SERVICE DATE
Dec 19, 2024

PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates — 5-UR-111

FINAL DECISION

This is the Final Decision on the joint application of Wisconsin Electric Power Company (WEPCO) and Wisconsin Gas LLC (WG) (together, applicants) for authority to adjust electric, natural gas, and steam rates for the 2025 and 2026 test years, and for approval of the applicants' 2025 Fuel Cost Plan. Final overall rate changes[1] for the test year ending December 31, 2025 are authorized consisting of a $144.0 million rate increase over currently authorized rates for WEPCO retail electric operations, or 4.17 percent, a $41.3 million rate increase over currently authorized rates for WEPCO natural gas operations, or 7.10 percent, a $1.5 million rate increase over currently authorized rates for WEPCO steam operations, or 4.97 percent, and a $34.5 million rate increase over currently authorized rates for WG natural gas operations, or 4.15 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 $313.5 million rate increase over currently authorized rates for WEPCO retail electric operations, or 8.69 percent, a $71.1 million rate increase over currently authorized rates for WEPCO natural gas operations, or 11.57 percent, a $1.5 million rate increase over currently authorized rates for WEPCO steam operations, or 4.92 percent, and a $58.0 million rate increase over currently authorized rates for WG natural gas operations, or 6.71 percent, based on a 9.80 ROE.

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

Introduction

On April 12, 2024, the applicants filed a joint application requesting approval to adjust electric, natural gas, and steam rates.

On May 9, 2024, the Commission issued a Notice of Proceeding. (PSC REF#: 500853.) 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 Brotherhood of Electrical Workers, Local 2150 (IBEW), International Union of Operating Engineers, Local 420 (IUOE), Microsoft Corporation (Microsoft), City of Milwaukee (COM), Milwaukee Metropolitan Sewerage District (MMSD), RENEW Wisconsin, Inc. (RENEW), Roundy's Supermarkets, Inc. (Roundy's), Sierra Club, United Steelworkers Local 2006 (USW), Vote Solar, Walmart, Inc. (Walmart), Walnut Way Conservation Corp. (Walnut Way) and Wisconsin Industrial Energy Group (WIEG). (PSC REF#: 505921.)[2]

On June 20, 2024, a Prehearing Conference Memorandum was issued making determinations consistent with the Prehearing Conference that was held on June 14, 2024. The memorandum established the issues, schedule, and other facilitating matters for this proceeding

[2] Late in the proceeding on October 25, 2024, The Martin Drive Neighborhood Association, requested intervention. (PSC REF#: 522414.) As the request was more than 150 days past the deadline for intervening and did not articulate a basis for allowing intervention so far out of time per Wis. Admin. Code § PSC 2.21(4), the request was denied. (PSC REF#: 522414.)

pursuant to Wis. Admin. Code § PSC 2.04(4).[3] (PSC REF#: 505921.) The issues for hearing were identified as follows:

A. Should the Commission grant in whole or in part the applicants' request for electric, natural gas, and steam utility rate increases, and if so, under what terms and conditions?
   1. What are the applicants' revenue requirements for electric, natural gas, and steam 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 26, 2024, the Commission issued a Notice of Hearing scheduling both the party hearing session and public hearing sessions. (PSC REF#: 515246.) Pursuant to due notice, on October 1, 2024, and October 3, 2024, public hearings were held in person and virtually for members of the general public. (PSC REF#: 519613; PSC REF#: 519949.) The Commission's public hearing process involved the opportunity for members of the public to submit written comments either through the Commission's web site or at the public hearing, or to testify at the public hearing. The Commission received over 650 comments from members of the public. (PSC REF#: 521215.)

A party hearing was held virtually on September 24, 2024, to receive testimony and technical information from the parties to the proceeding. (PSC REF#: 519870.)

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

[3] On June 25, 2024, Microsoft filed a request to reschedule the party hearing date set forth in the Prehearing Conference Memorandum. (PSC REF#: 506304.) That request was subsequently withdrawn on August 6, 2024. (PSC REF#: 511830.) On September 24, 2024, Walnut Way filed a request for an order amending the briefing schedule. (PSC REF#: 516085.) The request was addressed during the party hearing session and a supplemental round of briefing following the receipt of all public comments was added.

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

Findings of Fact

1. WEPCO is an investor-owned electric, natural gas, and steam public utility as defined in Wis. Stat. § 196.01(5)(a). WEPCO provides electric, natural gas, and steam service in eastern Wisconsin.

2. WG is an investor-owned natural gas public utility as defined in Wis. Stat. § 196.01(5)(a). WG provides natural gas service in Wisconsin.

3. Currently authorized rates for WEPCO's Wisconsin retail electric utility operations will produce total tariff operating revenues of $3,456.0 million and $3,606.0 million for the 2025 and 2026 test years, respectively. This results in a retail net operating income of $483.8 million and $329.4 million, respectively, which is insufficient.

4. For WEPCO's retail electric utility operations, the estimated rate of return on average net investment rate base of $6,713.4 million and $6,823.6 million at current rates for the 2025 and 2026 test years, is 7.21 percent and 4.83 percent, respectively, which is insufficient.

5. A reasonable increase to WEPCO's Wisconsin retail electric operating revenues to produce a rate of return on WEPCO's average net investment rate base of 8.77 percent and 8.92 percent in the 2025 and 2026 test years is $144.0 million and $313.5 million, respectively.

6. WEPCO'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.

7. Currently authorized rates for WEPCO's natural gas operations will produce total tariff operating revenues of $581.4 million and $614.3 million for the 2025 and 2026 test years,

respectively.[4] This results in a net operating income of $88.8 million and $76.3 million, respectively, which is insufficient.

8. For WEPCO's natural gas utility operations, the estimated rate of return on average net investment rate base of $1,372.0 million and $1,454.8 million at current rates for the 2025 and 2026 test years, is 6.47 percent and 5.25 percent, respectively, which is insufficient.

9. A reasonable increase to the WEPCO's natural gas operating revenues to produce a rate of return on WEPCO's average net investment rate base of 8.66 percent and 8.80 percent in the 2025 and 2026 test years is $41.3 million and $71.1 million, respectively.

10. WEPCO'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.

11. Currently authorized rates for WEPCO's steam utility operations will produce total tariff operating revenues of $29.3 million and $29.5 million for the 2025 and 2026 test years, respectively. This results in a net operating income of $3.7 million and $3.7 million, respectively, which is insufficient.

12. For WEPCO's steam utility operations, the estimated rate of return on average net investment rate base of $55.5 million and $55.9 million at current rates for the 2025 and 2026 test years, is 6.60 percent and 6.64 percent, respectively, which is insufficient.

13. A reasonable increase to WEPCO's steam operating revenues to produce a rate of return on WEPCO's average net investment rate base of 8.51 percent and 7.54 percent in the 2025 and 2026 test years is $1.5 million and $1.5 million, respectively.

[4] 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.

14. WEPCO's filed steam operating income statement and net investment rate base for the 2025 and 2026 test years, as adjusted for Commission decisions, are reasonable.

15. Currently authorized rates for WG's natural gas operations will produce total tariff operating revenues of $832.1 million and $864.3 million for the 2025 and 2026 test years, respectively.[5] This results in a net operating income of $142.6 million and $134.7 million, respectively, which is insufficient.

16. For WG's natural gas utility operations, the estimated rate of return on average net investment rate base of $1,949.1 million and $2,049.1 million at current rates for the 2025 and 2026 test years, is 7.32 percent and 6.57 percent, respectively, which is insufficient.

17. A reasonable increase to WG's natural gas operating revenues to produce a rate of return on WG's average net investment rate base of 8.61 percent and 8.63 percent in the 2025 and 2026 test years is $34.5 million and $58.0 million, respectively.

18. WG'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.

19. A reasonable 2025 test year monitored fuel cost is $967.6 million on a Wisconsin retail basis. A reasonable 2025 Fuel Cost Plan level for WEPCO's total company monitored fuel costs is $990.8 million. The fuel cost plan year monitored fuel cost divided by the authorized level of native requirements of 23,568,705 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $42.04.

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

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

21. 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.

22. 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.

23. It is reasonable to incorporate the fuel costs associated with the "open season" purchased natural gas capacity for the Port Washington Generating Station Units 1 and 2.

24. It is reasonable to incorporate the update of purchased power capacity costs for 2026.

25. 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, heating oil, and the Argus Powder River Basin for spot coal as of mid-month of October 2024 to forecast the applicants' 2025 monitored fuel costs.

26. It is reasonable to set WEPCO's 2025 Fuel Cost Plan level at $990.8 million, or $42.04 per MWh, as shown in Appendix I.

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

28. It is reasonable for WEPCO to file for a 2026 Fuel Cost Plan in 2025 in accordance with Wis. Admin. Code ch. PSC 116.

29. It is reasonable for WEPCO to seek reconciliation of its 2025 Fuel Cost Plan consistent with the requirements of Wis. Admin. Code § PSC 116.07.

30. 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 requirement, and to not address the accounting treatment for any such costs at this time.

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

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

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

34. It is reasonable for WEPCO to return the 2024 transmission escrow credit balance in one year (2025), and to amortize the 2025 deferred transmission amount in 2025 and the 2026 deferred transmission amount in 2026.

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

36. It is reasonable to accept Commission staff's electric O&M maintenance expense adjustment for Oak Creek Power Plant (OCPP), Rothschild Biomass facility (Rothschild Biomass), Blue Sky Green Field wind farm (Blue Sky), and Glacier Hills Wind Park (Glacier Hills).

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

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

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

40. It is not necessary to require the applicants to provide specific data in its initial data request responses in the next rate proceeding demonstrating the specific customer benefits associated with payment of all advertising expenses for which the applicants intend to seek recovery in that proceeding.

41. It is reasonable to require the applicants to provide specific data in its initial data request responses in the next rate proceeding demonstrating the specific customer benefits associated with payment of all Board of Director expenses for which the applicants intend to seek recovery in that proceeding.

42. It is reasonable to accept WEPCO's requested forestry management expense budgets for inclusion in the 2025 and 2026 test year electric revenue requirements.

43. It is not necessary to authorize WEPCO to escrow or defer the difference between the authorized forestry management amount and actual forestry management expense.

44. It is reasonable to require WEPCO 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.

45. It is reasonable to accept Commission staff's adjustment to WEPCO's storm damage expense.

46. A reasonable amount of Storm Hardening Program expense for WEPCO is $44 million for the 2025 test year and $50 million for the 2026 test year.

47. It is reasonable to require WEPCO to file annual Storm Hardening Program pre-construction reports containing the information detailed in this Final Decision no later than the first quarter of each year beginning in 2025, and post-construction reports no later than the second quarter of each year beginning in 2025.

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

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

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

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

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

53. 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.

54. It is reasonable to exclude all incentive compensation from the 2025 and 2026 test year revenue requirements for the applicants' electric, natural gas, and steam operations.

55. It is reasonable to accept Commission staff's adjustment related to the applicants' medical and dental expense that is associated with non-represented FTE adjustments for the 2025 and 2026 test year revenue requirements.

56. It is reasonable to accept Commission staff's adjustment related to injuries and damages in the applicants' 2025 and 2026 test year revenue requirements.

57. It is reasonable to accept WEPCO's proposed Fund for Lake Michigan budget for the 2025 and 2026 test year electric revenue requirements.

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

59. It is reasonable to accept Commission staff's adjustments for WG's plant in service and CWIP for the 2025 and 2026 test years.

60. It is reasonable to include all of the identified cost overruns for Badger Hollow II in WEPCO's 2025 and 2026 test year electric revenue requirements.

61. It is reasonable to accept WEPCO's proposal to amortize the regulatory asset balance associated with Badger Hollow II over the remaining life of the plant.

62. It is reasonable to include all of the identified cost overruns for Bluff Creek Liquified Natural Gas Project (Bluff Creek LNG) in WEPCO's 2025 and 2026 test year natural gas revenue requirements.

63. It is reasonable to include all of the identified cost overruns for Ixonia Liquified Natural Gas Project (Ixonia LNG) in WG's 2025 and 2026 test year revenue requirements.

64. It is reasonable to accept WG's proposal to amortize the regulatory asset balance associated with Ixonia LNG over the remaining life of the plant.

65. It is reasonable for WEPCO 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.

66. It is reasonable to accept WEPCO'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 require a true-up in WEPCO's next rate proceeding.

67. It is reasonable for WEPCO 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.

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

69. It is reasonable to allow recovery of the Michigan Avenue Replacement project in WG's 2025 and 2026 natural gas revenue requirement.

70. It is reasonable to exclude the impact for the Paris Reciprocating Internal Combustion Engine (Paris RICE) from WEPCO's 2025 and 2026 test year revenue requirements.

71. It is reasonable in this proceeding to include the amount associated with the undepreciated balance for Oak Creek Power Plant (OCPP) Units 7 and 8 scheduled for retirement. It is reasonable to calculate this amount by amortizing the undepreciated balance over 17 years using a traditional declining balance, and applying carrying costs on the undepreciated balance at WEPCO's authorized weighted average cost of capital, as proposed by WEPCO.

72. It reasonable to require deferral accounting treatment to capture the differences between estimated and actual revenue requirement impacts associated with retiring OCPP Units 7 and 8 resulting from a change in the units' December 2025 retirement date.

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

74. It is reasonable to allow the 2025 and 2026 test year revenue deficiencies for WEPCO's steam operations to be levelized.

75. It is reasonable for the applicants to continue to defer, with carrying costs at the applicants' short-term debt rate, any impacts of the Inflation Reduction Act (IRA) to the applicants' next rate proceeding.

76. It is reasonable for the applicants 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.

77. It is reasonable to accept Commission staff's adjustments to WEPCO's transmission expenses for the 2025 and 2026 test years.

78. It is reasonable for WEPCO to amortize the related acquisition and revenue requirement deferrals for West Riverside 2 over four years.

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

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

81. It is reasonable to authorize deferral accounting treatment for the applicants' Bring Your Own Device (BYOD) pilot program until the applicants' next rate proceeding.

82. The Customer Service Conservation (CSC) activities proposed by the applicants for 2025 and 2026 are reasonable and consistent with the Commission's historical definition of CSC activities.

83. A reasonable estimate of escrowed conservation expense to be recorded in 2025 for WEPCO electric operations is $40.8 million and WEPCO natural gas operations is $8.2 million.

84. A reasonable estimate of escrowed conservation expense to be recorded for WG's operations in 2025 is $11.5 million.

85. A reasonable estimate of escrowed conservation expense to be recorded in 2026 for WEPCO electric operations is $42.9 million and WEPCO natural gas operations is $8.9 million.

86. A reasonable estimate of escrowed conservation expense to be recorded for WG's operations in 2026 is $12.4 million.

87. It is reasonable for the applicants to amortize and include the revenue requirement impacts of the regulatory asset and regulatory liability amortizations as detailed in Appendix J, for all items listed for 2025 and 2026 or until the Commission authorizes a different amortization expense to be recorded.

88. It is reasonable to require the applicants to file a depreciation study for Commission approval no later than January 26, 2027.

89. It is reasonable to require the applicants 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.

90. It is reasonable to require the applicants in future rate proceedings to present the second year of a 2-year test year rate proceeding as a change from presently authorized rates.

91. It is reasonable to accept all other Commission staff audit adjustments made to the applicants' filed electric, natural gas, and steam revenue requirement not contested by any party.

92. It is reasonable for WEPCO to have $810.0 million in off-balance sheet obligations for 2025 and $829.1 million in off-balance sheet obligations for 2026.

93. It is reasonable for WG to have no off-balance sheet obligations for 2025 and 2026.

94. An appropriate target level for WEPCO's average common equity measured on a financial capital structure basis is 53.00 percent for 2025 and 2026 test years.

95. An appropriate target level for WG's average common equity measured on a financial capital structure basis is 53.00 percent for 2025 and 2026 test years.

96. A reasonable financial capital structure for WEPCO for the 2025 test year consists of 53.00 percent common equity, 37.74 percent long-term debt, 1.75 percent short-term debt, 0.27 preferred stock, and 7.24 percent debt equivalence for off-balance sheet obligations, including subsidiary debt. A reasonable financial capital structure for WEPCO for the 2026 test year consists of 53.00 percent common equity, 38.72 percent long-term debt, 1.65 percent short-term debt, 0.23 preferred stock, and 6.39 percent debt equivalence for off-balance sheet obligations, including subsidiary debt.

97. A reasonable financial capital structure for WG for the 2025 test year consists of 53.00 percent common equity, 43.19 percent long-term debt, and 3.81 percent short-term debt. A reasonable financial capital structure for WG for the 2026 test year consists of 53.00 percent common equity, 44.06 percent long-term debt, and 2.94 percent short-term debt.

98. A reasonable regulatory capital structure for WEPCO for the 2025 test year consists of 57.06 percent common equity, 40.45 percent long-term debt, 2.19 percent short-term debt, and 0.29 preferred stock. A reasonable regulatory capital structure for WEPCO for the 2026 test year consists of 56.54 percent common equity, 40.97 percent long-term debt, 2.24 percent short-term debt, and 0.25 preferred stock.

99. A reasonable regulatory capital structure for WG for the 2025 test year consists of 52.75 percent common equity, 43.37 percent long-term debt, and 3.88 percent short-term debt. A reasonable regulatory capital structure for WG for the 2026 test year consists of 52.76 percent common equity, 44.16 percent long-term debt, and 3.09 percent short-term debt.

100. A reasonable return on utility common stock equity for the applicants in 2025 and 2026 is 9.80 percent.

101. A reasonable interest rate for short-term borrowing through commercial paper for WEPCO is 4.88 percent for the 2025 test year and 4.27 percent for the 2026 test year.

102. A reasonable interest rate for short-term borrowing through commercial paper for WG is 5.17 percent for the 2025 test year and 4.38 percent for the 2026 test year.

103. A reasonable average embedded cost for long-term debt for WEPCO is 4.99 percent for the 2025 test year and 5.19 percent for the 2026 test year.

104. A reasonable average embedded cost for long-term debt for WG is 4.65 percent for the 2025 test year and 4.91 percent for the 2026 test year.

105. A reasonable average cost for WEPCO's preferred stock is 3.95 percent for the 2025 and 2026 test years.

106. A reasonable weighted average composite cost of capital for WEPCO in 2025 and 2026 is 7.72 percent and 7.78, respectively.

107. A reasonable weighted average composite cost of capital for WG in 2025 and 2026 is 7.39 percent and 7.47 percent, respectively.

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

109. It is reasonable for WEPCO's Earning Sharing Mechanism (ESM), as described in the Opinion section of this Final Decision, to remain in place until WEPCO's next rate proceeding.

110. It is reasonable for WG's Earning Sharing Mechanism (ESM), as approved in docket 5-UR-110, to remain in place until WG's next rate proceeding.

111. It is reasonable for the applicants 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.

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

113. It is reasonable to consider the full range of electric cost-of-service study (COSS) results presented in the record when allocating test year 2025 electric revenue responsibility.

114. It is reasonable to consider the full range of COSS results presented in the record when allocating test year 2026 electric revenue responsibility.

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

116. It is reasonable to approve the electric revenue allocations for WEPCO's 2025 and 2026 test years proposed by Commission staff, as adjusted for final revenue requirement.

117. It is reasonable to accept the comprehensive electric rate design proposed by Commission staff in Ex.-PSC-Nye-1, as adjusted for final revenue requirement, for the 2025 test year.

118. It is reasonable to accept the comprehensive electric rate design proposed by

Commission staff in Ex.-PSC-Nye-2r, as adjusted for final revenue requirement, for the 2026 test year.

119. It is reasonable to authorize the rate design for WEPCO's Cg-3 customer class as proposed by Commission staff.

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

121. It is reasonable to require WEPCO 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.

122. It is reasonable to authorize the rate design for WEPCO's Cp-1 customer class as proposed by Commission staff.

123. It is reasonable to authorize WEPCO's proposed credit mechanism changes to the Cp-1 tariff for customers with operations that are categorized under Standard Industry Classification (SIC) code 4952.

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

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

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

127. It is reasonable to require the applicants 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.

128. It is reasonable to increase the capacity cap on the CGS-CU tariff from 1,000 kW to 5,000 kW.

129. It is reasonable to authorize WEPCO's proposal to offer bi-directional metering for the CGS-NM tariff with an implementation date of June 1, 2025.

130. It is reasonable to authorize WEPCO's proposal to increase the Real Time Market Pricing rider participation cap from 300 MW to 500 MW.

131. It is reasonable to authorize the increased Renewable Pathway Premium rate from $0.00717 per kWh to $0.01768 per kWh for one-year subscriptions and from $0.00531 per kWh to $0.01582 per kWh for five-year subscriptions.

132. It is reasonable for WEPCO to add language clarifying its annual deadline for firm demand nominations to the Cp-3, Cp3S, Cg-3C, and Cg-3S tariffs.

133. It is reasonable to authorize WEPCO's uncontested proposed update and clarification for dishonored payment charges and the proposed revision to notification and load control mechanisms for demand response.

134. It is reasonable to authorize WEPCO's proposed minor administrative changes and clarifications to its electric rate sheets.

135. It is reasonable to authorize all of WEPCO's uncontested rate design proposals.

136. It is reasonable to consider the full range of natural gas COSS results presented in the record when allocating the 2025 test year natural gas revenue responsibility for WEPCO natural gas operations.

137. It is reasonable to consider the full range of natural gas COSS results presented in the record when allocating the 2026 test year natural gas revenue responsibility for WEPCO natural gas operations.

138. It is reasonable to approve the natural gas revenue allocations for WEPCO's 2025 and 2026 test years proposed by Commission staff, as adjusted for final revenue requirement.

139. It is reasonable to accept the comprehensive natural gas rate design for WEPCO gas operations proposed by Commission staff in Ex.-PSC-Nye-5 and Ex.-PSC-Nye-6, as adjusted for final revenue requirement, for the 2025 and 2026 test years, respectively.

140. It is reasonable to approve the rate changes for natural gas service as shown in Appendices F and G for WG and Appendices D and E for WEPCO natural gas operations.

141. It is reasonable to consider the full range of natural gas COSS results presented in the record when allocating the 2025 test year natural gas revenue responsibility for WG.

142. It is reasonable to consider the full range of natural gas COSS results presented in the record when allocating the 2026 test year natural gas revenue responsibility for WG.

143. It is reasonable to approve the natural gas revenue allocations for WG's 2025 and 2026 test years proposed by Commission staff, as adjusted for final revenue requirement.

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

145. 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.

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

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

148. It is reasonable to update the applicants' base cost of fuel for steam service consistent with Ex.-PSC-Nye-7.

149. It is reasonable to approve the rate changes for steam service as shown in Appendix H.

150. It is reasonable to require WEPCO to update and conduct a comprehensive loss study before or as part of its next rate proceeding.

151. It is reasonable to require WEPCO to eliminate the prohibition of on-site generation, regardless of size, from its Experimental Short Term Productivity Rider (STRP) tariff.

152. It is reasonable to require WEPCO to revise the Real Time Market Pricing (RTMP) Rider tariff to include a conjunctive billing provision similar to the provision in Cp-1.

153. 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, 196.026, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, 196.40, and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision authorizing the applicants to place in effect the rates and rules for electric, steam, and natural gas service set forth in Appendices B, C, D, E, F, G, and H, and the fuel cost treatment set forth in Appendix I.

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 progress 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

Applicants and its Business Operations

The applicants are public utilities, as defined in Wis. Stat. § 196.01(5). WEPCO conducts its operations primarily in three operating segments: an electric utility segment (WEPCO electric), a natural gas utility segment (WEPCO gas), and a steam utility segment (WEPCO steam). In Wisconsin, WEPCO serves approximately 1,145,000 electric customers and approximately 506,000 natural gas customers. WEPCO steam serves about 400 steam customers downtown and the near south side in Milwaukee, Wisconsin. WG is a natural gas distribution public utility that serves approximately 657,000 natural gas customers in Wisconsin.

WEPCO and WG are operating subsidiaries of WEC Energy Group, Inc., a holding company based in Milwaukee, Wisconsin.

The applicants' service territory presents unique challenges. As analyzed by CUB in this proceeding, 43 percent, or 205 out of the 473 census tracts served by WEPCO, have a higher unemployment rate than the statewide average. Forty percent have a higher percentage of families with income below the poverty line when compared to statewide numbers. For WG, 46 percent of the census tracts have a higher unemployment rate than the statewide average and 44 percent have a higher percentage of families with income below the poverty line when compared to statewide. These challenges appear to be especially pronounced in Milwaukee County. Within the area served by WEPCO and WG, 118 tracts, largely within Milwaukee 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. As Walnut Way presented, Black and majority Hispanic and Latinx neighborhoods in the metro Milwaukee area experience disproportionately high energy burden rates compared to majority white census tract neighborhoods.

The Application

The applicants filed for approval a 2025 Fuel Cost Plan pursuant to Wis. Admin. Code § PSC 116.03, an increase to WEPCO's electric, natural gas, and steam rates as described in the

Revenue Requirement section below, an increase to WG's 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 650 comments, most of which were related to affordability of the applicants' 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,[6] 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

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[6] *See, e.g.* Wis. Stat. §§ 196.499(5)(am), 196.504(8), 196.54(2).

convincing evidence" or "a preponderance of the evidence,"[7] Wis. Stat. § 196.37 does not 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

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

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 applicants provided substantial evidence to support each of the Commission’s determinations.

Thus, the burden carried by the applicants 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 applicants in the present docket do 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 applicants must satisfy.

Evidentiary Record

The applicants, other parties, and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates and rates for the applicants' 2025 and 2026 electric, natural gas, and steam utility operations. As noted above, members of the public provided testimony and submitted written comments. This evidence was accepted into the record. (PSC REF#: 524055)

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#: 523759.) 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 applicants filed for separate 2025 and 2026 test years. The applicants concluded that WEPCO's current electric, natural gas, and steam rates and WG's natural gas rates were insufficient and proposed a base rate increase in 2025 and 2026. For WEPCO's total company electric rates for the 2025 test year, the applicants requested a 6.9 percent increase above 2024 authorized rates, and an incremental increase of approximately 4.6 percent for the 2026 test year.

For WEPCO's natural gas rates for the 2025 test year, the applicants requested a 10.0 percent increase above 2024 authorized rates, and an incremental increase of approximately 4.6 percent for the 2026 test year. For WG's natural gas rates for the 2025 test year, the applicants requested an 8.2 percent increase above 2024 authorized rates, and an incremental increase of approximately 3.3 percent for the 2026 test year. For WEPCO's steam rates for the 2025 test year, the applicants requested an 8.4 percent increase above 2024 authorized rates, and for the 2026 test year the applicants proposed to maintain the requested 2025 steam rates.

The applicants claimed the main drivers impacting WEPCO's electric revenue requirement for the 2025 and 2026 test years include investments in rate base; significant inflation; and higher capital costs due to increased interest rates. According to the applicants, WEPCO's natural gas revenue requirement drivers include investments in rate base; increased O&M costs; regulatory amortizations; and cost of capital. The applicants claimed that WEPCO's steam revenue requirement drivers include investments to improve steam system reliability; increased O&M costs; and a decrease in other operating revenue. Finally, the applicants claimed that WG's natural gas revenue requirement drivers include investments in rate base; increased O&M costs; regulatory amortizations; and cost of capital.

Commission staff reviewed 2025 and 2026 test year filing information for WEPCO's electric, natural gas, and steam operations and WG's natural gas operations. Based on its review, Commission staff determined that for the 2025 and 2026 test years WEPCO's retail electric operations would require an increase above currently authorized 2024 retail electric rates of 3.74 percent and 8.17 percent, respectively; WEPCO's natural gas rates would require an increase above currently authorized 2024 natural gas rates of 6.40 percent and 11.55 percent, respectively; WEPCO's steam rates would require an increase above currently authorized 2024 steam rates of 5.84 percent and 5.69 percent, respectively; and WG would require an increase above currently authorized 2024 natural gas rates of 3.63 percent and 6.06 percent, respectively.

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,[8] among other requirements. In setting just and reasonable utility rates, the Commission is tasked with first estimating the revenues that the applicants need 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 service the utility will provide during the test year(s), and estimating the applicants' reasonable expenses[9] in order to determine the appropriate revenue requirement, or the total revenues the utility must collect from customers in the rates it charges them.

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

[8] Wis. Stat. § 196.03.
[9] For many income statement items, reasonable expenses are estimated based on historic budget-to-actuals or historic average. 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 in the future test year on a rolling basis, thus smoothing out variances.

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 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 applicants' 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 other financial and ratemaking mechanisms provide the state's utilities a reasonable opportunity to earn their authorized equity returns, even in the face of unexpected costs. 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 or Certificate of Public Convenience and Necessity, 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, its shareholders, and the applicants' 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 utility 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 utility's fuel cost plan and establishes the utility's rates in accordance with the approved fuel cost plan. Wis. Admin. Code § PSC 116.03(3).

The fuel cost plan filed as part of the applicants' April 12, 2024 application to adjust electric, natural gas, and steam rates reflected a preliminary fuel cost estimate for WEPCO's 2025 fuel plan year of $42.67 per MWh, which is a 0.7 percent decrease from the 2024 fuel cost plan approved by the Commission in docket 5-UR-110. (PSC REF#: 487244.) Commission staff conducted an audit of WEPCO'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 WEPCO's 2025 Fuel Cost Plan monitored fuel costs is $990.8 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 23,568,705 MWh results in an average net monitored fuel cost per MWh of $42.04. Appendix I shows the monthly fuel costs to be used for monitoring purposes.

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

PSC 116.07. WEPCO shall file for its 2026 Fuel Cost Plan in 2025 in accordance with Wis. Admin. Code ch. PSC 116.

Uncontested Fuel Adjustments

Commission staff proposed various adjustments to WEPCO's filed 2025 fuel costs that were not contested by any party. These adjustments included: (1) an increase in fuel costs of approximately $0.212 million to reflect updating the New York Mercantile Exchange futures as of May 15, 2024, for 2025 for natural gas; (2) an increase in fuel costs of approximately $8.9 million to reflect updates of actual coal inventories, spot coal prices, coal and rail contract price updates and heating oil futures as of May 15, 2024, for 2025; (3) an increase in fuel costs of approximately $2.4 million to reflect updates for planned outage changes, equivalent unplanned outage rates and extending the operation of Edgewater 5 through the end of 2025; (4) a decrease in fuel costs of approximately $0.058 million to reflect updated information on transmission facilities impacting monitored fuel costs; (5) an increase in fuel costs of approximately $5.8 million to reflect updates to the Elm Road Generating Station (ERGS) project to co-fire the ERGS with natural gas; (6) a decrease in fuel costs of approximately $1.2 million to reflect updates to back-end adjustments which are fuel costs addressed outside of the economic dispatch model. This adjustment includes updates to capacity sales based on actual 2024 and 2025 Midcontinent Independent System Operator, Inc. (MISO) Planning Reserve Auction results, emission chemical costs for Weston Unit 3 Activated Coke and Paris Reciprocating Internal Combustion Engine units, energy contracts and Renewable Energy Credits, natural gas fixed and demand costs, Firm Transmission Rights/Auction Revenue Rights revenues based on most recent auction results, auxiliary load based on 2023 actuals, mark-to-market value of hedging as of May 15, 2024, Fox Generation Station risk management costs based on 2025 forecast volumes, MISO rates, charges, and credits using most recent data through May 2024, Energy for Tomorrow forecast based on most recent information, and Account 509 emission allowance costs reflecting June 2024 market pricing for allowances.

