA	NA
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	NA
Peak Day Margin	$ -	$ -	$ -	NA	NA
Other Margin					
Total All Margin Rates	$ 0.2993	$ 0.2510	$ 0.1766	NA	NA
Peak Demand	$ -	$ -	$ -	NA	NA
Annual Demand	$ 0.0159	$ 0.0159	$ 0.0159	NA	NA
Balancing	$ -	$ -	$ -		
Commodity	$ 0.3615	$ 0.3615	$ 0.3615	NA	NA
Total Natural Gas Rate Per Therm	$ 0.3774	$ 0.3774	$ 0.3774	NA	NA
Total Rate	$ 0.6767	$ 0.6284	$ 0.5540	NA	NA
Act 141 Surcharge Rate	$ 0.0068	$ 0.0068	$ 0.0068	NA	NA

NA = Not Available

2024 Current Rates

Rates - Description	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5000	$ -	$ -	NA	NA
Enhanced Telemetry Service	$ 0.1973	$ -	$ -		
Transportation Administrative	$ -	$ -	$ -	NA	NA
Daily Demand Charge	$ -			NA	NA
Distribution Margin per therm	$ 0.2716	$ 0.2234	$ 0.1491	NA	NA
Competitive Supply Margin	$ 0.0271	$ 0.0271	$ 0.0271	NA	NA
Daily Balancing Margin	$ 0.0003	$ 0.0003	$ 0.0003	NA	NA
Peak Day Margin	$ -	$ -	$ -	NA	NA
Other Margin					
Total All Margin Rates	$ 0.2990	$ 0.2508	$ 0.1765	NA	NA
Peak Demand	$ -	$ -	$ -	NA	NA
Annual Demand	$ 0.0159	$ 0.0159	$ 0.0159	NA	NA
Balancing	$ -	$ -	$ -		
Commodity	$ 0.3615	$ 0.3615	$ 0.3615	NA	NA
Total Natural Gas Rate Per Therm	$ 0.3774	$ 0.3774	$ 0.3774	NA	NA
Total Rate	$ 0.6764	$ 0.6282	$ 0.5539	NA	NA
Act 141 Surcharge Rate	$ 0.0064	$ 0.0064	$ 0.0064	NA	NA

NA = Not Available

Final Change in Rates

Rates - Description	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation
Daily Facitilties Charge	$ -	$ -	$ -	NA	NA
Enhanced Telemetry Service					
Transportation Administrative	$ -	$ -	$ -	NA	NA
Daily Demand Charge	$ -	$ -	$ -	NA	NA
Distribution Margin per therm	$ (0.0100)	$ (0.0101)	$ (0.0102)	NA	NA
Competitive Supply Margin	$ 0.0099	$ 0.0099	$ 0.0099	NA	NA
Daily Balancing Margin	$ 0.0004	$ 0.0004	$ 0.0004	NA	NA
Peak Day Margin	$ -	$ -	$ -	NA	NA
Other Margin					
Total All Margin Rates	$ 0.0003	$ 0.0002	$ 0.0001	NA	NA
Peak Demand	$ -	$ -	$ -	NA	NA
Annual Demand	$ -	$ -	$ -	NA	NA
Balancing				NA	NA
Commodity	$ -	$ -	$ -	NA	NA
Total Natural Gas Rate Per Therm	$ -	$ -	$ -	NA	NA
Total Rate	$ 0.0003	$ 0.0002	$ 0.0001	NA	NA
Act 141 Surcharge Rate	$ 0.0004	$ 0.0004	$ 0.0004	NA	NA

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Residential Rg-3

	Transportation Service					Sales Service			
	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change		Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv	$ 44.9984	$ 44.9984	$ -		$/Mo. Fixed or equiv.	$ 16.9999	$ 16.9999	$ -	
$/Day Fixed or equi	$ 1.4794	$ 1.4794	$ -		$/Day Fixed or equiv.	$ 0.5589	$ 0.5589	$ -	
$/Therm-Winter	$ 0.1494	$ 0.1616	$ 0.0122		$/Therm-Winter	$ 0.6706	$ 0.6935	$ 0.0229	
$/Therm-Summer	$ 0.1494	$ 0.1616	$ 0.0122		$/Therm-Summer	$ 0.5546	$ 0.5775	$ 0.0229	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
294		$ 583.90	$ 587.49	$ 3.59	0.61%		$ 394.93	$ 401.66	$ 6.73	1.70%
588		$ 627.83	$ 635.00	$ 7.17	1.14%		$ 585.86	$ 599.33	$ 13.47	2.30%
781		$ 656.66	$ 666.19	$ 9.53	1.45%		$ 711.20	$ 729.09	$ 17.89	2.52%
838	303438	$ 665.18	$ 675.40	$ 10.22	1.54%		$ 748.22	$ 767.41	$ 19.19	2.56%
1,176		$ 715.68	$ 730.02	$ 14.34	2.00%		$ 967.73	$ 994.66	$ 26.93	2.78%
1,470		$ 759.60	$ 777.53	$ 17.93	2.36%		$ 1,158.66	$ 1,192.32	$ 33.66	2.91%
1,764		$ 803.52	$ 825.04	$ 21.52	2.68%		$ 1,349.59	$ 1,389.99	$ 40.40	2.99%
2,058		$ 847.45	$ 872.55	$ 25.10	2.96%		$ 1,540.53	$ 1,587.65	$ 47.12	3.06%
2,352		$ 891.37	$ 920.06	$ 28.69	3.22%		$ 1,731.46	$ 1,785.32	$ 53.86	3.11%
2,646		$ 935.29	$ 967.57	$ 32.28	3.45%		$ 1,922.39	$ 1,982.98	$ 60.59	3.15%
2,940		$ 979.22	$ 1,015.09	$ 35.87	3.66%		$ 2,113.32	$ 2,180.65	$ 67.33	3.19%
3,234		$ 1,023.14	$ 1,062.60	$ 39.46	3.86%		$ 2,304.26	$ 2,378.31	$ 74.05	3.21%
3,528		$ 1,067.06	$ 1,110.11	$ 43.05	4.03%		$ 2,495.19	$ 2,575.98	$ 80.79	3.24%
3,822		$ 1,110.99	$ 1,157.62	$ 46.63	4.20%		$ 2,686.12	$ 2,773.64	$ 87.52	3.26%
4,116		$ 1,154.91	$ 1,205.13	$ 50.22	4.35%		$ 2,877.05	$ 2,971.31	$ 94.26	3.28%
4,410		$ 1,198.84	$ 1,252.64	$ 53.80	4.49%		$ 3,067.98	$ 3,168.97	$ 100.99	3.29%
4,704		$ 1,242.76	$ 1,300.15	$ 57.39	4.62%		$ 3,258.92	$ 3,366.64	$ 107.72	3.31%
4,998		$ 1,286.68	$ 1,347.66	$ 60.98	4.74%		$ 3,449.85	$ 3,564.30	$ 114.45	3.32%
	Winter Qty %	81.75%	81.75%			Winter Qty %	81.75%	81.75%		
	Summer QTY %	18.25%	18.25%			Summer QTY %	18.25%	18.25%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Seasonal Opportunity Sales Medium 20,001 therms to 200,000 therms annually

		Transportation Service					Sales Service			
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equ	NA	NA	NA		$/Mo. Fixed or equiv.	$ 21.21	$ 21.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.6973	$ 0.6973	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm	NA	NA	NA		$/Therm Step 1	$ 0.6764	$ 0.6767	$ 0.0003	
						$/Therm Step 2	$ 0.6282	$ 0.6284	$ 0.0002	
						$/Therm Step 3	$ 0.5539	$ 0.5540	$ 0.0001	

Usage in Therms	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
7,500		NA	NA	NA	NA		$ 5,327.51	$ 5,329.76	$ 2.25	0.04%
9,747	119	NA	NA	NA	NA		$ 6,847.39	$ 6,850.31	$ 2.92	0.04%
20,000		NA	NA	NA	NA		$ 13,444.92	$ 13,450.22	$ 5.30	0.04%
30,000		NA	NA	NA	NA		$ 19,751.02	$ 19,758.37	$ 7.35	0.04%
40,000		NA	NA	NA	NA		$ 26,057.12	$ 26,066.52	$ 9.40	0.04%
50,000		NA	NA	NA	NA		$ 31,805.67	$ 31,816.37	$ 10.70	0.03%
60,000		NA	NA	NA	NA		$ 37,405.92	$ 37,417.72	$ 11.80	0.03%
70,000		NA	NA	NA	NA		$ 43,006.17	$ 43,019.07	$ 12.90	0.03%
80,000		NA	NA	NA	NA		$ 48,606.42	$ 48,620.42	$ 14.00	0.03%
90,000		NA	NA	NA	NA		$ 54,206.67	$ 54,221.77	$ 15.10	0.03%
100,000		NA	NA	NA	NA		$ 59,806.92	$ 59,823.12	$ 16.20	0.03%
110,000		NA	NA	NA	NA		$ 65,407.17	$ 65,424.47	$ 17.30	0.03%
120,000		NA	NA	NA	NA		$ 71,007.42	$ 71,025.82	$ 18.40	0.03%
130,000		NA	NA	NA	NA		$ 76,607.67	$ 76,627.17	$ 19.50	0.03%
140,000		NA	NA	NA	NA		$ 82,207.92	$ 82,228.52	$ 20.60	0.03%
150,000		NA	NA	NA	NA		$ 87,808.17	$ 87,829.87	$ 21.70	0.02%
160,000		NA	NA	NA	NA		$ 93,408.42	$ 93,431.22	$ 22.80	0.02%
	Winter Qty %	NA	NA			Winter Qty %	5.00%	5.00%		
	Summer QTY %	NA	NA			Drying Season QTY %	95.00%	95.00%		

Gas Cost Rates:	Firm	Interruptible		
Base Average Commodity Cost:	$ 0.3615	$ 0.3615	$ 4,821.49	$ 253.76
Base Average Peak Demand Cost:	$ -	$ -		$ 254.51
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159		$ 5,329.76
Base Average Balancing Cost:	$ -	$ -		
Base Average Surcharge Cost:	$ -	$ -		
Totals:	$ 0.3774	$ 0.3774		

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Seasonal Opportunity Sales Medium Over 200,000 therms annually

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	NA	NA	NA		$/Mo. Fixed or equiv.	$ 21.21	$ 21.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.6973	$ 0.6973	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ -	NA	NA	
	$/Therm	NA	NA	NA		$/Therm Step 1	$ 0.6764	$ 0.6767	$ 0.0003	
						$/Therm Step 2	$ 0.6282	$ 0.6284	$ 0.0002	
						$/Therm Step 3	$ 0.5539	$ 0.5540	$ 0.0001	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000		NA	NA	NA	NA		$ 114,706.92	$ 114,732.32	$ 25.40	0.02%
206,000		NA	NA	NA	NA		$ 118,034.00	$ 118,060.00	$ 26.01	0.02%
212,000		NA	NA	NA	NA		$ 121,361.07	$ 121,387.69	$ 26.61	0.02%
218,000		NA	NA	NA	NA		$ 124,688.15	$ 124,715.37	$ 27.22	0.02%
224,000	0	NA	NA	NA	NA		$ 128,015.22	$ 128,043.05	$ 27.82	0.02%
230,000		NA	NA	NA	NA		$ 131,342.30	$ 131,370.73	$ 28.43	0.02%
236,000		NA	NA	NA	NA		$ 134,669.37	$ 134,698.41	$ 29.04	0.02%
242,000		NA	NA	NA	NA		$ 137,996.45	$ 138,026.09	$ 29.64	0.02%
248,000		NA	NA	NA	NA		$ 141,323.52	$ 141,353.77	$ 30.25	0.02%
254,000		NA	NA	NA	NA		$ 144,650.60	$ 144,681.45	$ 30.85	0.02%
260,000		NA	NA	NA	NA		$ 147,977.67	$ 148,009.13	$ 31.46	0.02%
266,000		NA	NA	NA	NA		$ 151,304.75	$ 151,336.81	$ 32.07	0.02%
272,000		NA	NA	NA	NA		$ 154,631.82	$ 154,664.50	$ 32.67	0.02%
278,000		NA	NA	NA	NA		$ 157,958.90	$ 157,992.18	$ 33.28	0.02%
284,000		NA	NA	NA	NA		$ 161,285.97	$ 161,319.86	$ 33.88	0.02%
290,000		NA	NA	NA	NA		$ 164,613.05	$ 164,647.54	$ 34.49	0.02%
296,000		NA	NA	NA	NA		$ 167,940.12	$ 167,975.22	$ 35.10	0.02%
	Winter Qty %	NA	NA			Winter Qty %	0.50%	0.50%		
	Summer QTY %	NA	NA			Drying Season QTY %	99.50%	99.50%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3774	$ 0.3774

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Commercial/Industrial Standard 0 to 2000 therms
CG-FST

Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 45.0000	$ 45.0000	$ -	$/Mo. Fixed or equiv.	$ 16.9999	$ 16.9999	$ -
$/Day Fixed or equiv.	$ 1.4794	$ 1.4794	$ -	$/Day Fixed or equiv.	$ 0.5589	$ 0.5589	$ -
Demand Charge	N/A	N/A	N/A	Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.1494	$ 0.1616	$ 0.0122	$/Therm-Winter	$ 0.6706	$ 0.6935	$ 0.0229
$/Therm-Summer	$ 0.1494	$ 0.1616	$ 0.0122	$/Therm-Summer	$ 0.5546	$ 0.5775	$ 0.0229

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
235		N/A	N/A	N/A	N/A		$ 358.19	$ 363.57	$ 5.38	1.50%
335		N/A	N/A	N/A	N/A		$ 423.80	$ 431.48	$ 7.68	1.81%
435		N/A	N/A	N/A	N/A		$ 489.42	$ 499.38	$ 9.96	2.04%
535		N/A	N/A	N/A	N/A		$ 555.03	$ 567.28	$ 12.25	2.21%
635		N/A	N/A	N/A	N/A		$ 620.64	$ 635.19	$ 14.55	2.34%
735		N/A	N/A	N/A	N/A		$ 686.26	$ 703.09	$ 16.83	2.45%
820		N/A	N/A	N/A	N/A		$ 742.03	$ 760.81	$ 18.78	2.53%
956	18418	N/A	N/A	N/A	N/A		$ 831.26	$ 853.16	$ 21.90	2.63%
1,056		N/A	N/A	N/A	N/A		$ 896.88	$ 921.06	$ 24.18	2.70%
1,156		N/A	N/A	N/A	N/A		$ 962.49	$ 988.96	$ 26.47	2.75%
1,256		N/A	N/A	N/A	N/A		$ 1,028.10	$ 1,056.87	$ 28.77	2.80%
1,356		N/A	N/A	N/A	N/A		$ 1,093.72	$ 1,124.77	$ 31.05	2.84%
1,456		N/A	N/A	N/A	N/A		$ 1,159.33	$ 1,192.67	$ 33.34	2.88%
1,556		N/A	N/A	N/A	N/A		$ 1,224.94	$ 1,260.58	$ 35.64	2.91%
1,656		N/A	N/A	N/A	N/A		$ 1,290.56	$ 1,328.48	$ 37.92	2.94%
1,756		N/A	N/A	N/A	N/A		$ 1,356.17	$ 1,396.38	$ 40.21	2.96%
1,900		N/A	N/A	N/A	N/A		$ 1,450.65	$ 1,494.16	$ 43.51	3.00%
	Winter Qty %	0.00%	0.00%			Winter Qty %	87.53%	87.53%		
	Summer QTY %	0.00%	0.00%			Summer QTY %	12.47%	12.47%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms
CG-FST

Transportation Service | Sales Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 90.0000	$ -	$ (90.0000)		$/Mo. Fixed or equiv.	$ 33.9998	$ 33.9998	$ -	
	$/Day Fixed or equiv.	$ 2.9588	$ -	$ (2.9588)		$/Day Fixed or equiv.	$ 1.1178	$ 1.1178	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1494	$ 0.1616	$ 0.0122		$/Therm-Winter	$ 0.6706	$ 0.6935	$ 0.0229	
	$/Therm-Summer	$ 0.1494	$ 0.1616	$ 0.0122		$/Therm-Summer	$ 0.5546	$ 0.5775	$ 0.0229	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
235		N/A	N/A	N/A	N/A		$ 334.33	$ 339.71	$ 5.38	1.61%
335		N/A	N/A	N/A	N/A		$ 389.79	$ 397.46	$ 7.67	1.97%
435		N/A	N/A	N/A	N/A		$ 445.25	$ 455.21	$ 9.96	2.24%
535		N/A	N/A	N/A	N/A		$ 500.71	$ 512.96	$ 12.25	2.45%
635		N/A	N/A	N/A	N/A		$ 556.17	$ 570.71	$ 14.54	2.61%
735		N/A	N/A	N/A	N/A		$ 611.63	$ 628.46	$ 16.83	2.75%
835		N/A	N/A	N/A	N/A		$ 667.09	$ 686.21	$ 19.12	2.87%
935		N/A	N/A	N/A	N/A		$ 722.55	$ 743.96	$ 21.41	2.96%
1,035		N/A	N/A	N/A	N/A		$ 778.01	$ 801.71	$ 23.70	3.05%
1,135		N/A	N/A	N/A	N/A		$ 833.47	$ 859.46	$ 25.99	3.12%
1,235		N/A	N/A	N/A	N/A		$ 888.93	$ 917.21	$ 28.28	3.18%
1,335		N/A	N/A	N/A	N/A		$ 944.39	$ 974.96	$ 30.57	3.24%
1,435		N/A	N/A	N/A	N/A		$ 999.85	$ 1,032.71	$ 32.86	3.29%
1,535		N/A	N/A	N/A	N/A		$ 1,055.31	$ 1,090.46	$ 35.15	3.33%
1,635		N/A	N/A	N/A	N/A		$ 1,110.77	$ 1,148.21	$ 37.44	3.37%
1,735		N/A	N/A	N/A	N/A		$ 1,166.23	$ 1,205.96	$ 39.73	3.41%
1,835		N/A	N/A	N/A	N/A		$ 1,221.69	$ 1,263.71	$ 42.02	3.44%
	Winter Qty %	0.00%	0.00%			Winter Qty %	0.00%	0.00%		
	Summer QTY %	0.00%	0.00%			Summer QTY %	100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Commercial/IndustrialSmall 2001 to 20000 therms
CG-FS and CG-TS

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 63.9997	$ 63.9997	$ -		$/Mo. Fixed or equiv.	$ 30.0000	$ 30.0000	$ -	
	$/Day Fixed or equiv.	$ 2.1041	$ 2.1041	$ -		$/Day Fixed or equiv.	$ 0.9863	$ 0.9863	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1339	$ 0.1434	$ 0.0095		$/Therm-Winter	$ 0.6551	$ 0.6753	$ 0.0202	
	$/Therm-Summer	$ 0.1339	$ 0.1434	$ 0.0095		$/Therm-Summer	$ 0.5391	$ 0.5593	$ 0.0202	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
2,001		$ 1,035.93	$ 1,054.94	$ 19.01	1.84%		$ 1,627.15	$ 1,667.57	$ 40.42	2.48%
3,001		$ 1,169.83	$ 1,198.34	$ 28.51	2.44%		$ 2,260.40	$ 2,321.02	$ 60.62	2.68%
4,001		$ 1,303.73	$ 1,341.74	$ 38.01	2.92%		$ 2,893.66	$ 2,974.48	$ 80.82	2.79%
5,600		$ 1,517.84	$ 1,571.04	$ 53.20	3.50%		$ 3,906.24	$ 4,019.36	$ 113.12	2.90%
5,727	14657	$ 1,534.84	$ 1,589.25	$ 54.41	3.54%		$ 3,986.66	$ 4,102.35	$ 115.69	2.90%
6,700		$ 1,665.13	$ 1,728.78	$ 63.65	3.82%		$ 4,602.82	$ 4,738.16	$ 135.34	2.94%
7,700		$ 1,799.03	$ 1,872.18	$ 73.15	4.07%		$ 5,236.08	$ 5,391.62	$ 155.54	2.97%
8,700		$ 1,932.93	$ 2,015.58	$ 82.65	4.28%		$ 5,869.34	$ 6,045.08	$ 175.74	2.99%
9,700		$ 2,066.83	$ 2,158.98	$ 92.15	4.46%		$ 6,502.59	$ 6,698.53	$ 195.94	3.01%
10,700		$ 2,200.73	$ 2,302.38	$ 101.65	4.62%		$ 7,135.85	$ 7,351.99	$ 216.14	3.03%
11,700		$ 2,334.63	$ 2,445.78	$ 111.15	4.76%		$ 7,769.11	$ 8,005.45	$ 236.34	3.04%
12,700		$ 2,468.53	$ 2,589.18	$ 120.65	4.89%		$ 8,402.37	$ 8,658.91	$ 256.54	3.05%
13,700		$ 2,602.43	$ 2,732.58	$ 130.15	5.00%		$ 9,035.62	$ 9,312.36	$ 276.74	3.06%
14,700		$ 2,736.33	$ 2,875.98	$ 139.65	5.10%		$ 9,668.88	$ 9,965.82	$ 296.94	3.07%
15,700		$ 2,870.23	$ 3,019.38	$ 149.15	5.20%		$ 10,302.14	$ 10,619.28	$ 317.14	3.08%
16,700		$ 3,004.13	$ 3,162.78	$ 158.65	5.28%		$ 10,935.39	$ 11,272.73	$ 337.34	3.08%
19,100		$ 3,325.49	$ 3,506.94	$ 181.45	5.46%		$ 12,455.21	$ 12,841.03	$ 385.82	3.10%
	Winter Qty %	81.17%	81.17%			Winter Qty %	81.17%	81.17%		
	Summer QTY %	18.83%	18.83%			Summer QTY %	18.83%	18.83%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms
CG-FS