The Commission therefore finds it reasonable to accept all of the uncontested monitored fuel adjustments to WEPCO's forecasted 2025 monitored 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 WEPCO's native system requirement used in the fuel modeling. 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 WEPCO's 2025 fuel costs to reflect the impact of the adjustment to WEPCO'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). WEPCO proposed modeling West Riverside using an EFOR based on the historical actual outage rate. Commission staff typically uses a 5-year historical average as the basis for forecasting EFOR. However, West Riverside went into service in May 2020, and does not have 5 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 decrease of $0.412 million to WEPCO's 2025 fuel costs. CUB and Walnut Way 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 Wisconsin Public Service Corporation (WPSC) 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 WEPCO's 2025 fuel costs.

NYMEX and Other Updates

Consistent with past Commission practice, Commission staff proposed a final update to WEPCO'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 Energy Information Administration Short-Term Energy Outlook (EIA STEO). This information was included in a delayed exhibit filed by Commission staff. (PSC REF#: 523396.) These adjustments were not contested by any party and resulted in a decrease to WEPCO's 2025 fuel costs by $31.2 million.

The Commission finds it reasonable to accept these uncontested final adjustments to reflect updated commodities pricing. Additionally, the Commission accepts the applicants' uncontested request to update purchased power capacity costs for 2026. These costs are non-monitored and therefore not included in monitored fuel costs.

WEPCO also requested an increase in fuel costs for natural gas capacity costs for the Port Washington Generating Station (PWGS) due to an acquisition during an open season period. Commission staff reviewed the documentation submitted by WEPCO and found it to be sufficient to support the requested increase in monitored fuel costs. No parties contested this adjustment. Based on the record, the Commission finds it reasonable to authorize the inclusion in the 2025 fuel costs of the purchased natural gas capacity for the PWGS units.

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 applicants included minor estimated expense in its filed 2025 and 2026 revenue requirements for ash disposal costs related to compliance with the new EPA CCR regulations. 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, WEPCO could file a request for deferral accounting treatment. The applicants did not offer objections to this approach.

In light of the uncertainty, 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 and Natural Gas Sales Adjustments

Commission staff adjusted the electric sales forecast for WEPCO's residential rate class RG-1 by increasing the sales forecast by 29,102,231 kilowatt-hours (kWh) and 28,794,404kWh for the 2025 and 2026 test years, respectively. This increase in kWh resulted in an increase of $5.8 million and $5.7 million to the sales revenue forecast for the 2025 and 2026 test years, respectively. Commission staff's adjustment to the residential rate class results from a higher customer count forecast. The historical customer counts had a strong linear growth rate;

therefore, Commission staff chose to use a three-year compound annual growth rate to forecast the 2025 and 2026 test year total. The remaining portion of the sales adjustment were changes in electric wholesale revenue driven primarily by changes to the fuel costs.

Commission staff adjusted WEPCO's natural gas sales by increasing the sales forecast by 6,466,365 therms and 7,847,829 therms for the 2025 and 2026 test years, respectively. Commission staff's adjustment to the small commercial and industrial gas sales results from staff identifying two months within the weather normalized forecast which were lower than expected. Commission staff set these months equal to actuals then utilized a four-year compound annual growth rate to forecast customer usage. Commission staff also utilized a four-year compound annual growth rate to adjust the customer count to reflect the strong historical growth rate. These adjustments and a NYMEX update resulted in an increase of $4.0 million for the 2025 test year and $5.2 million for the 2026 test year.

Commission staff adjusted WG's natural gas sales by increasing the sales forecast by 9,307,043 therms and 11,456,593 therms for the 2025 and 2026 test years, respectively. Commission staff's adjustment to the small commercial and industrial gas sales results from utilizing a four-year compound annual growth rate to forecast customer usage. Additionally, staff increased the small transportation gas forecast by 3,222,693 therms and 5,043,971 therms for the 2025 and 2026 test years, respectively. Commission staff used the average of the utility forecasted growth rate along with the Commission staff forecasted four-year compound annual growth rate to forecast the test year totals in order to factor in anticipated slowed growth that may occur. These adjustments and a NYMEX update resulted in an increase of $6.4 million for the 2025 test year and $8.5 million for the 2026 test year.

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

The applicants disagreed with Commission's staff's sales adjustment and argued 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 applicants further argued that Commission staff's analysis failed to incorporate several important factors that are summarized in the applicants' testimony and as a result, stated that the Commission should select the applicants' as-filed forecast due to the more sophisticated, forward looking, and reasonable methodology it employed.

The Commission is not persuaded by the applicants' arguments. Commission staff's methodology utilizes a standard approach which not only looks at historical averages, but it 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 and natural gas sales adjustments for the 2025 and 2026 test years.

Transmission Escrow

WEPCO's 2024 year-end transmission escrow balance is expected to be a credit amount of $24.3 million. WEPCO proposed to return the credit in 2025 rather than amortizing it over two years. WEPCO stated that the forecasted 2025 deferred amount will be amortized in 2025 and the forecast for 2026 deferred amount will be amortized in 2026. Commission staff did not identify any concerns with WEPCO's request as the balance of the escrow is forecasted to be zero at the end of 2026. Therefore, the Commission finds it reasonable to amortize the forecasted transmission escrow balance as proposed by WEPCO for the 2025 and 2026 test years.

O&M Maintenance Expense Adjustments

Commission staff proposed an adjustment to the O&M expenses for the OCPP, Rothschild Biomass, Blue Sky and Glacier Hills plants that was calculated using a three-year budget to actual analysis to adjust the applicants' test year budgets amounts to be consistent with the applicants' past maintenance spending. The 2025 maintenance adjustments resulted in a decrease of $2.4 million for OCPP, a decrease of $0.776 million for Rothschild Biomass, a decrease of $0.480 million to Blue Sky, and a decrease of $0.573 million for Glacier Hills maintenance. The 2026 maintenance adjustments included a decrease of $0.837 million for Rothschild Biomass, a decrease of $0.514 million to Blue Sky, and a decrease of $0.602 million for Glacier Hills maintenance. The applicants stated that although the applicants disagreed with Commission staff's methodology, the applicants were not contesting these reductions to plant O&M expenses 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 Generating Station (Whitewater) which resulted in a decrease of $1.3 million and $1.4 million in 2025 and 2026. The applicants objected to Commission staff's methodology and stated that this adjustment could not be true of Whitewater. The Commission approved the applicants' 50 percent acquisition on December 22, 2022, and the purchase closed on January 1, 2023. Therefore, WEPCO 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 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 applicants, the Commission could find that the WEPCO's original budget for Whitewater is reasonable. Conversely, as WEPCO 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 WEPCO'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 applicants' forecast given the limited information that was available to the applicants when that 2023 budget was estimated. Therefore, the Commission finds it reasonable to accept WEPCO'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 Company (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 intended to seek recovery.

In this proceeding, the applicants 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-Maly-2, which included the applicants' 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 $1.4 million in WEPCO electric O&M, $0.247 million for WEPCO natural gas O&M, $0.005 million in WEPCO steam O&M, and $0.408 million in WG natural gas O&M for the 2025 test year, as well as decreases of $1.5 million in WEPCO electric O&M, $0.254 million for WEPCO natural gas O&M, $0.005 million for WEPCO steam O&M and $0.418 million for WG natural gas O&M for the 2026 test, 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 applicants bear 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 applicants did not produce specific data demonstrating specific customer benefits.

The applicants testified that the Commission's historic practice of including a portion of industry association fees in rates is reasonable and justified. In addition, the applicants 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 cases 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 applicants did provide some information but in the future the record would benefit from a more robust presentation by the applicants. The Commission finds that the information supplied did demonstrate that participation in the associations identified by the applicants 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 association dues consistent with past Commission practice, and as identified in Ex.-PSC-Maly-2, in the applicants 2025 and 2026 electric, natural gas, and steam revenue requirements. Further, the Commission finds it reasonable to require the applicants to provide detailed information 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 applicants intend 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 promotional advertising, institutional or goodwill advertising expenses and economic development expenses resulting in a decrease of $0.825 million for WEPCO electric operations, $0.115 million for WEPCO natural gas operations, $0.005 million for WEPCO steam operations, and $0.317 million for WG natural gas operations for the 2025 test year revenue requirement. For the 2026 test year the adjustment resulted in revenue requirement decreases of $0.811 million for WEPCO electric operations, $0.118 million for WEPCO natural gas operations, $0.006 million or WEPCO steam operations, and $0.325 million for WG natural gas operations. 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. The Commission finds it reasonable and consistent with past practice to accept Commission staff's adjustment for promotional advertising, institutional or goodwill advertising.

CUB stated that only those advertising expenses that provide a customer benefit should be allowed in rates and proposed that the applicants 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 applicants 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 applicants have 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 that it is not necessary to require the applicants to provide specific data in their next rate proceeding demonstrating the customer benefit associated with advertising expenses for which they seek recovery.

Board of Director Costs

CUB identified that the applicants were seeking approximately $5.9 million in Board of Directors fees for the 2025 and 2026 test years, and an additional $3.7 million in Board of Directors Insurance for the test years. CUB recommended the Commission require that the applicants 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 applicants to provide specific data in their initial data request response in their next rate proceeding demonstrating the specific customer benefits associated with Board of Director costs for which they seek recovery.

Forestry Management Expense

WEPCO requested a $26.0 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 (EAB) infestation. WEPCO's overall proposed forestry management expense budget was approximately $45 million for 2025 and $47.5 million for 2026.

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 WEPCO's request. This adjustment resulted in a decrease of $20.8 million and $22.6 million for the 2025 and 2026 test years electric revenue requirement, respectively.

WEPCO used the following six criteria to identify and prioritize the projects for their proposed forestry management budget increase:

1. Poor performing feeders
2. Previous trimmed areas 6-7 years ago,
3. Extensive tree contact,
4. High risk corridors (number of customers impacted and tree density),
5. Construction plans, and
6. Ash content.

With the increase in requested forestry O&M, WEPCO stated its intention to reduce their vegetation non-MED (Major Event Day) System Average Interruption Frequency Index (SAIFI) from 0.45 in 2023 to 0.17 in 2030. WEPCO's reliability metrics have been regressing during the 2013 through 2022 period with the trend projected to continue on that path if tree related outages are left unaddressed. The project identification was primarily driven by the amount of tree contact seen by the projects, which is significant for many of the projects identified by WEPCO. WEPCO stated that the reduction in number of miles of forestry cleared and increase in the years between tree clearing is leading to the increase in tree related outages. Comparatively, WEPCO cleared 1,485 miles of distribution lines in 2020 whereas only 648 miles were cleared in 2023. With the increase in the frequency of tree related outages, WEPCO has seen a decrease in customer satisfaction related to forestry during this period. WEPCO received three times the reports or call regarding fallen trees in 2023 as compared to 2021.

WEPCO stated that EAB infestation is significantly increasing the number of tree contact related outages in the areas around Milwaukee and that Stevens Point, Appleton, Green Bay, and up to Door County are starting to see the Ash tree decline occur. WEPCO in its Hazard/Danger Tree Removal Program asserts that 6 percent of its tree population is Ash trees which are causing 14 percent of the outages, and that 30 percent of this Ash tree population has become hazardous. The tree related outages due to trees outside of its right-of-way have on average increased 6 percent annually as well. WEPCO also stated that $5.5 million of the $26 million requested forestry related O&M increase will be used to remove dead or dying Ash trees.

WEPCO 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 WEPCO to escrow or defer differences in costs between the requested amounts and actual spend in the test years. According to WEPCO, including the requested amounts in the revenue requirement subject to escrow or deferral accounting would allow it to “true up” the amount spent in a future rate case 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 applicants are not entitled to ongoing dollar-for-dollar recovery of every cost.

The Commission thanks the parties and Commission staff for the comprehensive dialogue on this issue. Based upon the record evidence, the Commission finds that WEPCO made a sound case for the requested budgetary increases 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 WEPCO to a shorter tree trimming cycle sooner. The increase in forestry management budget will expedite addressing tree related outages and reliability metrics in WEPCO's service territory, and the projects identified by WEPCO will address the reliability and customer satisfaction concerns in areas which have seen significant number of tree contact outages. Therefore, the Commission finds it reasonable to accept WEPCO's forestry management expense increase as proposed for the 2025 and 2026 test years.

As the robust record on this topic supports the reasonableness of the forestry management budget proposed by WEPCO and in light of WEPCO past overspending in this area, the Commission finds it is not reasonable to authorize WEPCO to escrow or defer the difference between authorized and actual forestry management expense for the 2025 and 2026 test years. The Commission also notes 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 utility 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.

Forestry Management Reporting

Commission staff recommended that should the Commission find WEPCO's proposed forestry management expense to be reasonable, the Commission consider requiring WEPCO 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 WEPCO 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 WEPCO 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 WEPCO'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 EAB Infested hazard trees removed by project and cost for such hazard tree removal.
7. Report on assessment of reliability benefits.

Storm Damage Expense

WEPCO identified an $8.0 million increase for major storm damage due to more frequent and serious summer and winter storms. Commission staff proposed an adjustment to limit the test year amounts to the three-year inflated average of actual expenses pending the Commission's determination of the reasonableness of the applicants' request. This adjustment resulted in revenue requirement decreases to WEPCO electric operations of $1.5 million for the 2025 test year and $1.5 million for the 2026 test year.

The Commission finds Commission staff's approach to be reasonable and therefore accepts Commission staff's Storm Damage expense adjustments for the 2025 and 2026 test years.

Storm Hardening Expense

WEPCO anticipates spending approximately $50 million on the Storm Hardening Program in 2025; $40 million will be invested in overhead to underground projects, and $10 million will be invested in sectionalizing and automation projects. For 2026, WEPCO anticipates spending approximately $56 million; approximately $46 million will be invested in overhead to underground projects, and $10 million will be invested in sectionalizing and automation projects.

The Commission's Final Decision in docket 5-UR-110 (PSC REF#: 455451), authorized inclusion of $38 million in capital expenditures in the 2023 test year for the Storm Hardening Program which WEPCO, at that time, anticipated the total cost to be approximately $700 million over the life of the program. WEPCO underspent the 2023 budget by $20.8 million, and on an average monthly basis, is projected to underspend the 2024 budget by approximately $5.6 million, for a total 2-year underspend of $26.4 million. WEPCO stated that it was delayed earlier in 2024 but is on path to utilize its entire $44 million program budget in 2024. Commission staff suggested reducing each year by $13.2 million, which is one half of the estimated $26.4 million underspent amount from the 2023 to 2024 period. The projects that have been completed so far have shown improvement in reliability as stated by WEPCO. Commission staff raised concerns about funding the same project more than once as the projects roll over into the next year.

The Commission notes that while 2023 saw underspending due to supply chain issues, WEPCO is expected to meet its 2024 budget, suggesting a return to planned spending levels. Therefore, as a middle-ground modification, the Commission finds it reasonable to extend the 2024 budget amount of $44.0 million into 2025 and to authorize a 2026 budget amount of $50.0 million. This modified proposal aims to balance cost controls with program effectiveness and emphasizes the importance of these investments in enhancing system resilience and achieving long-term cost-effectiveness.

Docket 5-UR-111

Storm Hardening Program Reporting

Commission staff suggested that the Commission consider new order condition language requiring the applicants to file a Storm Hardening Program pre-construction report in docket 5-UR-111, no later than the first quarter of each year beginning in 2025, and a post-construction report, no later than the second quarter of each year beginning in 2025. This report is requesting reliability metric and data for SAIFI and System Average Interruption Duration Index (SAIDI) and should include the following information:

1. Number, identification, year approved, and timeline for project.
2. Pre-construction report with the 3-year average SAIFI and SAIDI performance and expected level of reliability improvement for all relevant project areas.
3. Details of the progress made during the previous year, status of projects pending from earlier years, and the progress made to-date under this O&M item.
4. Comparison of total budgeted and actual annual cost.
5. Post-construction project area SAIFI and SAIDI level improvements for individual projects.

The Commission finds the above reporting requirements to be reasonable. The reporting requirements will provide critical oversight, particularly to address concerns about past underspending and the possibility of reallocating funds for previously approved projects and ensuring that funds are not used for the same project more than once. Therefore, WEPCO shall file annual Storm Hardening Program pre-construction reports no later than the first quarter of each year beginning in 2025, and post-construction reports, no later than the second quarter of each year beginning in 2025.

Leak Detection and Repair

The applicants identified various expected impacts of the LDAR proposed rule[10] and based on an assumed effective date of March 1, 2025, included the associated compliance costs in their test year forecasts. In addition, the applicants identified that until the rule is finalized, the precise cost impact is difficult to estimate, and stated that 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 $5.8 million for WEPCO natural gas operations and $8.0 million for WG in each of the 2025 and 2026 test year 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 applicants 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

[10] The U.S. 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.)

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 for both 2025 and 2026 test years. CUB also noted that if the Commission believes that the effective date of the rules may be further in the future, the Commission could grant the requested increase for only the 2026 test year. The applicants 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 applicants' proposed forecast due to the unknowns and finds that the applicants 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 revenue requirements. Further, if the program gains more certainty, the Commission finds it reasonable for the applicants to include an analysis of offsetting losses in gas supply forecasts noting that the applicants' 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 applicants 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 Commission finds it is not necessary to address the accounting treatment for future LDAR expenses at this time. However, this does not prevent the applicants 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 (FTE) 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 each utility 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 74 FTEs for electric operations, 9 FTEs for natural gas operations, and 2 FTEs for steam operations, for an overall labor decrease for WEPCO of $10.2 million for the 2025 test year. For 2026, WEPCO's regular FTE forecast was consistent with the linear trend therefore, no change was made for the 2026 test year. For WG, the adjustment resulted in a 35 FTE reduction for both the 2025 and 2026 test years, for an overall labor decrease of $2.5 million and $3.1 million, respectively. For part-time and seasonal employees, Commission staff used a three-year average to determine an appropriate FTE level and an appropriate expense level per FTE. For WEPCO, the adjustment resulted in a decreased expense amount for the 2025 and 2026 test years of $0.756 million and $0.892 million, respectively. For WG, the adjustment resulted in a decreased expense amount for the 2025 and 2026 test years of $0.561 million and $0.590 million, respectively.

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

IUOE and IBEW agreed with the applicants and testified regarding the importance of increasing Union staffing levels and that headcount requirements should be forecasted by looking forward, not back. They argued increasing customer counts, additional workloads related to leak detection and repair (LDAR) and additional infrastructure hardening efforts all support increasing in-housing Union headcount.

The Commission finds it reasonable 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 applicants' previous rate proceeding in docket 5-UR-110 (PSC REF#: 455451), in which the Commission did not fully accept FTE adjustments due to labor market challenges. Further, the Commission does not find it necessary to authorize 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 WG 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 $0.399 million and $0.419 million, respectively. CUB supported Commission staff's proposed payroll adjustment for overtime hours. The applicants disagreed with Commission staff's adjustments and argued that if they cannot add employees and as seasonal work increases, they will need to rely on more part-time and seasonal employees, overtime, and contractors. The applicants asserted 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 applicants' argument is less persuasive. Therefore, the Commission finds it reasonable to accept Commission staff's payroll adjustment related to overtime hours for WG's natural gas 2025 and 2026 revenue requirements.

Inflation Rate for Non-Represented Employee Wages

Commission staff proposed an adjustment to the electric, natural gas, and steam 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 2025 test year of $2.4 million for WEPCO and $0.449 million for WG and a decreased expense amount for the 2026 test year of $3.6 million for WEPCO and $0.284 million for WG.

The applicants disagreed with the inflation rate used by Commission staff. The applicants 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 and IBEW agreed with the applicants 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 $1.4 million and $0.455 million in 2025 and 2026, respectively, for WEPCO electric operations; a decrease of $0.103 million and $0.003 million in 2025 and 2026, respectively, for WEPCO natural gas operations; a decrease of $0.01 million and $0.003 million in 2025 and 2026, respectively, for WEPCO steam operations; and a decrease of $0.246 million and $0.080 million in 2025 and 2026, respectively, for WG operations. The applicants asserted the final revenue requirement should include appropriate medical and dental expenses to cover the applicants' 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 that 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 expenses for the applicants' 2025 and 2026 test year electric, natural gas, and steam operations revenue requirements.

Incentive Compensation

The applicants 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 applicants' revenue requirement pending a Commission decision. This adjustment resulted in a decrease to O&M non-labor of $13.2 million for WEPCO and $2.3 million for WG for the 2025 test year and $12.3 million for WEPCO and $2.3 million for WG for the 2026 test year. In addition, this adjustment resulted in a decrease to 2025 O&M labor of $12.1 million for WEPCO and $2.3 million for WG; and a decrease of $12.3 million for WEPCO and $2.3 million for WG for the 2026 test year.

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 (SWL&P) 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 SWL&P 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 applicants acknowledged that the Commission has not included incentive compensation in rates in prior cases. However, the applicants 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 applicants in this proceeding was 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 applicants' 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 for the applicants' electric, natural gas, and steam operations.

Injuries and Damages

Commission staff held injuries and damages expenses to a two-year average plus inflation. The applicants stated that these expenses relate to insurance premiums and deductibles and argued that staff's adjustment failed to account for the significant increase in insurance costs for the utility sector. While the applicants made reference to general industry trends, they did not provide specific corroborating evidence for their insurance premiums in the 2025 and 2026 test years. Given that the applicants did not provide compelling evidence demonstrating how the utilities' insurance premiums will increase in the test years, the Commission finds it reasonable to accept Commission staff's adjustment related to injuries and damages for the applicants' 2025 and 2026 test year electric, natural gas, and steam operations revenue requirements.

Fund for Lake Michigan

In 2008, to resolve a dispute relating to a Wisconsin Pollutant Discharge Elimination System (WPDES) permit for the Elm Road Generating Station, WEPCO, along with MGE and

WPPI Energy, entered into a settlement agreement, subject to Commission approval of rate recovery, to help fund Lake Michigan improvement projects. WEPCO requested $3.3 million in the revenue requirement for both the 2025 and 2026 test years. Recovery of the annual payments under the WPDES agreement are to be approved by the Commission on a case-by-case basis. Commission staff did not adjust WEPCO's request. The Commission finds it reasonable to accept WEPCO's requested Fund for Lake Michigan expense in the 2025 and 2026 test year electric revenue requirements.

WEPCO Plant in Service and CWIP

Commission staff adjusted the 2023 balance to reflect year-end actuals for plant in service, CWIP, and accumulated depreciation. 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 case; 2015, 2020, and 2023.

This adjustment resulted in a $247.1 million reduction to the 2025 total company average plant in service for WEPCO electric, $241.6 million for Wisconsin retail; a $27.8 million reduction to the 2025 average natural gas plant in service for WEPCO gas; a $1.2 million reduction to the 2025 average for WEPCO steam plant in service. Additionally, the 2025 test year electric average CWIP balances decreased $309.0 million while the natural gas and steam average CWIP balances decreased $8.9 million and $2.4 million respectively. For the 2026 test year, the adjustments resulted in a $238.6 million reduction to the total company average plant in service for WEPCO electric, $236.8 million for Wisconsin retail; a $13.2 million reduction to the average natural gas plant in service for WEPCO gas; and a $0.530 million reduction to the average WEPCO steam plant in service. The 2026 test-year electric average CWIP balance increased $105.3 million while the natural gas and steam average CWIP balances decreased $6.7 million and $0.952 million respectively. CUB and Walnut Way supported Commission staff's adjustment.

WEPCO disagreed with Commission staff's methodology including citing that the budget-to-actual methodology does not always result in a lower than 100 percent factor, that the past performance against a forecasted amount is not indicative of the future. In addition, WEPCO stated that Commission staff's "budget-to-actual" adjustment does not account for any 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 WEPCO's electric, natural gas and steam plant in service and CWIP for the 2025 and 2026 test years.

WG Plant in Service and CWIP

Commission staff adjusted the 2023 balance to reflect year-end actuals for plant in service, CWIP, and accumulated depreciation. 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 case; 2015, 2020, and 2023.

The adjustment resulted in a $54.8 million reduction to the 2025 test year average plant in service and a $20.3 million increase to the average CWIP balance. For 2026, the adjustment resulted in a $43.1 million reduction to the average plant in service and a $19.3 million increase to the average CWIP balance. CUB and Walnut Way noted support for Commission staff's adjustment.

WG disagreed with Commission staff's methodology including citing that the budget-to-actual methodology does not always result in a lower than 100 percent factor, that the past performance against a forecasted amount is not indicative of the future. In addition, WG stated that Commission staff's "budget-to-actual" adjustment does not account for any 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 WG's 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.

Badger Hollow II Cost Overrun

WEPCO's acquisition of Badger Hollow II was approved by Final Decision dated March 6, 2020, in docket 5-BS-234.[11] Order Condition 6 stated:

> The Commission, consistent with its past practice, shall review in a future rate case the recoverability of costs associated with the acquisition, O&M costs, and revenues associated with the projects; provided, however, that in no event shall the recoverability of the acquisition costs exceed $194.9 million plus allowance for funds used during construction (AFUDC), and provided, however, that the applicants may include costs associated with AFUDC because the applicants may take ownership of the project prior to construction, and provided that the calculation of AFUDC shall not be based on a cost greater than $194.9 million. The applicants may not earn a current return on CWIP for any costs associated with Badger Hollow II. Notwithstanding the foregoing, the applicants may request in a future rate case recovery of acquisition costs in excess of $194.9 million plus AFUDC in the event that acquisition costs increase as a result of force majeure event (provided, however, that the applicants have provided notice to the Commission within 30 days learning of any such force majeure event(s).) Costs attributable to force majeure events may increase the cost basis for calculation of AFUDC at the Commission's discretion. This exception does not bind the Commission to any specific treatment or recoverability of acquisition costs in any future rate case proceeding.

On July 28, 2022, WEPCO filed a *Force Majeure* Change Order Notice describing two change orders. The two change orders combine for a total cost overrun of $32.0 million. WEPCO cited the following as contributing to the cost overruns:

[11] Final Decision, *Joint Application of Madison Gas and Electric Company and Wisconsin Electric Power Company for Approval to Acquire Ownership Interests in the Badger Hollow II Solar Electric Generating Facility*, Docket 5-BS-234 (Wis. PSC Mar. 6, 2020) (PSC REF#: 385279).

- Global supply chain events which caused price increases for balance of system commodities, including steel;
- Labor market events which led to increases in labor costs; and
- Module market and supply chain issues, which increased costs and delayed shipments.

In the Final Decision on Reopening in docket 5-UR-110, the Commission found it reasonable to defer $10.0 million of cost overruns, without carrying costs, to a future rate proceeding, when all of the project costs could be thoroughly reviewed. (PSC REF#: 487244.) At the time of the Commission's Final Decision on Reopening, Badger Hollow II was not yet in service. Badger Hollow II was placed in service on December 22, 2023.

On September 5, 2023, WEPCO filed a third charge order for a total cost overrun of an additional $13.6 million, citing the implementation of the Uyghur Forced Labor Prevention Act (UFLPA) which contributed to restrictions and delayed importation of modules causing increases in a variety of related project costs, including:

- Extending the duration of developer staff being required on site to manage the project and site during construction to ensure safety of the site and the public;
- Contract staffing costs for additional mobilization and de-mobilization activities;
- Costs to extend warranties of equipment such as inverters, racking systems, and single-axis tracking systems; and
- Additional land owner payments prior to placing Badger Hollow 2 in-service.

In this proceeding, WEPCO requested recovery of $10.8 million in cost overruns. Commission staff removed all revenue requirement impacts related to the cost overruns pending

Commission authorization. This adjustment resulted in a decrease in WEPCO's electric operation by $0.383 million, $0.382 million for Wisconsin Retail, for both the 2025 and 2026 test years.

WEPCO stated that these costs were incapable of prior estimation and outside WEPCO's control and should not be borne by shareholders alone. Additionally, WEPCO stated that if WEPCO did not accept these costs, there would have been a potential delay of commercial operation of the needed generation resources. WEPCO indicated that it and its co-owners aggressively negotiated the change orders, and that the ultimate cost reflect a good-faith, arm's length negotiation and resolution of significant and unexpected problems. WEPCO 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 WEPCO 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 WEPCO only be allowed recovery of the depreciation of the plant associated with the cost overruns.

As noted previously, WEPCO is afforded a presumption that the costs associated with the project are prudent. The Commission finds that the information from WEPCO and Commission staff supports the reasonableness of these costs. While CUB objected to the costs, it did not present substantive evidence of imprudence. While additional detail regarding the events and costs incurred in response thereto could have been more robust, the Commission finds that the record evidence that was presented and not rebutted shows that WEPCO's explanation of the events and responses thereto were reasonable. The Commission recognizes CUB's concerns and affirms the importance of careful scrutiny of project cost overruns in order to protect customers from unreasonable costs. However, in light of the evidence in the record, the Commission finds it reasonable to include all of the identified cost overruns associated with Badger Hollow II in WEPCO's 2025 and 2026 test year electric revenue requirements. The Commission also finds it reasonable to require WEPCO to amortize the regulatory asset balance over the remaining life of the plant.

In the Commission's Final Decision on Reopening in docket 5-UR-110 (PSC REF#: 487244), WEPCO was ordered to defer the incremental revenue requirement impact of the change to the in-service date for Badger Hollow II, with carrying costs at the short-term debt rate, to a future rate proceeding.

Bluff Creek Liquified Natural Gas Project (Bluff Creek LNG) and Ixonia Liquified Natural Gas Project (Ixonia LNG)

The construction authorization for Bluff Creek LNG and Ixonia LNG was approved by the Commission's Final Decision, dated December 21, 2021, in docket 5-CG-106.[12] The estimated cost of the Bluff Creek LNG was $204.8 million including AFUDC. The estimated cost of the Ixonia LNG was $204.3 million including AFUDC.

Order Condition 7 of the Final Decision in docket 5-CG-106 stated:

> If it is discovered or identified that the project cost, including force majeure costs, may exceed the estimated cost by more than 10 percent, the applicants shall notify the Commission within 30 days of when it becomes aware of the possible change or cost increase.

[12] Final Decision, *Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for a Certificate of Authority under Wis. Stat. § 196.49 and Wis. Admin. Code § PSC 133.03 to Construct a System of New Liquefied Natural Gas Facilities and Associated Natural Gas Pipelines near Ixonia and Bluff Creek, Wisconsin*, Docket 5-CG-106 (Wis. PSC Dec. 22, 2021) (PSC REF#: 427782).

Total actual costs for the Bluff Creek LNG filed in quarterly progress reports stated that the project had cost overruns of $7.1 million. The Bluff Creek LNG project was placed in service on November 11, 2023.