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or eq	$ 121.9982	$ 6.0012	$ (115.9970)		$/Mo. Fixed or eq	$ 59.9999	$ 59.9999	$ -	
	$/Day Fixed or eq	$ 4.0109	$ 0.1973	$ (3.8136)		$/Day Fixed or eq	$ 1.9726	$ 1.9726	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1339	$ 0.1434	$ 0.0095		$/Therm-Winter	$ 0.6551	$ 0.6753	$ 0.0202	
	$/Therm-Summer	$ 0.1339	$ 0.1434	$ 0.0095		$/Therm-Summer	$ 0.5391	$ 0.5593	$ 0.0202	

Usage in Therms	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
2,001		N/A	N/A	N/A	N/A		$ 1,438.74	$ 1,479.16	$ 40.42	2.81%
3,001		N/A	N/A	N/A	N/A		$ 1,977.84	$ 2,038.46	$ 60.62	3.06%
4,001		N/A	N/A	N/A	N/A		$ 2,516.94	$ 2,597.76	$ 80.82	3.21%
5,001		N/A	N/A	N/A	N/A		$ 3,056.04	$ 3,157.06	$ 101.02	3.31%
6,001		N/A	N/A	N/A	N/A		$ 3,595.14	$ 3,716.36	$ 121.22	3.37%
7,001		N/A	N/A	N/A	N/A		$ 4,134.24	$ 4,275.66	$ 141.42	3.42%
8,001		N/A	N/A	N/A	N/A		$ 4,673.34	$ 4,834.96	$ 161.62	3.46%
9,001		N/A	N/A	N/A	N/A		$ 5,212.44	$ 5,394.26	$ 181.82	3.49%
10,001		N/A	N/A	N/A	N/A		$ 5,751.54	$ 5,953.56	$ 202.02	3.51%
11,001		N/A	N/A	N/A	N/A		$ 6,290.64	$ 6,512.86	$ 222.22	3.53%
12,001		N/A	N/A	N/A	N/A		$ 6,829.74	$ 7,072.16	$ 242.42	3.55%
13,001		N/A	N/A	N/A	N/A		$ 7,368.84	$ 7,631.46	$ 262.62	3.56%
14,001		N/A	N/A	N/A	N/A		$ 7,907.94	$ 8,190.76	$ 282.82	3.58%
15,001		N/A	N/A	N/A	N/A		$ 8,447.04	$ 8,750.06	$ 303.02	3.59%
16,001		N/A	N/A	N/A	N/A		$ 8,986.14	$ 9,309.36	$ 323.22	3.60%
17,001		N/A	N/A	N/A	N/A		$ 9,525.24	$ 9,868.66	$ 343.42	3.61%
18,001		N/A	N/A	N/A	N/A		$ 10,064.34	$ 10,427.96	$ 363.62	3.61%
	Winter Qty %	0.00%	0.00%			Winter Qty %	0.00%	0.00%		
	Summer QTY %	100.00%	100.00%			Summer QTY %	100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Commercial/Industrial Medium 20001 to 200000 therms
CG-M and CG-TM

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 183.9995	$ -		$/Mo. Fixed or equiv.	$ 149.9998	$ 149.9998	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.0493	$ -		$/Day Fixed or equiv.	$ 4.9315	$ 4.9315	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Winter	$ 0.6212	$ 0.6495	$ 0.0283	
	$/Therm-Summer	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Summer	$ 0.5052	$ 0.5335	$ 0.0283	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		$ 4,208.09	$ 4,560.11	$ 352.02	8.37%		$ 13,665.24	$ 14,231.27	$ 566.03	4.14%
42,300		$ 6,437.99	$ 7,182.47	$ 744.48	11.56%		$ 26,893.73	$ 28,090.82	$ 1,197.09	4.45%
43,087	1281	$ 6,516.69	$ 7,275.03	$ 758.34	11.64%		$ 27,360.60	$ 28,579.96	$ 1,219.36	4.46%
53,000		$ 7,507.99	$ 8,440.79	$ 932.80	12.42%		$ 33,241.31	$ 34,741.21	$ 1,499.90	4.51%
63,000		$ 8,507.99	$ 9,616.79	$ 1,108.80	13.03%		$ 39,173.64	$ 40,956.54	$ 1,782.90	4.55%
73,000		$ 9,507.99	$ 10,792.79	$ 1,284.80	13.51%		$ 45,105.96	$ 47,171.86	$ 2,065.90	4.58%
83,000		$ 10,507.99	$ 11,968.79	$ 1,460.80	13.90%		$ 51,038.29	$ 53,387.19	$ 2,348.90	4.60%
93,000		$ 11,507.99	$ 13,144.79	$ 1,636.80	14.22%		$ 56,970.61	$ 59,602.51	$ 2,631.90	4.62%
103,000		$ 12,507.99	$ 14,320.79	$ 1,812.80	14.49%		$ 62,902.93	$ 65,817.83	$ 2,914.90	4.63%
113,000		$ 13,507.99	$ 15,496.79	$ 1,988.80	14.72%		$ 68,835.26	$ 72,033.16	$ 3,197.90	4.65%
123,000		$ 14,507.99	$ 16,672.79	$ 2,164.80	14.92%		$ 74,767.58	$ 78,248.48	$ 3,480.90	4.66%
133,000		$ 15,507.99	$ 17,848.79	$ 2,340.80	15.09%		$ 80,699.91	$ 84,463.81	$ 3,763.90	4.66%
143,000		$ 16,507.99	$ 19,024.79	$ 2,516.80	15.25%		$ 86,632.23	$ 90,679.13	$ 4,046.90	4.67%
153,000		$ 17,507.99	$ 20,200.79	$ 2,692.80	15.38%		$ 92,564.55	$ 96,894.45	$ 4,329.90	4.68%
163,000		$ 18,507.99	$ 21,376.79	$ 2,868.80	15.50%		$ 98,496.88	$ 103,109.78	$ 4,612.90	4.68%
173,000		$ 19,507.99	$ 22,552.79	$ 3,044.80	15.61%		$ 104,429.20	$ 109,325.10	$ 4,895.90	4.69%
183,000		$ 20,507.99	$ 23,728.79	$ 3,220.80	15.71%		$ 110,361.53	$ 115,540.43	$ 5,178.90	4.69%
	Winter Qty %	75.89%	75.89%			Winter Qty %	75.89%	75.89%		
	Summer QTY %	24.11%	24.11%			Summer QTY %	24.11%	24.11%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774
Transportation Administrative Charge:	$ 0.9205	

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms
CG-M

Transportation Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 361.9979	$ 6.0012	$ (355.9967)	
	$/Day Fixed or equiv.	$ 11.9013	$ 0.1973	$ (11.7040)	
	Demand Charge	$ -	$ -	$ -	
	$/Therm-Winter	$ 0.1000	$ 0.1176	$ 0.0176	
	$/Therm-Summer	$ 0.1000	$ 0.1176	$ 0.0176	

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 299.9996	$ 299.9996	$ -	
$/Day Fixed or equiv.	$ 9.8630	$ 9.8630	$ -	
Demand Charge	$ -	$ -	$ -	
$/Therm-Winter	$ 0.6212	$ 0.6495	$ 0.0283	
$/Therm-Summer	$ 0.5052	$ 0.5335	$ 0.0283	

Transportation Service

Usage in Therms	Customer Demand Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001	0	N/A	N/A	N/A	N/A
30,001	0	N/A	N/A	N/A	N/A
40,001	0	N/A	N/A	N/A	N/A
50,001	0	N/A	N/A	N/A	N/A
60,001	0	N/A	N/A	N/A	N/A
70,001	0	N/A	N/A	N/A	N/A
80,001	0	N/A	N/A	N/A	N/A
90,001	0	N/A	N/A	N/A	N/A
100,001	0	N/A	N/A	N/A	N/A
110,001	0	N/A	N/A	N/A	N/A
120,001	0	N/A	N/A	N/A	N/A
130,001	0	N/A	N/A	N/A	N/A
140,001	0	N/A	N/A	N/A	N/A
150,001	0	N/A	N/A	N/A	N/A
160,001	0	N/A	N/A	N/A	N/A
170,001	0	N/A	N/A	N/A	N/A
180,001	0	N/A	N/A	N/A	N/A
Winter Qty %		0.00%	0.00%		
Summer QTY %		100.00%	100.00%		

Sales Service

Usage in Therms	Customer Demand Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001	0	$ 11,904.50	$ 12,470.53	$ 566.03	4.75%
30,001	0	$ 16,956.50	$ 17,805.53	$ 849.03	5.01%
40,001	0	$ 22,008.50	$ 23,140.53	$ 1,132.03	5.14%
50,001	0	$ 27,060.50	$ 28,475.53	$ 1,415.03	5.23%
60,001	0	$ 32,112.50	$ 33,810.53	$ 1,698.03	5.29%
70,001	0	$ 37,164.50	$ 39,145.53	$ 1,981.03	5.33%
80,001	0	$ 42,216.50	$ 44,480.53	$ 2,264.03	5.36%
90,001	0	$ 47,268.50	$ 49,815.53	$ 2,547.03	5.39%
100,001	0	$ 52,320.50	$ 55,150.53	$ 2,830.03	5.41%
110,001	0	$ 57,372.50	$ 60,485.53	$ 3,113.03	5.43%
120,001	0	$ 62,424.50	$ 65,820.53	$ 3,396.03	5.44%
130,001	0	$ 67,476.50	$ 71,155.53	$ 3,679.03	5.45%
140,001	0	$ 72,528.50	$ 76,490.53	$ 3,962.03	5.46%
150,001	0	$ 77,580.50	$ 81,825.53	$ 4,245.03	5.47%
160,001	0	$ 82,632.50	$ 87,160.53	$ 4,528.03	5.48%
170,001	0	$ 87,684.50	$ 92,495.53	$ 4,811.03	5.49%
180,001	0	$ 92,736.50	$ 97,830.53	$ 5,094.03	5.49%
Winter Qty %		0.00%	0.00%		
Summer QTY %		100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Commercial/Industrial Large Over 200000 therms
CG-FL and CG-TL

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -		$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -		$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073		Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Winter	$ 0.5699	$ 0.5951	$ 0.0252	
	$/Therm-Summer	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Summer	$ 0.4539	$ 0.4791	$ 0.0252	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	3018	$ 18,393.13	$ 21,315.16	$ 2,922.03	15.89%	3018	$ 111,759.71	$ 116,821.74	$ 5,062.03	4.53%
337,500	3018	$ 25,089.38	$ 30,005.16	$ 4,915.78	19.59%	3018	$ 182,876.47	$ 191,403.50	$ 8,527.03	4.66%
475,000	3018	$ 31,785.63	$ 38,695.16	$ 6,909.53	21.74%	3018	$ 253,993.23	$ 265,985.26	$ 11,992.03	4.72%
590,121	3018	$ 37,392.02	$ 45,970.81	$ 8,578.79	22.94%	3018	$ 313,535.28	$ 328,428.36	$ 14,893.08	4.75%
750,000	3018	$ 45,178.13	$ 56,075.16	$ 10,897.03	24.12%	3018	$ 396,226.75	$ 415,148.78	$ 18,922.03	4.78%
821,900	3018	$ 48,679.66	$ 60,619.24	$ 11,939.58	24.53%	5300	$ 433,750.94	$ 454,501.51	$ 20,750.57	4.78%
916,300	5800	$ 53,687.28	$ 67,015.97	$ 13,328.69	24.83%	3018	$ 482,239.24	$ 505,352.03	$ 23,112.79	4.79%
1,053,800	3018	$ 59,973.19	$ 75,275.32	$ 15,302.13	25.51%	3018	$ 553,356.00	$ 579,933.79	$ 26,577.79	4.80%
1,191,300	3018	$ 66,669.44	$ 83,965.32	$ 17,295.88	25.94%	3018	$ 624,472.76	$ 654,515.55	$ 30,042.79	4.81%
1,328,800	3018	$ 73,365.69	$ 92,655.32	$ 19,289.63	26.29%	3018	$ 695,589.52	$ 729,097.31	$ 33,507.79	4.82%
1,466,300	3018	$ 80,061.94	$ 101,345.32	$ 21,283.38	26.58%	3018	$ 766,706.28	$ 803,679.07	$ 36,972.79	4.82%
1,603,800	3018	$ 86,758.19	$ 110,035.32	$ 23,277.13	26.83%	3018	$ 837,823.04	$ 878,260.83	$ 40,437.79	4.83%
1,741,300	3018	$ 93,454.44	$ 118,725.32	$ 25,270.88	27.04%	3018	$ 908,939.80	$ 952,842.59	$ 43,902.79	4.83%
1,878,800	3018	$ 100,150.69	$ 127,415.32	$ 27,264.63	27.22%	3018	$ 980,056.56	$ 1,027,424.35	$ 47,367.79	4.83%
2,016,300	3018	$ 106,846.94	$ 136,105.32	$ 29,258.38	27.38%	3018	$ 1,051,173.32	$ 1,102,006.11	$ 50,832.79	4.84%
2,153,800	3018	$ 113,543.19	$ 144,795.32	$ 31,252.13	27.52%	3018	$ 1,122,290.08	$ 1,176,587.87	$ 54,297.79	4.84%
2,291,300	3018	$ 120,239.44	$ 153,485.32	$ 33,245.88	27.65%	3018	$ 1,193,406.84	$ 1,251,169.63	$ 57,762.79	4.84%

	Old	New		Old	New
Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms
CG-FL

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -		$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -		$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073		Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Winter	$ 0.5699	$ 0.5951	$ 0.0252	
	$/Therm-Summer	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Summer	$ 0.4539	$ 0.4791	$ 0.0252	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	3018	N/A	N/A	N/A	N/A	3018	$ 95,161.15	$ 100,223.18	$ 5,062.03	5.32%
337,500	3018	N/A	N/A	N/A	N/A	3018	$ 157,572.40	$ 166,099.43	$ 8,527.03	5.41%
475,000	3018	N/A	N/A	N/A	N/A	3018	$ 219,983.65	$ 231,975.68	$ 11,992.03	5.45%
612,500	3018	N/A	N/A	N/A	N/A	3018	$ 282,394.90	$ 297,851.93	$ 15,457.03	5.47%
750,000	3018	N/A	N/A	N/A	N/A	3018	$ 344,806.15	$ 363,728.18	$ 18,922.03	5.49%
887,500	3018	N/A	N/A	N/A	N/A	3018	$ 407,217.40	$ 429,604.43	$ 22,387.03	5.50%
1,025,000	3018	N/A	N/A	N/A	N/A	3018	$ 469,628.65	$ 495,480.68	$ 25,852.03	5.50%
1,162,500	3018	N/A	N/A	N/A	N/A	3018	$ 532,039.90	$ 561,356.93	$ 29,317.03	5.51%
1,300,000	3018	N/A	N/A	N/A	N/A	3018	$ 594,451.15	$ 627,233.18	$ 32,782.03	5.51%
1,437,500	3018	N/A	N/A	N/A	N/A	3018	$ 656,862.40	$ 693,109.43	$ 36,247.03	5.52%
1,575,000	3018	N/A	N/A	N/A	N/A	3018	$ 719,273.65	$ 758,985.68	$ 39,712.03	5.52%
1,712,500	3018	N/A	N/A	N/A	N/A	3018	$ 781,684.90	$ 824,861.93	$ 43,177.03	5.52%
1,850,000	3018	N/A	N/A	N/A	N/A	3018	$ 844,096.15	$ 890,738.18	$ 46,642.03	5.53%
1,987,500	3018	N/A	N/A	N/A	N/A	3018	$ 906,507.40	$ 956,614.43	$ 50,107.03	5.53%
2,125,000	3018	N/A	N/A	N/A	N/A	3018	$ 968,918.65	$ 1,022,490.68	$ 53,572.03	5.53%
2,262,500	3018	N/A	N/A	N/A	N/A	3018	$ 1,031,329.90	$ 1,088,366.93	$ 57,037.03	5.53%
2,400,000	3018	N/A	N/A	N/A	N/A	3018	$ 1,093,741.15	$ 1,154,243.18	$ 60,502.03	5.53%

Winter Qty %	0.00%	0.00%	Winter Qty %	0.00%	0.00%
Summer QTY %	100.00%	100.00%	Summer QTY %	100.00%	100.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interruptible Commercial/Industrial Medium 20001 to 200000 therms
CG-IM and CG-TM

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 183.9995	$ -		$/Mo. Fixed or equiv.	$ 156.0010	$ 156.0010	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.0493	$ -		$/Day Fixed or equiv.	$ 5.1288	$ 5.1288	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Winter	$ 0.5045	$ 0.5320	$ 0.0275	
	$/Therm-Summer	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Summer	$ 0.5045	$ 0.5320	$ 0.0275	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		$ 4,208.09	$ 4,560.11	$ 352.02	8.37%		$ 11,962.52	$ 12,512.54	$ 550.02	4.60%
30,001		$ 5,208.09	$ 5,736.11	$ 528.02	10.14%		$ 17,007.52	$ 17,832.54	$ 825.02	4.85%
40,001		$ 6,208.09	$ 6,912.11	$ 704.02	11.34%		$ 22,052.52	$ 23,152.54	$ 1,100.02	4.99%
50,001		$ 7,208.09	$ 8,088.11	$ 880.02	12.21%		$ 27,097.52	$ 28,472.54	$ 1,375.02	5.07%
60,001		$ 8,208.09	$ 9,264.11	$ 1,056.02	12.87%		$ 32,142.52	$ 33,792.54	$ 1,650.02	5.13%
70,001		$ 9,208.09	$ 10,440.11	$ 1,232.02	13.38%		$ 37,187.52	$ 39,112.54	$ 1,925.02	5.18%
80,001		$ 10,208.09	$ 11,616.11	$ 1,408.02	13.79%		$ 42,232.52	$ 44,432.54	$ 2,200.02	5.21%
90,001		$ 11,208.09	$ 12,792.11	$ 1,584.02	14.13%		$ 47,277.52	$ 49,752.54	$ 2,475.02	5.24%
103,000		$ 12,507.99	$ 14,320.79	$ 1,812.80	14.49%		$ 53,835.51	$ 56,668.01	$ 2,832.50	5.26%
113,000		$ 13,507.99	$ 15,496.79	$ 1,988.80	14.72%		$ 58,880.51	$ 61,988.01	$ 3,107.50	5.28%
125,000		$ 14,707.99	$ 16,907.99	$ 2,200.00	14.96%		$ 64,934.51	$ 68,372.01	$ 3,437.50	5.29%
135,000		$ 15,707.99	$ 18,083.99	$ 2,376.00	15.13%		$ 69,979.51	$ 73,692.01	$ 3,712.50	5.31%
145,000		$ 16,707.99	$ 19,259.99	$ 2,552.00	15.27%		$ 75,024.51	$ 79,012.01	$ 3,987.50	5.31%
155,000		$ 17,707.99	$ 20,435.99	$ 2,728.00	15.41%		$ 80,069.51	$ 84,332.01	$ 4,262.50	5.32%
165,000		$ 18,707.99	$ 21,611.99	$ 2,904.00	15.52%		$ 85,114.51	$ 89,652.01	$ 4,537.50	5.33%
175,000		$ 19,707.99	$ 22,787.99	$ 3,080.00	15.63%		$ 90,159.51	$ 94,972.01	$ 4,812.50	5.34%
185,000		$ 20,707.99	$ 23,963.99	$ 3,256.00	15.72%		$ 95,204.51	$ 100,292.01	$ 5,087.50	5.34%
	Winter Qty %	75.89%	75.89%			Winter Qty %	75.89%	75.89%		
	Summer QTY %	24.11%	24.11%			Summer QTY %	24.11%	24.11%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3774	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interruptible Commercial/Industrial Large 200001 to 2400000 therms
CG-IL and CG-TL