Total actual costs for the Ixonia LNG filed in quarterly progress reports stated that the project had cost overruns of $16.8 million. In the Commission's Final Decision on Reopening in docket 5-UR-110 it ordered WG to defer, without carrying costs, the Ixonia LNG cost overruns to a future rate proceeding, when all of the project costs could be thoroughly reviewed. (PSC REF#: 487244.) At the time of the Commission's decision on reopening, the Ixonia LNG was not yet in service. The Ixonia LNG was placed in service on February 1, 2024.

The applicants identified that the cost overruns for the Bluff Creek LNG and the Ixonia LNG were due to a difference between quotes for labor and materials from 2019 and start of construction during the COVID-19 pandemic on January 5, 2022. The applicants further stated that supply chain issues caused by the COVID-19 pandemic and site condition issues for the Ixonia LNG facility resulted in further cost overruns.

Commission staff removed all revenue requirement impacts related to the cost overruns pending Commission authorization. For the Bluff Creek LNG, this adjustment resulted in a decrease in WEPCO's electric operation by $0.631 million and $0.615 million for WEPCO gas operations in 2025 and 2026, respectively. For the Ixonia LNG, the adjustment resulted in a decrease of $0.493 million for WG's revenue requirement in both the 2025 and 2026 test years.

The applicants stated the cost forecasts were "developed prior to the COVID-19 pandemic and costs simply increased when construction commenced nearly two years after the pandemic began" and that these additional costs were prudent investments. (Surrebuttal-WEPCO WG-Zgonc-cr-12.)

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

As noted previously, the applicants are afforded a presumption that the costs associated with the projects are prudent. The Commission finds that the information from the applicants and Commission staff supports the reasonableness of these costs. While CUB objected to the costs, it did not present substantive evidence of imprudence. The Commission finds that the record evidence that was presented and not rebutted shows that applicants' explanation of the events and responses thereto were reasonable. In light of the evidence in the record, the Commission finds it reasonable to include all of the identified cost overruns associated with Bluff Creek LNG in WEPCO's 2025 and 2026 test year natural gas revenue requirements and the cost overruns associated with the Ixonia LNG in WG's 2025 and 2026 test year natural gas revenue requirements.

In the Commission's Final Decision on Reopening in docket 5-UR-110 (PSC REF#: 487244), WG was ordered to defer, without carrying costs, the Ixonia LNG cost overruns to a future rate proceeding. WG stated that these costs were deferred into a regulatory asset as ordered. WG proposed to, beginning in 2025, amortize these costs over the remaining life of the plant. The Commission finds this request reasonable and accepts WG's proposal to amortize the regulatory asset over the remaining life of the underlying plant.

Paris Solar Generating and Battery Energy Storage System (Paris Solar and BESS)

WEPCO'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, WEPCO 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. WEPCO 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, WEPCO and the co-owners of the Paris Solar and BESS notified the Commission that they were proceeding with the BESS component of the project. WEPCO and the co-owners negotiated a new contract price and guaranteed completion date for the BESS component. WEPCO 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. WEPCO 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 WEPCO's electric operation by $12.1 million, $11.8 million for Wisconsin retail; and an increase for WEPCO steam operations by $0.012 million. For the 2026 test year, adjustment resulted in a decrease in WEPCO's electric operation by $15.2 million, $14.9 million for Wisconsin retail; and an increase for WEPCO steam operations by $0.012 million.

WEPCO stated that these costs were incapable of prior estimation and outside WEPCO's control and should not be borne by shareholders alone. Additionally, WEPCO stated that if WEPCO did not accept these costs, there would have been a potential delay of commercial operation of the needed generation resources. WEPCO indicated that it and its co-owners aggressively negotiated the change orders, and that the ultimate cost reflect a good-faith, arm's length negotiation and resolution of significant and unexpected problems. WEPCO 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 WEPCO 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 applicants only be allowed recovery of the depreciation of the plant associated with the cost overruns.

Unlike Badger Hollow II, Bluff Creek LNG and Ixonia LNG, 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. In light of this difference, 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 WEPCO to defer the cost overruns associated with the Paris Solar and BESS, without any carrying costs, to a future rate proceeding. 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.[13]

In the Commission's Final Decision on Reopening in docket 5-UR-110 (PSC REF#: 487244), WEPCO 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 short-term debt rate, to a future rate proceeding. WEPCO identified that the forecasted

[13] *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).

regulatory liability associated with the deferral at the end of 2024 will be $35.8 million and WEPCO 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 WEPCO's next rate proceeding.

Darien Solar and Battery Energy Storage System (Darien Solar and BESS)

WEPCO'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.[14] Order Point 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.

WEPCO's acquisition cost was identified as $338.3 million, excluding AFUDC.

On September 27, 2023, and October 18, 2023, WEPCO 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

[14] 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).

- Additional winter storage and snow removal costs; and,
- Increase cost of spare modules.

WEPCO stated that these costs were incapable of prior estimation and outside WEPCO's control and should not be borne by shareholders alone. Additionally, WEPCO 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 WEPCO's electric operation by $1.7 million, $1.7 million for the Wisconsin retail and an increase in WEPCO steam operations by $0.003 million for the 2025 test year; and a decrease WEPCO electric operations by $1.6 million, $1.5 million for the Wisconsin retail and an increase WEPCO steam operations by $0.012 million for the 2026 test year.

WEPCO 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 WEPCO's prudent investment into these needed and Commission-approved projects. In addition, WEPCO stated that even with added cost overruns the Darien Solar project remains competitive with the levelized costs for more recent solar projects.[15] When faced with force

[15] 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.

majeure notices from the developers, WEPCO 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.

CUB stated the costs should be disallowed because WEPCO 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 WEPCO 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 WEPCO to defer the cost overruns associated with the Darien Solar and BESS, without carrying costs, to a future rate proceeding. Additionally, consistent with the Paris Solar and BESS project, the Commission finds it reasonable to require WEPCO 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 WEPCO's short-term debt rate, to a future rate proceeding.

Michigan Avenue Replacement project

WG planned to file for approval of a Michigan Avenue Replacement project with a planned completion date of December 2025. As the application had not yet been filed, Commission staff removed all revenue requirement impacts pending an application filing and Commission authorization. The adjustment resulted in a decrease to WG's revenue requirement by $0.128 million in 2025 and $0.872 million in 2026.

In subsequent testimony, WG noted the Michigan Avenue Replacement project is projected to cost $8.0 million to construct, which is below the $8.139 million threshold for a Certificate of Authority (CA). WG initially indicated in this docket that it would file for a CA for the Michigan Avenue Replacement project, because it had not incorporated the updated thresholds for a CA approval in its analysis of capital projects. Because the Michigan Avenue Replacement project is below the threshold for a CA, WG contended that the project should be included in WG's revenue requirement for test years 2025 and 2026.

The Commission finds that consistent with past Commission practice, projects that fall under the CA threshold are treated as routine capital expenditures and additions. Therefore, the Commission finds it reasonable to include the increased revenue requirement impacts for the Michigan Avenue Replacement project in WG's 2025 and 2026 test years natural gas revenue requirement.

Paris Reciprocating Internal Combustion Engine (Paris RICE)

WEPCO filed for Commission approval to construct the Paris RICE project, a natural gas electric generating facility in docket 6630-CE-316. As the Commission has not yet authorized this project, Commission staff removed all revenue requirement impacts from the 2025 and 2026 test year plant and CWIP estimates. This adjustment resulted in an increase of $0.646 million for WEPCO electric operations, $0.640 million for Wisconsin retail; a decrease of $0.043 million for WEPCO gas operations; and a decrease for WEPCO steam operations by $0.002 for the 2025 test year. For the 2026 test year the adjustment resulted in a decrease for WEPCO electric operations $17.8 million, $17.4 million for Wisconsin retail; an increase for WEPCO gas operations by $0.165 million; and an increase for WEPCO steam operations by $0.005 million.

WEPCO requested that the Commission should either include the Paris RICE project in rates for test year 2026 or authorize Wisconsin Electric to defer the revenue requirement associated with the Paris RICE project once it is operational.

The Commission notes that as the Paris RICE project has not yet been approved, inclusion of the project cost in revenue requirement would be premature. Therefore, consistent with past Commission practice which does not assume future approvals or denials, the Commission finds it reasonable to exclude the revenue requirement impacts associated with Paris RICE from WEPCO's 2025 and 2026 revenue requirement.

Oak Creek Power Plant (OCPP)

Oak Creek Power Plant (OCPP) Units 7 and 8 are scheduled for retirement in 2025. WEPCO requested Commission approval to recover the remaining net plant balances over the estimated useful life prior to its early retirement. Upon retirement, the net plant balances will move from plant and accumulated depreciation to a regulatory asset. WEPCO proposed to amortize the remaining balance of OCPP Units 7 and 8, and the remaining common plant, starting in January 2026 evenly over 17 years.

Commission staff suggested that the Commission could find WEPCO's request to be reasonable and consistent with prior Commission decisions relating to 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), docket 6680-UR-121 (PSC REF#: 355884), and Pulliam Units 5 and 6 and Weston Unit 1 in its Final Decision in docket 6690-UR-123 (PSC REF#: 226374.)

In docket 5-UR-110 (PSC REF#: 455451) the Commission ordered the applicants to submit additional analysis in its next rate proceeding on alternatives regarding recovery of the remaining useful life of retired OCPP Units, including without limitation an analysis of the levelization of the remaining net book value using a variety of assumptions, additional cost sharing methodologies, and securitization of the full remaining value of environmental controls, and to report back to the Commission on any U.S. Department of Energy (DOE) funding opportunities that may mitigate costs associated with the retirement of the OCPP.

WIEG recommended the recovery of the remaining net book value of OCPP Units 7, and 8 on a levelized basis over a 25-year amortization period and utilizing securitization financing for at least the $443 million in remaining environmental costs.

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 OCPP retirement as this strikes a more reasonable balance than asking customers to pay for everything including a generous shareholder return. CUB further provided 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. If anything, it increases the amount paid by customers, on a nominal dollar basis due to an increase in carrying costs. Extending the levelization period similarly adds to these carrying costs. CUB reaffirmed that it would be appropriate for the Commission to allow the applicants to depreciate the remaining net book value of OCPP once it has been retired, but not allow a return.

WEPCO argued 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 their full costs, including a reasonable return on those costs, may be recovered from customers. Additionally, WEPCO stated that retiring the OCPP units will save customers millions of dollars in O&M costs. WEPCO further 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 and had not identified any precedent for both disallowing a return on retired plant while simultaneously extending and levelizing recovery.

Commission staff identified that WEPCO disclosed a remaining balance of $443 million of undepreciated environmental controls on these units. Customers are currently paying the cost of equity for these out of service or soon to be out of service assets. According to the applicants' analysis, over the remaining 17-year depreciable life of the assets, securitization would reduce the net present value impact to the revenue requirement by $102.2 million when comparing securitization to a levelized cost recovery approach. Securitization would also reduce the net present value impact to the revenue requirement by $117.5 million, when compared to a traditional cost recovery approach.

The Commission expresses disappointment that WEPCO indicated that due to Wisconsin statutory requirements that are interpreted to prohibit the Commission from requiring securitization, it was not willing to pursue securitization in order to save customers costs. The Commission must also respond to WEPCO's suggestion that adopting a non-traditional approach to addressing retired assets, such as the one proposed by CUB, would constitute an unconstitutional taking.[16] 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.

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,

[16] 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.

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, however, the Commission finds that disallowing all carrying costs does not strike the right balance when this decision is considered among the other decisions the Commission is making in this case. Accordingly, consistent with prior Commission decisions regarding early plant retirements, the Commission finds it reasonable in this proceeding for WEPCO to record a regulatory asset for the remaining undepreciated balance for OCPP units scheduled for retirement, and to amortize the balance over the assets remaining useful life of 17 years using a traditional declining balance, with carrying costs on the undepreciated balance at WEPCO's authorized weighted average cost of capital.

Due to the potential change in the actual retirement date compared to the planned retirement date, WIEG recommended the Commission include in its decision an order condition requiring the applicants 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 regarding WP&L's base rate case for the early retirement of Edgewater 5. (PSC REF#: 427760.) By including such an order condition in connection with OCPP Unit 7 and 8, WIEG stated that customers will be protected should WEPCO decide to retire the plant prior to December 31, 2025. WEPCO agreed that it is prudent to allow for the possibility of changes in the retirement date. 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.) Given the potential for change in the retirement date, the Commission also finds it reasonable to require WEPCO to defer the difference between the estimated and actual revenue requirement impact associated with retiring OCPP Units 7 and 8 resulting from changes in the Units' December 2025 retirement date.

Bad Debt

The applicants 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 arrear balances associated with COVID-19. In addition, the applicants 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 17 percent higher than pre-COVID. In addition, the applicants 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 20,000 active customers at any given time when the program started in 2021 to approximately 32,000 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.

Walnut Way recommended that the applicants not be allowed to claim LIFT costs through increased rates as Walnut Way believes the applicants did not demonstrate that the LIFT credits are incremental costs above and beyond the costs that are already included in rates.

Additionally, the applicants requested to recover the 2024 forecast balance from customers in 2026. This would result in an increase in bad debt expense in 2026 from 2025, but only because costs were shifted to 2026 in the interest of mitigating increases in residential customers bills in 2025. Commission staff did not have any concerns with the applicants' request as the balance of the escrow is still forecasted to be zero at the end of 2026. CUB recommended that the Commission direct that the LIFT deferral balance be amortized over a 4-year period instead of two years. The applicants 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 applicants and that in the interest of gradualism, the 2024 forecast balance shall be recovered from customers over two years (2025-2026).

Steam Levelization

WEPCO estimated a revenue requirement deficiency of $2.5 million for its 2025 steam operations and no change for the 2026 test year. At WEPCO's request, and consistent with past Commission practice, Commission staff levelized the 2025 and 2026 test year revenue deficiencies for WEPCO's steam operations to hold 2025 rates flat in 2026. Use of this approach maintains the 2025 authorized rates into 2026 test year, thus avoiding a change to the 2026 steam rates. If this approach is not used, the revenue requirement impact would have been an increase of $0.143 million in the 2025 test year and a decrease of $0.143 million in the 2026 test year.

Consistent with past practice, the Commission finds it reasonable to allow the 2025 and 2026 test year revenue deficiencies for steam operations to be levelized.

Inflation Reduction Act (IRA)

On August 16, 2022, the IRA of 2022 was signed into law. In the Commission's Final Decision in docket 5-UR-110, the Commission ordered the applicants to defer, with carrying costs at the applicants' short-term debt rate, any impacts of the IRA. The applicants requested the Commission continue to authorize the applicants 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 applicants to continue to defer, with carrying costs at the applicants' short-term debt rate, any impacts of the IRA which are currently unknown or unable to be estimated to include in the applicants' revenue requirement. Such a deferral ensures that both the applicants and customers are kept whole related to these tax benefits.

Transmission Expenses

Commission staff proposed adjustments to WEPCO's filed transmission expenses for 2025 and 2026 based on the MISO update for 2025 and 2026 estimated costs for Schedules 26 and 26A on June 12, 2024. The total company impact of these updates was increases of approximately $6.2 million for 2025 and approximately $14.6 million for 2026. In addition, WEPCO provides transmission services to the data center and one other customer. These customers reimburse WEPCO for these transmission costs. This resulted in a decrease of approximately $0.211 million for 2025 and approximately $1.7 million for 2026.

The Commission finds it reasonable to accept Commission staff's adjustments related to transmission expense for the 2025 and 2026 test years.

Distribution-connected utility-owned solar generation and BESS projects and DRER projects

The applicants requested authorization to amortize the acquisition costs related to distribution-connected utility-owned solar generation and BESS projects and DRER projects beginning in 2025 for 25 years, the estimated life of those facilities. The DRER projects are beneath the CA threshold so a separate construction docket will not be filed. Commission staff stated that the Commission could find this request reasonable as it would align the amortization of the acquisition costs with the life of the asset.

The Commission concurs and finds the applicants' request reasonable. The Commission authorizes the amortization of 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.

West Riverside 2

In the Commission's Final Decision in docket 5-UR-110 (PSC REF#: 455451) it ordered the applicants to utilize deferral accounting treatment, with carrying costs at the short-term debt rate, for the cost impacts associated with the proposed acquisition in docket 5-BS-265 (PSC REF#: 461711) for the West Riverside project. The applicants identified that the forecast 2024 deferred ending balance, which also includes the West Riverside 2 as approved in docket 5-BS-273 (PSC REF#: 495982), is estimated to be $19.2 million. The applicants requested to amortize the related acquisition and revenue requirement deferrals over four years to soften the rate pressure associated with collecting the balance in 2025 and 2026. Commission staff did not have any concerns with the applicants' request.

The Commission finds that in the interest of gradualism, spreading the costs over four years as requested by the applicants is reasonable.

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 applicants stated that they intend to adopt the new safe harbor method which would impact the applicants' deferred tax liabilities. At this time the precise impact on the applicants' deferred taxes has not been calculated and is not reflected in the 2025 or 2026 test year revenue requirement.

Commission staff proposed requiring the applicants 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 applicants to defer, with carrying costs at the applicants' 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 applicants' 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 applicants and customers are kept whole.

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

WEPCO identified that through its parent company, WEC Energy Group, that WEPCO along with WPSC are applying for DOE loans or grants, however, no amounts were included in the WEPCO's 2025 or 2026 revenue requirement as no amounts had been awarded yet. WEPCO 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 WEPCO to defer, with or without carrying costs at WEPCO's short term debt rate, the net impact of any loans or grant funds received to be addressed in WEPCO's next full rate proceeding.

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

Bring Your Own Device

The applicants requested deferral accounting treatment for the Bring Your Own Device (BYOD) pilot program. The components of that program are discussed later in this Final Decision. Commission staff did not have concerns with this request. The Commission finds the applicants' 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 applicants' revenue requirement.

Conservation

The applicants proposed electric and natural gas CSC activities for inclusion in their 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 applicants' 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 applicants' proposed CSC activities are appropriate for inclusion in the conservation budget.

The applicants proposed a total conservation budget for 2025 of $60.5 million, with $40.8 million allocated to WEPCO electric operations, $8.2 million allocated to WEPCO natural gas operations, and $11.5 million allocated to WG natural gas operations. Of the $40.8 million for WEPCO electric operations, $35.5 million was for WEPCO's required Focus on Energy (Focus) contribution and $5.3 million was for CSC activities, including voluntary programs. Of the $8.2 million for WEPCO natural gas operations, $6.0 million was for WEPCO's required Focus contribution and $2.2 million was for its CSC activities, including voluntary programs. Of the $11.5 million for WG natural gas operations, $8.7 million was for WG's required Focus contribution and $2.8 million was for its CSC activities, including voluntary programs.

The applicants proposed a total 2026 conservation budget of $64.2 million with $42.9 million allocated to WEPCO electric operations, $8.9 million to WEPCO natural gas operations, and $12.4 million to WG natural gas operations. Of the $42.9 million for WEPCO electric operations, $37.4 million was for WEPCO's required Focus contribution and $5.5 million was for CSC activities, including voluntary programs. Of the $8.9 million for WEPCO natural gas operations, $6.6 million was for WEPCO's required Focus contribution and $2.3 million was for CSC activities, including voluntary programs. Of the $12.4 million for WG natural gas operations, $9.5 million was for WG's required Focus contribution and $2.9 million was for its CSC activities, including voluntary programs.

The Commission finds a reasonable level of expensed conservation costs recoverable in rates for the 2025 test year is $40.8 million for WEPCO electric operations, $8.2 million for WEPCO natural gas operations, and $11.5 million for WG. The Commission finds a reasonable level of expensed conservation costs recoverable in rates for the 2026 test year is $42.9 million for WEPCO electric operations, $8.9 million for WEPCO natural gas operations, and $12.4 million for WG. It is reasonable to direct the applicants 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 applicants sought Commission approval for continued deferral and escrow accounting treatment of several deferrals over a 2-year period, 2025 through 2026 which were not contested by any party and not listed separately as contested for a Commission decision. Therefore, consistent with past Commission practice, the Commission finds it reasonable for the applicants to continue deferral and escrow accounting treatment over the 2-year period, 2025 through 2026, as identified in Appendix J.

Depreciation Study

Based on past Commission practice, large investor-owned utilities had been completing depreciation studies every 5 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 6630-ER-104 (PSC REF#: 401903,) Commission staff had identified that the applicants have not completed a depreciation study since 2014 and the Commission required the applicants to file a depreciation study by June 1, 2021, in its Final Decision. On June 30, 2021, the applicants filed a depreciation study in docket 5-DU-103 requesting that the Commission certify depreciation rates for electric, natural gas, and common utility assets. The Commission issued its Final Decision in docket 5-DU-103 (PSC REF#: 429718) on January 26, 2022, approving the proposed depreciation rates effective as of January 1, 2023. In this proceeding Commission staff recommended the Commission consider setting a date the applicants should file a new depreciation study for the Commission's approval.

The Commission notes that, in line with past commission practice, large investor-owned utilities (IOUs) conducted depreciation studies every five years 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 applicants to file a depreciation study for the Commission's approval within 5 years from the date of the last Final Decision, or no later than January 26, 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. 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 (PSC REF#: 402247) where in its Final Decision, the Commission found it reasonable to require 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 cases in order to avoid changing standards mid-process. To be consistent across utilities, the Commission finds it reasonable to require the applicants and Commission staff, starting in their 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 applicants identified that the 2026 test year impacts are shown as incremental or based on the applicants' requested revenue requirement and deficiency for the 2025 test year. Commission staff has historically presented the revenue requirement and resulting deficiency based on presently authorized rates for both test years given that the first year in a two-year test year rate proceeding has not yet been authorized. In addition, historically the Commission has based its decisions regarding revenue requirement impacts based on using presently 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 are shown using 2024 authorized rates as the basis for the present rates presentation.

Commission staff suggested that the Commission consider identifying its preferred presentation for the second year in a two-year test year rate proceeding at either presenting 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 applicants.

The applicants stated that if the Commission provided any specific direction regarding the presentation of the second year, it should be 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 require both presentations be used by both the applicants 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 applicants to present the second year of a two-year test year rate proceeding as a change from presently authorized rates.

Other Uncontested Audit Adjustments to Revenue Requirement

There were a number of other Commission staff adjustments proposed to the applicants' filed electric, natural gas, and steam revenue requirements that were not contested by any party. The Commission finds these uncontested 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, the Commission authorizes the reflection in the electric, natural gas, and steam revenue requirements for WEPCO and natural gas revenue requirements for WG, the Commission staff adjustments not contested by any party and not listed separately as contested for a Commission decision. Accordingly, per Commission decision, the WEPCO electric, natural gas and steam operations and the WG natural gas operation's 2025 and 2026 test years' operating income statements at present rates which were updated, and which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2025 Test Year:

	WEPCO				
	Electric	**Electric WI Jur**	**Gas**	**Steam**	**WG**
Revenues:	**(000's)**	**(000's)**	**(000's)**	**(000's)**	**(000's)**
Sales Revenue	$ 3,508,646	$ 3,455,979	$ 581,397	$ 29,261	$ 832,123
Opportunity Sales	140,291	136,500	-	-	-
Other Operating Revenues	16,028	15,657	(3,867)	(1,381)	9,393
Total Operating Revenues	3,664,965	3,608,136	577,530	27,880	841,516
O&M Expense:					
Fuel & Purchased Power	1,201,084	1,172,430	-	-	-
Purchased Gas	-	-	302,163	-	409,531
Manufactured Gas Production	-	-	(7)	-	14,278
Other Production	625,577	612,919	-	-	-
Generation Transfer	(9,780)	(9,511)	-	9,780	-
Transmission	394,731	394,611	(530)	-	(1,005)
Gas Supply	-	-	1,437	-	2,399
Gas Storage	-	-	26,689	-	28,833
Distribution	120,759	120,759	24,961	7,653	41,377
Customer Accounts	79,665	79,665	16,938	32	18,176
Customer Service	58,277	58,193	13,608	4	20,076
Sales Expense	-	-	-	-	-
Administrative and General	106,155	104,669	16,476	1,223	23,211
Total O&M Expense	3,175,764	3,124,371	401,735	18,692	556,876
Depr, Decomm, & Amort	420,393	416,177	61,031	3,502	94,409
Regulatory Amortizations	24,401	23,263	847	82	5,204
Taxes Other Than Income Taxes	132,852	129,219	7,066	1,240	10,861
Regulatory Amort-Tax Items	119	118	37	-	57
Income Taxes	(96,966)	(95,990)	12,666	1,131	22,435
Deferred Income Taxes	89,283	88,893	5,337	(425)	9,089
Investment Tax Credits	29,213	28,957	(13)	(5)	(40)
Total Operating Expenses	3,175,763	3,124,371	488,706	24,217	698,890
Net Operating Income	$ 489,202	$ 483,765	$ 88,824	$ 3,663	$ 142,626

2026 Test Year:

	WEPCO				
	Electric	**Electric WI Jur**	**Gas**	**Steam**	**WG**
Revenues:	**(000's)**	**(000's)**	**(000's)**	**(000's)**	**(000's)**
Sales Revenue	$ 3,661,273	$ 3,605,953	$ 614,308	$ 29,544	$ 864,305
Opportunity Sales	102,347	99,571	-	-	-
Other Operating Revenues	15,535	15,188	1,916	(178)	6,302
Total Operating Revenues	3,779,154	3,720,712	616,224	29,366	870,608
O&M Expense:					
Fuel & Purchased Power	1,327,405	1,297,907	-		
Purchased Gas	-	-	332,524	-	440,344
Manufactured Gas Production	-	-	(7)	-	14,279
Other Production	626,393	614,573	-	-	-
Generation Transfer	(10,832)	(10,535)	-	10,832	-
Transmission	461,926	461,803	(530)	-	(1,005)
Gas Supply	-	-	1,489	-	2,475
Gas Storage	-	-	26,827	-	28,929
Distribution	126,189	126,189	25,848	7,808	42,776
Customer Accounts	172,989	172,989	39,776	33	18,494
Customer Service	58,825	58,742	13,795	4	20,296
Sales Expense	-	-	-	-	-
Administrative and General	105,623	104,357	17,112	1,313	23,959
Total O&M Expense	2,868,519	2,826,025	456,834	19,991	590,547
Depr, Decomm, & Amort	398,680	395,381	64,780	3,588	101,495
Regulatory Amortizations	109,060	107,173	847	82	5,204
Taxes Other Than Income Taxes	137,625	134,336	7,897	1,284	11,969
Regulatory Amort-Tax Items	119	118	37	-	57
Income Taxes	(88,484)	(88,414)	10,268	849	20,977
Deferred Income Taxes	19,904	19,832	(758)	(137)	5,728
Investment Tax Credits	(3,136)	(3,113)	(13)	(5)	(40)
Total Operating Expenses	3,442,287	3,391,340	539,892	25,652	735,937
Net Operating Income	$ 336,867	$ 329,372	$ 76,332	$ 3,714	$ 134,671

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 to WEPCO's filed electric, natural gas, and steam, and WG's natural gas average net investment rate bases are appropriate. Accordingly, the estimated 2025 and 2026 WEPCO electric, natural gas, steam and WG natural gas average net investment rate bases, which the Commission finds reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2025 Test Year:

	WEPCO				
	Electric (000's)	**Electric WI Jur (000's)**	**Gas (000's)**	**Steam (000's)**	**WG (000's)**
Plant in Service	$ 12,499,823	$ 12,391,479	$ 2,364,240	$ 127,532	$ 3,527,546
Accum Depreciation	(4,409,393)	(4,368,071)	(821,493)	(63,043)	(1,221,138)
Net Plant in Service	8,090,430	8,023,408	1,542,747	64,489	2,306,407
Fuel Inventory	50,198	48,820	-	-	157
Gas Storage	-	-	32,912	-	42,897
Materials & Supplies Inv	154,653	152,403	17,899	-	6,551
Deferred Taxes	(1,481,461)	(1,467,745)	(218,906)	(9,007)	403,149)
Customer Advances	(43,444)	(43,444)	(2,739)	-	(3,721)
Avg Net Inv Rate Base	$ 6,770,378	$ 6,713,441	$ 1,371,914	$ 55,482	$ 1,949,142

2026 Test Year:

	WEPCO				
	Electric (000's)	**Electric WI Jur (000's)**	**Gas (000's)**	**Steam (000's)**	**WG (000's)**
Plant in Service	$ 12,209,749	$ 12,121,985	$ 2,505,878	$ 130,687	$ 3,718,722
Accum Depreciation	(3,991,409)	(3,963,291)	(871,837)	(65,892)	(1,301,782)
Net Plant In Service	8,218,341	8,158,693	1,634,041	64,795	2,416,940
Fuel Inventory	45,930	44,671	-	-	157
Gas Storage	-	-	35,493	-	46,748
Materials & Supplies Inv	154,653	152,732	17,899	-	6,551
Deferred Taxes	(1,502,615)	(1,489,024)	(229,919)	(8,887)	(417,593)
Customer Advances	(43,444)	(43,444)	(2,739)	-	(3,721)
Avg Net Inv Rate Base	$ 6,872,865	$ 6,823,628	$ 1,454,775	$ 55,908	$ 2,049,082

Financial Capital Structure

Cost of Capital and 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 applicants' financial flexibility and creditworthiness, and its ability to attract new capital, among other principles. As a public utility, the applicants' 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 applicants' regulatory capital structure and cost of capital.

WEPCO 2025	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$ 5,957,814	57.06%	9.80%	5.59%
Preferred Stock	$30,450	0.29%	3.95%	0.01%
Long-Term Debt	$4,223,462	40.45%	4.99%	2.02%
Short-Term Debt	$229,085	2.19%	4.88%	0.11%
Total Utility Capital	$10,440,810	100.00%		7.73%

WEPCO 2026	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$6,932,952	56.54%	9.80%	5.54%
Preferred Stock	$30,450	0.25%	3.95%	0.01%
Long-Term Debt	$5,023,462	40.97%	5.19%	2.13%
Short-Term Debt	$274,698	2.24%	4.27%	0.10%
Total Utility Capital	$12,261,561	100.00%		7.77%

WG 2025	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$1,241,331	52.75%	9.80%	5.17%
Long-Term Debt	$1,020,769	43.37%	4.65%	2.02%
Short-Term Debt	$91,347	3.88%	5.17%	0.20%
Total Utility Capital	$2,353,447	100.00%		7.39%

WG 2026	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$1,302,296	52.76%	9.80%	5.17%
Long-Term Debt	$1,090,000	44.16%	4.91%	2.17%
Short-Term Debt	$76,179	3.09%	4.38%	0.14%
Total Utility Capital	$2,468,475	100.00%		7.48%

As seen in the tables above, a reasonable weighted average cost of capital for WEPCO for the 2025 and 2026 test years is 7.73 percent and 7.77 percent, respectively. It generates an economic cost of capital of 9.83 percent in 2025 and 9.85 percent in 2026; and a pre-tax interest coverage ratio of 4.61 times in 2025 and 4.41 times in 2026. A reasonable weighted average cost of capital for WG for the 2025 and 2026 test years is 7.39 percent and 7.48 percent, respectively. It generates an economic cost of capital of 9.32 percent in 2025 and 9.41 percent in 2026; and a pre-tax interest coverage ratio of 4.20 times in 2025 and 4.13 times in 2026.