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -		$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -		$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073		Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Winter	$ 0.4532	$ 0.4776	$ 0.0244	
	$/Therm-Summer	$ 0.0487	$ 0.0632	$ 0.0145		$/Therm-Summer	$ 0.4532	$ 0.4776	$ 0.0244	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	7498	$ 19,053.93	$ 22,008.66	$ 2,954.73	15.51%	7498	$ 99,617.95	$ 104,552.68	$ 4,934.73	4.95%
356,600	7498	$ 26,680.35	$ 31,905.78	$ 5,225.43	19.59%	6100	$ 170,382.86	$ 179,128.43	$ 8,745.57	5.13%
494,100	7498	$ 33,376.60	$ 40,595.78	$ 7,219.18	21.63%	7498	$ 232,904.07	$ 245,014.84	$ 12,110.77	5.20%
631,600	7498	$ 40,072.85	$ 49,285.78	$ 9,212.93	22.99%	7498	$ 295,219.07	$ 310,684.84	$ 15,465.77	5.24%
645,000	7498	$ 40,725.43	$ 50,132.66	$ 9,407.23	23.10%	7498	$ 301,291.95	$ 317,084.68	$ 15,792.73	5.24%
782,500	7498	$ 47,421.68	$ 58,822.66	$ 11,400.98	24.04%	7498	$ 363,606.95	$ 382,754.68	$ 19,147.73	5.27%
916,300	5800	$ 53,687.28	$ 67,015.97	$ 13,328.69	24.83%	7498	$ 424,245.11	$ 446,657.56	$ 22,412.45	5.28%
1,053,800	7498	$ 60,633.99	$ 75,968.82	$ 15,334.83	25.29%	7498	$ 486,560.11	$ 512,327.56	$ 25,767.45	5.30%
1,191,300	7498	$ 67,330.24	$ 84,658.82	$ 17,328.58	25.74%	7498	$ 548,875.11	$ 577,997.56	$ 29,122.45	5.31%
1,328,800	7498	$ 74,026.49	$ 93,348.82	$ 19,322.33	26.10%	7498	$ 611,190.11	$ 643,667.56	$ 32,477.45	5.31%
1,466,300	7498	$ 80,722.74	$ 102,038.82	$ 21,316.08	26.41%	7498	$ 673,505.11	$ 709,337.56	$ 35,832.45	5.32%
1,603,800	7498	$ 87,418.99	$ 110,728.82	$ 23,309.83	26.66%	7498	$ 735,820.11	$ 775,007.56	$ 39,187.45	5.33%
1,741,300	7498	$ 94,115.24	$ 119,418.82	$ 25,303.58	26.89%	7498	$ 798,135.11	$ 840,677.56	$ 42,542.45	5.33%
1,878,800	7498	$ 100,811.49	$ 128,108.82	$ 27,297.33	27.08%	7498	$ 860,450.11	$ 906,347.56	$ 45,897.45	5.33%
2,016,300	7498	$ 107,507.74	$ 136,798.82	$ 29,291.08	27.25%	7498	$ 922,765.11	$ 972,017.56	$ 49,252.45	5.34%
2,153,800	7498	$ 114,203.99	$ 145,488.82	$ 31,284.83	27.39%	7498	$ 985,080.11	$ 1,037,687.56	$ 52,607.45	5.34%
2,291,300	7498	$ 120,900.24	$ 154,178.82	$ 33,278.58	27.53%	7498	$ 1,047,395.11	$ 1,103,357.56	$ 55,962.45	5.34%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interruptible Commercial/Industrial Super Large Over 2400000 therms
CG-ISL and CG-TSL

Usage in Therms	Transportation Service		Old Annual Rate		New Annual Rate		Increase (Decrease)	Percent of Change	Sales Service		Old Annual Rate		New Annual Rate		Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$	3,739.9999	$	3,739.9999	$	-		$/Mo. Fixed or equiv.	$	3,706.0001	$	3,706.0001	$	-	
	$/Day Fixed or equiv.	$	122.9589	$	122.9589	$	-		$/Day Fixed or equiv.	$	122.0384	$	122.0384	$	-	
	Demand Charge	$	0.1000	$	0.1100	$	0.0100		Demand Charge	$	0.1000	$	0.1100	$	0.0100	
	$/Therm-Winter	$	0.0297	$	0.0321	$	0.0024		$/Therm-Winter	$	0.4342	$	0.4465	$	0.0123	
	$/Therm-Summer	$	0.0297	$	0.0321	$	0.0024		$/Therm-Summer	$	0.4342	$	0.4465	$	0.0123	

Usage in Therms	Demand Charge Quantity		Old Annual Bill		New Annual Bill		Increase (Decrease)	Percent of Change	Demand Charge Quantity		Old Annual Bill		New Annual Bill		Increase (Decrease)	Percent of Change
2,400,001	4168	$	116,576.83	$	122,378.51	$	5,801.68	4.98%	4168	$	1,087,041.25	$	1,116,602.94	$	29,561.69	2.72%
3,187,501	4168	$	139,965.58	$	147,657.26	$	7,691.68	5.50%	4168	$	1,428,973.75	$	1,468,221.69	$	39,247.94	2.75%
3,975,001	4168	$	163,354.33	$	172,936.01	$	9,581.68	5.87%	4168	$	1,770,906.25	$	1,819,840.44	$	48,934.19	2.76%
4,762,501	4168	$	186,743.08	$	198,214.76	$	11,471.68	6.14%	4168	$	2,112,838.75	$	2,171,459.19	$	58,620.44	2.77%
5,550,001	4168	$	210,131.83	$	223,493.51	$	13,361.68	6.36%	4168	$	2,454,771.25	$	2,523,077.94	$	68,306.69	2.78%
6,000,000	4168	$	223,496.80	$	237,938.48	$	14,441.68	6.46%	4168	$	2,650,160.82	$	2,724,002.50	$	73,841.68	2.79%
6,842,900	33500	$	251,464.13	$	268,222.09	$	16,757.96	6.66%	33500	$	3,019,081.20	$	3,103,583.87	$	84,502.67	2.80%
7,630,400	4168	$	271,919.68	$	290,274.32	$	18,354.64	6.75%	4168	$	3,358,080.50	$	3,451,976.10	$	93,895.60	2.80%
8,417,900	4168	$	295,308.43	$	315,553.07	$	20,244.64	6.86%	4168	$	3,700,013.00	$	3,803,594.85	$	103,581.85	2.80%
9,205,400	4168	$	318,697.18	$	340,831.82	$	22,134.64	6.95%	4168	$	4,041,945.50	$	4,155,213.60	$	113,268.10	2.80%
9,992,900	4168	$	342,085.93	$	366,110.57	$	24,024.64	7.02%	4168	$	4,383,878.00	$	4,506,832.35	$	122,954.35	2.80%
10,780,400	4168	$	365,474.68	$	391,389.32	$	25,914.64	7.09%	4168	$	4,725,810.50	$	4,858,451.10	$	132,640.60	2.81%
11,567,900	4168	$	388,863.43	$	416,668.07	$	27,804.64	7.15%	4168	$	5,067,743.00	$	5,210,069.85	$	142,326.85	2.81%
12,355,400	4168	$	412,252.18	$	441,946.82	$	29,694.64	7.20%	4168	$	5,409,675.50	$	5,561,688.60	$	152,013.10	2.81%
13,142,900	4168	$	435,640.93	$	467,225.57	$	31,584.64	7.25%	4168	$	5,751,608.00	$	5,913,307.35	$	161,699.35	2.81%
13,930,400	4168	$	459,029.68	$	492,504.32	$	33,474.64	7.29%	4168	$	6,093,540.50	$	6,264,926.10	$	171,385.60	2.81%
14,717,900	4168	$	482,418.43	$	517,783.07	$	35,364.64	7.33%	4168	$	6,435,473.00	$	6,616,544.85	$	181,071.85	2.81%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:		Firm		Interruptible
Base Average Commodity Cost:	$	0.3615	$	0.3615
Base Average Peak Demand Cost:	$	0.1160	$	-
Base Average Annual Demand Cost:	$	0.0159	$	0.0159
Base Average Balancing Cost:	$	-	$	-
Base Average Surcharge Cost:	$	-	$	-
Totals:	$	0.4934	$	0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Commercial/Industrial Extra Super Large Over 15000000 therms
CG-IXSL and CG-TXSL

Transportation Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 29,781.4998	$ 33,492.3331	$ 3,710.8333	
	$/Day Fixed or equiv.	$ 979.1178	$ 1,101.1178	$ 122.0000	
	Demand Charge	$ 0.0450	$ 0.0475	$ 0.0025	
	$/Therm-Winter	$ 0.0096	$ 0.0101	$ 0.0005	
	$/Therm-Summer	$ 0.0096	$ 0.0101	$ 0.0005	

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 30,416.6667	$ 33,458.3333	$ 3,041.6667	
$/Day Fixed or equiv.	$ 1,000.1973	$ 1,100.1973	$ 100.0000	
Demand Charge	$ 0.0450	$ 0.0475	$ 0.0025	
$/Therm-Winter	$ 0.4141	$ 0.4245	$ 0.0104	
$/Therm-Summer	$ 0.4141	$ 0.4245	$ 0.0104	

Transportation Service

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
15,000,000	72243	$ 504,628.93	$ 556,839.54	$ 52,210.61	10.35%
15,937,500	72243	$ 513,628.93	$ 566,308.29	$ 52,679.36	10.26%
16,875,000	72243	$ 522,628.93	$ 575,777.04	$ 53,148.11	10.17%
17,812,500	72243	$ 531,628.93	$ 585,245.79	$ 53,616.86	10.09%
18,750,000	72243	$ 540,628.93	$ 594,714.54	$ 54,085.61	10.00%
19,332,500	72243	$ 546,220.93	$ 600,597.79	$ 54,376.86	9.96%
20,000,000	660000	$ 579,078.00	$ 635,258.00	$ 56,180.00	9.70%
20,937,500	72243	$ 561,628.93	$ 616,808.29	$ 55,179.36	9.82%
21,875,000	72243	$ 570,628.93	$ 626,277.04	$ 55,648.11	9.75%
22,812,500	72243	$ 579,628.93	$ 635,745.79	$ 56,116.86	9.68%
23,750,000	72243	$ 588,628.93	$ 645,214.54	$ 56,585.61	9.61%
24,687,500	72243	$ 597,628.93	$ 654,683.29	$ 57,054.36	9.55%
25,625,000	72243	$ 606,628.93	$ 664,152.04	$ 57,523.11	9.48%
26,562,500	72243	$ 615,628.93	$ 673,620.79	$ 57,991.86	9.42%
27,500,000	72243	$ 624,628.93	$ 683,089.54	$ 58,460.61	9.36%
28,437,500	72243	$ 633,628.93	$ 692,558.29	$ 58,929.36	9.30%
29,375,000	72243	$ 642,628.93	$ 702,027.04	$ 59,398.11	9.24%

Sales Service

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
15,000,000	72243	$ 6,579,822.95	$ 6,772,503.56	$ 192,680.61	2.93%
15,937,500	72243	$ 6,968,041.70	$ 7,170,472.31	$ 202,430.61	2.91%
16,875,000	72243	$ 7,356,260.45	$ 7,568,441.06	$ 212,180.61	2.88%
17,812,500	72243	$ 7,744,479.20	$ 7,966,409.81	$ 221,930.61	2.87%
18,750,000	72243	$ 8,132,697.95	$ 8,364,378.56	$ 231,680.61	2.85%
19,332,500	72243	$ 8,373,911.20	$ 8,611,649.81	$ 237,738.61	2.84%
20,000,000	660000	$ 8,676,772.01	$ 8,922,922.01	$ 246,150.00	2.84%
20,937,500	72243	$ 9,038,541.70	$ 9,292,972.31	$ 254,430.61	2.81%
21,875,000	72243	$ 9,426,760.45	$ 9,690,941.06	$ 264,180.61	2.80%
22,812,500	72243	$ 9,814,979.20	$ 10,088,909.81	$ 273,930.61	2.79%
23,750,000	72243	$ 10,203,197.95	$ 10,486,878.56	$ 283,680.61	2.78%
24,687,500	72243	$ 10,591,416.70	$ 10,884,847.31	$ 293,430.61	2.77%
25,625,000	72243	$ 10,979,635.45	$ 11,282,816.06	$ 303,180.61	2.76%
26,562,500	72243	$ 11,367,854.20	$ 11,680,784.81	$ 312,930.61	2.75%
27,500,000	72243	$ 11,756,072.95	$ 12,078,753.56	$ 322,680.61	2.74%
28,437,500	72243	$ 12,144,291.70	$ 12,476,722.31	$ 332,430.61	2.74%
29,375,000	72243	$ 12,532,510.45	$ 12,874,691.06	$ 342,180.61	2.73%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3774	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interruptible Commercial/Industrial Electric Generation Medium 20001 to 200000 therms
CG-IEGM

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 198.5843	$ 14.5848		$/Mo. Fixed or equiv.	$ 156.0010	$ 156.0010	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.5288	$ 0.4795		$/Day Fixed or equiv.	$ 5.1288	$ 5.1288	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Winter	$ 0.5045	$ 0.5320	$ 0.0275	
	$/Therm-Summer	$ 0.1000	$ 0.1176	$ 0.0176		$/Therm-Summer	$ 0.5045	$ 0.5320	$ 0.0275	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		N/A	N/A	N/A	N/A		$ 11,962.52	$ 12,512.54	$ 550.02	4.60%
30,001		N/A	N/A	N/A	N/A		$ 17,007.52	$ 17,832.54	$ 825.02	4.85%
40,001		N/A	N/A	N/A	N/A		$ 22,052.52	$ 23,152.54	$ 1,100.02	4.99%
50,001		N/A	N/A	N/A	N/A		$ 27,097.52	$ 28,472.54	$ 1,375.02	5.07%
60,001		N/A	N/A	N/A	N/A		$ 32,142.52	$ 33,792.54	$ 1,650.02	5.13%
70,001		N/A	N/A	N/A	N/A		$ 37,187.52	$ 39,112.54	$ 1,925.02	5.18%
80,001		N/A	N/A	N/A	N/A		$ 42,232.52	$ 44,432.54	$ 2,200.02	5.21%
90,001		N/A	N/A	N/A	N/A		$ 47,277.52	$ 49,752.54	$ 2,475.02	5.24%
100,001		N/A	N/A	N/A	N/A		$ 52,322.52	$ 55,072.54	$ 2,750.02	5.26%
110,001		N/A	N/A	N/A	N/A		$ 57,367.52	$ 60,392.54	$ 3,025.02	5.27%
120,001		N/A	N/A	N/A	N/A		$ 62,412.52	$ 65,712.54	$ 3,300.02	5.29%
130,001		N/A	N/A	N/A	N/A		$ 67,457.52	$ 71,032.54	$ 3,575.02	5.30%
140,001		N/A	N/A	N/A	N/A		$ 72,502.52	$ 76,352.54	$ 3,850.02	5.31%
150,001		N/A	N/A	N/A	N/A		$ 77,547.52	$ 81,672.54	$ 4,125.02	5.32%
160,001		N/A	N/A	N/A	N/A		$ 82,592.52	$ 86,992.54	$ 4,400.02	5.33%
175,000		N/A	N/A	N/A	N/A		$ 90,159.51	$ 94,972.01	$ 4,812.50	5.34%
185,000		N/A	N/A	N/A	N/A		$ 95,204.51	$ 100,292.01	$ 5,087.50	5.34%
	Winter Qty %	75.89%	75.89%			Winter Qty %	75.89%	75.89%		
	Summer QTY %	24.11%	24.11%			Summer QTY %	24.11%	24.11%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3774	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interruptible Commercial/Industrial Electric Generation Large Over 200000 therms
CG-IEGL

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 7,607.7498	$ 7,607.7498	$ -		$/Mo. Fixed or equiv.	$ 7,573.7500	$ 7,573.7500	$ -	
	$/Day Fixed or equiv.	$ 250.1178	$ 250.1178	$ -		$/Day Fixed or equiv.	$ 249.1973	$ 249.1973	$ -	
	Demand Charge	$ 0.0720	$ 0.0720	$ -		Demand Charge	$ 0.0720	$ 0.0720	$ -	
	$/Therm-Winter	$ 0.0132	$ 0.0370	$ 0.0238		$/Therm-Winter	$ 0.3972	$ 0.4214	$ 0.0242	
	$/Therm-Summer	$ 0.0132	$ 0.0370	$ 0.0238		$/Therm-Summer	$ 0.3972	$ 0.4214	$ 0.0242	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	145190	N/A	N/A	N/A	N/A	145190	$ 180,850.69	$ 185,690.69	$ 4,840.00	2.68%
337,500	145190	N/A	N/A	N/A	N/A	145190	$ 235,465.69	$ 243,633.19	$ 8,167.50	3.47%
475,000	145190	N/A	N/A	N/A	N/A	145190	$ 290,080.69	$ 301,575.69	$ 11,495.00	3.96%
612,500	145190	N/A	N/A	N/A	N/A	145190	$ 344,695.69	$ 359,518.19	$ 14,822.50	4.30%
750,000	145190	N/A	N/A	N/A	N/A	145190	$ 399,310.69	$ 417,460.69	$ 18,150.00	4.55%
887,500	145190	N/A	N/A	N/A	N/A	145190	$ 453,925.69	$ 475,403.19	$ 21,477.50	4.73%
1,025,000	145190	N/A	N/A	N/A	N/A	145190	$ 508,540.69	$ 533,345.69	$ 24,805.00	4.88%
1,162,500	145190	N/A	N/A	N/A	N/A	145190	$ 563,155.69	$ 591,288.19	$ 28,132.50	5.00%
1,300,000	145190	N/A	N/A	N/A	N/A	145190	$ 617,770.69	$ 649,230.69	$ 31,460.00	5.09%
1,437,500	145190	N/A	N/A	N/A	N/A	145190	$ 672,385.69	$ 707,173.19	$ 34,787.50	5.17%
1,575,000	145190	N/A	N/A	N/A	N/A	145190	$ 727,000.69	$ 765,115.69	$ 38,115.00	5.24%
1,712,500	145190	N/A	N/A	N/A	N/A	145190	$ 781,615.69	$ 823,058.19	$ 41,442.50	5.30%
1,850,000	145190	N/A	N/A	N/A	N/A	145190	$ 836,230.69	$ 881,000.69	$ 44,770.00	5.35%
1,987,500	145190	N/A	N/A	N/A	N/A	145190	$ 890,845.69	$ 938,943.19	$ 48,097.50	5.40%
2,125,000	145190	N/A	N/A	N/A	N/A	145190	$ 945,460.69	$ 996,885.69	$ 51,425.00	5.44%
2,262,500	145190	N/A	N/A	N/A	N/A	145190	$ 1,000,075.69	$ 1,054,828.19	$ 54,752.50	5.47%
4,236,600	145190	N/A	N/A	N/A	N/A	140500	$ 1,783,850.53	$ 1,886,376.25	$ 102,525.72	5.75%
	Winter Qty %	54.58%	54.58%			Winter Qty %	54.58%	54.58%		
	Summer QTY %	45.42%	45.42%			Summer QTY %	45.42%	45.42%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3615	$ 0.3615
Base Average Peak Demand Cost:	$ 0.1160	$ -
Base Average Annual Demand Cost:	$ 0.0159	$ 0.0159
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4934	$ 0.3774

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Change of Total Revenue Dollar Amounts between Current and Final Revenue
for the test year ended December 31, 2026

Sales Customers - All	Average Customer Counts	Total Therms	Current Rates 2026 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2026 Total Revenues	Final 2026 Gas Revenues	Final 2026 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Residential Sales Service	312,017	261,128,673	$ 241,886,999	$ 131,963,360	$ 109,923,639	$ 256,249,076	$ 131,963,360	$ 124,285,716	$ 14,362,077	5.94%
Residential Sales Service - Seasonal	1,343	1,169,049	$ 1,356,497	$ 597,035	$ 759,462	$ 1,420,798	$ 597,035	$ 823,763	$ 64,301	4.74%
Firm Commercial/Industrial Standard 0 to 2000 therms	18,805	18,645,046	$ 16,833,988	$ 9,693,962	$ 7,140,026	$ 17,859,468	$ 9,693,962	$ 8,165,506	$ 1,025,480	6.09%
Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms	28	29,795	$ 30,233	$ 13,431	$ 16,802	$ 31,869	$ 13,431	$ 18,438	$ 1,636	5.41%
Firm Commercial/IndustrialSmall 2001 to 20000 therms	14,964	87,725,653	$ 63,806,441	$ 44,234,050	$ 19,572,391	$ 67,815,505	$ 44,234,050	$ 23,581,455	$ 4,009,064	6.28%
Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms	4	25,032	$ 17,551	$ 10,962	$ 6,589	$ 18,691	$ 10,962	$ 7,729	$ 1,140	6.50%
Firm Commercial/Industrial Medium 20001 to 200000 therms	1,308	58,571,095	$ 38,621,298	$ 28,782,111	$ 9,839,187	$ 40,483,860	$ 28,782,111	$ 11,701,749	$ 1,862,562	4.82%
Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Commercial/Industrial Large Over 200000 therms	25	11,668,936	$ 6,396,865	$ 5,173,854	$ 1,223,011	$ 6,713,875	$ 5,173,854	$ 1,540,021	$ 317,010	4.96%
Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Medium 20001 to 200000 therms	11	1,916,081	$ 1,038,297	$ 774,171	$ 264,126	$ 1,097,692	$ 774,171	$ 323,521	$ 59,395	5.72%
Interruptible Commercial/Industrial Large 200001 to 2400000 therms	1	248,755	$ 127,020	$ 87,024	$ 39,996	$ 134,098	$ 87,024	$ 47,074	$ 7,078	5.57%
Interruptible Commercial/Industrial Super Large Over 2400000 therm	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Medium 20001 t	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Large Over 200(	2	15,354,017	$ 5,874,619	$ 5,137,814	$ 736,805	$ 6,240,049	$ 5,137,814	$ 1,102,235	$ 365,430	6.22%
Commercial/Industrial Electric Generation Extra Super Large Over 150(	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 1 1 to 3,000 therms	22	362,134	$ 255,810	$ 142,046	$ 113,764	$ 255,882	$ 142,046	$ 113,836	$ 72	0.03%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	438,552	$ 286,632	$ 176,644	$ 109,988	$ 286,281	$ 176,644	$ 109,637	$ (351)	-0.12%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	529,396	$ 318,310	$ 224,872	$ 93,438	$ 317,833	$ 224,872	$ 92,961	$ (477)	-0.15%
PWRDEPT	8	30,200,829	$ 14,747,289	$ 10,893,787	$ 3,853,502	$ 15,683,517	$ 10,893,787	$ 4,789,730	$ 936,228	6.35%
PWRDEPT FIRM	-	730,777	$ 374,188	$ 281,013	$ 93,175	$ 397,134	$ 281,013	$ 116,121	$ 22,946	6.13%
Total - Sales Customers - All	348,537	488,743,820	$ 391,972,037	$ 238,186,136	$ 153,785,901	$ 415,005,628	$ 238,186,136	$ 176,819,492	$ 23,033,591	5.88%

Transportation Customers - All	Average Customer Counts	Total Therms	Current Rates 2026 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2026 Total Revenues	Final 2026 Gas Revenues	Final 2026 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/IndustrialSmall 0 to 20000 therms	171	2,523,420	$ 469,092	$ -	$ 469,092	$ 554,886	$ -	$ 554,886	$ 85,794	18.29%
Commercial/Industrial Medium 20001 to 200000 therms	558	42,744,300	$ 5,505,401	$ -	$ 5,505,401	$ 6,364,560	$ -	$ 6,364,560	$ 859,159	15.61%
Commercial/Industrial Large 200000 to 2400000 therms	226	153,437,476	$ 10,973,411	$ -	$ 10,973,411	$ 13,341,095	$ -	$ 13,341,095	$ 2,367,684	21.58%
Commercial/Industrial Super Large Over 2400000 therms	24	134,817,253	$ 5,816,559	$ -	$ 5,816,559	$ 6,429,353	$ -	$ 6,429,353	$ 612,794	10.54%
Commercial/Industrial Extra Super Large Over 15000000 therms	6	159,106,315	$ 4,069,840	$ -	$ 4,069,840	$ 5,501,590	$ -	$ 5,501,590	$ 1,431,750	35.18%
CSR TSL-IG4T	1	9,297,700	$ 207,744	$ -	$ 207,744	$ 218,170	$ -	$ 218,170	$ 10,426	5.02%
PWRDEPT	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
PWRDEPT FIRM	0	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Power Generation Contracted Service	1	80,523,533	$ 442,402	$ -	$ 442,402	$ 442,402	$ -	$ 442,402	$ -	0.00%
Total - Transportation Customers - All	987	582,449,997	$ 27,484,449	$ -	$ 27,484,449	$ 32,852,056	$ -	$ 32,852,056	$ 5,367,607	19.53%

Note1: Gas Costs are priced at Final base rates under both current Gas Revenues and Final 2026 Gas Revenues.

Wisconsin Public Service Corporation
Change of Total Revenue Dollar Amounts between Current and Final Revenue
for the test year ended December 31, 2026

All Customers - All	Average Customer Counts	Total Therms	Current Rates 2026 Total Revenues	Current Rates[1] Gas Revenues	Current Rates Total Margin Revenues	Final 2026 Total Revenues	Final 2026 Gas Revenues	Final 2026 Total Margin Revenues	Final Total Revenue $ Change	Final Total Revenue % Change
Residential Sales Service	312,017	261,128,673	$ 241,886,999	$ 131,963,360	$ 109,923,639	$ 256,249,076	$ 131,963,360	$ 124,285,716	$ 14,362,077	5.94%
Residential Sales Service - Seasonal	1,343	1,169,049	$ 1,356,497	$ 597,035	$ 759,462	$ 1,420,798	$ 597,035	$ 823,763	$ 64,301	4.74%
Firm Commercial/Industrial Standard 0 to 2000 therms	18,805	18,645,046	$ 16,833,988	$ 9,693,962	$ 7,140,026	$ 17,859,468	$ 9,693,962	$ 8,165,506	$ 1,025,480	6.09%
Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms	28	29,795	$ 30,233	$ 13,431	$ 16,802	$ 31,869	$ 13,431	$ 18,438	$ 1,636	5.41%
Firm Commercial/IndustrialSmall 2001 to 20000 therms	14,964	87,725,653	$ 63,806,441	$ 44,234,050	$ 19,572,391	$ 67,815,505	$ 44,234,050	$ 23,581,455	$ 4,009,064	6.28%
Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms	4	25,032	$ 17,551	$ 10,962	$ 6,589	$ 18,691	$ 10,962	$ 7,729	$ 1,140	6.50%
Firm Commercial/Industrial Medium 20001 to 200000 therms	1,308	58,571,095	$ 38,621,298	$ 28,782,111	$ 9,839,187	$ 40,483,860	$ 28,782,111	$ 11,701,749	$ 1,862,562	4.82%
Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Commercial/Industrial Large Over 200000 therms	25	11,668,936	$ 6,396,865	$ 5,173,854	$ 1,223,011	$ 6,713,875	$ 5,173,854	$ 1,540,021	$ 317,010	4.96%
Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Medium 20001 to 200000 therms	11	1,916,081	$ 1,038,297	$ 774,171	$ 264,126	$ 1,097,692	$ 774,171	$ 323,521	$ 59,395	5.72%
Interruptible Commercial/Industrial Large 200001 to 2400000 therms	1	248,755	$ 127,020	$ 87,024	$ 39,996	$ 134,098	$ 87,024	$ 47,074	$ 7,078	5.57%
Interruptible Commercial/Industrial Large Over 2400000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Commercial/Industrial Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Medium 20001 t	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interruptible Commercial/Industrial Electric Generation Large Over 200(	2	15,354,017	$ 5,874,619	$ 5,137,814	$ 736,805	$ 6,240,049	$ 5,137,814	$ 1,102,235	$ 365,430	6.22%
Commercial/Industrial Electric Generation Extra Super Large Over 150(	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 1 1 to 3,000 therms	22	362,134	$ 255,810	$ 142,046	$ 113,764	$ 255,882	$ 142,046	$ 113,836	$ 72	0.03%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 2 3,001 to 10,000 therms	-	438,552	$ 286,632	$ 176,644	$ 109,988	$ 286,281	$ 176,644	$ 109,637	$ (351)	-0.12%
Intrptbl Cmmrcl/Indstrl Snl Opprnty Sls Step 3 Over 10,000 therms	-	529,396	$ 318,310	$ 224,872	$ 93,438	$ 317,833	$ 224,872	$ 92,961	$ (477)	-0.15%
Commercial/IndustrialSmall 0 to 20000 therms	171	2,523,420	$ 469,092	$ -	$ 469,092	$ 554,886	$ -	$ 554,886	$ 85,794	18.29%
Commercial/Industrial Medium 20001 to 200000 therms	558	42,744,300	$ 5,505,401	$ -	$ 5,505,401	$ 6,364,560	$ -	$ 6,364,560	$ 859,159	15.61%
Commercial/Industrial Large 200000 to 2400000 therms	226	153,437,476	$ 10,973,411	$ -	$ 10,973,411	$ 13,341,095	$ -	$ 13,341,095	$ 2,367,684	21.58%
Commercial/Industrial Super Large Over 2400000 therms	24	134,817,253	$ 5,816,559	$ -	$ 5,816,559	$ 6,429,353	$ -	$ 6,429,353	$ 612,794	10.54%
Commercial/Industrial Extra Super Large Over 15000000 therms	6	159,106,315	$ 4,069,840	$ -	$ 4,069,840	$ 5,501,590	$ -	$ 5,501,590	$ 1,431,750	35.18%
Electric Generation Small 0 to 20000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Electric Generation Medium 20001 to 200000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Electric Generation Large 200000 to 2400000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Electric Generation Super Large Over 2400000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Electric Generation Extra Super Large Over 15000000 therms	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
CSR TSL-IG2T	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
CSR TSL-IG4T	1	9,297,700	$ 207,744	$ -	$ 207,744	$ 218,170	$ -	$ 218,170	$ 10,426	5.02%
PWRDEPT	8	30,200,829	$ 14,747,289	$ 10,893,787	$ 3,853,502	$ 15,683,517	$ 10,893,787	$ 4,789,730	$ 936,228	6.35%
PWRDEPT FIRM	0	730,777	$ 374,188	$ 281,013	$ 93,175	$ 397,134	$ 281,013	$ 116,121	$ 22,946	6.13%
Power Generation Contracted Service	1	80,523,533	$ 442,402	$ -	$ 442,402	$ 442,402	$ -	$ 442,402	$ -	0.00%
Total - All Customers - All	349,523	1,071,193,817	$ 419,456,486	$ 238,186,136	$ 181,270,350	$ 447,857,684	$ 238,186,136	$ 209,671,548	$ 28,401,198	6.77%

Note1: Gas Costs are priced at Final base rates under both current
Gas Revenues and Final 2026 Gas Revenues.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2026

Residential Service and Commercial FST (0 to 2,000 therms annually) Service

2026 Final Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5589	$ 1.1178	$ 0.5589	NA	$ 0.5589
Enhanced Telemetry Service	$ -	$ -	$ -		$ 0.1973
Transportation Administrative	$ -	$ -	$ -	NA	$ 0.9205
Daily Demand Charge	$ -		$ -	NA	$ -
Distribution Margin per therm	$ 0.1920	$ 0.1920	$ 0.1920	NA	$ 0.1920
Competitive Supply Margin	$ 0.0380	$ 0.0380	$ 0.0380	NA	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	$ 0.0007
Peak Day Margin	$ 0.0015	$ 0.0015	$ 0.0015	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.2322	$ 0.2322	$ 0.2322	NA	$ 0.1927
Peak Demand	$ 0.1154	$ 0.1154	$ 0.1154	NA	$ -
Annual Demand	$ 0.0155	$ 0.0155	$ 0.0155	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ 0.3884	$ 0.3884	$ 0.3884	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	$ 0.5193	NA	$ -
Total Rate	$ 0.7515	$ 0.7515	$ 0.7515	NA	$ 0.1927
Act 141 Surcharge Rate	$ 0.0073	$ 0.0073	$ 0.0066	NA	$ 0.0066

NA = Not Available

2024 Current Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.5589	$ 1.1178	$ 0.5589	NA	$ 0.5589
Enhanced Telemetry Service	$ -	$ -	$ -		$ 0.1973
Transportation Administrative	$ -	$ -	$ -	NA	$ 0.9205
Daily Demand Charge	$ -		$ -	NA	$ -
Distribution Margin per therm	$ 0.1491	$ 0.1491	$ 0.1491	NA	$ 0.1491
Competitive Supply Margin	$ 0.0271	$ 0.0271	$ 0.0271	NA	$ -
Daily Balancing Margin	$ 0.0003	$ 0.0003	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.1772	$ 0.1772	$ 0.1772	NA	$ 0.1494
Peak Demand	$ 0.1154	$ 0.1154	$ 0.1154	NA	$ -
Annual Demand	$ 0.0155	$ 0.0155	$ 0.0155	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ 0.3884	$ 0.3884	$ 0.3884	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	$ 0.5193	NA	$ -
Total Rate	$ 0.6965	$ 0.6965	$ 0.6965	NA	$ 0.1494
Act 141 Surcharge Rate	$ 0.0067	$ 0.0067	$ 0.0064	NA	$ 0.0064

NA = Not Available

Final Change in Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Firm Commercial FST Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ -	$ -	$ -	NA	$ -
Enhanced Telemetry Service					
Transportation Administrative	$ -	$ -	$ -	NA	$ -
Daily Demand Charge	$ -	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.0429	$ 0.0429	$ 0.0429	NA	$ 0.0429
Competitive Supply Margin	$ 0.0109	$ 0.0109	$ 0.0109	NA	$ -
Daily Balancing Margin	$ 0.0004	$ 0.0004	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0008	$ 0.0008	$ 0.0008	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.0550	$ 0.0550	$ 0.0550	NA	$ 0.0433
Peak Demand	$ -	$ -	$ -	NA	$ -
Annual Demand	$ -	$ -	$ -	NA	$ -
Balancing	$ -	$ -	$ -	NA	$ -
Commodity	$ -	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ -	$ -	$ -	NA	$ -
Total Rate	$ 0.0550	$ 0.0550	$ 0.0550	NA	$ 0.0433
Act 141 Surcharge Rate	$ 0.0006	$ 0.0006	$ 0.0002	NA	$ 0.0002

NA = Not Available

CG-FS Commercial Industrial Small 2,001 to 20,000 Therms Annually

2026 Final Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.9863	$ 1.9726	NA	NA	$ 0.9863
Enhanced Telemetry Service		$ -			$ 0.1973
Transportation Administrative	$ -	$ -	NA	NA	$ 0.9205
Daily Demand Charge	$ -		NA	NA	$ -
Distribution Margin per therm	$ 0.1672	$ 0.1672	NA	NA	$ 0.1672
Competitive Supply Margin	$ 0.0380	$ 0.0380	NA	NA	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	NA	NA	$ 0.0007
Peak Day Margin	$ 0.0015	$ 0.0015	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.2074	$ 0.2074	NA	NA	$ 0.1679
Peak Demand	$ 0.1154	$ 0.1154	NA	NA	$ -
Annual Demand	$ 0.0155	$ 0.0155	NA	NA	$ -
Balancing	$ -	$ -			
Commodity	$ 0.3884	$ 0.3884	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	NA	NA	$ -
Total Rate	$ 0.7267	$ 0.7267	NA	NA	$ 0.1679
Act 141 Surcharge Rate	$ 0.0066	$ 0.0066	NA	NA	$ 0.0066

NA = Not Available

2024 Current Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.9863	$ 1.9726	NA	NA	$ 0.9863
Enhanced Telemetry Service		$ -			$ 0.1973
Transportation Administrative	$ -	$ -	NA	NA	$ 0.9205
Daily Demand Charge	$ -		NA	NA	$ -
Distribution Margin per therm	$ 0.1336	$ 0.1336	NA	NA	$ 0.1336
Competitive Supply Margin	$ 0.0271	$ 0.0271	NA	NA	$ -
Daily Balancing Margin	$ 0.0003	$ 0.0003	NA	NA	$ 0.0003
Peak Day Margin	$ 0.0007	$ 0.0007	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.1617	$ 0.1617	NA	NA	$ 0.1339
Peak Demand	$ 0.1154	$ 0.1154	NA	NA	$ -
Annual Demand	$ 0.0155	$ 0.0155	NA	NA	$ -
Balancing	$ -	$ -			
Commodity	$ 0.3884	$ 0.3884	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	NA	NA	$ -
Total Rate	$ 0.6810	$ 0.6810	NA	NA	$ 0.1339
Act 141 Surcharge Rate	$ 0.0064	$ 0.0064	NA	NA	$ 0.0064

NA = Not Available

Final Change in Rates

Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ -	$ -	NA	NA	$ -
Enhanced Telemetry Service					$ -
Transportation Administrative	$ -	$ -	NA	NA	$ -
Daily Demand Charge	$ -	$ -	NA	NA	$ -
Distribution Margin per therm	$ 0.0336	$ 0.0336	NA	NA	$ 0.0336
Competitive Supply Margin	$ 0.0109	$ 0.0109	NA	NA	$ -
Daily Balancing Margin	$ 0.0004	$ 0.0004	NA	NA	$ 0.0004
Peak Day Margin	$ 0.0008	$ 0.0008	NA	NA	$ -
Other Margin					
Total All Margin Rates	$ 0.0457	$ 0.0457	NA	NA	$ 0.0340
Peak Demand	$ -	$ -	NA	NA	$ -
Annual Demand	$ -	$ -	NA	NA	$ -
Balancing			NA	NA	
Commodity	$ -	$ -	NA	NA	$ -
Total Natural Gas Rate Per Therm	$ -	$ -	NA	NA	$ -
Total Rate	$ 0.0457	$ 0.0457	NA	NA	$ 0.0340
Act 141 Surcharge Rate	$ 0.0002	$ 0.0002	NA	NA	$ 0.0002

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2026

CG-{FM,IM} Commercial Industrial Medium 20,001 to 200,000 Therms Annually

Rates - Description	2026 Final Rates					2024 Current Rates					Final Change in Rates				
	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	$ 4.9315	$ 9.8630	$ 4.9315	$ 4.9315	$ 4.9315	$ 4.9315	$ 9.8630	$ 4.9315	$ 4.9315	$ 4.9315	$ -	$ -	$ -	$ -	$ -
Enhanced Telemetry Service	$ 0.1973	$ 0.3946	$ 0.1973	$ 0.1973	$ 0.1973	$ 0.1973	$ 0.3946	$ 0.1973	$ 0.1973	$ 0.1973	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ 0.9205	$ -	$ -	$ -	$ -	$ 0.9205	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1194	$ 0.1194	$ 0.1194	$ 0.1194	$ 0.1194	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0997	$ 0.0197	$ 0.0197	$ 0.0197	$ 0.0197	$ 0.0197
Competitive Supply Margin	$ 0.0380	$ 0.0380	$ 0.0380	$ 0.0380	$ -	$ 0.0271	$ 0.0271	$ 0.0271	$ 0.0271	$ -	$ 0.0109	$ 0.0109	$ 0.0109	$ 0.0109	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0003	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0015	$ 0.0015	$ -	$ -	$ -	$ 0.0007	$ 0.0007	$ -	$ -	$ -	$ 0.0008	$ 0.0008	$ -	$ -	$ -
Other Margin															
Total All Margin Rates	$ 0.1596	$ 0.1596	$ 0.1581	$ 0.1581	$ 0.1201	$ 0.1278	$ 0.1278	$ 0.1271	$ 0.1271	$ 0.1000	$ 0.0318	$ 0.0318	$ 0.0310	$ 0.0310	$ 0.0201
Peak Demand	$ 0.1154	$ 0.1154	$ -	$ -	$ -	$ 0.1154	$ 0.1154	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0155	$ 0.0155	$ 0.0155	$ 0.0155	$ -	$ 0.0155	$ 0.0155	$ 0.0155	$ 0.0155	$ -	$ -	$ -	$ -	$ -	$ -
Balancing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					
Commodity	$ 0.3884	$ 0.3884	$ 0.3884	$ 0.3884	$ -	$ 0.3884	$ 0.3884	$ 0.3884	$ 0.3884	$ -	$ -	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	$ 0.4039	$ 0.4039	$ -	$ 0.5193	$ 0.5193	$ 0.4039	$ 0.4039	$ -	$ -	$ -	$ -	$ -	$ -
Total Rate	$ 0.6789	$ 0.6789	$ 0.5620	$ 0.5620	$ 0.1201	$ 0.6471	$ 0.6471	$ 0.5310	$ 0.5310	$ 0.1000	$ 0.0318	$ 0.0318	$ 0.0310	$ 0.0310	$ 0.0201
Act 141 Surcharge Rate	$ 0.0066	$ 0.0066	$ 0.0066	$ 0.0066	$ 0.0066	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0064	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002