Assessing the reasonableness of the applicants' capital structure depends upon three important principles. First, capital structure decisions must be based on the applicants' needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for the applicants and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of the applicants should be similar to typical electric utility dividend practices as long as the applicants is below the estimated test-year common equity ratio.

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 applicants 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 applicants and those of its customers. The applicants, like other Wisconsin IOUs, are making significant, capital-intensive investments to transition their generation fleet and to maintain a reliable infrastructure for customers. The financial integrity of a utility is an important factor in this transition so that it can attract the capital it needs. To date, the strong financial health of these applicants has resulted in their 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 it 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.

Capital Structure – Common Equity Ratio

In this proceeding, the applicants 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 5-UR-110 (PSC REF#: 455451) 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 applicants' prior rate case, docket 5-UR-110. The Commission is not persuaded that there is a sufficient basis for an increase or decrease of applicants' equity ratio. For WEPCO, maintaining a financial common equity ratio of 53.00 percent saves the applicants' customers approximately $3.3 million in 2025 and $3.2 million in 2026 compared to the equity layer increase proposed in the application. For WG, maintaining a financial common equity ratio of 53.00 percent saves the applicants' customers approximately $0.808 million in 2025 and $0.797 million in 2026 compared to the equity layer increase proposed in the application. Therefore, the Commission finds it reasonable to maintain the applicants' financial equity ratio at 53.00 percent for both test years.

Commission staff observed that a financial capital structure of 53.00 percent equity for WEPCO in 2025 and 2026 results in regulatory capital consisting of 57.09 percent equity for 2025 and 56.58 percent for 2026. Commission staff proposed that the Commission consider, as a means of addressing the large regulatory capital structure for WEPCO, implementing an imputed financial capital structure consisting of a 50.50 percent financial equity layer in 2025 and 2026, that results in an imputed regulatory capital structure of 54.39 percent in 2025 and 53.91 percent in 2026. The applicants objected to this proposal.

The Commission does not find there is sufficient evidence in the record before it to support imputing a capital structure of 50.50 percent financial equity to WEPCO. Specifically, the record lacked evidence demonstrating how an imputed capital structure would impact the credit metrics and risk profile of WEPCO. Any departure from the current structure should be justified by clear evidence that gets to the core of the underlying issue. The Commission is not persuaded that aligning WEPCO with other utilities is enough to support this proposal. Therefore, the Commission does not accept Commission staff's proposal and does not impute a capital structure to WEPCO.

Commissioner Hawkins dissents.

Cost of Capital – Return on 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 applicants, Commission staff, and multiple intervenors provided recommendations for the applicants' ROE in this docket. The applicants argued that its ROE should be increased to 10.00 percent. CUB argued for a 9.30 percent ROE. Walmart and the City of Milwaukee argued that a ROE of 10.00 percent and 9.80 percent, respectively, was too high but did not provide specific recommendations. Commission staff presented a range from 8.66 percent to 10.09 percent for WEPCO and 8.67 percent to 10.03 percent for WG.

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.

Cost of Capital – Short-Term Debt

WEPCO's filing in this proceeding forecasted a short-term debt cost rate of 4.88 percent on $195.9 million in 2025 and a cost rate of 4.27 percent on $214.0 million in 2026. WG's filing in this proceeding forecasted a short-term debt cost rate of 5.17 percent on $89.9 million in 2025 and a cost rate of 4.38 percent on $72.7 million in 2026. Commission staff estimated short-term cost rates of 5.21 percent for WEPCO in 2025 and 4.44 percent in 2026. Commission staff estimated short-term cost rates of 5.33 percent for WG in 2025 and 4.51 percent in 2026.

For WEPCO, the Commission finds the average cost of short-term debt of 4.88 percent and 4.27 percent for the 2025 and 2026 test years, respectively to be reasonable. For WG, the Commission finds the average cost of short-term debt of 5.17 percent and 4.38 percent for the 2025 and 2026 test years, respectively to be reasonable.

Cost of Capital – Long-Term Debt

The Commission considered competing proposals from the applicants and Commission staff regarding the applicants' forecasted embedded cost of long-term debt in the test years. The applicants 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 applicants' credit rating, for their proposal.

The Commission is persuaded by Commission staff's perspective and finds it reasonable to reduce the applicants' forecast for long-term debt to be issued in the test year to an interest rate of 5.75 percent. Therefore, a reasonable estimate for the WEPCO's embedded cost of long-term debt is 4.99 percent on $4,223.5 million for 2025 and 5.19 percent on $5,023.5 million for 2026. A reasonable estimate for the WG's embedded cost of long-term debt is 4.65 percent on $1,020.8 million for 2025 and 4.91 percent on $1,090.0 million for 2026. However, the Commission declines to further reduce the applicants' forecast based on recent news of interest rate reductions by the Federal Reserve.

Docket 5-UR-111

In this docket Commission staff reviewed the previous two rate cases filed by the applicants in order to determine whether the applicants 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 WEPCO. Commission staff recommended that the Commission consider a new order point that would require the applicants 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 staff's proposal but recommended the carrying costs be set equal to 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 WEPCO, Commission staff, and intervenors regarding this proposal as a first step.

While considering the applicants' forecasting and issuing behavior for long-term debt, the Commission believes that additional information from the applicants is needed regarding any unintended consequences of Commission staff's proposed order condition to defer the applicants' 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 applicants to provide, in its next rate proceeding, 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.

Earnings Sharing Mechanism

The Commission may use a variety of tools, including ESMs, 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 applicants and other IOUs have voluntarily offered to have such mechanisms in place. In this rate proceeding the applicants proposed to keep the ESM authorized in docket 5-UR-110 (PSC REF#: 455451) in place for the test years. Commission staff analysis showed that under the current ESM, the applicants over earning their authorized ROE would have resulted in a refund to customers in 6 of the last 10 years.

Under this ESM, the applicants retained all earnings less than or equal to 15 basis points above authorized ROE, the applicants were required to return to customers an amount equal to 50.00 percent of earnings between 15 and 75 basis points above authorized ROE, and the applicants were required to return to customers an amount equal to 100 percent of earnings equal to or in excess of 75 basis points above the authorized ROE.

CUB suggested modifying the ESM for WEPCO to lower the threshold at which 100 percent of earnings above the authorized ROE are returned to customers to 40 basis points over the authorized ROE instead of 75 basis points. CUB argued that its suggested modification to the revenue sharing mechanism would account for uncertainty regarding Microsoft. A WEC windfall could result from assuming a market-based Electronics and Information Technology Manufacturing (EITM) rate for Microsoft in the test years when Microsoft ultimately taking service under Cp-1. Thus, a modified ESM might be more just and reasonable, considering both investor and customer perspectives. CUB did not extend this suggestion to WG and recommended a continuation of WG's current ESM which was uncontested.

The applicants argued that there was no basis to modify the ESM, which was the result of a negotiated settlement, and no basis for the Commission to conclude the ESM does not protect customers with respect to changes in Microsoft's current demand forecast.

The Commission is persuaded by CUB's argument and finds CUB's proposal offers protections for customers. Further, the Commission's decision is not directly influenced by the new customer rate, rather it is based on prior revenue figures showing earnings above the authorized level and reflects a broader view of the proposal's reasonableness given the overall case. Therefore, in addition to setting an ROE of 9.80 percent, the Commission finds it is reasonable to impose an ESM on WEPCO. 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. Under the ESM, WEPCO shall retain all earnings less than or equal to 15 basis points above authorized ROE, return to customers an amount equal to 50.00 percent of earnings between 15 and 40 basis points above authorized ROE, and return to customers an amount equal to 100 percent of earnings equal to or in excess of 40 basis points above the authorized ROE. This ESM provides a balance that allows investors to benefit from an earned ROE that is above the authorized 9.80 percent while protecting customers from bearing the cost of excessive overearning.

Chairperson Strand dissents.

In addition to setting an ROE of 9.80 percent, the Commission also finds it reasonable to imposes an ESM on WG. 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. Under the ESM, WG shall retain all earnings less than or equal to 15 basis points above authorized ROE, return to customers an amount equal to 50.00 percent of earnings between 15 and 75 basis points above authorized ROE, and return to customers an amount equal to 100 percent of earnings equal to or in excess of 75 basis points above the authorized ROE. This ESM provides a balance that allows investors to benefit from an earned ROE that is above the authorized 9.80 percent while protecting customers from bearing the cost of excessive overearning.

Off-Balance-Sheet Financial Obligations

Off-balance-sheet financial obligations (OBOs) 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 OBOs affect the financial risks and credit ratings of the utility, the Commission includes imputed debt associated with OBOs in calculating the applicants' financial capital structure.[17] The imputed debt results in additional costs to customers, 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

[17] 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.

utility. However, if additional common equity is included 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 applicants' financial capital structure. This information is most readily available from the applicants and shall be provided as part of its next rate proceeding.

The information shall include, at a minimum, all of the following information:

1. The minimum annual lease and 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 S&P 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.

For WEPCO, the Commission finds it reasonable to impute $810.0 million for OBOs for 2025 and $829.0 million for 2026. WG had no OBOs.

Dividend Restriction

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 applicants' dividend restriction shall match the dividend restrictions of the other Wisconsin jurisdictional operating utilities within the WEC holding company. The applicants 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 applicants 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.

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 WEPCO'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 89.39 percent and 88.37 percent, respectively. The estimate of the WG'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 86.53 percent and 87.37 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	Electric WI Jur	Natural Gas	Steam	WG
Cost of Capital	7.73%	7.73%	7.73%	7.73%	7.39%
Ratio of Average Percent of Utility Investment Rate Base to Capital Applicable Primarily to Utility Operations	89.39%	89.39%	89.39%	89.39%	86.53%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Net Investment Rate Base	8.65%	8.65%	8.65%	8.65%	8.54%
Total Average CWIP Balances (000’s)	981,330	981,330	107,698	(1,554)	45,659
Percent of CWIP Receiving Current Return	5.50%	5.50%	2.20%	56.80%	35.20%
Amount of CWIP Receiving Current Return (000’s)	54,447	54,447	2,372	(883)	16,067
Current Earnings on CWIP Receiving Current Return at the Adjusted Cost of Capital	4,708	4,710	205	(76)	1,372
Average Net Investment Rate Base (000’s)	6,770,378	6,713,441	1,371,914	55,482	1,949,142
Adjustment to Required Return to Provide a Return on CWIP	0.07%	0.07%	0.01%	-0.14%	0.07%
Earnings on Regulatory Items at Specified Rate	3,360	3,360	0.00%	0.00%	0.00%
Regulatory Items at Specified Rate	0.05%	0.05%	-	-	-
Adjusted Required Return on Net Investment Rate Base	8.77%	8.77%	8.66%	8.51%	8.61%

2026 Test Year:

	Electric Total Co	Electric WI Jur	Natural Gas	Steam	WG
Cost of Capital	7.77%	7.77%	7.77%	7.77%	7.48%
Ratio of Average Percent of Utility Investment Rate Base to Capital Applicable Primarily to Utility Operations	88.37%	88.37%	88.37%	88.37%	87.37%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Net Investment Rate Base	8.80%	8.80%	8.80%	8.80%	8.56%
Total Average CWIP Balances (000's)	2,043,112	2,389,848	349,729	(3,002)	70,159
Percent of CWIP Receiving Current Return	2.70%	2.33%	0.32%	55.26%	26.10%
Amount of CWIP Receiving Current Return (000's)	55,694	55,694	1,122	(1,659)	18,291
Current Earnings on CWIP Receiving Current Return at the Adjusted Cost of Capital	4,899	4,899	99	(146)	1,565
Average Net Investment Rate Base (000's)	6,872,865	6,823,628	1,454,775	55,908	2,041,207
Adjustment to Required Return to Provide a Return on CWIP	0.07%	0.07%	0.01%	-0.26%	0.08%
Earnings on Regulatory Items at Specified Rate	3,809	3,809	0.00%	0.00%	0.00%
Regulatory Items at Specified Rate	0.06%	0.06%	-	-	-
Adjusted Required Return on Net Investment Rate Base	8.92%	8.92%	8.80%	8.54%	8.63%

Calculation of Deficiencies

On the basis of the findings in this Final Decision, a $144.0 million and $313.5 million increase in WEPCO Wisconsin retail electric utility revenues are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively. For WEPCO natural gas operations, a $41.3 million and $71.1 million increase in natural gas utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively. For WEPCO steam operations, a $1.5 million and $1.5 million increase in steam utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively. For WG natural gas operations, a $34.5 million and $58.0 million increase in natural gas utility revenues, are reasonable for the purpose of determining reasonable and just rates for 2025 and 2026, respectively. These increases are computed as follows:

2025 Test Year:

	Electric Total Co	Electric WI Jur	Natural Gas	Steam	WG
Adjusted Net Operating Income at Present Rates (000's)	$489,202	$483,765	$88,825	$3,663	$142,626
Average Net Investment Rate Base (000's)	$6,770,378	$6,713,441	$1,371,914	$55,482	$1,949,142
Return on Average Net Investment Rate Base at Present Rates	7.23%	7.21%	6.47%	6.60%	7.32%
Required Return on Average Net Investment Rate Base	8.77%	8.77%	8.66%	8.51%	8.61%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.54%	1.56%	2.19%	1.91%	1.29%
Earnings Deficiency on Average Net Investment Rate Base (000's)	$104,327	$104,773	$30,015	$1,058	$25,135
Tax Gross-up Factor	1.3744	1.3744	1.3744	1.3744	1.3744
Revised Revenue Deficiency (000's)	$143,387	$144,000	$41,253	$1,454	$34,546
Required Percentage Rate Increase	4.09%	4.17%	7.10%	4.97%	4.15%

2026 Test Year:

	Electric Total Co	Electric WI Jur	Natural Gas	Steam	WG
Adjusted Net Operating Income at Present Rates (000's)	$ 336,867	$ 329,372	$ 76,333	$ 3,714	$ 134,671
Average Net Investment Rate Base (000's)	$6,872,865	$6,823,628	$1,454,775	$ 55,908	$2,049,082
Return on Average Net Investment Rate Base at Present Rates	4.90%	4.83%	5.25%	6.64%	6.57%
Required Return on Average Net Investment Rate Base	8.92%	8.92%	8.80%	8.54%	8.63%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	4.02%	4.10%	3.56%	1.89%	2.06%
Earnings Deficiency on Average Net Investment Rate Base (000's)	$ 276,405	$ 279,507	$ 51,734	$ 1,058	$ 42,207
Tax Gross-up Factor	1.3744	1.3744	1.3744	1.3744	1.3744
Adjustment to Monitored Fuel at 2025 $/MWh	(72,638)	(70,647)	-	-	-
Revised Revenue Deficiency (000's)	$ 307,253	$ 313,507	$ 71,103	$ 1,454	$ 58,009
Required Percentage Rate Increase	8.39%	8.69%	11.57%	4.92%	6.71%

Electric Cost of Service, Revenue Allocation and Rates

2025 and 2026 Electric Cost of Service

WEPCO, intervenors, and Commission staff provided testimony regarding electric cost of service and the appropriate allocation methods for the allocation of plant and expenses that make up the applicants' revenue requirement for the 2025 and 2026 test years. WEPCO proposed a COSS model that uses the applicants-preferred assumptions for COSS. At the request of Commission staff, WEPCO prepared a range of COSS models for Commission consideration. These models covered a variety of different allocations including the 12 coincident peak (CP) and 4-CP production allocators, and demand/energy splits for production plant. WEPCO 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 Capacity TOU (12-CP) and Capacity Basic Customer (12-CP) COSS 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 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 studies in the record for the purposes of class revenue requirement allocation for the 2025 and 2026 test years.

WEPCO also testified that it added new customer classes to its electric class COSS representing its services for a dedicated renewable energy rider; other renewable premiums, including energy for tomorrow and renewable pathways; and a general primary other group. The "general primary other" customer group is assigned to the large customer class and reflects the service provided to large users. The Commission finds it reasonable to authorize WEPCO's proposed changes to the customer classes in its electric COSS to reflect its current array of customer classes more accurately.

Electric Revenue Allocation – 2025 Test Year

WEPCO, CUB, WIEG, Walmart, and Commission staff provided testimony on electric revenue allocation for the 2025 test year. WEPCO, WIEG, CUB, and Commission staff each provided a revenue allocation proposal. WEPCO's revenue allocation was based on WEPCO's originally filed test year revenue requirement. It recovered approximately $239.6 million, which translates to an increase of 6.94 percent over current retail electric tariff revenues. WIEG, CUB, and Commission staff offered alternative revenue allocations reflecting Commission staff's adjustment to WEPCO's test year revenue requirement. Commission staff proposed an alternative electric revenue allocation for the 2025 test year that recovers approximately $134.7 million, or 3.89 percent, above WEPCO's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2025 test year at a 3.9 percent overall increase, 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 WEPCO and Commission staff. Given the residential affordability challenges noted in this proceeding, CUB offered two electric revenue allocation proposals for the 2025 test year (CUB Proposed A and

CUB Proposed B) at a 3.89 percent overall increase, these allocations generally allocated smaller increases to the residential customer classes and larger increases to the primary service customer 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 customer 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 proposed by Commission staff, as proposed in Ex.-PSC-Nye-1 and as adjusted for the final revenue requirement, and shown in Appendix B. The Commission finds that this allocation facilitates a reasonable approach to rate design as this allocation follows the directionality of the COSS and promotes gradualism.

Electric Revenue Allocation – 2026 Test Year

WEPCO, CUB, WIEG, Walmart, and Commission staff provided testimony on electric revenue allocation for the 2026 test year. WEPCO, WIEG, CUB, and Commission staff each provided a revenue allocation proposal. WEPCO, WIEG, and CUB provided revenue allocations for 2026 using its 2025 proposed revenues as a starting point, while Commission staff used 2024 revenues. WEPCO's revenue allocation was based on WEPCO's originally filed test year revenue requirement. It recovered approximately $183.6 million, which translates to an increase of 4.78 percent over the proposed 2025 retail electric tariff revenues. WIEG, CUB, and Commission staff offered alternative revenue allocations reflecting Commission staff's adjustment to WEPCO's test year revenue requirement. Commission staff's proposed electric revenue allocation for the 2026 test year recovers approximately $303.2 million, or 8.41 percent, above WEPCO's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2026 test year at a 4.50 percent overall increase, 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 WEPCO and Commission staff. Given the residential affordability challenges noted in this proceeding, CUB offered two electric revenue allocation proposals for the 2026 test year (CUB Proposed A and CUB Proposed B) at a 4.51 percent overall increase.

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 customer 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 proposed by Commission staff, as proposed in Ex.-PSC-Nye-2 and as adjusted for the final revenue requirement, and shown in Appendix C. The Commission finds that this allocation facilitates a reasonable approach to rate design as this allocation follows the directionality of the COSS and promotes gradualism.

Electric Customer Rates and Tariff Changes

Overall Rate Design

WEPCO and Commission staff provided comprehensive electric rate design proposals that include rates for all customer classes. The comprehensive rate designs proposed by WEPCO and Commission staff share some similarities, but Commission staff's proposed rate design offers a gradual approach to the overall increase to all customer classes, considering limiting rate shocks where possible. The Commission generally chooses one of the comprehensive electric rate design proposals in addition to making separate decisions on specific rate design sub-issues. The Commission finds that a gradual approach to the overall increases to all customer classes contained in the rate design proposed by Commission staff, as modified by the Commission determinations in the above sections of this Final Decision, is reasonable and consistent with the Commission's other decisions regarding revenue allocation.

Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed by Commission staff in Ex.-PSC-Nye-1 for the 2025 test year and Ex.-PSC-Nye-2r for the 2026 test year, adjusted for final revenue requirement. The authorized rates appear in Appendices B and C. The Commission directs WEPCO to file final form tariff sheet consistent with those rates.

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

- Modifying the rate structure of the Cg-3 class, increasing the demand-related charges for the Cg-3 customer class;
- Fully phasing-in the Cp-1 High-Load Factor Credit;
- Modifying the rate structure of the Cp-1 class, applying the entire increase allocated to the Cp-1 customer class to the demand charges;
- Adopting the proposed credit mechanism changes to the Cp-1 tariff in regard to sewage wastewater treatment facilities in SIC 4952;

- Development of a BYOD demand response pilot;
- Development of an EV-R pilot program;
- Adopting the proposed changes to the EV-C program;
- Expansion of one or more parallel generation tariffs;
- Adopting the proposed modifications to the standard net meter tariff (CGS-NM);
- Adopting the proposed modifications to the standard net meter tariff (CGS-CU);
- Increasing the Real Time Market Pricing rider participation cap to 500 MW;
- Clarifying its annual deadline related to firm demand nominations;
- Continuation of and development of LIFT; and
- Other miscellaneous tariff clarifications or alterations.

Rate Structure of the Cg-3 Class

Walmart and Roundy's proposed altering the existing rate structure of the Cg-3 class by lowering energy charges and increasing demand-related charges. Walmart and Roundy's stated that this proposal would alter the cost recovery of the Cg-3 rates to more accurately reflect how those costs are incurred to the utility. WEPCO responded by suggesting that any changes to the Cg-3 rate design should be made in moderation and accompanied by corresponding changes to the Cp-1 rate design to prevent price discrepancies.

The Commission continues to believe gradualism is important in rate design. Large changes in demand-related charges, such as those proposed by Walmart and Roundy's, 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-3 as proposed by Commission staff given its adherence to general rate design principles and more gradual application of changes.

High-Load Factor Credit

Order Condition 8 in the Commission's Final Decision in docket 5-UR-110[18] required WEPCO to offer a high load factor credit for the Cp-1 class, at a phased-in credit value of $0.01/kWh. WEPCO initially proposed to continue to offer the high-load factor credit at the phased in value that was authorized in docket 5-UR-110. WIEG proposed to fully phase-in the credit, suggesting a more rapid implementation of the incentive. WEPCO responded to WIEG's request, stating that it is not opposed to fully phasing in the high load factor credit, and provided additional information on what the full value of that credit would be. WEPCO also commented that should the credit be fully implemented, other rate components of the Cp-1 class would need adjusting such that the class still achieves the desired revenue allocation and that it may be more appropriate to fully phase this credit in over the next two years to moderate the impacts to customers.

The Commission does not find it reasonable to fully phase in the High Load Factor Credit, as WEPCO did not provide the robust analysis on customer impacts resulting from the credit that was requested in the prior rate case proceeding, docket 5-UR-110. Therefore, the Commission finds it reasonable to order WEPCO 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 WEPCO's next rate proceeding.

[18] See Final Decision in docket 5-UR-110. (PSC REF#: 455451.)

Rate Structure of the Cp-1 Class

WIEG proposed applying the entire increase allocated to the Cp-1 customer class to the demand charges. WEPCO responded that this could lead to additional revenue collection from Cp customers, unrelated to the general rate increase. WEPCO estimated that applying the entire increase to demand charges could result in a substantial 30 percent increase in Cp-1 primary billed on-peak demand rates over two years. WEPCO also suggested adjusting energy rates to balance the demand charge increase and maintain revenue targets. The Commission is concerned that the full adjustment could negatively impact low load factor customers and notes the lack of comprehensive analysis on how WIEG's proposal might affect other customers. Absent additional analysis, the Commission prefers a gradual approach to the demand rate adjustment, aligning with Commission staff's rate design. Therefore, the Commission finds the Cp-1 rate design proposed by Commission staff to be reasonable.

Credit Mechanism Changes to the Cp-1 Tariff in Regard to Sewage Wastewater Treatment Facilities in SIC 4952

WEPCO proposed modifications to the existing Cp-1 customer demand charge limitation provision established in docket 5-UR-110. These proposed modifications would convert the limitation into a credit mechanism. WEPCO proposed a credit system based on monthly demands used for billing. WEPCO explained qualifying accounts with operations categorized under Standard Industry Classification (SIC) code 4952 and a billed customer maximum demand of 4 MW or more would receive credits on their monthly bills. These credits would consist of 25 percent of the billed on-peak demand rate established for the 2025 test year, increasing to 50 percent for the 2026 test year and 25 percent of the customer demand charge rate established for both the 2025 and 2026 test years. WEPCO stated specific credit amounts per kW would be reflected in the final approved tariff language. Milwaukee Metropolitan Sewerage District (MMSD) commented in support of this proposal and provided additional evidence of MMSD's unique load shape to support the conclusion that the proposed rate design variant is reasonable and appropriate. MMSD noted that the proposed changes are consistent with the Commission's practices and are designed to ensure just and reasonable rates for all customers. Commission staff commented that the Commission could consider whether the proposed credit mechanism is the most effective way to address the cost recovery concerns and whether the proposed criteria for qualifying for the credit is appropriate. No other parties raised concerns about the proposals. Therefore, the Commission finds it reasonable to authorize WEPCO's proposed credit mechanism changes to the Cp-1 tariff in regard to customers with operations that are categorized under SIC code 4952.

BYOD Demand Response Pilot

WEPCO proposed to implement a BYOD demand response pilot program, an optional service available to residential electric customers served on schedules Rg-1 and Rg-2 with central air conditioning. Participating customers would provide WEPCO with the ability to remotely control their devices during high electricity demand periods in order to reduce overall demand. The Commission has previously approved a BYOD pilot for MGE, which has shown to be a generally successful program[19].

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

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

- Has WEPCO 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 WEPCO to add a customer battery storage option in the proposed BYOD program?

WEPCO did not provide the 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 WEPCO 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. WEPCO stated they have no plan for vendor selection at this time, though they expect 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 WEPCO 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 WEPCO to select a vendor with the ability to expand the program to other clean energy technologies, like battery storage, in the future.

WEPCO, Vote Solar, CUB, and RENEW provided testimony on WEPCO's proposed participation limit of 7,000 devices for the proposed BYOD program. WEPCO 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 WEPCO gains experience with such a pilot. Vote Solar proposed a capacity cap of 64,000, which they stated is scaled to the size of WEPCO's service territory and sales.

WEPCO requested an effective date of January 1, 2026, citing a one-year implementation timeline. WEPCO 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 WEPCO intend to promote the program after they have 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 WEPCO's BYOD program with a bumped-up implementation date for the 2025 cooling season.

WEPCO, Vote Solar, CUB, and RENEW provided testimony on WEPCO'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. WEPCO argued that inclusion of customer battery storage as an option is premature, as WEPCO 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 program limit to 64,000 devices on the basis that the higher cap would improve cost effectiveness of the program. The Commission notes that WEPCO's larger size warrants a higher participation limit than that proposed for MGE. Additionally, the Commission finds it reasonable to authorize WEPCO's proposed implementation date of January 1, 2026. While an earlier date might benefit some, as noted by WEPCO, a 2025 date is not feasible. The Commission does not find it reasonable to require WEPCO to include a customer battery 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 WEPCO to submit a report containing the following information within one year of the effective date of the Final Decision in this docket:

1. Details on the vendor that was selected, why said vendor was selected, and which vendors were not selected;
2. Detailed information on all costs associated with offering this program under the chosen vendor;
3. What data are available for collection under the chosen vendor;
4. Details on how the chosen vendor will protect the privacy of participating customers;
5. Anticipated benefits from offering this program and how those benefits will be measured;
6. How participating customers will interact with WEPCO and chosen vendor;

7. Provide an updated tariff sheet with rates based on the costs associated with the chosen vendor;
8. An anticipated timeline for when customers will be able to enroll on the program once a vendor is chosen; and
9. Information on program evaluation including what entity will conduct an evaluation, what aspects of the program WEPCO will evaluate and by what metrics, and the frequency throughout the year with which evaluations will occur.

In addition, the Commission finds it reasonable to require WEPCO 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, WEPCO shall also report on its efforts to collaborate with interested stakeholders regarding potential modifications or extensions to the BYOD program. Additionally, WEPCO 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 WEPCO's implementation of FERC Order No. 2222.

Residential Electric Vehicle Proposal

WEPCO 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 WEPCO's current COEV-R and WHEV-R pilot programs. WEPCO 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. WEPCO, 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. RENEW and WEPCO both commented that the proposed program would not be discriminatory.

WEPCO, CUB, RENEW, and Commission staff provided testimony on WEPCO'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 WEPCO to develop an EV charging pilot for multifamily housing?
- Is it reasonable to direct WEPCO to develop a program to support fleet and public transportation in low income and environmental justice communities, and explicitly track the costs of its promotion of transportation electrification?

WEPCO 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. WEPCO 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, Commission staff proposed a 400 kWh monthly cap.

Commission staff and RENEW commented on WEPCO's current proposal, which does not include 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 WEPCO explore other mandatory off-peak charging windows and penalties for charging during peak times.

WEPCO, RENEW, and Commission staff commented on the plan for verifying that a customer owns and uses an electric vehicle. WEPCO 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. RENEW and WEPCO 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 WEPCO 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. WEPCO 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.

Walnut Way proposed the Commission direct WEPCO to focus on public and fleet transportation initiatives in low-income communities, develop a program to support fleet and public transportation in environmental justice communities, and explicitly track the costs of its promotion of transportation electrification.

The Commission finds it reasonable to approve WEPCO'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 WEPCO 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 WEPCO's next rate proceeding. The Commission approves WEPCO'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 WEPCO to develop an EV charging pilot for multifamily housing or public and fleet transportation initiatives for low-income customers 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 WEPCO 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 WEPCO 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, WEPCO shall also include in its report information on its collaboration with stakeholders regarding modifications and expansions to the program, including but not limited to multifamily solutions and public and fleet transportation initiatives for low-income customers. The Commission also finds it reasonable to require WEPCO to report on these collaboration efforts in a follow up report in WEPCO'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 WEPCO's COEV-R and WHEV-R tariffs.

Commercial Electric Vehicle Proposal

WEPCO 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 WEPCO; and eliminating the program's pilot status and thus removing the 100 MW enrollment cap.

WEPCO, RENEW, Walmart and Commission staff commented on the proposal to raise the minimum required commercial EV charging installation size from 50 kW to 150 kW. WEPCO noted that the those falling in the 50–150 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. Walmart was in favor of WEPCO's proposal, as it promotes EV charging infrastructure.

The Commission finds it reasonable to increase 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 concerns about customers in the 50 to 150 kW range, the Commission directs WEPCO 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.

WEPCO and Commission staff commented on the proposal to remove the option for customers to purchase charging equipment directly from WEPCO. WEPCO cited a lack of customer interest as the impetus for this proposal. Neither Commission staff nor any other parties raised any issues with this proposal. The Commission finds it reasonable to remove the option for customers to purchase charging equipment directly from WEPCO given the demonstrated lack of interest from customers regarding this option.

WEPCO and Commission staff commented on WEPCO'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 removing the 100 MW 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.

Expansion of One or More Parallel Generation Tariffs

Vote Solar proposed the following changes to WEPCO's parallel generation offerings:

- Require WEPCO 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 $0.01139/kWh, based on the utility's marginal cost of service calculation and consistent with the Commission's prior practice, or $0.01133/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 WEPCO to review ATC schedules and charges, review its own ATC invoices, and propose actual buyback rates to replace the $0 "placeholder" value in WEPCO'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 case. Thus, the Commission finds it reasonable to direct WEPCO to address the proposed changes in a new TE docket to be opened by Commission staff by April 1, 2025.