NA = Not Available

NA = Not Available

NA = Not Available

CG-{FL,IL} Commercial Industrial Large 200,001 to 2,400,000 Therms Annually

Rates - Description	2026 Final Rates					2024 Current Rates					Final Change in Rates				
	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	$ 21.3698	$ 42.7396	NA	$ 21.3698	$ 21.3698	$ 21.3698	$ 42.7396	NA	$ 21.3698	$ 21.3698	$ -	$ -	NA	$ -	$ -
Enhanced Telemetry Service	$ 0.1973	$ 0.3946		$ 0.1973	$ 0.1973	$ 0.1973	$ 0.3946		$ 0.1973	$ 0.1973	$ -	$ -	NA	$ -	$ -
Transportation Administrative	$ -	$ -	NA	$ -	$ 0.9205	$ -	$ -	NA	$ -	$ 0.9205	$ -	$ -	NA	$ -	$ -
Daily Demand Charge	$ 0.1548	$ 0.1548	NA	$ 0.1548	$ 0.1548	$ 0.1475	$ 0.1475	NA	$ 0.1475	$ 0.1475	$ 0.0073	$ 0.0073	NA	$ 0.0073	$ 0.0073
Distribution Margin per therm	$ 0.0629	$ 0.0629	NA	$ 0.0629	$ 0.0629	$ 0.0484	$ 0.0484	NA	$ 0.0484	$ 0.0484	$ 0.0145	$ 0.0145	NA	$ 0.0145	$ 0.0145
Competitive Supply Margin	$ 0.0380	$ 0.0380	NA	$ 0.0380	$ -	$ 0.0271	$ 0.0271	NA	$ 0.0271	$ -	$ 0.0109	$ 0.0109	NA	$ 0.0109	$ -
Daily Balancing Margin	$ 0.0007	$ 0.0007	NA	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	NA	$ 0.0003	$ 0.0003	$ 0.0004	$ 0.0004	NA	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0015	$ 0.0015	NA	$ -	$ -	$ 0.0007	$ 0.0007	NA	$ -	$ -	$ 0.0008	$ 0.0008	NA	$ -	$ -
Other Margin															
Total All Margin Rates	$ 0.1031	$ 0.1031	NA	$ 0.1016	$ 0.0636	$ 0.0765	$ 0.0765	NA	$ 0.0758	$ 0.0487	$ 0.0266	$ 0.0266	NA	$ 0.0258	$ 0.0149
Peak Demand	$ 0.1154	$ 0.1154	NA	$ -	$ -	$ 0.1154	$ 0.1154	NA	$ -	$ -	$ -	$ -	NA	$ -	$ -
Annual Demand	$ 0.0155	$ 0.0155	NA	$ 0.0155	$ -	$ 0.0155	$ 0.0155	NA	$ 0.0155	$ -	$ -	$ -	NA	$ -	$ -
Balancing	$ -	$ -		$ -	$ -	$ -	$ -		$ -	$ -					
Commodity	$ 0.3884	$ 0.3884	NA	$ 0.3884	$ -	$ 0.3884	$ 0.3884	NA	$ 0.3884	$ -	$ -	$ -	NA	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5193	$ 0.5193	NA	$ 0.4039	$ -	$ 0.5193	$ 0.5193	NA	$ 0.4039	$ -	$ -	$ -	NA	$ -	$ -
Total Rate	$ 0.6224	$ 0.6224	NA	$ 0.5055	$ 0.0636	$ 0.5958	$ 0.5958	NA	$ 0.4797	$ 0.0487	$ 0.0266	$ 0.0266	NA	$ 0.0258	$ 0.0149
Act 141 Surcharge Rate	$ 0.0066	$ 0.0066	NA	$ 0.0066	$ 0.0066	$ 0.0064	$ 0.0064	NA	$ 0.0064	$ 0.0064	$ 0.0002	$ 0.0002	NA	$ 0.0002	$ 0.0002

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2026

CG-SL Commercial Industrial Super Large 2,400,001 to 15,000,000 Therms Annually

	2026 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	NA	NA	NA	$ 121.8411	$ 121.8411	NA	NA	NA	$ 121.8411	$ 121.8411	NA	NA	NA	$ -	$ -
Enhanced Telemetry Service				$ 0.1973	$ 0.1973				$ 0.1973	$ 0.1973					$ -
Transportation Administrative	NA	NA	NA	$ -	$ 0.9205	NA	NA	NA	$ -	$ 0.9205	NA	NA	NA	$ -	$ -
Daily Demand Charge	NA	NA	NA	$ 0.1100	$ 0.1100	NA	NA	NA	$ 0.1000	$ 0.1000	NA	NA	NA	$ 0.0100	$ 0.0100
Distribution Margin per therm	NA	NA	NA	$ 0.0330	$ 0.0330	NA	NA	NA	$ 0.0294	$ 0.0294	NA	NA	NA	$ 0.0036	$ 0.0036
Competitive Supply Margin	NA	NA	NA	$ 0.0380	$ -	NA	NA	NA	$ 0.0271	$ -	NA	NA	NA	$ 0.0109	$ -
Daily Balancing Margin	NA	NA	NA	$ 0.0007	$ 0.0007	NA	NA	NA	$ 0.0003	$ 0.0003	NA	NA	NA	$ 0.0004	$ 0.0004
Peak Day Margin	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -
Other Margin															
Total All Margin Rates	NA	NA	NA	$ 0.0717	$ 0.0337	NA	NA	NA	$ 0.0568	$ 0.0297	NA	NA	NA	$ 0.0149	$ 0.0040
Peak Demand	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -	NA	NA	NA	$ -	$ -
Annual Demand	NA	NA	NA	$ 0.0155	$ -	NA	NA	NA	$ 0.0155	$ -	NA	NA	NA	$ -	$ -
Balancing				$ -					$ -						
Commodity	NA	NA	NA	$ 0.3884	$ -	NA	NA	NA	$ 0.3884	$ -	NA	NA	NA	$ -	$ -
Total Natural Gas Rate Per Therm	NA	NA	NA	$ 0.4039	$ -	NA	NA	NA	$ 0.4039	$ -	NA	NA	NA	$ -	$ -
Total Rate	NA	NA	NA	$ 0.4756	$ 0.0337	NA	NA	NA	$ 0.4607	$ 0.0297	NA	NA	NA	$ 0.0149	$ 0.0040
Act 141 Surcharge Rate	NA	NA	NA	$ 0.0066	$ 0.0066	NA	NA	NA	$ 0.0064	$ 0.0064	NA	NA	NA	$ 0.0002	$ 0.0002

CG-IEGL Commercial Industrial Interruptible Electric Generation Large Over 200,000 Therms Annually

	2026 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	NA	NA	$ 249.0000	NA	$ 249.0000	NA	NA	$ 249.0000	NA	$ 249.0000	NA	NA	$ -	NA	$ -
Enhanced Telemetry Service			$ 0.1973		$ 0.1973			$ 0.1973		$ 0.1973					
Transportation Administrative	NA	NA	$ -	NA	$ 0.9205	NA	NA	$ -	NA	$ 0.9205	NA	NA	$ -	NA	$ -
Daily Demand Charge	NA	NA	$ 0.0720	NA	$ 0.0720	NA	NA	$ 0.0720	NA	$ 0.0720	NA	NA	$ -	NA	$ -
Distribution Margin per therm	NA	NA	$ 0.0358	NA	$ 0.0358	NA	NA	$ 0.0129	NA	$ 0.0129	NA	NA	$ 0.0229	NA	$ 0.0229
Competitive Supply Margin	NA	NA	$ 0.0071	NA	$ -	NA	NA	$ 0.0066	NA	$ -	NA	NA	$ 0.0005	NA	$ -
Daily Balancing Margin	NA	NA	$ 0.0007	NA	$ 0.0007	NA	NA	$ 0.0003	NA	$ 0.0003	NA	NA	$ 0.0004	NA	$ 0.0004
Peak Day Margin	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -
Other Margin															
Total All Margin Rates	NA	NA	$ 0.0436	NA	$ 0.0365	NA	NA	$ 0.0198	NA	$ 0.0132	NA	NA	$ 0.0238	NA	$ 0.0233
Peak Demand	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -	NA	NA	$ -	NA	$ -
Annual Demand	NA	NA	$ 0.0155	NA	$ -	NA	NA	$ 0.0155	NA	$ -	NA	NA	$ -	NA	$ -
Balancing			$ -					$ -							
Commodity	NA	NA	$ 0.3884	NA	$ -	NA	NA	$ 0.3884	NA	$ -	NA	NA	$ -	NA	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ 0.4039	NA	$ -	NA	NA	$ 0.4039	NA	$ -	NA	NA	$ -	NA	$ -
Total Rate	NA	NA	$ 0.4475	NA	$ 0.0365	NA	NA	$ 0.4237	NA	$ 0.0132	NA	NA	$ 0.0238	NA	$ 0.0233
Act 141 Surcharge Rate	NA	NA	$ 0.0066	NA	$ 0.0066	NA	NA	$ 0.0064	NA	$ 0.0064	NA	NA	$ 0.0002	NA	$ 0.0002

NA = Not Available

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Final and Current Rates
for the test year ended December 31, 2026

CG-XSL Commercial Industrial Extra Super Large Over 15,000,000 Therms Annually

	2026 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation	Firm Sales	Firm Seasonal Sales	Elec. Gen. Interruptible Sales	Interruptible Sales	Transportation
Daily Facilities Charge	NA	NA	$ 1,100.0000	$ 1,100.0000	$ 1,100.0000	NA	NA	$ 1,000.0000	$ 1,000.0000	$ 1,000.0000	NA	NA	$ 100.0000	$ 100.0000	$ 100.0000
Enhanced Telemetry Service			$ 0.1973	$ 0.1973	$ 0.1973			$ 0.1973	$ 0.1973	$ 0.1973					$ -
Transportation Administrative	NA	NA	$ -	$ -	$ 0.9205	NA	NA	$ -	$ -	$ 0.9205	NA	NA	$ -	$ -	$ -
Daily Demand Charge	NA	NA	$ 0.0475	$ 0.0475	$ 0.0475	NA	NA	$ 0.0450	$ 0.0450	$ 0.0450	NA	NA	$ 0.0025	$ 0.0025	$ 0.0025
Distribution Margin per therm	NA	NA	$ 0.0164	$ 0.0164	$ 0.0164	NA	NA	$ 0.0093	$ 0.0093	$ 0.0093	NA	NA	$ 0.0071	$ 0.0071	$ 0.0071
Competitive Supply Margin	NA	NA	$ 0.0380	$ 0.0380	$ -	NA	NA	$ 0.0271	$ 0.0271	$ -	NA	NA	$ 0.0109	$ 0.0109	$ -
Daily Balancing Margin	NA	NA	$ 0.0007	$ 0.0007	$ 0.0007	NA	NA	$ 0.0003	$ 0.0003	$ 0.0003	NA	NA	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -
Other Margin															
Total All Margin Rates	NA	NA	$ 0.0551	$ 0.0551	$ 0.0171	NA	NA	$ 0.0367	$ 0.0367	$ 0.0096	NA	NA	$ 0.0184	$ 0.0184	$ 0.0075
Peak Demand	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -
Annual Demand	NA	NA	$ 0.0155	$ 0.0155	$ -	NA	NA	$ 0.0155	$ 0.0155	$ -	NA	NA	$ -	$ -	$ -
Balancing	NA	NA	$ -	$ -		NA	NA	$ -	$ -						
Commodity	NA	NA	$ 0.3884	$ 0.3884	$ -	NA	NA	$ 0.3884	$ 0.3884	$ -	NA	NA	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	NA	NA	$ 0.4039	$ 0.4039	$ -	NA	NA	$ 0.4039	$ 0.4039	$ -	NA	NA	$ -	$ -	$ -
Total Rate	NA	NA	$ 0.4590	$ 0.4590	$ 0.0171	NA	NA	$ 0.4406	$ 0.4406	$ 0.0096	NA	NA	$ 0.0184	$ 0.0184	$ 0.0075
Act 141 Surcharge Rate	NA	NA	$ 0.0066	$ 0.0066	$ 0.0066	NA	NA	$ 0.0064	$ 0.0064	$ 0.0064	NA	NA	$ 0.0002	$ 0.0002	$ 0.0002

NA = Not Available

NA = Not Available

IG-SOS Interruptible Agricultural Seasonal Opportunity Sales

	2026 Final Rates					2024 Current Rates					Final Change in Rates				
Rates - Description	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation	Interruptible Sales Step 1	Interruptible Sales Step 2	Interruptible Sales Step 3	Interruptible Sales	Transportation
Daily Facilities Charge	$ 0.5000	$ -	$ -	NA	NA	$ 0.5000	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA
Enhanced Telemetry Service	$ 0.1973	$ -	$ -			$ 0.1973	$ -	$ -							
Transportation Administrative	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA
Daily Demand Charge	$ -			NA	NA	$ -			NA	NA	$ -	$ -	$ -	NA	NA
Distribution Margin per therm	$ 0.2605	$ 0.2113	$ 0.1369	NA	NA	$ 0.2716	$ 0.2234	$ 0.1491	NA	NA	$ (0.0111)	$ (0.0121)	$ (0.0122)	NA	NA
Competitive Supply Margin	$ 0.0380	$ 0.0380	$ 0.0380	NA	NA	$ 0.0271	$ 0.0271	$ 0.0271	NA	NA	$ 0.0109	$ 0.0109	$ 0.0109	NA	NA
Daily Balancing Margin	$ 0.0007	$ 0.0007	$ 0.0007	NA	NA	$ 0.0003	$ 0.0003	$ 0.0003	NA	NA	$ 0.0004	$ 0.0004	$ 0.0004	NA	NA
Peak Day Margin	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA
Other Margin															
Total All Margin Rates	$ 0.2992	$ 0.2500	$ 0.1756	NA	NA	$ 0.2990	$ 0.2508	$ 0.1765	NA	NA	$ 0.0002	$ (0.0008)	$ (0.0009)	NA	NA
Peak Demand	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA	$ -	$ -	$ -	NA	NA
Annual Demand	$ 0.0155	$ 0.0155	$ 0.0155	NA	NA	$ 0.0155	$ 0.0155	$ 0.0155	NA	NA	$ -	$ -	$ -	NA	NA
Balancing	$ -	$ -	$ -			$ -	$ -	$ -						NA	NA
Commodity	$ 0.3884	$ 0.3884	$ 0.3884	NA	NA	$ 0.3884	$ 0.3884	$ 0.3884	NA	NA	$ -	$ -	$ -	NA	NA
Total Natural Gas Rate Per Therm	$ 0.4039	$ 0.4039	$ 0.4039	NA	NA	$ 0.4039	$ 0.4039	$ 0.4039	NA	NA	$ -	$ -	$ -	NA	NA
Total Rate	$ 0.7031	$ 0.6539	$ 0.5795	NA	NA	$ 0.7029	$ 0.6547	$ 0.5804	NA	NA	$ 0.0002	$ (0.0008)	$ (0.0009)	NA	NA
Act 141 Surcharge Rate	$ 0.0066	$ 0.0066	$ 0.0066	NA	NA	$ 0.0064	$ 0.0064	$ 0.0064	NA	NA	$ 0.0002	$ 0.0002	$ 0.0002	NA	NA

NA = Not Available

NA = Not Available

NA = Not Available

Reflects natural gas rate per therm at proposed natural gas cost rates.

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Residential Rg-3

Transportation Service	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv	$ 44.9984	$ 44.9984	$ -		$/Mo. Fixed or equiv.	$ 16.9999	$ 16.9999	$ -	
$/Day Fixed or equi	$ 1.4794	$ 1.4794	$ -		$/Day Fixed or equiv.	$ 0.5589	$ 0.5589	$ -	
$/Therm-Winter	$ 0.1494	$ 0.1927	$ 0.0433		$/Therm-Winter	$ 0.6965	$ 0.7515	$ 0.0550	
$/Therm-Summer	$ 0.1494	$ 0.1927	$ 0.0433		$/Therm-Summer	$ 0.5811	$ 0.6361	$ 0.0550	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
294		$ 583.90	$ 596.63	$ 12.73	2.18%		$ 402.60	$ 418.77	$ 16.17	4.02%
588		$ 627.83	$ 653.29	$ 25.46	4.06%		$ 601.21	$ 633.55	$ 32.34	5.38%
781		$ 656.66	$ 690.48	$ 33.82	5.15%		$ 731.59	$ 774.54	$ 42.95	5.87%
838	303438	$ 665.18	$ 701.46	$ 36.28	5.45%		$ 770.09	$ 816.18	$ 46.09	5.99%
1,176		$ 715.68	$ 766.60	$ 50.92	7.11%		$ 998.42	$ 1,063.10	$ 64.68	6.48%
1,470		$ 759.60	$ 823.25	$ 63.65	8.38%		$ 1,197.03	$ 1,277.88	$ 80.85	6.75%
1,764		$ 803.52	$ 879.90	$ 76.38	9.51%		$ 1,395.64	$ 1,492.66	$ 97.02	6.95%
2,058		$ 847.45	$ 936.56	$ 89.11	10.52%		$ 1,594.24	$ 1,707.43	$ 113.19	7.10%
2,352		$ 891.37	$ 993.21	$ 101.84	11.43%		$ 1,792.85	$ 1,922.21	$ 129.36	7.22%
2,646		$ 935.29	$ 1,049.87	$ 114.58	12.25%		$ 1,991.46	$ 2,136.99	$ 145.53	7.31%
2,940		$ 979.22	$ 1,106.52	$ 127.30	13.00%		$ 2,190.06	$ 2,351.76	$ 161.70	7.38%
3,234		$ 1,023.14	$ 1,163.17	$ 140.03	13.69%		$ 2,388.67	$ 2,566.54	$ 177.87	7.45%
3,528		$ 1,067.06	$ 1,219.83	$ 152.77	14.32%		$ 2,587.27	$ 2,781.31	$ 194.04	7.50%
3,822		$ 1,110.99	$ 1,276.48	$ 165.49	14.90%		$ 2,785.88	$ 2,996.09	$ 210.21	7.55%
4,116		$ 1,154.91	$ 1,333.13	$ 178.22	15.43%		$ 2,984.49	$ 3,210.87	$ 226.38	7.59%
4,410		$ 1,198.84	$ 1,389.79	$ 190.95	15.93%		$ 3,183.09	$ 3,425.64	$ 242.55	7.62%
4,704		$ 1,242.76	$ 1,446.44	$ 203.68	16.39%		$ 3,381.70	$ 3,640.42	$ 258.72	7.65%
4,998		$ 1,286.68	$ 1,503.10	$ 216.42	16.82%		$ 3,580.31	$ 3,855.20	$ 274.89	7.68%

	Old Annual Bill	New Annual Bill		Old Annual Bill	New Annual Bill
Winter Qty %	81.83%	81.83%	Winter Qty %	81.83%	81.83%
Summer QTY %	18.17%	18.17%	Summer QTY %	18.17%	18.17%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Seasonal Opportunity Sales Medium 20,001 therms to 200,000 therms annually

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equ	NA	NA	NA		$/Mo. Fixed or equiv.	$ 21.21	$ 21.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.6973	$ 0.6973	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm	NA	NA	NA		$/Therm Step 1	$ 0.6917	$ 0.6919	$ 0.0002	
						$/Therm Step 2	$ 0.6435	$ 0.6427	$ (0.0008)	
						$/Therm Step 3	$ 0.5692	$ 0.5683	$ (0.0009)	

Usage in Therms	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
7,500		NA	NA	NA	NA		$ 5,442.26	$ 5,443.76	$ 1.50	0.03%
9,747	119	NA	NA	NA	NA		$ 6,996.51	$ 6,998.46	$ 1.95	0.03%
20,000		NA	NA	NA	NA		$ 13,750.92	$ 13,747.92	$ (3.00)	-0.02%
30,000		NA	NA	NA	NA		$ 20,210.02	$ 20,199.52	$ (10.50)	-0.05%
40,000		NA	NA	NA	NA		$ 26,669.12	$ 26,651.12	$ (18.00)	-0.07%
50,000		NA	NA	NA	NA		$ 32,570.67	$ 32,544.42	$ (26.25)	-0.08%
60,000		NA	NA	NA	NA		$ 38,323.92	$ 38,289.22	$ (34.70)	-0.09%
70,000		NA	NA	NA	NA		$ 44,077.17	$ 44,034.02	$ (43.15)	-0.10%
80,000		NA	NA	NA	NA		$ 49,830.42	$ 49,778.82	$ (51.60)	-0.10%
90,000		NA	NA	NA	NA		$ 55,583.67	$ 55,523.62	$ (60.05)	-0.11%
100,000		NA	NA	NA	NA		$ 61,336.92	$ 61,268.42	$ (68.50)	-0.11%
110,000		NA	NA	NA	NA		$ 67,090.17	$ 67,013.22	$ (76.95)	-0.11%
120,000		NA	NA	NA	NA		$ 72,843.42	$ 72,758.02	$ (85.40)	-0.12%
130,000		NA	NA	NA	NA		$ 78,596.67	$ 78,502.82	$ (93.85)	-0.12%
140,000		NA	NA	NA	NA		$ 84,349.92	$ 84,247.62	$ (102.30)	-0.12%
150,000		NA	NA	NA	NA		$ 90,103.17	$ 89,992.42	$ (110.75)	-0.12%
160,000		NA	NA	NA	NA		$ 95,856.42	$ 95,737.22	$ (119.20)	-0.12%
	Winter Qty %	NA	NA			Winter Qty %	5.00%	5.00%		
	Summer QTY %	NA	NA			Drying Season QTY %	95.00%	95.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3760	$ 0.3760
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0167	$ 0.0167
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3927	$ 0.3927

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Seasonal Opportunity Sales Large Over 200,000 therms annually

	Transportation Service						Sales Service			
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	NA	NA	NA		$/Mo. Fixed or equiv.	$ 21.21	$ 21.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.6973	$ 0.6973	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ -	NA	NA	
	$/Therm	NA	NA	NA		$/Therm Step 1	$ 0.6917	$ 0.6919	$ 0.0002	
						$/Therm Step 2	$ 0.6435	$ 0.6427	$ (0.0008)	
						$/Therm Step 3	$ 0.5692	$ 0.5683	$ (0.0009)	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000		NA	NA	NA	NA		$ 117,766.92	$ 117,604.02	$ (162.90)	-0.14%
206,000		NA	NA	NA	NA		$ 121,185.80	$ 121,017.53	$ (168.27)	-0.14%
212,000		NA	NA	NA	NA		$ 124,604.67	$ 124,431.04	$ (173.64)	-0.14%
218,000		NA	NA	NA	NA		$ 128,023.55	$ 127,844.54	$ (179.01)	-0.14%
224,000	0	NA	NA	NA	NA		$ 131,442.42	$ 131,258.05	$ (184.37)	-0.14%
230,000		NA	NA	NA	NA		$ 134,861.30	$ 134,671.56	$ (189.74)	-0.14%
236,000		NA	NA	NA	NA		$ 138,280.17	$ 138,085.07	$ (195.11)	-0.14%
242,000		NA	NA	NA	NA		$ 141,699.05	$ 141,498.58	$ (200.47)	-0.14%
248,000		NA	NA	NA	NA		$ 145,117.92	$ 144,912.08	$ (205.84)	-0.14%
254,000		NA	NA	NA	NA		$ 148,536.80	$ 148,325.59	$ (211.21)	-0.14%
260,000		NA	NA	NA	NA		$ 151,955.67	$ 151,739.10	$ (216.57)	-0.14%
266,000		NA	NA	NA	NA		$ 155,374.55	$ 155,152.61	$ (221.94)	-0.14%
272,000		NA	NA	NA	NA		$ 158,793.42	$ 158,566.12	$ (227.31)	-0.14%
278,000		NA	NA	NA	NA		$ 162,212.30	$ 161,979.62	$ (232.68)	-0.14%
284,000		NA	NA	NA	NA		$ 165,631.17	$ 165,393.13	$ (238.04)	-0.14%
290,000		NA	NA	NA	NA		$ 169,050.05	$ 168,806.64	$ (243.41)	-0.14%
296,000		NA	NA	NA	NA		$ 172,468.92	$ 172,220.15	$ (248.78)	-0.14%

Winter Qty %	NA	NA	Winter Qty %	0.50%	0.50%
Summer QTY %	NA	NA	Drying Season QTY %	99.50%	99.50%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3760	$ 0.3760
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0167	$ 0.0167
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3927	$ 0.3927

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Commercial/Industrial Standard 0 to 2000 therms
CG-FST

	Transportation Service				Sales Service		
	Old Annual Rate	New Annual Rate	Increase (Decrease)		Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 45.0000	$ 45.0000	$ -	$/Mo. Fixed or equiv.	$ 16.9999	$ 16.9999	$ -
$/Day Fixed or equiv.	$ 1.4794	$ 1.4794	$ -	$/Day Fixed or equiv.	$ 0.5589	$ 0.5589	$ -
Demand Charge	N/A	N/A	N/A	Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.1494	$ 0.1927	$ 0.0433	$/Therm-Winter	$ 0.6965	$ 0.7515	$ 0.0550
$/Therm-Summer	$ 0.1494	$ 0.1927	$ 0.0433	$/Therm-Summer	$ 0.5811	$ 0.6361	$ 0.0550

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
235		N/A	N/A	N/A	N/A		$ 364.31	$ 377.23	$ 12.92	3.55%
335		N/A	N/A	N/A	N/A		$ 432.52	$ 450.95	$ 18.43	4.26%
435		N/A	N/A	N/A	N/A		$ 500.74	$ 524.66	$ 23.92	4.78%
535		N/A	N/A	N/A	N/A		$ 568.95	$ 598.38	$ 29.43	5.17%
635		N/A	N/A	N/A	N/A		$ 637.17	$ 672.09	$ 34.92	5.48%
735		N/A	N/A	N/A	N/A		$ 705.38	$ 745.81	$ 40.43	5.73%
820		N/A	N/A	N/A	N/A		$ 763.37	$ 808.47	$ 45.10	5.91%
956	18418	N/A	N/A	N/A	N/A		$ 856.14	$ 908.72	$ 52.58	6.14%
1,056		N/A	N/A	N/A	N/A		$ 924.36	$ 982.44	$ 58.08	6.28%
1,156		N/A	N/A	N/A	N/A		$ 992.57	$ 1,056.15	$ 63.58	6.41%
1,256		N/A	N/A	N/A	N/A		$ 1,060.79	$ 1,129.87	$ 69.08	6.51%
1,356		N/A	N/A	N/A	N/A		$ 1,129.00	$ 1,203.58	$ 74.58	6.61%
1,456		N/A	N/A	N/A	N/A		$ 1,197.22	$ 1,277.30	$ 80.08	6.69%
1,556		N/A	N/A	N/A	N/A		$ 1,265.43	$ 1,351.01	$ 85.58	6.76%
1,656		N/A	N/A	N/A	N/A		$ 1,333.65	$ 1,424.73	$ 91.08	6.83%
1,756		N/A	N/A	N/A	N/A		$ 1,401.86	$ 1,498.44	$ 96.58	6.89%
1,900		N/A	N/A	N/A	N/A		$ 1,500.09	$ 1,604.59	$ 104.50	6.97%

Winter Qty %	0.00%	0.00%	Winter Qty %	87.57%	87.57%
Summer QTY %	0.00%	0.00%	Summer QTY %	12.43%	12.43%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Commercial/Industrial Stnd Seasonal 0 to 2000 therms
CG-FST

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 90.0000	$ -	$ (90.0000)		$/Mo. Fixed or equiv.	$ 33.9998	$ 33.9998	$ -	
	$/Day Fixed or equiv.	$ 2.9588	$ -	$ (2.9588)		$/Day Fixed or equiv.	$ 1.1178	$ 1.1178	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1494	$ 0.1927	$ 0.0433		$/Therm-Winter	$ 0.6965	$ 0.7515	$ 0.0550	
	$/Therm-Summer	$ 0.1494	$ 0.1927	$ 0.0433		$/Therm-Summer	$ 0.5811	$ 0.6361	$ 0.0550	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
235		N/A	N/A	N/A	N/A		$ 340.56	$ 353.48	$ 12.92	3.79%
335		N/A	N/A	N/A	N/A		$ 398.67	$ 417.09	$ 18.42	4.62%
435		N/A	N/A	N/A	N/A		$ 456.78	$ 480.70	$ 23.92	5.24%
535		N/A	N/A	N/A	N/A		$ 514.89	$ 544.31	$ 29.42	5.71%
635		N/A	N/A	N/A	N/A		$ 573.00	$ 607.92	$ 34.92	6.09%
735		N/A	N/A	N/A	N/A		$ 631.11	$ 671.53	$ 40.42	6.40%
835		N/A	N/A	N/A	N/A		$ 689.22	$ 735.14	$ 45.92	6.66%
935		N/A	N/A	N/A	N/A		$ 747.33	$ 798.75	$ 51.42	6.88%
1,035		N/A	N/A	N/A	N/A		$ 805.44	$ 862.36	$ 56.92	7.07%
1,135		N/A	N/A	N/A	N/A		$ 863.55	$ 925.97	$ 62.42	7.23%
1,235		N/A	N/A	N/A	N/A		$ 921.66	$ 989.58	$ 67.92	7.37%
1,335		N/A	N/A	N/A	N/A		$ 979.77	$ 1,053.19	$ 73.42	7.49%
1,435		N/A	N/A	N/A	N/A		$ 1,037.88	$ 1,116.80	$ 78.92	7.60%
1,535		N/A	N/A	N/A	N/A		$ 1,095.99	$ 1,180.41	$ 84.42	7.70%
1,635		N/A	N/A	N/A	N/A		$ 1,154.10	$ 1,244.02	$ 89.92	7.79%
1,735		N/A	N/A	N/A	N/A		$ 1,212.21	$ 1,307.63	$ 95.42	7.87%
1,835		N/A	N/A	N/A	N/A		$ 1,270.32	$ 1,371.24	$ 100.92	7.94%
	Winter Qty %	0.00%	0.00%			Winter Qty %	0.00%	0.00%		
	Summer QTY %	0.00%	0.00%			Summer QTY %	100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Commercial/IndustrialSmall 2001 to 20000 therms
CG-FS and CG-TS

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 63.9997	$ 63.9997	$ -		$/Mo. Fixed or equiv.	$ 30.0000	$ 30.0000	$ -	
	$/Day Fixed or equiv.	$ 2.1041	$ 2.1041	$ -		$/Day Fixed or equiv.	$ 0.9863	$ 0.9863	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1339	$ 0.1679	$ 0.0340		$/Therm-Winter	$ 0.6810	$ 0.7267	$ 0.0457	
	$/Therm-Summer	$ 0.1339	$ 0.1679	$ 0.0340		$/Therm-Summer	$ 0.5656	$ 0.6113	$ 0.0457	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
2,001		$ 1,035.93	$ 1,103.96	$ 68.03	6.57%		$ 1,679.34	$ 1,770.78	$ 91.44	5.44%
3,001		$ 1,169.83	$ 1,271.86	$ 102.03	8.72%		$ 2,338.68	$ 2,475.82	$ 137.14	5.86%
4,001		$ 1,303.73	$ 1,439.76	$ 136.03	10.43%		$ 2,998.02	$ 3,180.86	$ 182.84	6.10%
5,600		$ 1,517.84	$ 1,708.24	$ 190.40	12.54%		$ 4,052.30	$ 4,308.22	$ 255.92	6.32%
5,727	14657	$ 1,534.84	$ 1,729.56	$ 194.72	12.69%		$ 4,136.04	$ 4,397.76	$ 261.72	6.33%
6,700		$ 1,665.13	$ 1,892.93	$ 227.80	13.68%		$ 4,777.57	$ 5,083.76	$ 306.19	6.41%
7,700		$ 1,799.03	$ 2,060.83	$ 261.80	14.55%		$ 5,436.91	$ 5,788.80	$ 351.89	6.47%
8,700		$ 1,932.93	$ 2,228.73	$ 295.80	15.30%		$ 6,096.25	$ 6,493.84	$ 397.59	6.52%
9,700		$ 2,066.83	$ 2,396.63	$ 329.80	15.96%		$ 6,755.59	$ 7,198.88	$ 443.29	6.56%
10,700		$ 2,200.73	$ 2,564.53	$ 363.80	16.53%		$ 7,414.93	$ 7,903.92	$ 488.99	6.59%
11,700		$ 2,334.63	$ 2,732.43	$ 397.80	17.04%		$ 8,074.27	$ 8,608.96	$ 534.69	6.62%
12,700		$ 2,468.53	$ 2,900.33	$ 431.80	17.49%		$ 8,733.61	$ 9,314.00	$ 580.39	6.65%
13,700		$ 2,602.43	$ 3,068.23	$ 465.80	17.90%		$ 9,392.95	$ 10,019.04	$ 626.09	6.67%
14,700		$ 2,736.33	$ 3,236.13	$ 499.80	18.27%		$ 10,052.29	$ 10,724.08	$ 671.79	6.68%
15,700		$ 2,870.23	$ 3,404.03	$ 533.80	18.60%		$ 10,711.63	$ 11,429.12	$ 717.49	6.70%
16,700		$ 3,004.13	$ 3,571.93	$ 567.80	18.90%		$ 11,370.97	$ 12,134.16	$ 763.19	6.71%
19,100		$ 3,325.49	$ 3,974.89	$ 649.40	19.53%		$ 12,953.38	$ 13,826.25	$ 872.87	6.74%
	Winter Qty %	81.23%	81.23%			Winter Qty %	81.23%	81.23%		
	Summer QTY %	18.77%	18.77%			Summer QTY %	18.77%	18.77%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Cmmrcl/Indstrl Sml Seasonal 2001 to 20000 therms
CG-FS

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or eq	$ 121.9982	$ 121.9982	$ -		$/Mo. Fixed or eq	$ 59.9999	$ 59.9999	$ -	
	$/Day Fixed or eq	$ 4.0109	$ 4.0109	$ -		$/Day Fixed or eq	$ 1.9726	$ 1.9726	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1339	$ 0.1679	$ 0.0340		$/Therm-Winter	$ 0.6810	$ 0.7267	$ 0.0457	
	$/Therm-Summer	$ 0.1339	$ 0.1679	$ 0.0340		$/Therm-Summer	$ 0.5656	$ 0.6113	$ 0.0457	

Usage in Therms	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Us	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
2,001		N/A	N/A	N/A	N/A		$ 1,491.77	$ 1,583.21	$ 91.44	6.13%
3,001		N/A	N/A	N/A	N/A		$ 2,057.37	$ 2,194.51	$ 137.14	6.67%
4,001		N/A	N/A	N/A	N/A		$ 2,622.97	$ 2,805.81	$ 182.84	6.97%
5,001		N/A	N/A	N/A	N/A		$ 3,188.57	$ 3,417.11	$ 228.54	7.17%
6,001		N/A	N/A	N/A	N/A		$ 3,754.17	$ 4,028.41	$ 274.24	7.30%
7,001		N/A	N/A	N/A	N/A		$ 4,319.77	$ 4,639.71	$ 319.94	7.41%
8,001		N/A	N/A	N/A	N/A		$ 4,885.37	$ 5,251.01	$ 365.64	7.48%
9,001		N/A	N/A	N/A	N/A		$ 5,450.97	$ 5,862.31	$ 411.34	7.55%
10,001		N/A	N/A	N/A	N/A		$ 6,016.57	$ 6,473.61	$ 457.04	7.60%
11,001		N/A	N/A	N/A	N/A		$ 6,582.17	$ 7,084.91	$ 502.74	7.64%
12,001		N/A	N/A	N/A	N/A		$ 7,147.77	$ 7,696.21	$ 548.44	7.67%
13,001		N/A	N/A	N/A	N/A		$ 7,713.37	$ 8,307.51	$ 594.14	7.70%
14,001		N/A	N/A	N/A	N/A		$ 8,278.97	$ 8,918.81	$ 639.84	7.73%
15,001		N/A	N/A	N/A	N/A		$ 8,844.57	$ 9,530.11	$ 685.54	7.75%
16,001		N/A	N/A	N/A	N/A		$ 9,410.17	$ 10,141.41	$ 731.24	7.77%
17,001		N/A	N/A	N/A	N/A		$ 9,975.77	$ 10,752.71	$ 776.94	7.79%
18,001		N/A	N/A	N/A	N/A		$ 10,541.37	$ 11,364.01	$ 822.64	7.80%
	Winter Qty %	0.00%	0.00%			Winter Qty %	0.00%	0.00%		
	Summer QTY %	100.00%	100.00%			Summer QTY %	100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Commercial/Industrial Medium 20001 to 200000 therms
CG-M and CG-TM

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 183.9995	$ -		$/Mo. Fixed or equiv.	$ 149.9998	$ 149.9998	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.0493	$ -		$/Day Fixed or equiv.	$ 4.9315	$ 4.9315	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Winter	$ 0.6471	$ 0.6789	$ 0.0318	
	$/Therm-Summer	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Summer	$ 0.5317	$ 0.5635	$ 0.0318	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		$ 4,208.09	$ 4,610.11	$ 402.02	9.55%		$ 14,187.77	$ 14,823.81	$ 636.04	4.48%
42,300		$ 6,437.99	$ 7,288.22	$ 850.23	13.21%		$ 27,998.83	$ 29,343.97	$ 1,345.14	4.80%
43,087	1281	$ 6,516.69	$ 7,382.74	$ 866.05	13.29%		$ 28,486.27	$ 29,856.44	$ 1,370.17	4.81%
53,000		$ 7,507.99	$ 8,573.29	$ 1,065.30	14.19%		$ 34,625.96	$ 36,311.36	$ 1,685.40	4.87%
63,000		$ 8,507.99	$ 9,774.29	$ 1,266.30	14.88%		$ 40,819.54	$ 42,822.94	$ 2,003.40	4.91%
73,000		$ 9,507.99	$ 10,975.29	$ 1,467.30	15.43%		$ 47,013.12	$ 49,334.52	$ 2,321.40	4.94%
83,000		$ 10,507.99	$ 12,176.29	$ 1,668.30	15.88%		$ 53,206.70	$ 55,846.10	$ 2,639.40	4.96%
93,000		$ 11,507.99	$ 13,377.29	$ 1,869.30	16.24%		$ 59,400.28	$ 62,357.68	$ 2,957.40	4.98%
103,000		$ 12,507.99	$ 14,578.29	$ 2,070.30	16.55%		$ 65,593.86	$ 68,869.26	$ 3,275.40	4.99%
113,000		$ 13,507.99	$ 15,779.29	$ 2,271.30	16.81%		$ 71,787.43	$ 75,380.83	$ 3,593.40	5.01%
123,000		$ 14,507.99	$ 16,980.29	$ 2,472.30	17.04%		$ 77,981.01	$ 81,892.41	$ 3,911.40	5.02%
133,000		$ 15,507.99	$ 18,181.29	$ 2,673.30	17.24%		$ 84,174.59	$ 88,403.99	$ 4,229.40	5.02%
143,000		$ 16,507.99	$ 19,382.29	$ 2,874.30	17.41%		$ 90,368.17	$ 94,915.57	$ 4,547.40	5.03%
153,000		$ 17,507.99	$ 20,583.29	$ 3,075.30	17.57%		$ 96,561.75	$ 101,427.15	$ 4,865.40	5.04%
163,000		$ 18,507.99	$ 21,784.29	$ 3,276.30	17.70%		$ 102,755.33	$ 107,938.73	$ 5,183.40	5.04%
173,000		$ 19,507.99	$ 22,985.29	$ 3,477.30	17.83%		$ 108,948.90	$ 114,450.30	$ 5,501.40	5.05%
183,000		$ 20,507.99	$ 24,186.29	$ 3,678.30	17.94%		$ 115,142.48	$ 120,961.88	$ 5,819.40	5.05%
	Winter Qty %	75.96%	75.96%			Winter Qty %	75.96%	75.96%		
	Summer QTY %	24.04%	24.04%			Summer QTY %	24.04%	24.04%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Cmmrcl/Indstrl Mdm Seasonal 20001 to 200000 therms
CG-M

Transportation Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 361.9979	$ 361.9979	$ -	
	$/Day Fixed or equiv.	$ 11.9013	$ 11.9013	$ -	
	Demand Charge	$ -	$ -	$ -	
	$/Therm-Winter	$ 0.1000	$ 0.1201	$ 0.0201	
	$/Therm-Summer	$ 0.1000	$ 0.1201	$ 0.0201	

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 299.9996	$ 299.9996	$ -	
$/Day Fixed or equiv.	$ 9.8630	$ 9.8630	$ -	
Demand Charge	$ -	$ -	$ -	
$/Therm-Winter	$ 0.6471	$ 0.6789	$ 0.0318	
$/Therm-Summer	$ 0.5317	$ 0.5635	$ 0.0318	

Usage in Therms	Customer Demand Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Customer Demand Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001	0	N/A	N/A	N/A	N/A	0	$ 12,434.53	$ 13,070.56	$ 636.03	5.12%
30,001	0	N/A	N/A	N/A	N/A	0	$ 17,751.53	$ 18,705.56	$ 954.03	5.37%
40,001	0	N/A	N/A	N/A	N/A	0	$ 23,068.53	$ 24,340.56	$ 1,272.03	5.51%
50,001	0	N/A	N/A	N/A	N/A	0	$ 28,385.53	$ 29,975.56	$ 1,590.03	5.60%
60,001	0	N/A	N/A	N/A	N/A	0	$ 33,702.53	$ 35,610.56	$ 1,908.03	5.66%
70,001	0	N/A	N/A	N/A	N/A	0	$ 39,019.53	$ 41,245.56	$ 2,226.03	5.70%
80,001	0	N/A	N/A	N/A	N/A	0	$ 44,336.53	$ 46,880.56	$ 2,544.03	5.74%
90,001	0	N/A	N/A	N/A	N/A	0	$ 49,653.53	$ 52,515.56	$ 2,862.03	5.76%
100,001	0	N/A	N/A	N/A	N/A	0	$ 54,970.53	$ 58,150.56	$ 3,180.03	5.78%
110,001	0	N/A	N/A	N/A	N/A	0	$ 60,287.53	$ 63,785.56	$ 3,498.03	5.80%
120,001	0	N/A	N/A	N/A	N/A	0	$ 65,604.53	$ 69,420.56	$ 3,816.03	5.82%
130,001	0	N/A	N/A	N/A	N/A	0	$ 70,921.53	$ 75,055.56	$ 4,134.03	5.83%
140,001	0	N/A	N/A	N/A	N/A	0	$ 76,238.53	$ 80,690.56	$ 4,452.03	5.84%
150,001	0	N/A	N/A	N/A	N/A	0	$ 81,555.53	$ 86,325.56	$ 4,770.03	5.85%
160,001	0	N/A	N/A	N/A	N/A	0	$ 86,872.53	$ 91,960.56	$ 5,088.03	5.86%
170,001	0	N/A	N/A	N/A	N/A	0	$ 92,189.53	$ 97,595.56	$ 5,406.03	5.86%
180,001	0	N/A	N/A	N/A	N/A	0	$ 97,506.53	$ 103,230.56	$ 5,724.03	5.87%
	Winter Qty %	0.00%	0.00%			Winter Qty %	0.00%	0.00%		
	Summer QTY %	100.00%	100.00%			Summer QTY %	100.00%	100.00%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Commercial/Industrial Large Over 200000 therms
CG-FL and CG-TL