Proposed Modifications to Customer-Owned Generation Tariffs

Proposed Modifications to The Standard Net Meter Tariff (CGS-CU)

RENEW proposed to increase the capacity cap on the CGS-CU tariff from 1,000 kW to 5,000 kW, noting that raising the capacity cap would bring WEPCO in-line with other Wisconsin utilities and provide Wisconsin businesses with opportunities to meet their sustainability and energy independence goals. WIEG and Vote Solar supported RENEW's proposal. The Commission finds it reasonable to increase the capacity cap on the CGS-CU 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.

Proposed Modifications to The Standard Net Meter Tariff (CGS-NM)

WEPCO and RENEW provided testimony on several proposed changes to the CGS-NM tariff including: WEPCO's proposal to offer bi-directional metering for their standard net meter tariff (CGS-NM) and the appropriate implementation date for the proposed CGS-NM tariff.

The Commission's December 29, 2022 Final Decision in docket 5-UR-110 mandated that WEPCO develop a plan to offer parallel generation customers the option of installing bi-directional meters where technically feasible.[20] This plan was due from WEPCO by itss next rate proceeding. In response, WEPCO proposed modifying the standard net meter tariff (CGS-NM) to provide customers with three metering options: series metering (the current standard), parallel metering, and a single bi-directional meter. All three options involve netting consumption and generation kilowatt-hours before applying pricing. The Commission finds WEPCO's proposed modifications to the standard net meter tariff (CGS-NM) are reasonable and in line with the requirements of the Final Decision in docket 5-UR-110.

WEPCO requested an effective date of January 1, 2026, in order to allow for the design, development, testing, and training necessary to offer this new option to CGS-NM customers. RENEW proposed the Commission require WEPCO implement the proposed tariff on January 1, 2025, rather than the January 1, 2026, date WEPCO proposed. WEPCO later stated that the earliest that the bidirectional meter option could be available for new interconnection applications on or after June 1, 2025. Therefore, the Commission finds June 1, 2025, is a reasonable implementation date, which WEPCO indicated was the earliest achievable timeline.

Increasing the Real Time Market Pricing Rider Participation Cap to 500 MW

WEPCO requested an increase in the participation limit for its Real Time Market Pricing Rider Participation (RTMP) service from 300 MW to 500 MW due to ongoing economic development in southeastern Wisconsin, which they believe will create additional demand for the RTMP service. Commission staff did not raise concerns regarding the proposal. The Commission finds WEPCO's proposal to increase the Real Time Market Pricing rider participation cap to 500 MW to be reasonable.

[20] See Final Decision in docket 5-UR-110. (PSC REF#: 455451.)

Renewable Pathway Premium

WEPCO proposed to increase the Renewable Pathway Premium rate, raising the premium from $0.00717 per kWh to $0.01768 per kWh for one-year subscriptions, and from $0.00531 per kWh to $0.01582 per kWh for five-year subscriptions. This proposed increase is based on updated data from the 2025 cost-of-service analysis and renewable facility costs. Neither Commission staff nor any other parties raised any issues with this proposal. Therefore, the Commission finds it reasonable to authorize the uncontested electric rate design proposal and increase the Renewable Pathway Premium rate.

Clarifying its Annual Deadline Related to Firm Demand Nominations

WEPCO proposed to clarify its annual deadline for firm demand nominations. WEPCO proposed this change to obtain the necessary information for registering its forecasted amount of demand response load with MISO. WEPCO has suggested setting a new deadline of January 15th each year for customers to submit any changes to their firm demand nominations, and to incorporate this deadline into the Cp-3 (Industrial Rate Schedule), Cp-3S (Seasonal Industrial Rate Schedule), Cg-3C (Commercial Rate Schedule with Customer-Controlled Interruption), and Cg-3S (Seasonal Commercial Rate Schedule with Customer-Controlled Interruption) rate schedules. The proposal aims to ensure that WEPCO can register its forecasted demand response load with MISO in a timely manner. Commission staff did not identify any concerns with this proposal and CUB and Walmart did not take a position. The Commission finds it reasonable for WEPCO to add language clarifying its annual deadline related to firm demand nominations.

Other Miscellaneous Tariff Clarifications or Alterations

WEPCO proposed numerous other minor changes (other than pricing changes). WEPCO's proposed changes include 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 WEPCO. The Commission finds it reasonable to approve the miscellaneous electric rate sheet changes as proposed by WEPCO.

Additionally, WIEG requested several updates and changes to various tariffs. Amongst the requests from WIEG, several were responded to by the applicants and Commission staff. The Commission ultimately finds that several smaller updates that were broadly supported are reasonable to authorize, including:

- Ordering WEPCO to conduct an updated and comprehensive loss study before or as part of its next rate proceeding.
- Eliminating WEPCO's experimental productivity rider (STPR) tarrif's prohibition on on-site generation
- Revising the real-time market pricing rider (RTMP) tariff to incorporate a conjunctive billing provision, similar to the Cp-1 tariff.

Uncontested Rate Design Proposals

WEPCO proposed several modifications to other tariffs which were not opposed by any interested parties. These issues included: WEPCO's proposed update and clarification on dishonored payment charges and WEPCO's revised notification and load control mechanisms for demand response. Neither Commission staff nor any other parties raised any issues with these proposals. The Commission finds it reasonable to authorize the uncontested electric rate design proposals.

Steam Cost of Service and Rates

Steam Revenue Allocation and Rate Design

WEPCO proposed a steam revenue allocation and rate design for the 2025 test year, and Commission staff filed an updated rate design for Commission staff's revenue requirement that largely mirrored the initial filing of WEPCO. WEPCO does not have an incremental increase between the 2025 and 2026 test years due to the Commission's decision on levelizing the 2025 and 2026 test year revenue deficiencies. Thus, Commission staff only offered a rate design for the 2025 test year, as no change is needed for the 2026 test year. The overall steam increase is 5.7 percent for the 2025 test year. WEPCO's proposed steam revenue allocations and rate designs were supported by Commission staff, and the Commission finds that the steam revenue allocations and rate designs proposed by Commission staff are reasonable. Additionally, the Commission finds that the uncontested issue of a new calculated base cost of fuel, as proposed by Commission staff, is reasonable. The steam revenue allocations and rate designs, including the development of base cost of fuel rates, appear in Appendix H.

Natural Gas Cost of Service, Revenue Allocations and Rate Designs

2025 and 2026 Natural Gas Cost of Service

The applicants and Commission staff provided testimony regarding natural gas COSS methodology. The applicants prepared COSS results, COSS A and COSS B, using parameters established by Commission staff. The applicants supported the use of multiple COSS models, recognizing a spectrum of allocation positions. Commission staff and CUB also supported the use of multiple COSS models, while WIEG opposed this approach. WIEG argued that the proposed models would unfairly shift costs from residential customers to larger transportation customers.

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 applicants, WIEG, CUB, and Commission staff provided testimony on the natural gas revenue allocations for the 2025 test year. Both the applicants and Commission staff provided comprehensive revenue allocation proposals for both WEPCO and WG natural gas. The applicants' revenue allocations were based on the applicants' originally filed test year revenue requirement. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicants' test year revenue requirement. Commission staff developed natural gas rates for the 2025 test year that recover approximately $37.2 million, or 6.39 percent, above WEPCO natural gas' margin revenue at present rates, and approximately $30.64 million, or 3.68 percent, above the WG's margin revenue at present rates.

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 rate setting goals, including gradualism in ratemaking. The Commission finds it reasonable to approve the natural gas revenue allocation for WEPCO natural gas initially proposed by Commission staff, as shown in Ex.-PSC-Nye-5 and as adjusted for the final revenue requirement, as shown in Appendix D. The Commission also finds it reasonable to approve the natural gas revenue allocation for WG initially proposed by Commission staff, as shown in Ex.-PSC-Nye-3 and as adjusted for the final revenue requirement, as shown in Appendix F. The Commission finds that these allocations follow the directionality of the COSS and promotes gradualism.

Natural Gas Revenue Allocation – 2026 Test Year

The applicants, CUB, WIEG, and Commission staff provided testimony on the natural gas revenue allocations for the 2026 test year. Both the applicants and Commission staff provided comprehensive revenue allocation proposals for both WEPCO and WG natural gas. The applicants' revenue allocations were based on the applicants' originally filed test year revenue requirement. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicants' test year revenue requirement. Commission staff developed natural gas rates for the 2026 test year that recover approximately $66.54 million, or 10.80 percent, above WEPCO natural gas' margin revenue at present rates, and approximately $53.22 million, or 6.15 percent, above the WG's margin revenue at present rates.

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 rate setting goals, including gradualism in ratemaking. The Commission finds it reasonable to approve the natural gas revenue allocation for WEPCO natural gas initially proposed by Commission staff, as shown in Ex.-PSC-Nye-6 and as adjusted for the final revenue requirement, as shown in

Appendix E. The Commission also finds it reasonable to approve the natural gas revenue allocation for WG initially proposed by Commission staff, as shown in Ex.-PSC-Nye-4 and as adjusted for the final revenue requirement, as shown in Appendix G. The Commission finds that these allocations follow the directionality of the COSS and promotes gradualism.

Natural Gas Rate Designs

Natural Gas Overall Rate Designs– 2025 Test Year

The applicants and Commission staff provided comprehensive natural gas rate design proposals for both WG and WEPCO natural gas for the 2025 test year that include rates for all customer classes. 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.

Commission staff largely preserved the rate design proposed by the applicants and made adjustments to distribution rates to achieve the offered revenue allocation. Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed for WEPCO natural gas by Commission staff in Ex.-PSC- Nye-5 for the 2025 test year, adjusted for final revenue requirement. The Commission also finds it reasonable to accept the comprehensive rate design proposed for WG by Commission staff in Ex.-PSC- Nye-3 for the 2025 test year, adjusted for final revenue requirement. The authorized rates appear in Appendices D and F.

Natural Gas Overall Rate Designs– 2026 Test Year

The applicants and Commission staff provided comprehensive natural gas rate design proposals for both WEPCO and WG natural gas for the 2026 test year that include rates for all customer classes. 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.

Commission staff largely preserved the rate design proposed by the applicants and made adjustments to distribution rates to achieve the offered revenue allocation. Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed for WEPCO natural gas by Commission staff in Ex.-PSC- Nye-6 for the 2026 test year, adjusted for final revenue requirement. The Commission also finds it reasonable to accept the comprehensive rate design proposed for WG by Commission staff in Ex.-PSC- Nye-4 for the 2026 test year, adjusted for final revenue requirement. The authorized rates appear in Appendices E and G.

The applicants' authorized rates as set forth in Appendices D through G 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 through G. 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 through G also shows some typical natural gas bills for the applicants' residential service, comparing existing rates with new rates, including the cost of natural gas.

Uncontested Rate Design Proposals

The applicants' proposed an update and clarification on dishonored payment charges, which was not opposed by any interested parties. Commission staff found the aforementioned proposal reasonable and notes that the change did not warrant concern. No other parties raised concerns about the proposal. Therefore, the Commission finds it reasonable to authorize the uncontested natural gas rate design proposal.

Electric and Natural Gas Tariff Issues

NSF Charges

Commission staff requested the applicants to break down the components of its NSF charge. The applicants responded that it was comprised of the applicants' 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 applicants of $12.74 or the administrative cost added to the average of the range of financial institution fees of $7.24. In direct testimony of Walnut Way witness Roger Colton, Walnut Way requested the that applicants NSF fee should be disapproved as lacking any foundation, let alone a cost-based foundation. The Commission indicated 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 consider cost disparities between physical and remote disconnections and reconnections in a future proceeding.

Affordability of Utility Services

Order Condition 15 in the Commission's December 29, 2022, Final Decision in docket 5-UR-110, stated:

> It is reasonable that the applicants shall work with, Commission staff, CUB, and other interested groups in developing alternative low-income assistance programs, including a potential Percentage of Income Payment Pilot, and a docket to investigate the development of such programs shall be opened by the Commission no later than April 1, 2023.

(PSC REF#: 455451)

A Notice of Investigation creating docket 5-UI-121 was issued by the Commission on March 16, 2023. (PSC REF#: 461997.) Discussions and meetings with the applicants, Commission staff, CUB, and other interested groups on the development of alternative low-income assistance programs, including a potential Percentage of Income Payment Pilot (PIPP), have been ongoing and evolving.

In docket 5-AF-107, the Commission's Final Decision found, "It is reasonable for the parties to negotiate on modifications to expand availability of the applicants' low-income payment plans." (PSC REF#: 421294.) This resulted in the creation and implementation of the applicants' Low-Income Forgiveness Tool (LIFT). Order Condition 14 from the Final Decision in docket 5-UR-110, stated:

> The applicants shall extend the current LIFT program and provide additional details regarding the program in separate TE/TG docket filings by the applicants. In those dockets, there shall also be a comprehensive review of the applicants' customer service rules/procedures, including the applicants' policy regarding $600 down payments for reconnection of low-income customer accounts.

A Notice of Investigation creating docket 5-TU-100 was issued by the Commission on June 22, 2023. (PSC REF#: 471143.) The Commission issued a Final Decision in this docket on February 28, 2024. (PSC REF#: 492295.) The applicants' implementation of modifications to LIFT is being monitored in docket 5-TU-100.

In this proceeding, there was participation by broad stakeholder groups continuing to raise concerns related to the applicants' service affordability. Walnut Way also challenged the applicants' compliance with the Commission's prior directives to the applicants to create alternative low-income programs and proposed that the Commission order interim remedial measures including imposing a date certain by which an alternative low-income program design be presented. Walnut Way and CUB proposed modifications to the LIFT program.

CUB proposed that the Commission require the applicants to provide, as part of its initial filings in its next rate case, 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.

Walnut Way recommended that the applicants make modifications to the LIFT program, including:

- Adopting a program of proving tiered bill credits for income eligible LIFT participants.
- Reducing the level of arrears required to be part of the program from $300 to $120.
- Extending LIFT program eligibility to any customer who has, within the immediately preceding twelve months, received benefits through the federal Supplemental Nutrition Assistance Program (SNAP)
- Removing the LIFT program eligibility criterion requiring a customer to have received at least one Energy Assistance Program (EAP) grant in the current or previous program year.

The Commission recognizes that work is on-going in Commission docket 5-UI-121 and 5-TU-100. 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 applicants' revenue requirements. Therefore, the Commission finds it reasonable to require the applicants to continue to work with staff on identifying and including additional reporting data for the LIFT program for inclusion in the initial filing for the applicants' next rate proceeding.

The Commission appreciates the various proposals presented by Walnut Way. These and other proposals require further analysis which must take into account the specific statutory authority the Commission has. While the Commission does not find that the applicants are in violation of its prior order points, the Commission encourages the applicants to continue to work with Commission staff and interested parties in these active dockets to assess performance of the existing LIFT program, potential modifications to LIFT, and consideration of other alternative programs. The Commission strongly encourages the applicants to prioritize this work, be responsive to involved parties, and move as quickly as possible toward a solution.

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 applicants' 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 134.05 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 applicants shall revise its existing rates and tariff provisions 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 applicants shall revise its existing rates and tariff provisions for electric, natural gas, and steam utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B, C, D, E, F, G, and H 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 applicants shall prepare bill messages that properly identify the rates authorized in this Final Decision. The applicants shall provide the messages to customers no later than the first billing containing the rates authorized in this Final Decision and shall file copies of these bill messages with the Commission before it provides the messages to customers.

5. The applicants shall file tariffs consistent with this Final Decision.

6. WEPCO shall implement the comprehensive electric rate design proposed by the applicants, as modified, and conditioned by this Final Decision.

7. WEPCO shall implement the rate design for the Cg-3 customer class as proposed by Commission staff.

8. WEPCO 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.

9. WEPCO shall implement the rate design for the Cp-1 customer class as proposed by Commission staff.

10. WEPCO shall implement the credit mechanism changes to the Cp-1 tariff in regard to sewage wastewater treatment facilities in SIC 4952.

11. WEPCO shall implement the Bring Your Own Device (BYOD) demand response pilot, with the modifications and conditions noted in this Final Decision.

12. WEPCO 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.

13. WEPCO shall file a report on the EV-R pilot containing the information identified in this Final Decision on year from the effective date of this Final Decision.

14. WEPCO shall report 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 WEPCO's next rate proceeding.

15. WEPCO shall implement the changes to WEPCO's EV-C pilot program, with the modifications noted in this Final Decision.

16. WEPCO shall investigate changes to its parallel generation tariffs in a separate TE docket to be opened no later than April 1, 2025.

17. WEPCO shall increase the capacity cap on the CGS-CU tariff from 1,000 kW to 5,000 kW.

18. WEPCO shall offer bi-directional metering and change the implementation date to June 1, 2025, for the proposed CGS-NM tariff.

19. WEPCO shall increase the Real Time Market Pricing rider participation cap from 300 MW to 500 MW.

20. WEPCO shall increase the Renewable Pathway Premium rate from $0.00717 per kWh to $0.01768 per kWh for one-year subscriptions and from $0.00531 per kWh to $0.01582 per kWh for five-year subscriptions.

21. WEPCO shall add language clarifying its annual deadline for firm demand nominations to the Cp-3, Cp3S, Cg-3C, and Cg-3S tariffs.

22. WEPCO shall update its electric rate sheets with the proposed minor administrative changes and clarifications.

23. WEPCO shall update its clarification on dishonored payment charges and revised notification and load control mechanisms for demand response.

24. WEPCO shall implement the comprehensive natural gas rate design for WEPCO gas operations as proposed by Commission staff in Ex.-PSC-Nye-5 and Ex.-PSC-Nye-6, as adjusted for final revenue requirement, for the 2025 and 2026 test years respectively.

25. WG shall implement the comprehensive natural gas rate design as proposed by Commission staff in Ex.-PSC-Nye-3 and Ex.-PSC-Nye-4, as adjusted for final revenue requirement, for the 2025 and 2026 test years respectively.

26. The applicants shall eliminate the incremental deterrence component of the NSF change and update the charge to $7.24, which is consist of the administrative cost added to the average of the range of financial institution fees.

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

28. WEPCO shall update the applicants' base cost of fuel for steam service consistent with Ex.-PSC-Nye-7.

29. WEPCO shall update the rate changes for steam service as shown in Appendix H.

30. WEPCO shall conduct an updated and comprehensive loss study before or as part of its next rate proceeding.

31. WEPCO shall eliminate its experimental productivity rider's prohibition on on-site generation.

32. WEPCO shall revise the real-time market pricing rider to incorporate a conjunctive billing provision, similar to the Cp-1 tariff.

33. WEPCO shall make the other electric and natural gas tariff changes discussed in this Final Decision.

34. The electric fuel costs in Appendix I shall be used for monitoring of the applicants' 2025 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

35. 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).

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

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

38. The applicants 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 applicants intend to seek recovery in that proceeding.

39. The applicants 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.

40. WEPCO 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 shall 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 applicants' 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 EAB Infested hazard trees removed by project and cost for such hazard tree removal.

41. WEPCO shall file a Storm Hardening Program pre-construction report in docket 5-UR-111, no later than the first quarter of each year beginning in 2025, and a post-construction report, no later than the second quarter of each year beginning in 2025. This report shall include the following information: (1) Number, identification, year approved, and timeline for project; (2) Pre-construction report with the 3-year average SAIFI and SAIDI performance and expected level of reliability improvement for all relevant project areas; (3) Details of the progress made during the previous year, status of projects pending from earlier years, and the progress made

to-date under this O&M item; (4) Comparison of total budgeted and actual annual cost; and (5) Post-construction project area SAIFI and SAIDI level improvements for individual projects.

42. WEPCO's shall amortize the regulatory asset balance associated with Badger Hollow II over the remaining life of the plant.

43. WG shall amortize the regulatory asset balance associated with Ixonia LNG over the remaining life of the plant.

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

45. WEPCO shall 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 require a true-up in WEPCO's next rate proceeding.

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

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

48. WEPCO shall recover any undepreciated balance for Oak Creek Power Plant (OCPP) units 7 and 8 scheduled for retirement over 17 years using a traditional declining balance, and to authorize carrying costs on the undepreciated balance at WEPCO's authorized weighted average cost of capital, as proposed by WEPCO.

49. WEPCO shall utilize deferral accounting treatment to capture the differences between the estimated and actual revenue requirement impacts associated with retiring Oak Creek Power Plant 7 and 8 resulting from a change in the units' December 2025 retirement date.

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

51. The applicants 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.

52. WEPCO shall amortize the related acquisition and revenue requirement deferrals for West Riverside over four years.

53. The applicants shall defer, with carrying costs at the applicants' authorized short-term debt rate, any impacts for the U.S Internal Revenue Service Revenue Procedure 2023-15.

54. The applicants to defer, with carrying costs at the applicants' authorized short-term debt rate, the net impact of any loans or grant funds from programs through the U.S. Department of Energy.

55. WEPCO shall utilize deferral accounting treatment for its BYOD pilot program.

56. WEPCO electric shall record annual conservation escrow expense of $40.8 million and $42.9 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 amortization expense to be recorded.

57. WEPCO gas shall record annual conservation escrow expense of $8.2 million and $8.9 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 amortization expense to be recorded.

58. WG shall record annual conservation escrow expense of $11.5 million and $12.4 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 amortization expense to be recorded.

59. The applicants shall amortize and include the revenue requirement impacts of the regulatory assets and regulatory liability amortizations as detailed in Appendix J, for all items listed for 2025 and 2026, or until the Commission authorizes a different amortization expense to be recorded.

60. The applicants shall file a depreciation study no later than January 26, 2027.

61. The applicants 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.

62. The applicants shall present the second year of a 2-year test year rate proceeding as a change from presently authorized rates.

63. The applicants 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.

64. The applicants shall submit, in the 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.

65. Effective January 1, 2025, WEPCO shall implement and ESM for the 2025 and 2026 test years. In determining earnings subject to the ESM, WEPCO shall measure the ROE on a fuel rule basis under Wis. Admin. Code ch. PSC 116. Under the ESM, WEPCO shall retain all earnings less than or equal to 15 basis points above authorized ROE, return to customers an amount equal to 50.00 percent of earnings between 15 and 40 basis points above authorized ROE, and return to customers an amount equal to 100 percent of earnings equal to or in excess of 40 basis points above the authorized ROE.

66. The ESM for WG, as approved in docket 5-UR-110 shall remain in place until the applicants' next rate proceeding.

67. The applicants shall submit a 10-year financial forecast in its next rate case.

68. The applicants shall submit, in its next rate proceeding application, 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 incremental impact associated with debt that is forecasted but not issued to be returned to customers.

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

70. 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.

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

72. Jurisdiction is retained.

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

By the Commission:

Cru Stubley
Secretary to the Commission

CS:JAM:arw:dsa DL:02037648

Attachments

See attached Notice of Rights

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

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

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

PETITION FOR REHEARING

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

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[21] 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

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

APPENDIX A

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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	7,623,957	$1,491,470,389	$1,580,731,748	5.98%		
Fg1	139,073	$25,818,791	$27,447,318	6.31%		
Rg2	224,724	$35,941,424	$38,230,243	6.37%		
Total Residential & Farm	7,987,754	$1,553,230,604	$1,646,409,309	6.00%		
Cg1	1,678,138	$282,214,358	$297,291,526	5.34%		
Cg6	114,283	$17,971,897	$18,088,957	0.65%		
TE1 & TE2	164	$33,476	$34,952	4.41%		
TSS	4,837	$911,891	$955,429	4.77%		
Total Small General Secondary	1,797,422	$301,131,623	$316,370,864	5.06%		
Total Small Customer Class	**9,785,176**	**$1,854,362,227**	**$1,962,780,173**	**5.85%**		
Cg2	**1,464,868**	**$206,158,065**	**$211,467,193**	**2.58%**		
Cg3	5,292,980	$680,524,191	$696,197,601	2.30%		
Cg3C	30,709	$3,613,545	$3,698,255	2.34%		
Cg3S	10,664	$1,403,848	$1,440,895	2.64%		
Total Large General Secondary	5,334,353	$685,541,584	$701,336,751	2.30%		
Total General Secondary	8,596,643	$1,192,831,272	$1,229,174,807	3.05%		
Cp1 Low	199,454	$23,070,820	$23,583,376	2.22%		
Cp1 Medium	4,288,258	$460,425,616	$468,886,992	1.84%		
Cp1 High	45,330	$4,576,551	$4,682,785	2.32%		
Cp3 Medium	411,046	$45,826,572	$47,425,041	3.49%		
Cp3S Low	7,641	$826,692	$856,952	3.66%		
Cp3S Medium	47,165	$5,367,103	$5,565,094	3.69%		
CpFN Medium	382,531	$34,586,995	$35,853,396	3.66%		
CpFN High	95,633	$8,544,150	$8,924,784	4.45%		
RTMP	804,153	$30,135,919	$30,893,248	2.51%		
RTP	388,216	$18,033,245	$18,033,554	0.00%		
Total General Primary	6,669,428	$631,393,663	$644,705,222	2.11%		
Gen Pri Other	532,932	$48,385,160	$48,385,160	0.00%		
Total Large Customer Class	**12,536,714**	**$1,365,320,407**	**$1,394,427,133**	**2.13%**		
Gl1	18,732	$5,208,060	$5,478,643	5.20%		
St1 & St2	48,105	$4,786,934	$5,011,745	4.70%		
Al1	2,726	$707,354	$741,374	4.81%		
Ms1	1,729	$363,143	$378,307	4.18%		
Ms2	4,450	$663,274	$700,742	5.65%		
Ms3	26,353	$6,225,968	$6,513,622	4.62%		
Ms4	12,389	$4,450,678	$4,665,031	4.82%		
LED	6,806	$5,331,193	$5,412,667	1.53%		
Mg1	66	$10,823	$11,421	5.52%		
Total Street Lighting & Other	**121,357**	**$27,747,428**	**$28,913,551**	4.20%		
COEV-R	0	$75,312	$75,312	0.00%		
WHEV-R	0	$1,392	$1,392	0.00%		
EV-C	0	$88,440	$88,440	0.00%		
Total EV Customer Class	**0**	**$165,144**	**$165,144**	0.00%		
RPP1		$125,475	$125,475	0.00%		
RPP5		$507,507	$507,507	0.00%		
DRER		$615,596	$615,596	0.00%		
EFT - Residential		$574,029	$574,029	0.00%		
EFT - C&I Small		$282,164	$282,164	0.00%		
EFT - C&I Large		$120,963	$120,963	0.00%		
Total Misc Customer Class		**$2,225,734**	**$2,225,734**	0.00%		
Total Wisconsin Retail	**23,908,114**	**$3,455,979,005**	**$3,599,978,928**	**4.17%**	**$3,599,978,518**	$409

Electric Rate Design - Test Year 2025

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	372,448,920	$0.49315	$183,673,185	372,448,920	$0.49315	$183,673,185	0.00%
Three PH per day	137,240	$0.49315	$67,680	137,240	$0.49315	$67,680	0.00%
Extra Meter per day	594,585	$0.05951	$35,384	594,585	$0.05951	$35,384	0.00%
Energy charge	7,622,628,189	$0.17154	$1,307,585,640	7,622,628,189	$0.18325	$1,396,846,616	6.83%
Fuel cost adjustment	7,622,628,189	$0.00000	$0	7,622,628,189	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,169,486	-$0.00176	-$5,578	3,169,486	-$0.00191	-$6,054	8.52%
Total Revenue: Residential Flat Rate - Rg1			**$1,491,356,310**			**$1,580,616,810**	
Farm Flat Rate - Fg1							
Customer charge							
Single PH per day	3,748,300	$0.49315	$1,848,474	3,748,300	$0.49315	$1,848,474	0.00%
Three PH per day	201,780	$0.49315	$99,508	201,780	$0.49315	$99,508	0.00%
Extra Meter per day	242,360	$0.05951	$14,423	242,360	$0.05951	$14,423	0.00%
Energy charge	139,073,300	$0.17154	$23,856,634	139,073,300	$0.18325	$25,485,182	6.83%
Fuel cost adjustment	139,073,300	$0.00000	$0	139,073,300	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	140,904	-$0.00176	-$248	140,904	-$0.00191	-$269	8.52%
Total Revenue: Farm Flat Rate - Fg1			**$25,818,791**			**$27,447,318**	
Residential Small TOU - Rg2							
Customer charge							
Single PH per day	5,480,501	$0.49315	$2,702,709	5,480,501	$0.49315	$2,702,709	0.00%
Three PH per day	14,965	$0.49315	$7,380	14,965	$0.49315	$7,380	0.00%
Extra Meter per day	133,225	$0.05951	$7,928	133,225	$0.05951	$7,928	0.00%
Energy charge							
On-peak	73,232,310	$0.23382	$17,123,179	73,232,310	$0.27006	$19,777,118	15.50%
Off-peak	151,491,577	$0.10628	$16,100,525	151,491,577	$0.10387	$15,735,430	-2.27%
Fuel cost adjustment							
Adjustment	224,723,887	$0.00000	$0	224,723,887	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	168,392	-$0.00176	-$296	168,392	-$0.00191	-$322	8.52%
Total Revenue: Residential Small TOU - Rg2			**$35,941,424**			**$38,230,243**	