Transportation Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0636	$ 0.0149	
	$/Therm-Summer	$ 0.0487	$ 0.0636	$ 0.0149	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	3018	$ 18,393.13	$ 21,395.16	$ 3,002.03	16.32%
337,500	3018	$ 25,089.38	$ 30,140.16	$ 5,050.78	20.13%
475,000	3018	$ 31,785.63	$ 38,885.16	$ 7,099.53	22.34%
590,121	3018	$ 37,392.02	$ 46,206.86	$ 8,814.84	23.57%
750,000	3018	$ 45,178.13	$ 56,375.16	$ 11,197.03	24.78%
821,900	3018	$ 48,679.66	$ 60,948.00	$ 12,268.34	25.20%
916,300	5800	$ 53,687.28	$ 67,382.49	$ 13,695.21	25.51%
1,053,800	3018	$ 59,973.19	$ 75,696.84	$ 15,723.65	26.22%
1,191,300	3018	$ 66,669.44	$ 84,441.84	$ 17,772.40	26.66%
1,328,800	3018	$ 73,365.69	$ 93,186.84	$ 19,821.15	27.02%
1,466,300	3018	$ 80,061.94	$ 101,931.84	$ 21,869.90	27.32%
1,603,800	3018	$ 86,758.19	$ 110,676.84	$ 23,918.65	27.57%
1,741,300	3018	$ 93,454.44	$ 119,421.84	$ 25,967.40	27.79%
1,878,800	3018	$ 100,150.69	$ 128,166.84	$ 28,016.15	27.97%
2,016,300	3018	$ 106,846.94	$ 136,911.84	$ 30,064.90	28.14%
2,153,800	3018	$ 113,543.19	$ 145,656.84	$ 32,113.65	28.28%
2,291,300	3018	$ 120,239.44	$ 154,401.84	$ 34,162.40	28.41%

	Old	New
Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
$/Therm-Winter	$ 0.5958	$ 0.6224	$ 0.0266	
$/Therm-Summer	$ 0.4804	$ 0.5070	$ 0.0266	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	3018	$ 116,994.21	$ 122,336.24	$ 5,342.03	4.57%
337,500	3018	$ 191,709.69	$ 200,709.22	$ 8,999.53	4.69%
475,000	3018	$ 266,425.17	$ 279,082.20	$ 12,657.03	4.75%
590,121	3018	$ 328,980.23	$ 344,699.48	$ 15,719.25	4.78%
750,000	3018	$ 415,856.14	$ 435,828.17	$ 19,972.03	4.80%
821,900	5300	$ 455,262.14	$ 477,163.37	$ 21,901.23	4.81%
916,300	3018	$ 506,221.12	$ 530,616.73	$ 24,395.61	4.82%
1,053,800	3018	$ 580,936.60	$ 608,989.71	$ 28,053.11	4.83%
1,191,300	3018	$ 655,652.08	$ 687,362.69	$ 31,710.61	4.84%
1,328,800	3018	$ 730,367.56	$ 765,735.67	$ 35,368.11	4.84%
1,466,300	3018	$ 805,083.04	$ 844,108.65	$ 39,025.61	4.85%
1,603,800	3018	$ 879,798.52	$ 922,481.63	$ 42,683.11	4.85%
1,741,300	3018	$ 954,514.00	$ 1,000,854.62	$ 46,340.62	4.85%
1,878,800	3018	$ 1,029,229.49	$ 1,079,227.60	$ 49,998.11	4.86%
2,016,300	3018	$ 1,103,944.97	$ 1,157,600.58	$ 53,655.61	4.86%
2,153,800	3018	$ 1,178,660.45	$ 1,235,973.56	$ 57,313.11	4.86%
2,291,300	3018	$ 1,253,375.93	$ 1,314,346.54	$ 60,970.61	4.86%

	Old	New
Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Cmmrcl/Indstrl Lrg Seasonal Over 200000 therms
CG-FL

	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
Usage in Therms										
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -		$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -		$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073		Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0636	$ 0.0149		$/Therm-Winter	$ 0.5958	$ 0.6224	$ 0.0266	
	$/Therm-Summer	$ 0.0487	$ 0.0636	$ 0.0149		$/Therm-Summer	$ 0.4804	$ 0.5070	$ 0.0266	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	3018	N/A	N/A	N/A	N/A	3018	$ 100,461.15	$ 105,803.18	$ 5,342.03	5.32%
337,500	3018	N/A	N/A	N/A	N/A	3018	$ 166,516.15	$ 175,515.68	$ 8,999.53	5.40%
475,000	3018	N/A	N/A	N/A	N/A	3018	$ 232,571.15	$ 245,228.18	$ 12,657.03	5.44%
612,500	3018	N/A	N/A	N/A	N/A	3018	$ 298,626.15	$ 314,940.68	$ 16,314.53	5.46%
750,000	3018	N/A	N/A	N/A	N/A	3018	$ 364,681.15	$ 384,653.18	$ 19,972.03	5.48%
887,500	3018	N/A	N/A	N/A	N/A	3018	$ 430,736.15	$ 454,365.68	$ 23,629.53	5.49%
1,025,000	3018	N/A	N/A	N/A	N/A	3018	$ 496,791.15	$ 524,078.18	$ 27,287.03	5.49%
1,162,500	3018	N/A	N/A	N/A	N/A	3018	$ 562,846.15	$ 593,790.68	$ 30,944.53	5.50%
1,300,000	3018	N/A	N/A	N/A	N/A	3018	$ 628,901.15	$ 663,503.18	$ 34,602.03	5.50%
1,437,500	3018	N/A	N/A	N/A	N/A	3018	$ 694,956.15	$ 733,215.68	$ 38,259.53	5.51%
1,575,000	3018	N/A	N/A	N/A	N/A	3018	$ 761,011.15	$ 802,928.18	$ 41,917.03	5.51%
1,712,500	3018	N/A	N/A	N/A	N/A	3018	$ 827,066.15	$ 872,640.68	$ 45,574.53	5.51%
1,850,000	3018	N/A	N/A	N/A	N/A	3018	$ 893,121.15	$ 942,353.18	$ 49,232.03	5.51%
1,987,500	3018	N/A	N/A	N/A	N/A	3018	$ 959,176.15	$ 1,012,065.68	$ 52,889.53	5.51%
2,125,000	3018	N/A	N/A	N/A	N/A	3018	$ 1,025,231.15	$ 1,081,778.18	$ 56,547.03	5.52%
2,262,500	3018	N/A	N/A	N/A	N/A	3018	$ 1,091,286.15	$ 1,151,490.68	$ 60,204.53	5.52%
2,400,000	3018	N/A	N/A	N/A	N/A	3018	$ 1,157,341.15	$ 1,221,203.18	$ 63,862.03	5.52%

	Old	New		Old	New
Winter Qty %	0.00%	0.00%	Winter Qty %	0.00%	0.00%
Summer QTY %	100.00%	100.00%	Summer QTY %	100.00%	100.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interruptible Commercial/Industrial Medium 20001 to 200000 therms
CG-IM and CG-TM

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 183.9995	$ -		$/Mo. Fixed or equiv.	$ 156.0010	$ 156.0010	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.0493	$ -		$/Day Fixed or equiv.	$ 5.1288	$ 5.1288	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Winter	$ 0.5310	$ 0.5620	$ 0.0310	
	$/Therm-Summer	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Summer	$ 0.5310	$ 0.5620	$ 0.0310	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		$ 4,208.09	$ 4,610.11	$ 402.02	9.55%		$ 12,492.54	$ 13,112.57	$ 620.03	4.96%
30,001		$ 5,208.09	$ 5,811.11	$ 603.02	11.58%		$ 17,802.54	$ 18,732.57	$ 930.03	5.22%
40,001		$ 6,208.09	$ 7,012.11	$ 804.02	12.95%		$ 23,112.54	$ 24,352.57	$ 1,240.03	5.37%
50,001		$ 7,208.09	$ 8,213.11	$ 1,005.02	13.94%		$ 28,422.54	$ 29,972.57	$ 1,550.03	5.45%
60,001		$ 8,208.09	$ 9,414.11	$ 1,206.02	14.69%		$ 33,732.54	$ 35,592.57	$ 1,860.03	5.51%
70,001		$ 9,208.09	$ 10,615.11	$ 1,407.02	15.28%		$ 39,042.54	$ 41,212.57	$ 2,170.03	5.56%
80,001		$ 10,208.09	$ 11,816.11	$ 1,608.02	15.75%		$ 44,352.54	$ 46,832.57	$ 2,480.03	5.59%
90,001		$ 11,208.09	$ 13,017.11	$ 1,809.02	16.14%		$ 49,662.54	$ 52,452.57	$ 2,790.03	5.62%
103,000		$ 12,507.99	$ 14,578.29	$ 2,070.30	16.55%		$ 56,565.01	$ 59,758.01	$ 3,193.00	5.64%
113,000		$ 13,507.99	$ 15,779.29	$ 2,271.30	16.81%		$ 61,875.01	$ 65,378.01	$ 3,503.00	5.66%
125,000		$ 14,707.99	$ 17,220.49	$ 2,512.50	17.08%		$ 68,247.01	$ 72,122.01	$ 3,875.00	5.68%
135,000		$ 15,707.99	$ 18,421.49	$ 2,713.50	17.27%		$ 73,557.01	$ 77,742.01	$ 4,185.00	5.69%
145,000		$ 16,707.99	$ 19,622.49	$ 2,914.50	17.44%		$ 78,867.01	$ 83,362.01	$ 4,495.00	5.70%
155,000		$ 17,707.99	$ 20,823.49	$ 3,115.50	17.59%		$ 84,177.01	$ 88,982.01	$ 4,805.00	5.71%
165,000		$ 18,707.99	$ 22,024.49	$ 3,316.50	17.73%		$ 89,487.01	$ 94,602.01	$ 5,115.00	5.72%
175,000		$ 19,707.99	$ 23,225.49	$ 3,517.50	17.85%		$ 94,797.01	$ 100,222.01	$ 5,425.00	5.72%
185,000		$ 20,707.99	$ 24,426.49	$ 3,718.50	17.96%		$ 100,107.01	$ 105,842.01	$ 5,735.00	5.73%
	Winter Qty %	75.96%	75.96%			Winter Qty %	75.96%	75.96%		
	Summer QTY %	24.04%	24.04%			Summer QTY %	24.04%	24.04%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4039	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interruptible Commercial/Industrial Large 200001 to 2400000 therms
CG-IL and CG-TL

Usage in Therms		Transportation Service Old Annual Rate	Transportation Service New Annual Rate	Increase (Decrease)	Percent of Change		Sales Service Old Annual Rate	Sales Service New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 683.9978	$ 683.9978	$ -		$/Mo. Fixed or equiv.	$ 649.9981	$ 649.9981	$ -	
	$/Day Fixed or equiv.	$ 22.4876	$ 22.4876	$ -		$/Day Fixed or equiv.	$ 21.5671	$ 21.5671	$ -	
	Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073		Demand Charge	$ 0.1475	$ 0.1548	$ 0.0073	
	$/Therm-Winter	$ 0.0487	$ 0.0636	$ 0.0149		$/Therm-Winter	$ 0.4797	$ 0.5055	$ 0.0258	
	$/Therm-Summer	$ 0.0487	$ 0.0636	$ 0.0149		$/Therm-Summer	$ 0.4797	$ 0.5055	$ 0.0258	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	7498	$ 19,053.93	$ 22,088.66	$ 3,034.73	15.93%	7498	$ 104,917.95	$ 110,132.68	$ 5,214.73	4.97%
356,600	7498	$ 26,680.35	$ 32,048.42	$ 5,368.07	20.12%	6100	$ 179,832.76	$ 189,077.57	$ 9,244.81	5.14%
494,100	7498	$ 33,376.60	$ 40,793.42	$ 7,416.82	22.22%	7498	$ 245,997.72	$ 258,800.23	$ 12,802.51	5.20%
631,600	7498	$ 40,072.85	$ 49,538.42	$ 9,465.57	23.62%	7498	$ 311,956.47	$ 328,306.48	$ 16,350.01	5.24%
645,000	7498	$ 40,725.43	$ 50,390.66	$ 9,665.23	23.73%	7498	$ 318,384.45	$ 335,080.18	$ 16,695.73	5.24%
782,500	7498	$ 47,421.68	$ 59,135.66	$ 11,713.98	24.70%	7498	$ 384,343.20	$ 404,586.43	$ 20,243.23	5.27%
916,300	5800	$ 53,687.28	$ 67,382.49	$ 13,695.21	25.51%	7498	$ 448,527.06	$ 472,222.33	$ 23,695.27	5.28%
1,053,800	7498	$ 60,633.99	$ 76,390.34	$ 15,756.35	25.99%	7498	$ 514,485.81	$ 541,728.58	$ 27,242.77	5.30%
1,191,300	7498	$ 67,330.24	$ 85,135.34	$ 17,805.10	26.44%	7498	$ 580,444.56	$ 611,234.83	$ 30,790.27	5.30%
1,328,800	7498	$ 74,026.49	$ 93,880.34	$ 19,853.85	26.82%	7498	$ 646,403.31	$ 680,741.08	$ 34,337.77	5.31%
1,466,300	7498	$ 80,722.74	$ 102,625.34	$ 21,902.60	27.13%	7498	$ 712,362.06	$ 750,247.33	$ 37,885.27	5.32%
1,603,800	7498	$ 87,418.99	$ 111,370.34	$ 23,951.35	27.40%	7498	$ 778,320.81	$ 819,753.58	$ 41,432.77	5.32%
1,741,300	7498	$ 94,115.24	$ 120,115.34	$ 26,000.10	27.63%	7498	$ 844,279.56	$ 889,259.83	$ 44,980.27	5.33%
1,878,800	7498	$ 100,811.49	$ 128,860.34	$ 28,048.85	27.82%	7498	$ 910,238.31	$ 958,766.08	$ 48,527.77	5.33%
2,016,300	7498	$ 107,507.74	$ 137,605.34	$ 30,097.60	28.00%	7498	$ 976,197.06	$ 1,028,272.33	$ 52,075.27	5.33%
2,153,800	7498	$ 114,203.99	$ 146,350.34	$ 32,146.35	28.15%	7498	$ 1,042,155.81	$ 1,097,778.58	$ 55,622.77	5.34%
2,291,300	7498	$ 120,900.24	$ 155,095.34	$ 34,195.10	28.28%	7498	$ 1,108,114.56	$ 1,167,284.83	$ 59,170.27	5.34%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interruptible Commercial/Industrial Super Large Over 2400000 therms
CG-ISL and CG-TSL

	Transportation Service					Sales Service				
Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 3,739.9999	$ 3,739.9999	$ -		$/Mo. Fixed or equiv.	$ 3,706.0001	$ 3,706.0001	$ -	
	$/Day Fixed or equiv.	$ 122.9589	$ 122.9589	$ -		$/Day Fixed or equiv.	$ 122.0384	$ 122.0384	$ -	
	Demand Charge	$ 0.1000	$ 0.1100	$ 0.0100		Demand Charge	$ 0.1000	$ 0.1100	$ 0.0100	
	$/Therm-Winter	$ 0.0297	$ 0.0337	$ 0.0040		$/Therm-Winter	$ 0.4607	$ 0.4756	$ 0.0149	
	$/Therm-Summer	$ 0.0297	$ 0.0337	$ 0.0040		$/Therm-Summer	$ 0.4607	$ 0.4756	$ 0.0149	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
2,400,001	4115	$ 116,571.53	$ 126,212.68	$ 9,641.15	8.27%	4115	$ 1,150,635.98	$ 1,186,437.14	$ 35,801.16	3.11%
3,187,501	4115	$ 139,960.28	$ 152,751.43	$ 12,791.15	9.14%	4115	$ 1,513,437.23	$ 1,560,972.14	$ 47,534.91	3.14%
3,975,001	4115	$ 163,349.03	$ 179,290.18	$ 15,941.15	9.76%	4115	$ 1,876,238.48	$ 1,935,507.14	$ 59,268.66	3.16%
4,762,501	4115	$ 186,737.78	$ 205,828.93	$ 19,091.15	10.22%	4115	$ 2,239,039.73	$ 2,310,042.14	$ 71,002.41	3.17%
5,550,001	4115	$ 210,126.53	$ 232,367.68	$ 22,241.15	10.58%	4115	$ 2,601,840.98	$ 2,684,577.14	$ 82,736.16	3.18%
6,000,000	4115	$ 223,491.50	$ 247,532.65	$ 24,041.15	10.76%	4115	$ 2,809,155.52	$ 2,898,596.67	$ 89,441.15	3.18%
6,842,900	33500	$ 251,464.13	$ 279,170.73	$ 27,706.60	11.02%	33500	$ 3,200,418.05	$ 3,302,712.26	$ 102,294.21	3.20%
7,630,400	4115	$ 271,914.38	$ 302,477.13	$ 30,562.75	11.24%	4115	$ 3,560,280.80	$ 3,674,014.91	$ 113,734.11	3.19%
8,417,900	4115	$ 295,303.13	$ 329,015.88	$ 33,712.75	11.42%	4115	$ 3,923,082.05	$ 4,048,549.91	$ 125,467.86	3.20%
9,205,400	4115	$ 318,691.88	$ 355,554.63	$ 36,862.75	11.57%	4115	$ 4,285,883.30	$ 4,423,084.91	$ 137,201.61	3.20%
9,992,900	4115	$ 342,080.63	$ 382,093.38	$ 40,012.75	11.70%	4115	$ 4,648,684.55	$ 4,797,619.91	$ 148,935.36	3.20%
10,780,400	4115	$ 365,469.38	$ 408,632.13	$ 43,162.75	11.81%	4115	$ 5,011,485.80	$ 5,172,154.91	$ 160,669.11	3.21%
11,567,900	4115	$ 388,858.13	$ 435,170.88	$ 46,312.75	11.91%	4115	$ 5,374,287.05	$ 5,546,689.91	$ 172,402.86	3.21%
12,355,400	4115	$ 412,246.88	$ 461,709.63	$ 49,462.75	12.00%	4115	$ 5,737,088.30	$ 5,921,224.91	$ 184,136.61	3.21%
13,142,900	4115	$ 435,635.63	$ 488,248.38	$ 52,612.75	12.08%	4115	$ 6,099,889.55	$ 6,295,759.91	$ 195,870.36	3.21%
13,930,400	4115	$ 459,024.38	$ 514,787.13	$ 55,762.75	12.15%	4115	$ 6,462,690.80	$ 6,670,294.91	$ 207,604.11	3.21%
14,717,900	4115	$ 482,413.13	$ 541,325.88	$ 58,912.75	12.21%	4115	$ 6,825,492.05	$ 7,044,829.91	$ 219,337.86	3.21%

Winter Qty %	54.58%	54.58%	Winter Qty %	54.58%	54.58%
Summer QTY %	45.42%	45.42%	Summer QTY %	45.42%	45.42%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Commercial/Industrial Extra Super Large Over 15000000 therms
CG-IXSL and CG-TXSL

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 30,450.6664	$ 33,492.3331	$ 3,041.6667		$/Mo. Fixed or equiv.	$ 30,416.6667	$ 33,458.3333	$ 3,041.6667	
	$/Day Fixed or equiv.	$ 1,001.1178	$ 1,101.1178	$ 100.0000		$/Day Fixed or equiv.	$ 1,000.1973	$ 1,100.1973	$ 100.0000	
	Demand Charge	$ 0.0450	$ 0.0475	$ 0.0025		Demand Charge	$ 0.0450	$ 0.0475	$ 0.0025	
	$/Therm-Winter	$ 0.0096	$ 0.0171	$ 0.0075		$/Therm-Winter	$ 0.4406	$ 0.4590	$ 0.0184	
	$/Therm-Summer	$ 0.0096	$ 0.0171	$ 0.0075		$/Therm-Summer	$ 0.4406	$ 0.4590	$ 0.0184	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
15,000,000	72243	$ 512,658.93	$ 661,839.54	$ 149,180.61	29.10%	72243	$ 6,977,322.95	$ 7,290,003.56	$ 312,680.61	4.48%
15,937,500	72243	$ 521,658.93	$ 677,870.79	$ 156,211.86	29.95%	72243	$ 7,390,385.45	$ 7,720,316.06	$ 329,930.61	4.46%
16,875,000	72243	$ 530,658.93	$ 693,902.04	$ 163,243.11	30.76%	72243	$ 7,803,447.95	$ 8,150,628.56	$ 347,180.61	4.45%
17,812,500	72243	$ 539,658.93	$ 709,933.29	$ 170,274.36	31.55%	72243	$ 8,216,510.45	$ 8,580,941.06	$ 364,430.61	4.44%
18,750,000	72243	$ 548,658.93	$ 725,964.54	$ 177,305.61	32.32%	72243	$ 8,629,572.95	$ 9,011,253.56	$ 381,680.61	4.42%
19,332,500	72243	$ 554,250.93	$ 735,925.29	$ 181,674.36	32.78%	72243	$ 8,886,222.45	$ 9,278,621.06	$ 392,398.61	4.42%
20,000,000	660000	$ 587,108.00	$ 775,258.00	$ 188,150.00	32.05%	660000	$ 9,206,772.01	$ 9,612,922.01	$ 406,150.00	4.41%
20,937,500	72243	$ 569,658.93	$ 763,370.79	$ 193,711.86	34.00%	72243	$ 9,593,385.45	$ 10,015,316.06	$ 421,930.61	4.40%
21,875,000	72243	$ 578,658.93	$ 779,402.04	$ 200,743.11	34.69%	72243	$ 10,006,447.95	$ 10,445,628.56	$ 439,180.61	4.39%
22,812,500	72243	$ 587,658.93	$ 795,433.29	$ 207,774.36	35.36%	72243	$ 10,419,510.45	$ 10,875,941.06	$ 456,430.61	4.38%
23,750,000	72243	$ 596,658.93	$ 811,464.54	$ 214,805.61	36.00%	72243	$ 10,832,572.95	$ 11,306,253.56	$ 473,680.61	4.37%
24,687,500	72243	$ 605,658.93	$ 827,495.79	$ 221,836.86	36.63%	72243	$ 11,245,635.45	$ 11,736,566.06	$ 490,930.61	4.37%
25,625,000	72243	$ 614,658.93	$ 843,527.04	$ 228,868.11	37.23%	72243	$ 11,658,697.95	$ 12,166,878.56	$ 508,180.61	4.36%
26,562,500	72243	$ 623,658.93	$ 859,558.29	$ 235,899.36	37.83%	72243	$ 12,071,760.45	$ 12,597,191.06	$ 525,430.61	4.35%
27,500,000	72243	$ 632,658.93	$ 875,589.54	$ 242,930.61	38.40%	72243	$ 12,484,822.95	$ 13,027,503.56	$ 542,680.61	4.35%
28,437,500	72243	$ 641,658.93	$ 891,620.79	$ 249,961.86	38.96%	72243	$ 12,897,885.45	$ 13,457,816.06	$ 559,930.61	4.34%
29,375,000	72243	$ 650,658.93	$ 907,652.04	$ 256,993.11	39.50%	72243	$ 13,310,947.95	$ 13,888,128.56	$ 577,180.61	4.34%
	Winter Qty %	54.58%	54.58%			Winter Qty %	54.58%	54.58%		
	Summer QTY %	45.42%	45.42%			Summer QTY %	45.42%	45.42%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4039	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interruptible Commercial/Industrial Electric Generation Medium 20001 to 200000 therms
CG-IEGM