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Residential Charger Only EV - COEV-R							
Fixed service and administration charge							
Bundled service per month	3,324	$20.00000	$66,480	3,324	$20.00000	$66,480	0.00%
Pre-paid service per month	1,104	$8.00000	$8,832	1,104	$8.00000	$8,832	0.00%
Energy charge							
On-peak (summer)	26,568	$0.28733	$7,634	26,568	$0.30694	$8,155	6.83%
On-peak (non-summer)	26,568	$0.18007	$4,784	26,568	$0.18325	$4,869	1.76%
Intermediate-peak (summer)	39,852	$0.18007	$7,176	39,852	$0.18325	$7,303	1.76%
Intermediate-peak (non-summer)	39,852	$0.18007	$7,176	39,852	$0.18325	$7,303	1.76%
Off-peak (summer)	597,756	$0.07303	$43,654	597,756	$0.07303	$43,654	0.00%
Off-peak (non-summer)	597,756	$0.07303	$43,654	597,756	$0.07303	$43,654	0.00%
Fuel cost adjustment	1,328,352	$0.00000	$0	1,328,352	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Charger Only EV - COEV-R			**$189,391**			**$190,249**	
Total Fixed Charge Revenue: Residential Charger Only EV - COEV-R			$75,312			$75,312	
Residential Whole Home EV - WHEV-R							
Fixed service and administration charge							
Bundled service per month	60	$20.00000	$1,200	60	$20.00000	$1,200	0.00%
Pre-paid service per month	24	$8.00000	$192	24	$8.00000	$192	0.00%
Total Revenue: Residential Whole Home EV - WHEV-R			**$1,392**			**$1,392**	
Commercial Electric Vehicle EV-C							
Fixed service and administration charge							
Bundled-single port, per month per port A	884	$24.00000	$21,216	884	$24.00000	$21,216	0.00%
Bundled-single port, per month per port B	849	$25.00000	$21,216	849	$25.00000	$21,216	0.00%
Bundled-single port, per month per port C	881	$25.00000	$22,032	881	$25.00000	$22,032	0.00%
Bundled-dual port, per month per port A	299	$26.00000	$7,776	299	$26.00000	$7,776	0.00%
Bundled-dual port, per month per port B	312	$26.00000	$8,100	312	$26.00000	$8,100	0.00%
Bundled-dual port, per month per port C	300	$27.00000	$8,100	300	$27.00000	$8,100	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			**$88,440**			**$88,440**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Secondary Flat Rate - Cg1							
Customer charge							
Single PH per day	24,656,080	$0.49315	$12,159,146	24,656,080	$0.49315	$12,159,146	0.00%
Three PH per day	10,889,059	$0.49315	$5,369,939	10,889,059	$0.49315	$5,369,939	0.00%
Extra Meter per day	6,032,355	$0.05951	$358,985	6,032,355	$0.05951	$358,985	0.00%
Energy charge	1,678,137,747	$0.15759	$264,457,728	1,678,137,747	$0.16659	$279,560,967	5.71%
Fuel cost adjustment	1,678,137,747	$0.00000	$0	1,678,137,747	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	84,103,607	-$0.00227	-$190,915	84,103,607	-$0.00258	-$216,987	13.66%
Act 141 capped contribution	84,103,607	$0.00071	$59,475	84,103,607	$0.00071	$59,475	0.00%
Total Revenue: General Secondary Flat Rate - Cg1			**$282,214,358**			**$297,291,526**	
General Secondary Small TOU - Cg6							
Customer charge							
Single PH per day	2,193,208	$0.49315	$1,081,581	2,193,208	$0.49315	$1,081,581	0.00%
Three PH per day	142,348	$0.49315	$70,199	142,348	$0.49315	$70,199	0.00%
Extra Meter per day	180,675	$0.05951	$10,752	180,675	$0.05951	$10,752	0.00%
Energy charge							
On-peak	37,361,675	$0.23324	$8,714,237	37,361,675	$0.25388	$9,485,382	8.85%
Off-peak	76,920,990	$0.10601	$8,154,394	76,920,990	$0.09765	$7,511,335	-7.89%
Fuel cost adjustment							
Adjustment	114,282,665	$0.00000	$0	114,282,665	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	35,566,029	-$0.00227	-$80,735	35,566,029	-$0.00258	-$91,760	13.66%
Act 141 capped contribution	35,566,029	$0.00060	$21,469	35,566,029	$0.00060	$21,469	0.00%
Total Revenue: General Secondary Small TOU - Cg6			**$17,971,897**			**$18,088,957**	
General Secondary Transmission Substations - TSSM & TSSU							
Customer charge							
TSSM Single PH per day	13,870	$0.49315	$6,840	13,870	$0.49315	$6,840	0.00%
TSSM Three PH per day	0	$0.49315	$0	0	$0.49315	$0	0.00%
TSSU Customer charge per month	33,580	$4.25000	$142,715	33,580	$4.25000	$142,715	0.00%
TSSM Extra Meter per day	0	$0.05951	$0	0	$0.05951	$0	0.00%
Energy charge							
TSSM annual	702,350	$0.15759	$110,683	702,350	$0.16659	$117,004	5.71%
TSSU annual	4,135,117	$0.15759	$651,653	4,135,117	$0.16659	$688,869	5.71%
Fuel cost adjustment	4,837,467	$0.00000	$0	4,837,467	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00258	$0	13.66%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Transmission Substations - TSSM & TSSU			**$911,891**			**$955,429**	

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
General Secondary Small TOU Demand - Cg2							
Customer charge							
Customer charge per day	3,216,664	$1.32000	$4,245,996	3,216,664	$1.32000	$4,245,996	0.00%
Extra Meter per day	3,763,515	$0.18542	$697,831	3,763,515	$0.18542	$697,831	0.00%
Energy charge							
On-peak	657,711,642	$0.12625	$83,036,095	657,711,642	$0.12782	$84,068,702	1.24%
Off-peak	807,156,306	$0.09018	$72,789,356	807,156,306	$0.09130	$73,693,371	1.24%
Demand charge							
On-peak minimum	1,374,070	$2.98400	$4,100,225	1,374,070	$3.20700	$4,406,642	7.47%
On-peak adjusted	397,081	$4.79900	$1,905,592	397,081	$5.15700	$2,047,747	7.46%
On-peak regular	3,532,091	$7.78300	$27,490,264	3,532,091	$8.36400	$29,542,409	7.46%
Customer maximum	4,906,162	$2.46000	$12,069,159	4,906,162	$2.64400	$12,971,892	7.48%
Fuel cost adjustment							
Adjustment	1,464,867,948	$0.00000	$0	1,464,867,948	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	99,824,755	-$0.00227	-$226,602	99,824,755	-$0.00258	-$257,548	13.66%
Act 141 capped contribution	99,824,755	$0.00050	$50,150	99,824,755	$0.00050	$50,150	0.00%
Total Revenue: General Secondary Small TOU Demand - Cg2			**$206,158,065**			**$211,467,193**	
General Secondary Large TOU - Cg3							
Customer charge							
Customer charge per day	2,244,972	$2.00000	$4,489,944	2,244,972	$2.00000	$4,489,944	0.00%
Extra Meter per day	1,540,665	$0.20000	$308,133	1,540,665	$0.20000	$308,133	0.00%
Energy charge							
On-peak	2,255,553,547	$0.09057	$204,285,485	2,255,553,547	$0.08969	$202,300,598	-0.97%
Off-peak	3,037,426,146	$0.05660	$171,918,320	3,037,426,146	$0.05511	$167,392,555	-2.63%
		$1.60018			$1.62747		1.71%
Demand charge							
On-peak minimum	1,113,642	$7.29900	$8,128,473	1,113,642	$7.84400	$8,735,408	7.47%
On-peak adjusted	305,345	$11.01400	$3,363,070	305,345	$11.83700	$3,614,369	7.47%
On-peak regular	12,866,304	$18.31300	$235,620,625	12,866,304	$19.68100	$253,221,729	7.47%
Customer maximum	17,734,397	$3.07500	$54,533,271	17,734,397	$3.30500	$58,612,182	7.48%
Fuel cost adjustment							
Adjustment	5,292,979,693	$0.00000	$0	5,292,979,693	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,142,538,270	-$0.00227	-$2,593,562	1,142,538,270	-$0.00258	-$2,947,749	13.66%
Act 141 capped contribution	1,142,538,270	$0.00041	$470,432	1,142,538,270	$0.00041	$470,432	0.00%
Total Revenue: General Secondary Large TOU - Cg3			**$680,524,191**			**$696,197,601**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Secondary Curtailable- Cg3C							
Customer charge							
Customer charge per day	9,125	$3.85000	$35,131	9,125	$3.85000	$35,131	0.00%
Extra Meter per day	0	$0.20000	$0	0	$0.20000	$0	0.00%
Energy charge							
On-peak	11,720,948	$0.09057	$1,061,566	11,720,948	$0.08969	$1,051,252	-0.97%
Off-peak	18,988,094	$0.05660	$1,074,726	18,988,094	$0.05511	$1,046,434	-2.63%
Curtailable credit	10,011,497	-$0.02080	-$208,239	10,011,497	-$0.02080	-$208,239	0.00%
Demand charge							
On-peak minimum	7,846	$7.29900	$57,268	7,846	$7.84400	$61,544	7.47%
On-peak adjusted	3,359	$11.01400	$36,996	3,359	$11.83700	$39,760	7.47%
On-peak regular	65,837	$18.31300	$1,205,673	65,837	$19.68100	$1,295,738	7.47%
Customer maximum	113,959	$3.07500	$350,424	113,959	$3.30500	$376,634	7.48%
Fuel cost adjustment							
Adjustment	30,709,042	$0.00000	$0	30,709,042	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00258	$0	13.66%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Curtailable- Cg3C			**$3,613,545**			**$3,698,255**	
General Secondary Seasonal Curtailable - Cg3S							
Customer charge							
Customer charge per day	2,555	$3.85000	$9,837	2,555	$3.85000	$9,837	0.00%
Extra Meter per day	0	$0.20000	$0	0	$0.20000	$0	0.00%
Energy charge							
On-peak	5,100,759	$0.09057	$461,976	5,100,759	$0.08969	$457,487	-0.97%
Off-peak	5,563,651	$0.05660	$314,903	5,563,651	$0.05511	$306,613	-2.63%
Demand charge							
On-peak minimum	6,798	$7.29900	$49,619	6,798	$7.84400	$53,324	7.47%
On-peak adjusted	2,766	$11.01400	$30,465	2,766	$11.83700	$32,741	7.47%
On-peak regular	26,111	$18.31300	$478,171	26,111	$19.68100	$513,891	7.47%
Curtailable credit	32,910	-$2.00000	-$65,820	32,910	-$2.00000	-$65,820	0.00%
Customer maximum	45,165	$3.07500	$138,882	45,165	$3.30500	$149,270	7.48%
Fuel cost adjustment							
Adjustment	10,664,410	$0.00000	$0	10,664,410	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	7,302,622	-$0.00227	-$16,577	7,302,622	-$0.00258	-$18,841	13.66%
Act 141 capped contribution	7,302,622	$0.00033	$2,394	7,302,622	$0.00033	$2,394	0.00%
Total Revenue: General Secondary Seasonal Curtailable - Cg3S			**$1,403,848**			**$1,440,895**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Primary - Cp1							
Customer charge							
Customer charge per day-low voltage	11,680	$19.76010	$230,798	11,680	$19.76010	$230,798	0.00%
Customer charge per day-med voltage	156,585	$19.76010	$3,094,135	156,585	$19.76010	$3,094,135	0.00%
Customer charge per day-high voltage	1,095	$19.76010	$21,637	1,095	$19.76010	$21,637	0.00%
Energy charge-low voltage							
On-peak (summer)	29,517,963	$0.09552	$2,819,556	29,517,963	$0.09610	$2,836,676	0.61%
On-peak (non-summer)	52,188,036	$0.08290	$4,326,388	52,188,036	$0.08341	$4,353,004	0.62%
Off-peak (summer)	41,583,624	$0.06206	$2,580,680	41,583,624	$0.06244	$2,596,481	0.61%
Off-peak (non-summer)	76,164,244	$0.06206	$4,726,753	76,164,244	$0.06244	$4,755,695	0.61%
Energy charge-med voltage							
On-peak (summer)	599,474,310	$0.09444	$56,614,354	599,474,310	$0.09501	$56,956,054	0.60%
On-peak (non-summer)	1,073,337,527	$0.08196	$87,970,744	1,073,337,527	$0.08246	$88,507,412	0.61%
Off-peak (summer)	929,209,816	$0.06018	$55,919,847	929,209,816	$0.06055	$56,263,654	0.61%
Off-peak (non-summer)	1,686,236,514	$0.06018	$101,477,713	1,686,236,514	$0.06055	$102,101,621	0.61%
Energy charge-high voltage							
On-peak (summer)	5,555,853	$0.09353	$519,639	5,555,853	$0.09409	$522,750	0.60%
On-peak (non-summer)	9,975,632	$0.08117	$809,722	9,975,632	$0.08166	$814,610	0.60%
Off-peak (summer)	10,603,599	$0.05960	$631,975	10,603,599	$0.05996	$635,792	0.60%
Off-peak (non-summer)	19,195,341	$0.05960	$1,144,042	19,195,341	$0.05996	$1,150,953	0.60%
Demand charge-low voltage							
On-peak (summer)	155,851	$20.66900	$3,221,284	155,851	$21.87200	$3,408,773	5.82%
On-peak (non-summer)	273,510	$14.87000	$4,067,094	273,510	$15.73500	$4,303,680	5.82%
Customer maximum	566,820	$2.33800	$1,325,225	566,820	$2.33800	$1,325,225	0.00%
Demand charge-med voltage							
On-peak (summer)	3,039,229	$20.43400	$62,103,605	3,039,229	$21.62400	$65,720,288	5.82%
On-peak (non-summer)	5,506,051	$14.70100	$80,944,456	5,506,051	$15.55700	$85,657,635	5.82%
Customer maximum	10,768,090	$2.31100	$24,885,056	10,768,090	$2.31100	$24,885,056	0.00%
Demand charge-high voltage							
On-peak (summer)	30,936	$20.23600	$626,021	30,936	$21.41500	$662,494	5.83%
On-peak (non-summer)	60,111	$14.55800	$875,096	60,111	$15.40700	$926,130	5.83%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	4,533,042,459	$0.00000	$0	4,533,042,459	$0.00000	$0	0.00%
Other							
Load factor credit	515,812,658	-$0.01000	-$5,158,127	515,812,658	-$0.01000	-$5,158,127	0.00%
SIC 4952 on-peak demand credit	75,229	$0.00000	$0	75,229	-$4.39500	-$330,631	0.00%
SIC 4952 customer maximum demand credit	237,966	$0.00000	$0	237,966	-$0.57800	-$137,544	0.00%
Act 141 capped credits	4,020,627,111	-$0.00227	-$9,126,824	4,020,627,111	-$0.00258	-$10,373,218	13.66%
Act 141 capped contribution	4,020,627,111	$0.00035	$1,422,117	4,020,627,111	$0.00035	$1,422,117	0.00%
Total Revenue: General Primary - Cp1			**$488,072,987**			**$497,153,153**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Primary Curtailable - Cp3							
Customer charge							
Customer charge per day-low voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-med voltage	8,760	$19.76010	$173,098	8,760	$19.76010	$173,098	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Energy charge-low voltage							
On-peak	0	$0.08530	$0	0	$0.08763	$0	2.73%
Off-peak	0	$0.06077	$0	0	$0.06243	$0	2.73%
Curtailable credit	0	-$0.02028	$0	0	-$0.02028	$0	0.00%
Energy charge-med voltage							
On-peak	161,000,511	$0.08433	$13,577,173	161,000,511	$0.08664	$13,949,084	2.74%
Off-peak	250,045,723	$0.06006	$15,017,746	250,045,723	$0.06171	$15,430,322	2.75%
Curtailable credit	75,150,958	-$0.02000	-$1,503,019	75,150,958	-$0.02000	-$1,503,019	0.00%
Energy charge-high voltage							
On-peak	0	$0.08351	$0	0	$0.08580	$0	2.74%
Off-peak	0	$0.05836	$0	0	$0.05996	$0	2.74%
Curtailable credit	0	-$0.01970	$0	0	-$0.01970	$0	0.00%
Demand charge-low voltage							
On-peak	0	$16.80300	$0	0	$17.78200	$0	5.83%
Customer maximum	0	$2.33800	$0	0	$2.33800	$0	0.00%
Demand charge-med voltage							
On-peak	926,401	$16.61200	$15,389,373	926,401	$17.58000	$16,286,130	5.83%
Customer maximum	1,586,315	$2.31100	$3,665,974	1,586,315	$2.31100	$3,665,974	0.00%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.41000	$0	5.83%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	411,046,234	$0.00000	$0	411,046,234	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	267,014,599	-$0.00227	-$606,123	267,014,599	-$0.00258	-$688,898	13.66%
Act 141 capped contribution	267,014,599	$0.00042	$112,350	267,014,599	$0.00042	$112,350	0.00%
Total Revenue: General Primary Curtailable - Cp3			**$45,826,572**			**$47,425,041**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Primary Seasonal Curtailable - Cp3S							
Customer charge							
Customer charge per day-low voltage	730	$19.76010	$14,425	730	$19.76010	$14,425	0.00%
Customer charge per day-med voltage	1,095	$19.76010	$21,637	1,095	$19.76010	$21,637	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Energy charge-low voltage							
On-peak	2,671,272	$0.08530	$227,860	2,671,272	$0.08763	$234,084	2.73%
Off-peak	4,969,505	$0.06077	$301,997	4,969,505	$0.06243	$310,246	2.73%
Energy charge-med voltage							
On-peak	19,114,512	$0.08433	$1,611,927	19,114,512	$0.08664	$1,656,081	2.74%
Off-peak	28,050,876	$0.06006	$1,684,736	28,050,876	$0.06171	$1,731,020	2.75%
Energy charge-high voltage							
On-peak	0	$0.08351	$0	0	$0.08580	$0	2.74%
Off-peak	0	$0.05836	$0	0	$0.05996	$0	2.74%
Demand charge-low voltage							
On-peak	16,126	$16.80300	$270,965	16,126	$17.78200	$286,753	5.83%
Customer maximum	18,690	$2.33800	$43,697	18,690	$2.33800	$43,697	0.00%
Curtailable credit	16,126	-$2.00000	-$32,252	16,126	-$2.00000	-$32,252	0.00%
Demand charge-med voltage							
On-peak	119,622	$16.61200	$1,987,161	119,622	$17.58000	$2,102,955	5.83%
Customer maximum	151,566	$2.31100	$350,269	151,566	$2.31100	$350,269	0.00%
Curtailable credit	119,622	-$2.00000	-$239,244	119,622	-$2.00000	-$239,244	0.00%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.41000	$0	5.83%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Curtailable credit	0	-$2.00000	$0	0	-$2.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	54,806,165	$0.00000	$0	54,806,165	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	26,586,143	-$0.00227	-$60,351	26,586,143	-$0.00258	-$68,592	13.66%
Act 141 capped contribution	26,586,143	$0.00041	$10,968	26,586,143	$0.00041	$10,968	0.00%
Total Revenue: General Primary Seasonal Curtailable - Cp3S			**$6,193,795**			**$6,422,046**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Primary Combined Firm & NonFirm - CpFN							
Customer charge							
Customer charge per day-med voltage	6,935	$26.30137	$182,400	6,935	$26.30137	$182,400	0.00%
Customer charge per day-high voltage	365	$26.30137	$9,600	365	$26.30137	$9,600	0.00%
Energy charge-med voltage							
On-peak firm	7,446,837	$0.08433	$627,992	7,446,837	$0.08664	$645,194	2.74%
On-peak non-firm	138,828,846	$0.07845	$10,891,123	138,828,846	$0.08060	$11,189,605	2.74%
Off-peak firm	13,508,282	$0.05893	$796,043	13,508,282	$0.06055	$817,926	2.75%
Off-peak non-firm	222,747,442	$0.05482	$12,211,015	222,747,442	$0.05633	$12,547,363	2.75%
Energy charge-high voltage							
On-peak firm	2,475,962	$0.08351	$206,768	2,475,962	$0.08580	$212,438	2.74%
On-peak non-firm	29,612,504	$0.07768	$2,300,299	29,612,504	$0.07981	$2,363,374	2.74%
Off-peak firm	4,658,262	$0.05836	$271,856	4,658,262	$0.05996	$279,309	2.74%
Off-peak non-firm	58,886,125	$0.05429	$3,196,928	58,886,125	$0.05578	$3,284,668	2.74%
Demand charge-med voltage							
On-peak firm	30,652	$16.61200	$509,191	30,652	$17.58000	$538,862	5.83%
On-peak non-firm	729,017	$11.25200	$8,202,899	729,017	$12.22000	$8,908,588	8.60%
Customer maximum	903,155	$2.31100	$2,087,191	903,155	$2.31100	$2,087,191	0.00%
Demand charge-high voltage							
On-peak firm	9,807	$16.45100	$161,335	9,807	$17.41000	$170,740	5.83%
On-peak non-firm	216,154	$11.09100	$2,397,364	216,154	$12.05000	$2,604,656	8.65%
Customer maximum	247,869	$0.00000	$0	247,869	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	478,164,260	$0.00000	$0	478,164,260	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	460,886,290	-$0.00227	-$1,046,212	460,886,290	-$0.00258	-$1,189,087	13.66%
Act 141 capped contribution	460,886,290	$0.00027	$125,353	460,886,290	$0.00027	$125,353	0.00%
Total Revenue: General Primary Combined Firm & NonFirm - CpFN			**$43,131,145**			**$44,778,181**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
General Primary Service - Standby - Cp4							
Customer charge							
Customer charge per day-low voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-med voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Extra Meter per day	0	$3.14334	$0	0	$3.14334	$0	0.00%
Energy charge-low voltage							
On-peak	0	$0.08711	$0	0	$0.08763	$0	0.60%
Off-peak	0	$0.06206	$0	0	$0.06243	$0	0.60%
Energy charge-med voltage							
On-peak	0	$0.08612	$0	0	$0.08664	$0	0.60%
Off-peak	0	$0.06134	$0	0	$0.06171	$0	0.60%
Energy charge-high voltage							
On-peak	0	$0.08529	$0	0	$0.08580	$0	0.60%
Off-peak	0	$0.05960	$0	0	$0.05996	$0	0.60%
Demand charge-low voltage							
On-peak	0	$16.80300	$0	0	$17.78200	$0	5.83%
Customer maximum	0	$2.33800	$0	0	$2.33800	$0	0.00%
Reserved	0	$1.99300	$0	0	$1.99300	$0	0.00%
Demand charge-med voltage							
On-peak	0	$16.61200	$0	0	$17.58000	$0	5.83%
Customer maximum	0	$2.31100	$0	0	$2.31100	$0	0.00%
Reserved	0	$1.96400	$0	0	$1.96400	$0	0.00%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.41000	$0	5.83%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Reserved	0	$1.93900	$0	0	$1.93900	$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%
Act 141 capped credits	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Primary Service - Standby - Cp4			**$0**			**$0**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Current Rate - Year 2025 Rate	Current Rate - Year 2025 Yield	Authorized Rate - Year 2025 Billing Component	Authorized Rate - Year 2025 Rate	Authorized Rate - Year 2025 Yield	2025
General Primary Service - Real-Time Market Pricing (RTMP)							
Customer charge							
Administration per day	37,230	$5.75300	$214,184	37,230	$5.75300	$214,184	0.00%
Energy charge							
Hourly LMP	804,153,124	$0.03210	$25,809,594	804,153,124	$0.03210	$25,809,594	0.00%
Embedded cost adder	804,153,124	$0.00050	$402,077	804,153,124	$0.00050	$402,077	0.00%
Demand charge							
Transmission demand	850,932	$4.36000	$3,710,064	850,932	$5.25000	$4,467,393	20.41%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Primary Service - Real-Time Market Pricing (RTMP)			**$30,135,919**			**$30,893,248**	
General Primary Service - Real-Time Pricing (RTP)							
Customer charge							
Customer charge per day	365	$26.30137	$9,600	365	$26.30137	$9,600	0.00%
Extra meter per day	1,095	$3.14334	$3,442	1,095	$3.14334	$3,442	0.00%
Scheduling per month	12	$1,000.000	$12,000	12	$1,000.000	$12,000	0.00%
Energy charge							
Hourly LMP	388,216,002	$0.03229	$12,533,971	388,216,002	$0.03229	$12,533,971	0.00%
Embedded cost adder (firm)	32,576,138	$0.02050	$667,811	32,576,138	$0.02050	$667,811	0.00%
Embedded cost adder (non-firm)	355,639,864	$0.01350	$4,801,138	355,639,864	$0.01350	$4,801,138	0.00%
Demand charge							
On-peak (summer)	105	$20.23600	$2,125	105	$21.41500	$2,249	5.83%
On-peak (non-summer)	217	$14.55800	$3,159	217	$15.40700	$3,343	5.83%
Total Revenue: General Primary Service - Real-Time Pricing (RTP)			**$18,033,245**			**$18,033,554**	
Electronics and Information Technology Manufacturing (EITM)							
Customer charge							
EITM Zone	13	$44,947	$600,000	13	$44,947	$600,000	0.00%
Customer specific	13	$6,950	$91,651	13	$6,950	$91,651	0.00%
Energy charge	532,932,403	$0.03084	$16,433,114	532,932,403	$0.03084	$16,433,114	0.00%
Demand charge							
Firm service capacity	3,225,421	$4.95437	$15,979,921	3,225,421	$4.95437	$15,979,921	0.00%
Customer maximum	3,225,421	$4.27377	$13,784,703	3,225,421	$4.27377	$13,784,703	0.00%
Gross Receipts Tax	$46,889,388	3.190%	$1,495,771	$46,889,388	3.190%	$1,495,771	0.00%
Total Revenue: Electronics and Information Technology Manufacturing (EITM)			**$48,385,160**			**$48,385,160**	

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Area Lighting - Gl1							
Standard high pressure sodium							
50 Watt	36	$12.18000	$438	36	$13.46000	$485	10.51%
70 Watt	15,000	$14.45000	$216,750	15,000	$15.58000	$233,700	7.82%
100 Watt	48,000	$15.37000	$737,760	48,000	$16.04000	$769,920	4.36%
150 Watt	3,900	$17.89000	$69,771	3,900	$18.67000	$72,813	4.36%
200 Watt	40,200	$20.90000	$840,180	40,200	$21.82000	$877,164	4.40%
250 Watt	3,360	$23.68000	$79,565	3,360	$24.72000	$83,059	4.39%
400 Watt	40,200	$31.55000	$1,268,310	40,200	$32.93000	$1,323,786	4.37%
Flood high pressure sodium							
70 Watt	348	$14.96000	$5,206	348	$15.62000	$5,436	4.41%
100 Watt	3,120	$18.20000	$56,784	3,120	$19.75000	$61,620	8.52%
150 Watt	336	$19.63000	$6,596	336	$20.49000	$6,885	4.38%
200 Watt	9,780	$22.46000	$219,659	9,780	$24.94000	$243,913	11.04%
250 Watt	432	$25.19000	$10,882	432	$26.29000	$11,357	4.37%
400 Watt	15,000	$32.81000	$492,150	15,000	$34.25000	$513,750	4.39%
Standard metal halide							
175 Watt	60	$28.57000	$1,714	60	$29.82000	$1,789	4.38%
250 Watt	204	$30.01000	$6,122	204	$31.32000	$6,389	4.37%
400 Watt	660	$34.74000	$22,928	660	$36.26000	$23,932	4.38%
Flood metal halide							
175 Watt	204	$30.06000	$6,132	204	$31.38000	$6,402	4.39%
250 Watt	2,100	$31.65000	$66,465	2,100	$33.04000	$69,384	4.39%
400 Watt	11,100	$36.17000	$401,487	11,100	$37.75000	$419,025	4.37%
1000 Watt	120	$68.90000	$8,268	120	$71.92000	$8,630	4.38%
Poles	120,000	$2.80000	$336,000	120,000	$3.00000	$360,000	7.14%
Spans	132,000	$2.73000	$360,360	132,000	$2.92000	$385,440	6.96%
Fuel cost adjustment	18,731,600	$0.00000	$0	18,731,600	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	2,478,384	-$0.00227	-$5,626	2,478,384	-$0.00258	-$6,394	13.66%
Act 141 capped contribution	2,478,384	$0.00006	$158	2,478,384	$0.00006	$158	0.00%
Total Revenue: Area Lighting - Gl1			**$5,208,060**			**$5,478,643**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Current Rate - Year 2025 Rate	Current Rate - Year 2025 Yield	Authorized Rate - Year 2025 Billing Component	Authorized Rate - Year 2025 Rate	Authorized Rate - Year 2025 Yield	2025
Street Lighting Small TOU - St1/St2							
Customer charge							
Single PH per day	155,855	$0.49315	$76,860	155,855	$0.49315	$76,860	0.00%
Three PH per day	13,505	$0.49315	$6,660	13,505	$0.49315	$6,660	0.00%
Extra Meter per day	0	$0.05951	$0	0	$0.05951	$0	0.00%
Energy charge-St1							
On-peak	886,930	$0.35386	$313,849	886,930	$0.37157	$329,557	5.00%
Off-peak	6,654,513	$0.06154	$409,519	6,654,513	$0.06462	$430,015	5.00%
Energy charge-St2							
On-Peak	4,770,549	$0.37047	$1,767,345	4,770,549	$0.38899	$1,855,696	5.00%
Off-Peak	35,792,726	$0.06443	$2,306,125	35,792,726	$0.06765	$2,421,378	5.00%
Fuel cost adjustment	48,104,718	$0.00000	$0	48,104,718	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	48,372,769	-$0.00227	-$109,806	48,372,769	-$0.00258	-$124,802	13.66%
Act 141 capped contribution	48,372,769	$0.00034	$16,382	48,372,769	$0.00034	$16,382	0.00%
Total Revenue: Street Lighting Small TOU - St1/St2			**$4,786,934**			**$5,011,745**	
Alley Lighting - Al1							
Lamp sizes							
0 - 10 Watt LED	0	$2.59000	$0	0	$2.72000	$0	5.02%
>10 - 20 Watt LED	0	$2.97000	$0	0	$3.12000	$0	5.05%
>20 - 30 Watt LED	2,100	$3.41000	$7,161	2,100	$3.58000	$7,518	4.99%
>30 - 40 Watt LED	1,464	$3.88000	$5,680	1,464	$4.07000	$5,958	4.90%
>40 - 50 Watt LED	384	$4.34000	$1,667	384	$4.55000	$1,747	4.84%
>50 - 60 Watt LED	0	$4.79000	$0	0	$5.02000	$0	4.80%
50 Watt HPS	0	$4.79000	$0	0	$5.02000	$0	4.80%
70 Watt HPS	111,600	$6.12000	$682,992	111,600	$6.42000	$716,472	4.90%
100 Watt HPS	2,160	$8.09000	$17,474	2,160	$8.49000	$18,338	4.94%
Fuel cost adjustment	2,725,972	$0.00000	$0	2,725,972	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,356,781	-$0.00227	-$7,620	3,356,781	-$0.00258	-$8,660	13.66%
Act 141 capped contribution	3,356,781	$0.00000	$0	3,356,781	$0.00000	$0	0.00%
Total Revenue: Alley Lighting - Al1			**$707,354**			**$741,374**	

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Street Lighting - Ms1							
Customer charge							
Flashers - <= 25 Watts	0	$3.40000	$0	0	$3.40000	$0	0.00%
Flashers - 25 to 75 Watts	1,548	$3.47000	$5,372	1,548	$3.47000	$5,372	0.00%
Flashers - Over 75 Watts	996	$5.57000	$5,548	996	$5.57000	$5,548	0.00%
Customer charge per day	165,600	$0.49315	$81,666	165,600	$0.49315	$81,666	0.00%
Energy charge	1,729,324	$0.15759	$272,524	1,729,324	$0.16659	$288,088	5.71%
Fuel cost adjustment	1,729,324	$0.00000	$0	1,729,324	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,290,244	-$0.00227	-$2,929	1,290,244	-$0.00258	-$3,329	13.66%
Act 141 capped contribution	1,290,244	$0.00075	$963	1,290,244	$0.00075	$963	0.00%
Total Revenue: Street Lighting - Ms1			**$363,143**			**$378,307**	
Street Lighting & Other - Ms2							
Energy charge	4,450,372	$0.14971	$666,265	4,450,372	$0.15826	$704,316	5.71%
Fuel cost adjustment	4,450,372	$0.00000	$0	4,450,372	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,880,718	-$0.00227	-$4,269	1,880,718	-$0.00258	-$4,852	13.66%
Act 141 capped contribution	1,880,718	$0.00068	$1,278	1,880,718	$0.00068	$1,278	0.00%
Total Revenue: Street Lighting & Other - Ms2			**$663,274**			**$700,742**	
Street Lighting - Ms3							
High pressure sodium lamps							
50 Watt	12,000	$12.18000	$146,160	12,000	$13.46000	$161,520	10.51%
70 Watt	16,800	$14.45000	$242,760	16,800	$15.58000	$261,744	7.82%
100 Watt	120,000	$15.37000	$1,844,400	120,000	$16.04000	$1,924,800	4.36%
150 Watt	90,000	$17.89000	$1,610,100	90,000	$18.67000	$1,680,300	4.36%
200 Watt	88,800	$20.90000	$1,855,920	88,800	$21.82000	$1,937,616	4.40%
250 Watt	20,400	$23.68000	$483,072	20,400	$24.72000	$504,288	4.39%
400 Watt	2,100	$31.55000	$66,255	2,100	$32.93000	$69,153	4.37%
Metal halide lamps							
175 Watt	0	$28.57000	$0	0	$29.82000	$0	4.38%
250 Watt	0	$30.01000	$0	0	$31.32000	$0	4.37%
400 Watt	0	$34.74000	$0	0	$36.26000	$0	4.38%
Fuel cost adjustment	26,352,992	$0.00000	$0	26,352,992	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	9,999,467	-$0.00227	-$22,699	9,999,467	-$0.00258	-$25,799	13.66%
Act 141 capped contribution	9,999,467	$0.00000	$0	9,999,467	$0.00000	$0	0.00%
Total Revenue: Street Lighting - Ms3			**$6,225,968**			**$6,513,622**	

Electric Rate Design - Test Year 2025

Rate Schedule	Current Rate - Year 2025 Billing Component	Rate	Yield	Authorized Rate - Year 2025 Billing Component	Rate	Yield	2025
Street Lighting - Ms4							
Customer charge							
Customer charge per Month			2,496,000			$2,496,000	
Non-standard lamps							
50 Watt HPS	0	$2.62000	$0	0	$2.91000	$0	11.07%
70 Watt HPS	3,300	$3.86000	$12,738	3,300	$4.28000	$14,124	10.88%
100 Watt HPS	50,400	$5.98000	$301,392	50,400	$6.64000	$334,656	11.04%
150 Watt HPS	90,000	$8.48000	$763,200	90,000	$9.41000	$846,900	10.97%
175 Watt MH	2,400	$9.62000	$23,088	2,400	$10.68000	$25,632	11.02%
200 Watt HPS	25,200	$11.22000	$282,744	25,200	$12.45000	$313,740	10.96%
250 Watt HPS	33,600	$13.96000	$469,056	33,600	$15.50000	$520,800	11.03%
400 Watt HPS	4,980	$21.59000	$107,518	4,980	$23.96000	$119,321	10.98%
1000 Watt HPS	0	$50.27000	$0	0	$55.80000	$0	11.00%
Fuel cost adjustment	12,389,277	$0.00000	$0	12,389,277	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,495,205	-$0.00227	-$7,934	3,495,205	-$0.00258	-$9,018	13.66%
Act 141 capped contribution	3,495,205	$0.00082	$2,876	3,495,205	$0.00082	$2,876	0.00%
Total Revenue: Street Lighting - Ms4			**$4,450,678**			**$4,665,031**	
LED Lighting - General Secondary - LED							
Customer charge							
Standard lighting fixture							
Category A	0	$8.44000	$0	0	$8.57000	$0	1.54%
Category B	26,400	$9.64000	$254,496	26,400	$9.78000	$258,192	1.45%
Category C	216,000	$11.06000	$2,388,960	216,000	$11.23000	$2,425,680	1.54%
Category D	57,600	$12.48000	$718,848	57,600	$12.67000	$729,792	1.52%
Category E	40,800	$13.90000	$567,120	40,800	$14.11000	$575,688	1.51%
Category F	8,400	$15.32000	$128,688	8,400	$15.55000	$130,620	1.50%
Category G	3,000	$16.74000	$50,220	3,000	$16.99000	$50,970	1.49%
Category H	3,600	$18.15000	$65,340	3,600	$18.42000	$66,312	1.49%
Category I	0	$19.58000	$0	0	$19.87000	$0	1.48%
Non-standard lighting fixture							
Category A	0	$5.65000	$0	0	$5.73000	$0	1.42%
Category B	0	$6.16000	$0	0	$6.25000	$0	1.46%
Category C	7,200	$6.76000	$48,672	7,200	$6.86000	$49,392	1.48%
Category D	7,200	$7.36000	$52,992	7,200	$7.47000	$53,784	1.49%
Category E	13,800	$7.94000	$109,572	13,800	$8.06000	$111,228	1.51%
Category F	4,800	$8.53000	$40,944	4,800	$8.66000	$41,568	1.52%
Category G	420	$9.13000	$3,835	420	$9.27000	$3,893	1.53%
Category H	10,200	$9.72000	$99,144	10,200	$9.87000	$100,674	1.54%
Category I	132	$10.31000	$1,361	132	$10.46000	$1,381	1.45%
Category J	0	$10.90000	$0	0	$11.06000	$0	1.47%
Category K	0	$11.49000	$0	0	$11.66000	$0	1.48%
Category L	2,820	$12.09000	$34,094	2,820	$12.27000	$34,601	1.49%
Category M	1,800	$12.68000	$22,824	1,800	$12.87000	$23,166	1.50%
Category N	0	$13.27000	$0	0	$13.47000	$0	1.51%
Category O	0	$13.86000	$0	0	$14.07000	$0	1.52%
Category P	0	$14.46000	$0	0	$14.68000	$0	1.52%
Category Q	0	$15.05000	$0	0	$15.28000	$0	1.53%
Category R	0	$15.63000	$0	0	$15.86000	$0	1.47%
Category S	0	$16.23000	$0	0	$16.47000	$0	1.48%
Category T	144	$16.83000	$2,424	144	$17.08000	$2,460	1.49%

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Energy charge							
0-3 kWh	0	$0.29000	$0	0	$0.29000	$0	0.00%
4-6 kWh	0	$0.58000	$0	0	$0.59000	$0	1.72%
7-9 kWh	0	$0.86000	$0	0	$0.87000	$0	1.16%
10-12 kWh	0	$1.15000	$0	0	$1.17000	$0	1.74%
13-15 kWh	18,000	$1.45000	$26,100	18,000	$1.47000	$26,460	1.38%
16-18 kWh	216,000	$1.73000	$373,680	216,000	$1.76000	$380,160	1.73%
19-21 kWh	3,600	$2.02000	$7,272	3,600	$2.05000	$7,380	1.49%
22-24 kWh	4,800	$2.32000	$11,136	4,800	$2.35000	$11,280	1.29%
25-27 kWh	0	$2.61000	$0	0	$2.65000	$0	1.53%
28-30 kWh	5,040	$2.89000	$14,566	5,040	$2.93000	$14,767	1.38%
31-33 kWh	11,640	$3.18000	$37,015	11,640	$3.23000	$37,597	1.57%
34-36 kWh	40,800	$3.47000	$141,576	40,800	$3.52000	$143,616	1.44%
37-39 kWh	8,400	$3.76000	$31,584	8,400	$3.82000	$32,088	1.60%
40-42 kWh	0	$4.05000	$0	0	$4.11000	$0	1.48%
43-45 kWh	2,568	$4.33000	$11,119	2,568	$4.39000	$11,274	1.39%
46-48 kWh	2,160	$4.62000	$9,979	2,160	$4.69000	$10,130	1.52%
49-51 kWh	0	$4.92000	$0	0	$4.99000	$0	1.42%
52-54 kWh	516	$5.20000	$2,683	516	$5.28000	$2,724	1.54%
55-57 kWh	8,400	$5.48000	$46,032	8,400	$5.56000	$46,704	1.46%
58-60 kWh	2,760	$5.79000	$15,980	2,760	$5.88000	$16,229	1.55%
61-63 kWh	0	$6.08000	$0	0	$6.17000	$0	1.48%
64-66 kWh	600	$6.36000	$3,816	600	$6.46000	$3,876	1.57%
67-69 kWh	0	$6.65000	$0	0	$6.75000	$0	1.50%
70-72 kWh	1,632	$6.94000	$11,326	1,632	$7.04000	$11,489	1.44%
73-75 kWh	0	$7.23000	$0	0	$7.34000	$0	1.52%
76-78 kWh	0	$7.52000	$0	0	$7.63000	$0	1.46%
79-81 kWh	0	$7.80000	$0	0	$7.92000	$0	1.54%
82-84 kWh	0	$8.10000	$0	0	$8.22000	$0	1.48%
85-87 kWh	0	$8.39000	$0	0	$8.52000	$0	1.55%
88-90 kWh	0	$8.67000	$0	0	$8.80000	$0	1.50%
91-93 kWh	0	$8.96000	$0	0	$9.09000	$0	1.45%
94-96 kWh	0	$9.25000	$0	0	$9.39000	$0	1.51%
97-99 kWh	0	$9.55000	$0	0	$9.69000	$0	1.47%
100-102 kWh	0	$9.83000	$0	0	$9.98000	$0	1.53%
103-105 kWh	0	$10.12000	$0	0	$10.27000	$0	1.48%
106-108 kWh	0	$10.41000	$0	0	$10.57000	$0	1.54%
109-111 kWh	0	$10.71000	$0	0	$10.87000	$0	1.49%
112-114 kWh	0	$10.99000	$0	0	$11.15000	$0	1.46%
115-117 kWh	0	$11.27000	$0	0	$11.44000	$0	1.51%
Fuel cost adjustment	6,806,308	$0.00000	$0	6,806,308	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	979,887	-$0.00227	-$2,224	979,887	-$0.00258	-$2,528	13.66%
Act 141 capped contribution	979,887	$0.00002	$19	979,887	$0.00002	$19	0.00%
Total Revenue: LED Lighting - General Secondary - LED			**$5,331,193**			**$5,412,667**	

Electric Rate Design - Test Year 2025

	Current Rate - Year 2025			Authorized Rate - Year 2025			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2025
Municipal Defense Sirens - Mg1							
Customer charge	120	$3.00000	$360	120	$3.00000	$360	0.00%
Energy charge	66,394	$0.15759	$10,463	66,394	$0.16659	$11,061	5.71%
Fuel cost adjustment	66,394	$0.00000	$0	66,394	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Municipal Defense Sirens - Mg1			**$10,823**			**$11,421**	
Telecom Equipment Service TE1							
Customer charge	864	$4.25000	$3,672	864	$4.25000	$3,672	0.00%
Energy charge	19,209	$0.15759	$3,027	19,209	$0.16659	$3,200	5.71%
Fuel cost adjustment	19,209	$0.00000	$0	19,209	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Telecom Equipment Service TE1			**$6,699**			**$6,872**	
Telecom Equipment Service TE2							
Customer charge	8,030	$0.49315	$3,960	8,030	$0.49315	$3,960	0.00%
Energy charge	144,788	$0.15759	$22,817	144,788	$0.16659	$24,120	5.71%
Fuel cost adjustment	144,788	$0.00000	$0	144,788	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Telecom Equipment Service TE2			**$26,777**			**$28,080**	
Energy For Tomorrow							
Energy for Tomorrow - Residential	49,570,704	$0.01158	$574,029	49,570,704	$0.01158	$574,029	0.00%
Energy for Tomorrow - Non-Residential	24,366,516	$0.01158	$282,164	24,366,516	$0.01158	$282,164	0.00%
Energy for Tomorrow - Non-Residential	12,157,056	$0.00995	$120,963	12,157,056	$0.00995	$120,963	0.00%
Total Revenue: Energy For Tomorrow			**$977,156**			**$977,156**	
Renewable Pathway							
Renewable Pathway (1 Year)	17,500,000	$0.00717	$125,475	17,500,000	$0.00717	$125,475	0.00%
Renewable Pathway (5 Year)	95,575,736	$0.00531	$507,507	95,575,736	$0.00531	$507,507	0.00%
Total Revenue: Renewable Pathway			**$632,982**			**$632,982**	
Dedicated Renewable Energy Rider							
Dedicated Renewable Energy Resource Cost	12	$51,300	$615,596	12	$51,300	$615,596	0.00%
Total Revenue: Dedicated Renewable Energy Rider			**$615,596**			**$615,596**	

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rg1 -- Residential Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.17154	$0.18325	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg2 -- Residential Service TOU			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base	$0.23382	$0.27006	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.10628	$0.10387	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Fg1 -- Farm Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.17154	$0.18325	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
COEV-R -- Residential Electric Vehicle Charger Only			
Fixed service and administration charge			
Bundled service	$20.000	$20.000	per Month
Pre-paid service	$8.000	$8.000	per Month
Energy charge			
On-peak (summer)	$0.28733	$0.30694	per kWh
On-peak (non-summer)	$0.18007	$0.18325	per kWh
Intermediate-peak (summer)	$0.18007	$0.18325	per kWh
Intermediate-peak (non-summer)	$0.18007	$0.18325	per kWh
Off-peak (summer)	$0.07303	$0.07303	per kWh
Off-peak (non-summer)	$0.07303	$0.07303	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
Cg1 -- General Secondary Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cg2 -- General Secondary Service - Demand			
Customer Charge	$1.32000	$1.32000	per Day
Extra Meter Charge	$0.18542	$0.18542	per Day
On-Peak Energy Charge - Base	$0.12625	$0.12782	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.09018	$0.09130	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$7.783	$8.364	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.04799)	($0.05157)	per kW per HOU less than 100
Customer Demand Charge	$2.460	$2.644	per kW
Cg3 -- General Secondary Service - Demand/TOU			
Customer Charge	$2.00000	$2.00000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.08969	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.05511	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$19.681	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.11837)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.305	per kW
Cg3C -- Gen. Sec. - Experimental Curtailable			
Customer Charge	$3.85000	$3.85000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.08969	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.05511	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$19.681	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.11837)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.305	per kW
Curtailable Credit	$0.02080	$0.02080	per kWh curtailable on-peak
Cg3S -- Gen. Sec. - Seasonal Curtailable			
Customer Charge	$3.85000	$3.85000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.08969	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.05511	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$19.681	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.11837)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.305	per kW
Curtailable Credit	$2.00000	$2.00000	per kW curtailable demand

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cg6 -- General Secondary Service - TOU			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base	$0.23324	$0.25388	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.10601	$0.09765	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TSSM - General Secondary Transmission Substations - Metered			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TSSU - General Secondary Transmission Substations - UnMetered			
Customer Charge	$4.25	$4.25	per Month
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TE1 - General Secondary Telecom Equipment - Small UnMetered			
Customer Charge	$4.25	$4.25	per Month
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TE2 - General Secondary Telecom Equipment - Large UnMetered			
Customer Charge	$0.49315	$0.49315	per Day, per point of connection
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
ERER1 & ERER3 Renewable Rider			
Energy for Tomorrow - 25%	$0.00290	$0.00290	per kWh
Energy for Tomorrow - 50%	$0.00579	$0.00579	per kWh
Energy for Tomorrow - 100%	$0.01158	$0.01158	per kWh
ERER2 Renewable Rider			
Energy for Tomorrow - < 70,000 kWh per month	$0.01158	$0.01158	per kWh
Energy for Tomorrow - >= 70,000 kWh per month	$0.00995	$0.00995	per kWh
ERER4 Renewable Rider			
Energy for Tomorrow - 25%	$0.00249	$0.00249	per kWh
Energy for Tomorrow - 50%	$0.00498	$0.00498	per kWh
Energy for Tomorrow - 100%	$0.00995	$0.00995	per kWh
Renewable Pathway Pilot			
One year subscription	$0.00717	$0.01768	per kWh
Five year subscription	$0.00531	$0.01582	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cp1 -- General Primary Service - TOU			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Summer Base (Low Voltage)	$0.09552	$0.09610	per kWh
On-Peak Energy Charge - Summer Base (Medium Voltage)	$0.09444	$0.09501	per kWh
On-Peak Energy Charge - Summer Base (High Voltage)	$0.09353	$0.09409	per kWh
On-Peak Energy Charge - Non-summer Base (Low Voltage)	$0.08290	$0.08341	per kWh
On-Peak Energy Charge - Non-summer Base (Medium Voltage)	$0.08196	$0.08246	per kWh
On-Peak Energy Charge - Non-summer Base (High Voltage)	$0.08117	$0.08166	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Summer Base (Low Voltage)	$0.06206	$0.06244	per kWh
Off-Peak Energy Charge - Summer Base (Medium Voltage)	$0.06018	$0.06055	per kWh
Off-Peak Energy Charge - Summer Base (High Voltage)	$0.05960	$0.05996	per kWh
Off-Peak Energy Charge - Non-summer Base (Low Voltage)	$0.06206	$0.06244	per kWh
Off-Peak Energy Charge - Non-summer Base (Medium Voltage)	$0.06018	$0.06055	per kWh
Off-Peak Energy Charge - Non-summer Base (High Voltage)	$0.05960	$0.05996	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Base (Low Voltage)	$20.669	$21.872	per kW
On-Peak Demand Charge - Summer Base (Meduim Voltage)	$20.434	$21.624	per kW
On-Peak Demand Charge - Summer Base (High Voltage)	$20.236	$21.415	per kW
On-Peak Demand Charge - Non-summer Base (Low Voltage)	$14.870	$15.735	per kW
On-Peak Demand Charge - Non-summer Base (Meduim Voltage)	$14.701	$15.557	per kW
On-Peak Demand Charge - Non-summer Base (High Voltage)	$14.558	$15.407	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.338	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.311	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Load Factor Credit	($0.010)	($0.010)	per kWh
SIC 4952 on-peak demand credit	$0.000	($4.395)	per kW
SIC 4952 customer maximum demand credit	$0.000	($0.578)	per kW

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cp3 -- Gen. Pri. Service - Curtailable			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08530	$0.08763	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08433	$0.08664	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08351	$0.08580	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06077	$0.06243	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06006	$0.06171	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05836	$0.05996	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$17.782	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$17.580	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.410	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.338	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.311	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$0.02028	$0.02028	per kWh curtailable on-peak
Curtailable Credit (Medium Voltage)	$0.02000	$0.02000	per kWh curtailable on-peak
Curtailable Credit (High Voltage)	$0.01970	$0.01970	per kWh curtailable on-peak
Cp3S -- Gen. Pri. - Seasonal Curtailable			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08530	$0.08763	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08433	$0.08664	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08351	$0.08580	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06077	$0.06243	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06006	$0.06171	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05836	$0.05996	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$17.782	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$17.580	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.410	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.338	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.311	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$2.000	$2.000	per kW curtailable demand
Curtailable Credit (Medium Voltage)	$2.000	$2.000	per kW curtailable demand
Curtailable Credit (High Voltage)	$2.000	$2.000	per kW curtailable demand

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Cp4 -- Gen. Pri. Service - Standby Service			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
Extra Meter Charge	$3.14334	$3.14334	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08711	$0.08763	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08612	$0.08664	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08529	$0.08580	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06206	$0.06243	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06134	$0.06171	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05960	$0.05996	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$17.782	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$17.580	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.410	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.338	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.311	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Reserved Demand Charge (Low Voltage)	$1.993	$1.993	per kW
Reserved Demand Charge (Medium Voltage)	$1.964	$1.964	per kW
Reserved Demand Charge (High Voltage)	$1.939	$1.939	per kW
Minimum On-Peak Standby Energy Charge (Low Voltage)	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (Medium Voltage)	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (High Voltage)	$0.03000	$0.03000	per kWh
Minimum Off-Peak Standby Energy Charge (Low Voltage)	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (Medium Voltage)	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (High Voltage)	$0.02000	$0.02000	per kWh
CpFN -- Gen Pri. Combined Firm & Non Firm			
Customer Charge - Medium Voltage	$26.30137	$26.30137	per Day
Customer Charge - High Voltage	$26.30137	$26.30137	
On-Peak Firm Energy Charge - Base (Medium Voltage)	$0.08433	$0.08664	per kWh
On-Peak Firm Energy Charge - Base (High Voltage)	$0.08351	$0.08580	per kWh
On-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.07845	$0.08060	per kWh
On-Peak Non Firm Energy Charge - Base (High Voltage)	$0.07768	$0.07981	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Firm Energy Charge - Base (Medium Voltage)	$0.05893	$0.06055	per kWh
Off-Peak Firm Energy Charge - Base (High Voltage)	$0.05836	$0.05996	per kWh
Off-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.05482	$0.05633	per kWh
Off-Peak Non Firm Energy Charge - Base (High Voltage)	$0.05429	$0.05578	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Firm Demand Charge - Base (Medium Voltage)	$16.612	$17.580	per kW
On-Peak Firm Demand Charge - Base (High Voltage)	$16.451	$17.410	per kW
On-Peak Non Firm Demand Charge - Base (Medium Voltage)	$11.252	$12.220	per kW
On-Peak Non Firm Demand Charge - Base (High Voltage)	$11.091	$12.050	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.311	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW

Wisconsin Electric Power Company
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Rate Schedule	Present Rate	Authorized Rate in 2025	
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	$25.00000	$25.00000	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	$27.00000	$27.00000	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
Real Time Market Pricing (RTMP)			
Administration Charge	$5.75300	$5.75300	per Day
Embedded Cost Adder	$0.00050	$0.00050	per kWh
Transmission Demand	$4.36000	$5.25000	per kW
Real Time Pricing (RTP)			
Customer Charge	$26.30137	$26.30137	per Day
Extra Meter Charge	$3.14334	$3.14334	per Day
Scheduling Charge	$1,000.00	$1,000.00	per Month
Embedded Cost Adder (firm)	$0.02050	$0.02050	per kWh
Embedded Cost Adder (non-firm)	$0.01350	$0.01350	per kWh
On-Peak Demand Charge - Summer Base	$20.23600	$21.41500	per kW
On-Peak Demand Charge - Non-summer Base	$14.55800	$15.40700	per kW
Electronics and Information Technology Manufacturing (EITM)			
Customer Demand Charge	$3.10000	$3.10000	per kW
Experimental Short Term Productivity Rider (STPR)			
Administration Charge	$100.00000	$100.00000	per Month
Excess energy charge, 1,000 kWh or more billed in period	$0.10000	$0.10000	per kWh per Excess Period
Excess energy charge, less than 1,000 kWh billed in period	$0.12000	$0.12000	per kWh per Excess Period
Experimental Dollars for Power (DFP)			
Energy Credit Option 1	$0.40000	$0.40000	per kWh
Energy Credit Option 2	$0.80000	$0.80000	per kWh
Energy Credit Option 3	$1.25000	$1.25000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
St1 -- Optional TOU Street Lighting Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge	$0.35386	$0.37157	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge	$0.06154	$0.06462	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
St2 -- Optional TOU Street Lighting Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge	$0.37047	$0.38899	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge	$0.06443	$0.06765	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Gl1 - Area Lighting			
Standard High Pressure Sodium			
50 Watt	$12.18	$13.46	per Month
70 Watt	$14.45	$15.58	per Month
100 Watt	$15.37	$16.04	per Month
150 Watt	$17.89	$18.67	per Month
200 Watt	$20.90	$21.82	per Month
250 Watt	$23.68	$24.72	per Month
400 Watt	$31.55	$32.93	per Month
Flood High Presure Sodium			
70 Watt	$14.96	$15.62	per Month
100 Watt	$18.20	$19.75	per Month
150 Watt	$19.63	$20.49	per Month
200 Watt	$22.46	$24.94	per Month
250 Watt	$25.19	$26.29	per Month
400 Watt	$32.81	$34.25	per Month
Standard Metal Halide			
175 Watt	$28.57	$29.82	per Month
250 Watt	$30.01	$31.32	per Month
400 Watt	$34.74	$36.26	per Month
Flood Metal Halide			
175 Watt	$30.06	$31.38	per Month
250 Watt	$31.65	$33.04	per Month
400 Watt	$36.17	$37.75	per Month
1000 Watt	$68.90	$71.92	per Month
Poles	$2.80	$3.00	per Month
Spans	$2.73	$2.92	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Al1 - Alley Lighting			
0 - 10 Watt LED	$2.59	$2.72	per Month
>10 - 20 Watt LED	$2.97	$3.12	per Month
>20 - 30 Watt LED	$3.41	$3.58	per Month
>30 - 40 Watt LED	$3.88	$4.07	per Month
>40 - 50 Watt LED	$4.34	$4.55	per Month
>50 - 60 Watt LED	$4.79	$5.02	per Month
50 Watt HPS	$4.79	$5.02	per Month
70 Watt HPS	$6.12	$6.42	per Month
100 Watt HPS	$8.09	$8.49	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Ms1 - Highway Lighting			
Customer Charge	$0.49315	$0.49315	per Day
Flasher (per flasher) - 25 Watts or Less	$3.40	$3.40	per Month per Flasher
Flasher (per flasher) - 25 Watts to 75 Watts	$3.47	$3.47	per Month per Flasher
Flasher (per flasher) - Greater than 75 Watts	$5.57	$5.57	per Month per Flasher
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms2 - Street Lighting			
Energy Charge - Base	$0.14971	$0.15826	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms3 - Street Lighting			
High Pressure Sodium Lamps			
50 Watt	$12.18	$13.46	per Month
70 Watt	$14.45	$15.58	per Month
100 Watt	$15.37	$16.04	per Month
150 Watt	$17.89	$18.67	per Month
200 Watt	$20.90	$21.82	per Month
250 Watt	$23.68	$24.72	per Month
400 Watt	$31.55	$32.93	per Month
Metal Halide Lamps			
175 Watt	$28.57	$29.82	per Month
250 Watt	$30.01	$31.32	per Month
400 Watt	$34.74	$36.26	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms4 - Street Lighting			
Customer Charge - Option A	1.90%	1.90%	per Month of Installed Costs
Customer Charge - Option B	0.50%	0.50%	per Month of Installed Costs
Non-Standard Lamps			
50 Watt HPS	$2.62	$2.91	per Month
70 Watt HPS	$3.86	$4.28	per Month
100 Watt HPS	$5.98	$6.64	per Month
150 Watt HPS	$8.48	$9.41	per Month
175 Watt MH	$9.62	$10.68	per Month
200 Watt HPS	$11.22	$12.45	per Month
250 Watt HPS	$13.96	$15.50	per Month
400 Watt HPS	$21.59	$23.96	per Month
1000 Watt HPS	$50.27	$55.80	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Mg1 - Municipal Defense Sirens			
Customer Charge	$3.00	$3.00	per Year per every 2 horsepower
Energy Charge - Base	$0.15759	$0.16659	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
LED			
Customer Charge			
Standard lighting fixture			
Category A	$8.44	$8.57	per Month, per Fixture
Category B	$9.64	$9.78	per Month, per Fixture
Category C	$11.06	$11.23	per Month, per Fixture
Category D	$12.48	$12.67	per Month, per Fixture
Category E	$13.90	$14.11	per Month, per Fixture
Category F	$15.32	$15.55	per Month, per Fixture
Category G	$16.74	$16.99	per Month, per Fixture
Category H	$18.15	$18.42	per Month, per Fixture
Category I	$19.58	$19.87	per Month, per Fixture
Category A (early removal)	$5.37	$5.42	per Month, per Fixture
Category B (early removal)	$6.06	$6.11	per Month, per Fixture
Category C (early removal)	$6.88	$6.95	per Month, per Fixture
Category D (early removal)	$7.70	$7.78	per Month, per Fixture
Category E (early removal)	$8.54	$8.63	per Month, per Fixture
Category F (early removal)	$9.37	$9.47	per Month, per Fixture
Category G (early removal)	$10.19	$10.30	per Month, per Fixture
Category H (early removal)	$11.01	$11.13	per Month, per Fixture
Category I (early removal)	$11.85	$11.99	per Month, per Fixture
Category A (after initial term)	$3.07	$3.15	per Month, per Fixture
Category B (after initial term)	$3.58	$3.67	per Month, per Fixture
Category C (after initial term)	$4.18	$4.28	per Month, per Fixture
Category D (after initial term)	$4.78	$4.89	per Month, per Fixture
Category E (after initial term)	$5.36	$5.48	per Month, per Fixture
Category F (after initial term)	$5.95	$6.08	per Month, per Fixture
Category G (after initial term)	$6.55	$6.69	per Month, per Fixture
Category H (after initial term)	$7.14	$7.29	per Month, per Fixture
Category I (after initial term)	$7.73	$7.88	per Month, per Fixture
Non-standard lighting fixture			
Category A	$5.65	$5.73	per Month, per Fixture
Category B	$6.16	$6.25	per Month, per Fixture
Category C	$6.76	$6.86	per Month, per Fixture
Category D	$7.36	$7.47	per Month, per Fixture
Category E	$7.94	$8.06	per Month, per Fixture
Category F	$8.53	$8.66	per Month, per Fixture
Category G	$9.13	$9.27	per Month, per Fixture
Category H	$9.72	$9.87	per Month, per Fixture
Category I	$10.31	$10.46	per Month, per Fixture
Category J	$10.90	$11.06	per Month, per Fixture
Category K	$11.49	$11.66	per Month, per Fixture
Category L	$12.09	$12.27	per Month, per Fixture
Category M	$12.68	$12.87	per Month, per Fixture
Category N	$13.27	$13.47	per Month, per Fixture
Category O	$13.86	$14.07	per Month, per Fixture
Category P	$14.46	$14.68	per Month, per Fixture
Category Q	$15.05	$15.28	per Month, per Fixture
Category R	$15.63	$15.86	per Month, per Fixture
Category S	$16.23	$16.47	per Month, per Fixture
Category T	$16.83	$17.08	per Month, per Fixture

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
LED (continued)			
Customer Charge (continued)			
Non-standard lighting fixture (continued)			
Category A (early removal)	$2.58	$2.58	per Month, per Fixture
Category B (early removal)	$2.58	$2.58	per Month, per Fixture
Category C (early removal)	$2.58	$2.58	per Month, per Fixture
Category D (early removal)	$2.58	$2.58	per Month, per Fixture
Category E (early removal)	$2.58	$2.58	per Month, per Fixture
Category F (early removal)	$2.58	$2.58	per Month, per Fixture
Category G (early removal)	$2.58	$2.58	per Month, per Fixture
Category H (early removal)	$2.58	$2.58	per Month, per Fixture
Category I (early removal)	$2.58	$2.58	per Month, per Fixture
Category J (early removal)	$2.58	$2.58	per Month, per Fixture
Category K (early removal)	$2.58	$2.58	per Month, per Fixture
Category L (early removal)	$2.58	$2.58	per Month, per Fixture
Category M (early removal)	$2.58	$2.58	per Month, per Fixture
Category N (early removal)	$2.58	$2.58	per Month, per Fixture
Category O (early removal)	$2.58	$2.58	per Month, per Fixture
Category P (early removal)	$2.58	$2.58	per Month, per Fixture
Category Q (early removal)	$2.58	$2.58	per Month, per Fixture
Category R (early removal)	$2.58	$2.58	per Month, per Fixture
Category S (early removal)	$2.58	$2.58	per Month, per Fixture
Category T (early removal)	$2.58	$2.58	per Month, per Fixture
Category A (after initial term)	$3.07	$3.15	per Month, per Fixture
Category B (after initial term)	$3.58	$3.67	per Month, per Fixture
Category C (after initial term)	$4.18	$4.28	per Month, per Fixture
Category D (after initial term)	$4.78	$4.89	per Month, per Fixture
Category E (after initial term)	$5.36	$5.48	per Month, per Fixture
Category F (after initial term)	$5.95	$6.08	per Month, per Fixture
Category G (after initial term)	$6.55	$6.69	per Month, per Fixture
Category H (after initial term)	$7.14	$7.29	per Month, per Fixture
Category I (after initial term)	$7.73	$7.88	per Month, per Fixture
Category J (after initial term)	$8.32	$8.48	per Month, per Fixture
Category K (after initial term)	$8.91	$9.08	per Month, per Fixture
Category L (after initial term)	$9.51	$9.69	per Month, per Fixture
Category M (after initial term)	$10.10	$10.29	per Month, per Fixture
Category N (after initial term)	$10.69	$10.89	per Month, per Fixture
Category O (after initial term)	$11.28	$11.49	per Month, per Fixture
Category P (after initial term)	$11.88	$12.10	per Month, per Fixture
Category Q (after initial term)	$12.47	$12.70	per Month, per Fixture
Category R (after initial term)	$13.05	$13.28	per Month, per Fixture
Category S (after initial term)	$13.65	$13.89	per Month, per Fixture
Category T (after initial term)	$14.25	$14.50	per Month, per Fixture