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 183.9995	$ 183.9995	$ -		$/Mo. Fixed or equiv.	$ 156.0010	$ 156.0010	$ -	
	$/Day Fixed or equiv.	$ 6.0493	$ 6.0493	$ -		$/Day Fixed or equiv.	$ 5.1288	$ 5.1288	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Winter	$ 0.5310	$ 0.5620	$ 0.0310	
	$/Therm-Summer	$ 0.1000	$ 0.1201	$ 0.0201		$/Therm-Summer	$ 0.5310	$ 0.5620	$ 0.0310	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
20,001		N/A	N/A	N/A	N/A		$ 12,492.54	$ 13,112.57	$ 620.03	4.96%
30,001		N/A	N/A	N/A	N/A		$ 17,802.54	$ 18,732.57	$ 930.03	5.22%
40,001		N/A	N/A	N/A	N/A		$ 23,112.54	$ 24,352.57	$ 1,240.03	5.37%
50,001		N/A	N/A	N/A	N/A		$ 28,422.54	$ 29,972.57	$ 1,550.03	5.45%
60,001		N/A	N/A	N/A	N/A		$ 33,732.54	$ 35,592.57	$ 1,860.03	5.51%
70,001		N/A	N/A	N/A	N/A		$ 39,042.54	$ 41,212.57	$ 2,170.03	5.56%
80,001		N/A	N/A	N/A	N/A		$ 44,352.54	$ 46,832.57	$ 2,480.03	5.59%
90,001		N/A	N/A	N/A	N/A		$ 49,662.54	$ 52,452.57	$ 2,790.03	5.62%
100,001		N/A	N/A	N/A	N/A		$ 54,972.54	$ 58,072.57	$ 3,100.03	5.64%
110,001		N/A	N/A	N/A	N/A		$ 60,282.54	$ 63,692.57	$ 3,410.03	5.66%
120,001		N/A	N/A	N/A	N/A		$ 65,592.54	$ 69,312.57	$ 3,720.03	5.67%
130,001		N/A	N/A	N/A	N/A		$ 70,902.54	$ 74,932.57	$ 4,030.03	5.68%
140,001		N/A	N/A	N/A	N/A		$ 76,212.54	$ 80,552.57	$ 4,340.03	5.69%
150,001		N/A	N/A	N/A	N/A		$ 81,522.54	$ 86,172.57	$ 4,650.03	5.70%
160,001		N/A	N/A	N/A	N/A		$ 86,832.54	$ 91,792.57	$ 4,960.03	5.71%
175,000		N/A	N/A	N/A	N/A		$ 94,797.01	$ 100,222.01	$ 5,425.00	5.72%
185,000		N/A	N/A	N/A	N/A		$ 100,107.01	$ 105,842.01	$ 5,735.00	5.73%
	Winter Qty %	75.96%	75.96%			Winter Qty %	75.96%	75.96%		
	Summer QTY %	24.04%	24.04%			Summer QTY %	24.04%	24.04%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4039	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interruptible Commercial/Industrial Electric Generation Large Over 200000 therms
CG-IEGL

Usage in Therms	Transportation Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change	Sales Service	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 7,607.7498	$ 7,607.7498	$ -		$/Mo. Fixed or equiv.	$ 7,573.7500	$ 7,573.7500	$ -	
	$/Day Fixed or equiv.	$ 250.1178	$ 250.1178	$ -		$/Day Fixed or equiv.	$ 249.1973	$ 249.1973	$ -	
	Demand Charge	$ 0.0720	$ 0.0720	$ -		Demand Charge	$ 0.0720	$ 0.0720	$ -	
	$/Therm-Winter	$ 0.0132	$ 0.0365	$ 0.0233		$/Therm-Winter	$ 0.4237	$ 0.4475	$ 0.0238	
	$/Therm-Summer	$ 0.0132	$ 0.0365	$ 0.0233		$/Therm-Summer	$ 0.4237	$ 0.4475	$ 0.0238	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
200,000	145190	N/A	N/A	N/A	N/A	145190	$ 186,150.69	$ 190,910.69	$ 4,760.00	2.56%
337,500	145190	N/A	N/A	N/A	N/A	145190	$ 244,409.44	$ 252,441.94	$ 8,032.50	3.29%
475,000	145190	N/A	N/A	N/A	N/A	145190	$ 302,668.19	$ 313,973.19	$ 11,305.00	3.74%
612,500	145190	N/A	N/A	N/A	N/A	145190	$ 360,926.94	$ 375,504.44	$ 14,577.50	4.04%
750,000	145190	N/A	N/A	N/A	N/A	145190	$ 419,185.69	$ 437,035.69	$ 17,850.00	4.26%
887,500	145190	N/A	N/A	N/A	N/A	145190	$ 477,444.44	$ 498,566.94	$ 21,122.50	4.42%
1,025,000	145190	N/A	N/A	N/A	N/A	145190	$ 535,703.19	$ 560,098.19	$ 24,395.00	4.55%
1,162,500	145190	N/A	N/A	N/A	N/A	145190	$ 593,961.94	$ 621,629.44	$ 27,667.50	4.66%
1,300,000	145190	N/A	N/A	N/A	N/A	145190	$ 652,220.69	$ 683,160.69	$ 30,940.00	4.74%
1,437,500	145190	N/A	N/A	N/A	N/A	145190	$ 710,479.44	$ 744,691.94	$ 34,212.50	4.82%
1,575,000	145190	N/A	N/A	N/A	N/A	145190	$ 768,738.19	$ 806,223.19	$ 37,485.00	4.88%
1,712,500	145190	N/A	N/A	N/A	N/A	145190	$ 826,996.94	$ 867,754.44	$ 40,757.50	4.93%
1,850,000	145190	N/A	N/A	N/A	N/A	145190	$ 885,255.69	$ 929,285.69	$ 44,030.00	4.97%
1,987,500	145190	N/A	N/A	N/A	N/A	145190	$ 943,514.44	$ 990,816.94	$ 47,302.50	5.01%
2,125,000	145190	N/A	N/A	N/A	N/A	145190	$ 1,001,773.19	$ 1,052,348.19	$ 50,575.00	5.05%
2,262,500	145190	N/A	N/A	N/A	N/A	145190	$ 1,060,031.94	$ 1,113,879.44	$ 53,847.50	5.08%
4,236,600	145190	N/A	N/A	N/A	N/A	140500	$ 1,896,120.43	$ 1,996,951.51	$ 100,831.08	5.32%
	Winter Qty %	54.58%	54.58%			Winter Qty %	54.58%	54.58%		
	Summer QTY %	45.42%	45.42%			Summer QTY %	45.42%	45.42%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3884	$ 0.3884
Base Average Peak Demand Cost:	$ 0.1154	$ -
Base Average Annual Demand Cost:	$ 0.0155	$ 0.0155
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5193	$ 0.4039

Transportation Administrative Charge: $ 0.9205

Wisconsin Public Service Corporation
Docket 6690-UR-128
Monitored Fuel Costs for 2025

	Monitored Fuel Costs	MWh	Monthly $/MWh	Cumulative $/MWh
January	$ 29,357,523	1,055,019	$ 27.83	$ 27.83
February	$ 24,818,407	946,916	26.21	27.06
March	$ 22,814,832	975,178	23.40	25.86
April	$ 21,408,557	891,041	24.03	25.44
May	$ 21,324,714	888,762	23.99	25.17
June	$ 19,926,159	977,819	20.38	24.35
July	$ 22,963,716	1,068,790	21.49	23.90
August	$ 26,616,831	1,108,595	24.01	23.92
September	$ 22,680,245	953,997	23.77	23.90
October	$ 22,184,108	929,013	23.88	23.90
November	$ 22,042,940	899,579	24.50	23.95
December	$ 29,549,947	1,004,105	29.43	24.42
Totals	$285,687,979	11,698,814	$ 24.42	

Wisconsin Public Service Corporation
Docket 6690-UR-128
Amortization Schedule
Dollars in 000's

Company / Description	Utility	Inc Stmt Account	Bal Sheet Account	12/2024 Ending Balance	2025 Deferral	2025 Amortization	12/2025 Ending Balance	2026 Deferral	2026 Amortization	12/2026 Ending Balance
Wisconsin Public Service Corporation										
Bluewater Operating Cost Escrow	WPS Gas	824	182/254	**8,841**	**13,102**	**(15,641)**	**6,302**	**9,339**	**(15,641)**	**0**
Crane Creek Depreciation Deferral - FERC	WPS Electric	407	254	**(87)**	**-**	**6**	**(81)**	**-**	**6**	**(75)**
Crane Creek Production Tax Credits - FERC	WPS Electric	410	182	**268**	**-**	**(19)**	**249**	**-**	**(19)**	**230**
Darien Solar Cost Overrun	WPS Electric	407	182	**-**	**3,225**	**-**	**3,225**	**-**	**-**	**3,225**
DER and DRER Acquisition Costs	WPS Electric	407	182	**421**	**460**	**(59)**	**822**	**480**	**(59)**	**1,243**
Earnings Sharing				(478)	**-**	**239**	**(239)**	**-**	**239**	**(0)**
Earning Sharing Electric	WPS Electric	421/456	254	(5)	-	3	(3)	-	3	(0)
Earning Sharing Gas	WPS Gas	421/495	254	(473)	-	237	(237)	-	237	(0)
Electric Transmission Costs	WPS Electric	407	254	**(275)**	**180,705**	**(165,200)**	**15,230**	**178,788**	**(194,017)**	**1**
Energy Efficiency Programs				(3,918)	**23,010**	**(21,750)**	**(2,659)**	**24,409**	**(21,750)**	**(0)**
CSC Escrow Act 141/SEERA Elec	WPS Electric	908	254	(20)	13,102	(13,496)	(414)	13,910	(13,496)	(0)
Conservation Escrow - Dir Costs / Amort Elec	WPS Electric	908	254	(3,297)	2,310	(696)	(1,683)	2,379	(696)	(0)
Farm Re-Wiring Escrow	WPS Electric	908	254	(775)	1,371	(1,004)	(408)	1,412	(1,004)	(0)
CSC Escrow Act 141/SEERA Gas	WPS Gas	908	254	(0)	4,591	(4,807)	(216)	5,022	(4,807)	(0)
Conservation Escrow - Dir Costs / Amort Gas	WPS Gas	908	254	173	1,636	(1,747)	62	1,685	(1,747)	0
Environmental Remediation Costs	WPS Gas	735	182	**38,665**	**6,445**	**(9,159)**	**35,951**	**6,014**	**(9,159)**	**32,806**
Forward Wind Deferral	WPS Electric	421	182/254	**(4,159)**	**-**	**1,040**	**(3,119)**	**-**	**1,040**	**(2,080)**
Fox 3 Generation Unit - CC1 Pre-certification Costs	WPS Electric	407	182/254	**(1,649)**	**-**	**412**	**(1,236)**	**-**	**412**	**(824)**
Guardian Lateral	WPS Electric	407	182	**12,971**	**-**	**(654)**	**12,317**	**-**	**(654)**	**11,664**
Income Tax Related				**(290,009)**	**-**	**17,407**	**(272,602)**	**(17,844)**	**29,723**	**(260,723)**
Def Tax-2010 Health Care Leg - Electric	WPS Electric	409	182	**1,297**		(236)	1,061		(236)	825
Def Tax-2010 Health Care Leg - Gas	WPS Gas	409	182	327		(59)	267		(59)	208
Def Int Contngt Tax - Electric	WPS Electric	407/409	182	**1,787**	-	(893)	893	-	(893)	(0)
Elec Def Tax - MI Law Change	WPS Electric	410	182	630		(27)	603		(27)	576
Gas Def Tax - MI Law Change	WPS Gas	410	182	252		(11)	242		(11)	231
DMD & R&E Tax Credits	WPS Electric	407	182/254	319		(160)	160		(160)	(0)
Inflation Reduction Act (Includes Carry)	WPS Electric	410/411	254	1,896	-	(948)	948	-	(948)	(0)
WPS - TR - Remeasure - Electric (P)	WPS Electric	410/411	254	(227,725)	-	6,835	(220,890)	-	24,889	(196,001)
WPS - TR - Remeasure - Electric (U) & (P)/(U) ARAM Escrow	WPS Electric	410/411	254	(6,100)	-	3,050	(3,050)	-	3,050	(0)
Electric Unprotected Remeasure True-up	WPS Electric	456	254	191	-	(191)	-	-	-	-
Gas Unprotected Remeasure True-up	WPS Gas	495	254	(5,640)	-	5,640	-	-	-	-
WPS - TR - Remeasure - Gas (P)	WPS Gas	410/411	254	(51,916)	-	1,745	(50,171)	-	1,439	(48,732)
WPS - TR - Remeasure - Gas (U) & (P)/(U) ARAM Escrow	WPS Gas	410/411	254	(5,132)	-	2,566	(2,566)	-	2,566	(0)
WPS TR - Remeasure - Electric (P) Weston 2	WPS Electric	410/411	254	(105)	-	7	(99)	-	7	(92)

Company / Description	Utility	Inc Stmt Account	Bal Sheet Account	12/2024 Ending Balance	2025 Deferral	2025 Amortization	12/2025 Ending Balance	2026 Deferral	2026 Amortization	12/2026 Ending Balance
Wisconsin Public Service Corporation										
WPS TR - Remeasure - Electric (P) Weston Other	WPS Electric	410/411	254	(89)	-	89	-	-	-	-
WPS TR - Remeasure - Electric (P) Columbia 1/2	WPS Electric	410/411	254	-	-	-	-	(17,844)	107	(17,737)
Merger and acquisition-related pension and other postretirement benefit costs	WPS Common	926	182	**3,710**	**-**	**(3,710)**	**(0)**	**-**	**-**	**(0)**
Other				(82)	**142**	**(102)**	**(41)**	**142**	**(102)**	**(0)**
Act 24 CUB Funding - Electric	WPS Electric	407	182	(0)	82	(82)	(0)	82	(82)	-
Act 24 CUB Funding - Gas	WPS Gas	407	182	(4)	60	(58)	(2)	60	(58)	-
Columbia 2023 O&M Deferral	WPS Electric	407	182	3,651	-	(1,825)	1,825	-	(1,825)	(0)
Electric Vehicle Pilot Rebate Payments	WPS Electric	407	182	149	-	(75)	75	-	(75)	(0)
Badger Hollow I Liquidated Damages	WPS Electric	407	254	(3,354)	-	1,677	(1,677)	-	1,677	(0)
Red Barn Liquidated Damages	WPS Electric	407	254	**(523)**	-	262	(262)	-	262	0
Paris Solar and BESS Cost Overrun	WPS Electric	407	182	**-**	**25,290**	**-**	**25,290**	**-**	**-**	**25,290**
Paris Solar Incremental RR Deferral	WPS Electric	407	182	**(6,883)**	**-**	**6,883**	**-**	**-**	**-**	**-**
Pension & OPEB Escrow	WPS Common	Various	182	**30,197**	**-**	**(15,099)**	**15,099**	**-**	**(15,099)**	**-**
Pension settlement accounting				**(2,561)**	**-**	**(30)**	**(2,591)**	**-**	**(30)**	**(2,621)**
Pension Settlement Accounting	WPS Common	926	182	1,882	**-**	(665)	1,217	**-**	(665)	552
Pension Curtailment Accounting	WPS Common	926	254	**(4,442)**	**-**	635	(3,808)	**-**	635	(3,173)
Plant Retirements				46,165	**7,878**	**(14,667)**	**39,376**	**216,094**	**(16,860)**	**238,610**
Pulliam 7&8 Plant Retirement - WI/MBR	WPS Electric	407	182	28,767	-	(3,606)	25,160	-	(3,606)	21,554
Pulliam 7&8 Plant Retirement - FERC	WPS Electric	407	182	526	-	(62)	464	-	(62)	402
Pulliam 7&8 AFUDC Equity	WPS Electric	409	182	238	-	(27)	211	-	(27)	184
Edgewater Plant Retirement - WI/MBR	WPS Electric	407	182	2,116	938	(1,069)	1,985	-	(1,069)	916
Edgewater Plant Retirement - FERC	WPS Electric	407	182	40	16	(19)	38	-	(19)	19
Edgewater AFUDC Equity	WPS Electric	409	182	25	-	(4)	21	-	(4)	17
Lincoln Wind Plant Retirement - WI	WPS Electric	407	182	2,240	-	(328)	1,912	-	(328)	1,584
Lincoln Wind Plant Retirement - FERC	WPS Electric	407	182	42	-	(6)	36	-	(6)	30
Lincoln Wind AFUDC Equity	WPS Electric	409	182	1	-	(0)	1	-	(0)	1
WPS Weston 2 NBV - COR Dollars	WPS Electric	407	182	12,313	6,620	(9,466)	9,466	-	(9,466)	-
Weston 2 AFUDC Equity	WPS Electric	409	182	24	-	(9)	15	-	(9)	6
WPS Weston 31 & 32 NBV - COR Dollars	WPS Electric	407	254	(170)	303	(67)	67	-	(67)	-
Weston 31/32 AFUDC Equity	WPS Electric	409	182	3	-	(3)	-	-	-	-
WPS Columbia 1 COR NBV	WPS Electric	407	182	-	-	-	-	(26,028)	(749)	(26,777)
WPS Columbia 1 Life NBV	WPS Electric	407	182	-	-	-	-	238,618	(1,426)	237,192
WPS Columbia 1/2 AFUDC Equity	WPS Electric	407	182	-	-	-	-	3,503	(21)	3,482
Reactive Power (Sch 2) Transmission O&M	WPS Electric	565	182	**13,356**	**-**	**(6,678)**	**6,678**	**-**	**(6,678)**	**-**
Red Barn Acquisition Costs	WPS Electric	407	182	**2,444**	**-**	**(87)**	**2,357**	**-**	**(87)**	**2,270**
Uncollectible Expense				**11,845**	**9,560**	**(15,537)**	**5,869**	**9,669**	**(15,537)**	**(0)**
Uncoll Exp Elec	WPS Electric	904	182	11,372	7,710	(13,441)	5,642	7,799	(13,441)	(0)

Company / Description	Utility	Inc Stmt Account	Bal Sheet Account	12/2024 Ending Balance	2025 Deferral	2025 Amortization	12/2025 Ending Balance	2026 Deferral	2026 Amortization	12/2026 Ending Balance
Wisconsin Public Service Corporation										
Uncoll Exp Gas	WPS Gas	904	182	**473**	1,851	(2,097)	227	1,870	(2,097)	(0)
Whitewater Gas Lateral	WPS Electric	407	182	**2,089**	**-**	**(157)**	**1,933**	**-**	**(157)**	**1,776**
Whitewater Acquisition Costs	WPS Electric	407	182	**228**	**-**	**(18)**	**210**	**-**	**(18)**	**193**
W3 ReAct	WPS Electric	421	182	**13,532**	**-**	**(4,511)**	**9,021**	**-**	**(4,511)**	**4,511**
Total				**(125,367)**	**269,817**	**(247,090)**	**(102,640)**	**427,091**	**(268,957)**	**55,494**