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
LED (continued)			
Energy Charge			
0-3 kWh	$0.29000	$0.29000	per Month, per Fixture
4-6 kWh	$0.58000	$0.59000	per Month, per Fixture
7-9 kWh	$0.86000	$0.87000	per Month, per Fixture
10-12 kWh	$1.15000	$1.17000	per Month, per Fixture
13-15 kWh	$1.45000	$1.47000	per Month, per Fixture
16-18 kWh	$1.73000	$1.76000	per Month, per Fixture
19-21 kWh	$2.02000	$2.05000	per Month, per Fixture
22-24 kWh	$2.32000	$2.35000	per Month, per Fixture
25-27 kWh	$2.61000	$2.65000	per Month, per Fixture
28-30 kWh	$2.89000	$2.93000	per Month, per Fixture
31-33 kWh	$3.18000	$3.23000	per Month, per Fixture
34-36 kWh	$3.47000	$3.52000	per Month, per Fixture
37-39 kWh	$3.76000	$3.82000	per Month, per Fixture
40-42 kWh	$4.05000	$4.11000	per Month, per Fixture
43-45 kWh	$4.33000	$4.39000	per Month, per Fixture
46-48 kWh	$4.62000	$4.69000	per Month, per Fixture
49-51 kWh	$4.92000	$4.99000	per Month, per Fixture
52-54 kWh	$5.20000	$5.28000	per Month, per Fixture
55-57 kWh	$5.48000	$5.56000	per Month, per Fixture
58-60 kWh	$5.79000	$5.88000	per Month, per Fixture
61-63 kWh	$6.08000	$6.17000	per Month, per Fixture
64-66 kWh	$6.36000	$6.46000	per Month, per Fixture
67-69 kWh	$6.65000	$6.75000	per Month, per Fixture
70-72 kWh	$6.94000	$7.04000	per Month, per Fixture
73-75 kWh	$7.23000	$7.34000	per Month, per Fixture
76-78 kWh	$7.52000	$7.63000	per Month, per Fixture
79-81 kWh	$7.80000	$7.92000	per Month, per Fixture
82-84 kWh	$8.10000	$8.22000	per Month, per Fixture
85-87 kWh	$8.39000	$8.52000	per Month, per Fixture
88-90 kWh	$8.67000	$8.80000	per Month, per Fixture
91-93 kWh	$8.96000	$9.09000	per Month, per Fixture
94-96 kWh	$9.25000	$9.39000	per Month, per Fixture
97-99 kWh	$9.55000	$9.69000	per Month, per Fixture
100-102 kWh	$9.83000	$9.98000	per Month, per Fixture
103-105 kWh	$10.12000	$10.27000	per Month, per Fixture
106-108 kWh	$10.41000	$10.57000	per Month, per Fixture
109-111 kWh	$10.71000	$10.87000	per Month, per Fixture
112-114 kWh	$10.99000	$11.15000	per Month, per Fixture
115-117 kWh	$11.27000	$11.44000	per Month, per Fixture
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2025	
Embedded Credits for Line Extensions			
Rg1, Rg2 & Fg1 Single Phase	$1,615	$1,757	per Customer
Rg1, Rg2 & Fg1 Three Phase	$4,036	$4,392	per Customer
Cg1 & Cg6 Single Phase	$1,836	$2,002	per Customer
Cg1 & Cg6 Three Phase	$3,671	$4,004	per Customer
Cg2, Cg3, Cg3C & Cg3S	$131.36	$148.31	per kW
TE1 & TE2	$6.93	$7.68	per Customer
General Primary	$128.88	$146.78	per kW
Standard Street Lighting	$104.38	$106.16	per Lamp
Act 141 Costs Embedded in Base Rates			
Rg1, Rg2, Fg1	$0.00176	$0.00191	per kWh
Cg1, Cg2, Cg3, Cg3C, Cg6, TSSM, TSSU,	$0.00227	$0.00258	per kWh
Cp1, Cp3, Cp4, CpFN	$0.00227	$0.00258	per kWh
Gl1, St1, St2, Al1, Ms1, Ms2, Ms3, Ms4, Mg1, TE1, LED	$0.00227	$0.00258	per kWh

Comparison of Bills for Residential and Farm

A	B	C	D	E	F	G

Rg1

Monthly Use (kWh)	Typical Bills					
	Current Rates		Authorized 2025		Authorized 2025 Change	
	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$49.31	$591.72	$51.65	$619.80	4.75%	$2.34
300	$66.46	$797.52	$69.97	$839.64	5.28%	$3.51
500	$100.77	$1,209.24	$106.62	$1,279.44	5.81%	$5.85
660	**$128.22**	**$1,538.64**	**$135.94**	**$1,631.28**	**6.02%**	**$7.72**
700	$135.08	$1,620.96	$143.27	$1,719.24	6.06%	$8.19
1,000	$186.54	$2,238.48	$198.25	$2,379.00	6.28%	$11.71
2,000	$358.08	$4,296.96	$381.50	$4,578.00	6.54%	$23.42
3,000	$529.62	$6,355.44	$564.75	$6,777.00	6.63%	$35.13

Fg1

Monthly Use (kWh)	Typical Bills					
	Current Rates		Authorized 2025		Authorized 2025 Change	
	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$49.31	$591.72	$51.65	$619.80	4.75%	$2.34
300	$66.46	$797.52	$69.97	$839.64	5.28%	$3.51
500	$100.77	$1,209.24	$106.62	$1,279.44	5.81%	$5.85
600	$117.92	$1,415.04	$124.95	$1,499.40	5.96%	$7.03
700	$135.08	$1,620.96	$143.27	$1,719.24	6.06%	$8.19
1,000	$186.54	$2,238.48	$198.25	$2,379.00	6.28%	$11.71
2,000	$358.08	$4,296.96	$381.50	$4,578.00	6.54%	$23.42
3,000	$529.62	$6,355.44	$564.75	$6,777.00	6.63%	$35.13

Rg2

Monthly Use (kWh)	Typical Bills					
	Current Rates		Authorized 2025		Authorized 2025 Change	
	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$44.57	$534.82	$46.61	$559.27	4.57%	$2.04
300	$59.35	$712.23	$62.41	$748.90	5.15%	$3.06
500	$88.92	$1,067.05	$94.01	$1,128.16	5.73%	$5.09
600	$103.71	$1,244.46	$109.82	$1,317.80	5.89%	$6.11
700	$118.49	$1,421.88	$125.62	$1,507.43	6.02%	$7.13
1,000	$162.84	$1,954.11	$173.03	$2,076.33	6.25%	$10.19
2,000	$310.68	$3,728.22	$331.05	$3,972.66	6.56%	$20.37
3,000	$458.53	$5,502.32	$489.08	$5,868.99	6.66%	$30.56

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	7,613,909	$1,490,486,513	$1,657,051,294	11.18%		
Fg1	136,503	$25,354,205	$28,340,881	11.78%		
Rg2	224,436	$35,910,289	$39,904,642	11.12%		
Total Residential & Farm	7,974,849	$1,551,751,007	$1,725,296,816	11.18%		
Cg1	1,676,121	$281,946,478	$313,131,465	11.06%		
Cg6	114,136	$17,953,715	$19,642,534	9.41%		
TE1 & TE2	164	$33,445	$36,495	9.12%		
TSS	4,832	$910,975	$1,000,941	9.88%		
Total Small General Secondary	1,795,253	$300,844,614	$333,811,435	10.96%		
Total Small Customer Class	**9,770,101**	**$1,852,595,621**	**$2,059,108,251**	**11.15%**		
Cg2	**1,463,108**	**$205,933,623**	**$221,380,634**	**7.50%**		
Cg3	5,286,619	$679,738,841	$734,914,799	8.12%		
Cg3C	30,672	$3,609,041	$3,916,404	8.52%		
Cg3S	10,652	$1,402,131	$1,522,560	8.59%		
Total Large General Secondary	5,327,943	$684,750,013	$740,353,763	8.12%		
Total General Secondary	8,586,304	$1,191,528,250	$1,295,545,832	8.73%		
Cp1 Low	201,607	$23,319,445	$24,587,339	5.44%		
Cp1 Medium	4,334,560	$465,491,939	$489,094,707	5.07%		
Cp1 High	45,820	$4,626,244	$4,885,539	5.60%		
Cp3 Medium	415,484	$46,306,327	$49,493,388	6.88%		
Cp3S Low	7,723	$835,475	$894,039	7.01%		
Cp3S Medium	47,675	$5,425,374	$5,812,168	7.13%		
CpFN Medium	386,662	$34,968,453	$37,553,177	7.39%		
CpFN High	96,665	$8,636,291	$9,346,015	8.22%		
RTMP	884,651	$36,584,300	$37,767,096	3.23%		
RTP	388,216	$19,729,945	$19,730,436	0.00%		
Total General Primary	6,809,065	$645,923,792	$679,163,904	5.15%		
Gen Pri Other	2,693,747	$186,551,047	$186,551,047	0.00%		
Total Large Customer Class	**14,830,755**	**$1,517,224,852**	**$1,606,068,713**	**5.86%**		
Gl1	18,750	$5,208,060	$5,776,837	10.92%		
St1 & St2	47,806	$4,757,144	$5,337,988	12.21%		
Al1	2,705	$707,354	$796,322	12.58%		
Ms1	1,717	$361,239	$392,840	8.75%		
Ms2	4,416	$658,158	$743,508	12.97%		
Ms3	26,151	$6,225,968	$7,011,018	12.61%		
Ms4	12,294	$4,450,678	$4,771,355	7.21%		
LED	6,763	$5,331,193	$5,572,069	4.52%		
Mg1	66	$10,811	$12,045	11.42%		
Total Street Lighting & Other	**120,669**	**$27,710,605**	**$30,413,981**	9.76%		
COEV-R	0	$75,312	$75,312	0.00%		
WHEV-R	0	$1,392	$1,392	0.00%		
EV-C	0	$88,440	$88,440	0.00%		
Total EV Customer Class	**0**	**$165,144**	**$165,144**	0.00%		
RPP1		$125,475	$125,475	0.00%		
RPP5		$604,977	$604,977	0.00%		
DRER		$615,596	$615,596	0.00%		
EFT - Residential		$574,029	$574,029	0.00%		
EFT - C&I Small		$282,164	$282,164	0.00%		
EFT - C&I Large		$120,963	$120,963	0.00%		
Total Misc Customer Class		**$2,323,203**	**$2,323,203**	0.00%		
Total Wisconsin Retail	**26,184,633**	**$3,605,953,048**	**$3,919,459,928**	**8.69%**	**$3,919,459,910**	$18

Electric Rate Design - Test Year 2026
We Energies

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	373,947,975	$0.49315	$184,412,444	373,947,975	$0.49315	$184,412,444	0.00%
Three PH per day	137,970	$0.49315	$68,040	137,970	$0.49315	$68,040	0.00%
Extra Meter per day	594,585	$0.05951	$35,384	594,585	$0.05951	$35,384	0.00%
Energy charge	7,612,580,999	$0.17154	$1,305,862,145	7,612,580,999	$0.19342	$1,472,425,417	12.76%
Fuel cost adjustment	7,612,580,999	$0.00000	$0	7,612,580,999	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,169,486	-$0.00176	-$5,578	3,169,486	-$0.00191	-$6,054	8.52%
Total Revenue: Residential Flat Rate - Rg1			**$1,490,372,434**			**$1,656,935,231**	
Farm Flat Rate - Fg1							
Customer charge							
Single PH per day	3,702,614	$0.49315	$1,825,944	3,702,614	$0.49315	$1,825,944	0.00%
Three PH per day	199,284	$0.49315	$98,277	199,284	$0.49315	$98,277	0.00%
Extra Meter per day	242,360	$0.05951	$14,423	242,360	$0.05951	$14,423	0.00%
Energy charge	136,503,495	$0.17154	$23,415,810	136,503,495	$0.19342	$26,402,506	12.76%
Fuel cost adjustment	136,503,495	$0.00000	$0	136,503,495	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	140,904	-$0.00176	-$248	140,904	-$0.00191	-$269	8.52%
Total Revenue: Farm Flat Rate - Fg1			**$25,354,205**			**$28,340,881**	
Residential Small TOU - Rg2							
Customer charge							
Single PH per day	5,502,289	$0.49315	$2,713,454	5,502,289	$0.49315	$2,713,454	0.00%
Three PH per day	14,934	$0.49315	$7,365	14,934	$0.49315	$7,365	0.00%
Extra Meter per day	133,225	$0.05951	$7,928	133,225	$0.05951	$7,928	0.00%
Energy charge							
On-peak	73,144,240	$0.23382	$17,102,586	73,144,240	$0.30084	$22,004,713	28.66%
Off-peak	151,291,419	$0.10628	$16,079,252	151,291,419	$0.10028	$15,171,503	-5.65%
Fuel cost adjustment							
Adjustment	224,435,659	$0.00000	$0	224,435,659	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	168,392	-$0.00176	-$296	168,392	-$0.00191	-$322	8.52%
Total Revenue: Residential Small TOU - Rg2			**$35,910,289**			**$39,904,642**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
Residential Charger Only EV - COEV-R							
Fixed service and administration charge							
Bundled service per month	3,324	$20.00000	$66,480	3,324	$20.00000	$66,480	0.00%
Pre-paid service per month	1,104	$8.00000	$8,832	1,104	$8.00000	$8,832	0.00%
Energy charge							
On-peak (summer)	26,568	$0.28733	$7,634	26,568	$0.30862	$8,199	7.41%
On-peak (non-summer)	26,568	$0.18007	$4,784	26,568	$0.19342	$5,139	7.41%
Intermediate-peak (summer)	39,852	$0.18007	$7,176	39,852	$0.19342	$7,708	7.41%
Intermediate-peak (non-summer)	39,852	$0.18007	$7,176	39,852	$0.19342	$7,708	7.41%
Off-peak (summer)	597,756	$0.07303	$43,654	597,756	$0.07303	$43,654	0.00%
Off-peak (non-summer)	597,756	$0.07303	$43,654	597,756	$0.07303	$43,654	0.00%
Fuel cost adjustment	1,328,352	$0.00000	$0	1,328,352	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Residential Charger Only EV - COEV-R			**$189,391**			**$191,375**	
Total Fixed Charge Revenue: Residential Charger Only EV - COEV-R			$75,312			$75,312	
Residential Whole Home EV - WHEV-R							
Fixed service and administration charge							
Bundled service per month	60	$20.00000	$1,200	60	$20.00000	$1,200	0.00%
Pre-paid service per month	24	$8.00000	$192	24	$8.00000	$192	0.00%
Total Revenue: Residential Whole Home EV - WHEV-R			**$1,392**			**$1,392**	
Commercial Electric Vehicle EV-C							
Fixed service and administration charge							
Bundled-single port, per month per port A	884	$24.00000	$21,216	884	$24.00000	$21,216	0.00%
Bundled-single port, per month per port B	849	$25.00000	$21,216	849	$25.00000	$21,216	0.00%
Bundled-single port, per month per port C	881	$25.00000	$22,032	881	$25.00000	$22,032	0.00%
Bundled-dual port, per month per port A	299	$26.00000	$7,776	299	$26.00000	$7,776	0.00%
Bundled-dual port, per month per port B	312	$26.00000	$8,100	312	$26.00000	$8,100	0.00%
Bundled-dual port, per month per port C	300	$27.00000	$8,100	300	$27.00000	$8,100	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			**$88,440**			**$88,440**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
General Secondary Flat Rate - Cg1							
Customer charge							
Single PH per day	24,726,287	$0.49315	$12,193,768	24,726,287	$0.49315	$12,193,768	0.00%
Three PH per day	10,920,056	$0.49315	$5,385,226	10,920,056	$0.49315	$5,385,226	0.00%
Extra Meter per day	6,032,355	$0.05951	$358,985	6,032,355	$0.05951	$358,985	0.00%
Energy charge	1,676,121,194	$0.15759	$264,139,939	1,676,121,194	$0.17621	$295,349,316	11.82%
Fuel cost adjustment	1,676,121,194	$0.00000	$0	1,676,121,194	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	84,103,607	-$0.00227	-$190,915	84,103,607	-$0.00256	-$215,305	12.78%
Act 141 capped contribution	84,103,607	$0.00071	$59,475	84,103,607	$0.00071	$59,475	0.00%
Total Revenue: General Secondary Flat Rate - Cg1			**$281,946,478**			**$313,131,465**	
General Secondary Small TOU - Cg6							
Customer charge							
Single PH per day	2,199,382	$0.49315	$1,084,625	2,199,382	$0.49315	$1,084,625	0.00%
Three PH per day	142,744	$0.49315	$70,394	142,744	$0.49315	$70,394	0.00%
Extra Meter per day	180,675	$0.05951	$10,752	180,675	$0.05951	$10,752	0.00%
Energy charge							
On-peak	37,315,297	$0.23324	$8,703,420	37,315,297	$0.29475	$10,998,684	26.37%
Off-peak	76,820,956	$0.10601	$8,143,790	76,820,956	$0.09825	$7,547,659	-7.32%
Fuel cost adjustment							
Adjustment	114,136,253	$0.00000	$0	114,136,253	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	35,566,029	-$0.00227	-$80,735	35,566,029	-$0.00256	-$91,049	12.78%
Act 141 capped contribution	35,566,029	$0.00060	$21,469	35,566,029	$0.00060	$21,469	0.00%
Total Revenue: General Secondary Small TOU - Cg6			**$17,953,715**			**$19,642,534**	
General Secondary Transmission Substations - TSSM & TSSU							
Customer charge							
TSSM Single PH per day	13,870	$0.49315	$6,840	13,870	$0.49315	$6,840	0.00%
TSSM Three PH per day	0	$0.49315	$0	0	$0.49315	$0	0.00%
TSSU Customer charge per month	33,580	$4.25000	$142,715	33,580	$4.25000	$142,715	0.00%
TSSM Extra Meter per day	0	$0.05951	$0	0	$0.05951	$0	0.00%
Energy charge							
TSSM annual	701,506	$0.15759	$110,550	701,506	$0.17621	$123,612	11.82%
TSSU annual	4,130,148	$0.15759	$650,870	4,130,148	$0.17621	$727,773	11.82%
Fuel cost adjustment	4,831,654	$0.00000	$0	4,831,654	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00256	$0	12.78%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Transmission Substations - TSSM & TSSU			**$910,975**			**$1,000,941**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Secondary Small TOU Demand - Cg2							
Customer charge							
Customer charge per day	3,225,850	$1.32000	$4,258,122	3,225,850	$1.32000	$4,258,122	0.00%
Extra Meter per day	3,763,515	$0.18542	$697,831	3,763,515	$0.18542	$697,831	0.00%
Energy charge							
On-peak	656,958,372	$0.12625	$82,940,994	656,958,372	$0.13521	$88,827,341	7.10%
Off-peak	806,149,301	$0.09018	$72,698,544	806,149,301	$0.09658	$77,857,899	7.10%
Demand charge							
On-peak minimum	1,372,542	$2.98400	$4,095,665	1,372,542	$3.27400	$4,493,703	9.72%
On-peak adjusted	396,639	$4.79900	$1,903,471	396,639	$5.26600	$2,088,701	9.73%
On-peak regular	3,528,166	$7.78300	$27,459,716	3,528,166	$8.54000	$30,130,538	9.73%
Customer maximum	4,900,704	$2.46000	$12,055,732	4,900,704	$2.70000	$13,231,901	9.76%
Fuel cost adjustment							
Adjustment	1,463,107,673	$0.00000	$0	1,463,107,673	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	99,824,755	-$0.00227	-$226,602	99,824,755	-$0.00256	-$255,551	12.78%
Act 141 capped contribution	99,824,755	$0.00050	$50,150	99,824,755	$0.00050	$50,150	0.00%
Total Revenue: General Secondary Small TOU Demand - Cg2			**$205,933,623**			**$221,380,634**	
General Secondary Large TOU - Cg3							
Customer charge							
Customer charge per day	2,251,300	$2.00000	$4,502,600	2,251,300	$2.00000	$4,502,600	0.00%
Extra Meter per day	1,540,665	$0.20000	$308,133	1,540,665	$0.20000	$308,133	0.00%
Energy charge							
On-peak	2,252,933,123	$0.09057	$204,048,153	2,252,933,123	$0.09761	$219,908,802	7.77%
Off-peak	3,033,686,199	$0.05660	$171,706,639	3,033,686,199	$0.06000	$182,021,172	6.01%
Demand charge							
On-peak minimum	1,112,379	$7.29900	$8,119,254	1,112,379	$8.00900	$8,909,043	9.73%
On-peak adjusted	304,997	$11.01400	$3,359,237	304,997	$12.08600	$3,686,194	9.73%
On-peak regular	12,851,697	$18.31300	$235,353,127	12,851,697	$20.09500	$258,254,851	9.73%
Customer maximum	17,712,139	$3.07500	$54,464,827	17,712,139	$3.37500	$59,778,469	9.76%
Fuel cost adjustment							
Adjustment	5,286,619,322	$0.00000	$0	5,286,619,322	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,142,538,270	-$0.00227	-$2,593,562	1,142,538,270	-$0.00256	-$2,924,898	12.78%
Act 141 capped contribution	1,142,538,270	$0.00041	$470,432	1,142,538,270	$0.00041	$470,432	0.00%
Total Revenue: General Secondary Large TOU - Cg3			**$679,738,841**			**$734,914,799**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Secondary Curtailable- Cg3C							
Customer charge							
Customer charge per day	9,125	$3.85000	$35,131	9,125	$3.85000	$35,131	0.00%
Extra Meter per day	0	$0.20000	$0	0	$0.20000	$0	0.00%
Energy charge							
On-peak	11,707,357	$0.09057	$1,060,335	11,707,357	$0.09761	$1,142,755	7.77%
Off-peak	18,964,781	$0.05660	$1,073,407	18,964,781	$0.06000	$1,137,887	6.01%
Curtailable credit	9,997,907	-$0.02080	-$207,956	9,997,907	-$0.02080	-$207,956	0.00%
Demand charge							
On-peak minimum	7,837	$7.29900	$57,202	7,837	$8.00900	$62,767	9.73%
On-peak adjusted	3,354	$11.01400	$36,941	3,354	$12.08600	$40,536	9.73%
On-peak regular	65,751	$18.31300	$1,204,098	65,751	$20.09500	$1,321,266	9.73%
Customer maximum	113,783	$3.07500	$349,883	113,783	$3.37500	$384,018	9.76%
Fuel cost adjustment							
Adjustment	30,672,138	$0.00000	$0	30,672,138	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	0	-$0.00227	$0	0	-$0.00256	$0	12.78%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Secondary Curtailable- Cg3C			**$3,609,041**			**$3,916,404**	
General Secondary Seasonal Curtailable - Cg3S							
Customer charge							
Customer charge per day	2,555	$3.85000	$9,837	2,555	$3.85000	$9,837	0.00%
Extra Meter per day	0	$0.20000	$0	0	$0.20000	$0	0.00%
Energy charge							
On-peak	5,094,859	$0.09057	$461,441	5,094,859	$0.09761	$497,309	7.77%
Off-peak	5,556,737	$0.05660	$314,511	5,556,737	$0.06000	$333,404	6.01%
Demand charge							
On-peak minimum	6,791	$7.29900	$49,568	6,791	$8.00900	$54,389	9.73%
On-peak adjusted	2,764	$11.01400	$30,443	2,764	$12.08600	$33,406	9.73%
On-peak regular	26,081	$18.31300	$477,621	26,081	$20.09500	$524,098	9.73%
Curtailable credit	32,870	-$2.00000	-$65,740	32,870	-$2.00000	-$65,740	0.00%
Customer maximum	45,084	$3.07500	$138,633	45,084	$3.37500	$152,159	9.76%
Fuel cost adjustment							
Adjustment	10,651,596	$0.00000	$0	10,651,596	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	7,302,622	-$0.00227	-$16,577	7,302,622	-$0.00256	-$18,695	12.78%
Act 141 capped contribution	7,302,622	$0.00033	$2,394	7,302,622	$0.00033	$2,394	0.00%
Total Revenue: General Secondary Seasonal Curtailable - Cg3S			**$1,402,131**			**$1,522,560**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
General Primary - Cp1							
Customer charge							
Customer charge per day-low voltage	11,680	$19.76010	$230,798	11,680	$19.76010	$230,798	0.00%
Customer charge per day-med voltage	156,585	$19.76010	$3,094,135	156,585	$19.76010	$3,094,135	0.00%
Customer charge per day-high voltage	1,095	$19.76010	$21,637	1,095	$19.76010	$21,637	0.00%
Energy charge-low voltage							
On-peak (summer)	29,827,376	$0.09552	$2,849,111	29,827,376	$0.09912	$2,956,490	3.77%
On-peak (non-summer)	52,760,565	$0.08290	$4,373,851	52,760,565	$0.08603	$4,538,991	3.78%
Off-peak (summer)	42,019,573	$0.06206	$2,607,735	42,019,573	$0.06440	$2,706,061	3.77%
Off-peak (non-summer)	76,999,942	$0.06206	$4,778,616	76,999,942	$0.06440	$4,958,796	3.77%
Energy charge-med voltage							
On-peak (summer)	605,758,619	$0.09444	$57,207,844	605,758,619	$0.09800	$59,364,345	3.77%
On-peak (non-summer)	1,085,113,030	$0.08196	$88,935,864	1,085,113,030	$0.08505	$92,288,863	3.77%
Off-peak (summer)	938,950,764	$0.06018	$56,506,057	938,950,764	$0.06246	$58,646,865	3.79%
Off-peak (non-summer)	1,704,737,881	$0.06018	$102,591,126	1,704,737,881	$0.06246	$106,477,928	3.79%
Energy charge-high voltage							
On-peak (summer)	5,614,096	$0.09353	$525,086	5,614,096	$0.09705	$544,848	3.76%
On-peak (non-summer)	10,085,083	$0.08117	$818,606	10,085,083	$0.08423	$849,467	3.77%
Off-peak (summer)	10,714,755	$0.05960	$638,599	10,714,755	$0.06185	$662,708	3.78%
Off-peak (non-summer)	19,405,940	$0.05960	$1,156,594	19,405,940	$0.06185	$1,200,257	3.78%
Demand charge-low voltage							
On-peak (summer)	157,485	$20.66900	$3,255,057	157,485	$22.58700	$3,557,114	9.28%
On-peak (non-summer)	276,509	$14.87000	$4,111,689	276,509	$16.25000	$4,493,271	9.28%
Customer maximum	572,945	$2.33800	$1,339,545	572,945	$2.39600	$1,372,776	2.48%
Demand charge-med voltage							
On-peak (summer)	3,071,090	$20.43400	$62,754,653	3,071,090	$22.33100	$68,580,511	9.28%
On-peak (non-summer)	5,566,454	$14.70100	$81,832,440	5,566,454	$16.06600	$89,430,650	9.29%
Customer maximum	10,884,515	$2.31100	$25,154,114	10,884,515	$2.36900	$25,785,416	2.51%
Demand charge-high voltage							
On-peak (summer)	31,261	$20.23600	$632,598	31,261	$22.11500	$691,337	9.29%
On-peak (non-summer)	60,771	$14.55800	$884,704	60,771	$15.91000	$966,867	9.29%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	4,581,987,624	$0.00000	$0	4,581,987,624	$0.00000	$0	0.00%
Other							
Load factor credit	515,812,656	-$0.01000	-$5,158,127	515,812,656	-$0.01000	-$5,158,127	0.00%
SIC 4952 on-peak demand credit	75,229	$0.00000	$0	75,229	-$9.07700	-$682,854	0.00%
SIC 4952 customer maximum demand credit	237,966	$0.00000	$0	237,966	-$0.59200	-$140,876	0.00%
Act 141 capped credits	4,020,627,111	-$0.00227	-$9,126,824	4,020,627,111	-$0.00256	-$10,292,805	12.78%
Act 141 capped contribution	4,020,627,111	$0.00035	$1,422,117	4,020,627,111	$0.00035	$1,422,117	0.00%
Total Revenue: General Primary - Cp1			**$493,437,628**			**$518,567,585**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Primary Curtailable - Cp3							
Customer charge							
Customer charge per day-low voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-med voltage	8,760	$19.76010	$173,098	8,760	$19.76010	$173,098	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Energy charge-low voltage							
On-peak	0	$0.08530	$0	0	$0.09040	$0	5.98%
Off-peak	0	$0.06077	$0	0	$0.06441	$0	5.99%
Curtailable credit	0	-$0.02028	$0	0	-$0.02028	$0	0.00%
Energy charge-med voltage							
On-peak	162,738,800	$0.08433	$13,723,763	162,738,800	$0.08937	$14,543,967	5.98%
Off-peak	252,745,674	$0.06006	$15,179,905	252,745,674	$0.06365	$16,087,262	5.98%
Curtailable credit	76,889,245	-$0.02000	-$1,537,785	76,889,245	-$0.02000	-$1,537,785	0.00%
Energy charge-high voltage							
On-peak	0	$0.08351	$0	0	$0.08850	$0	5.98%
Off-peak	0	$0.05836	$0	0	$0.06184	$0	5.96%
Curtailable credit	0	-$0.01970	$0	0	-$0.01970	$0	0.00%
Demand charge-low voltage							
On-peak	0	$16.80300	$0	0	$18.36200	$0	9.28%
Customer maximum	0	$2.33800	$0	0	$2.39600	$0	2.48%
Demand charge-med voltage							
On-peak	936,404	$16.61200	$15,555,543	936,404	$18.15400	$16,999,478	9.28%
Customer maximum	1,603,451	$2.31100	$3,705,575	1,603,451	$2.36900	$3,798,575	2.51%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.97800	$0	9.28%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	415,484,474	$0.00000	$0	415,484,474	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	267,014,599	-$0.00227	-$606,123	267,014,599	-$0.00256	-$683,557	12.78%
Act 141 capped contribution	267,014,599	$0.00042	$112,350	267,014,599	$0.00042	$112,350	0.00%
Total Revenue: General Primary Curtailable - Cp3			**$46,306,327**			**$49,493,388**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
General Primary Seasonal Curtailable - Cp3S							
Customer charge							
Customer charge per day-low voltage	730	$19.76010	$14,425	730	$19.76010	$14,425	0.00%
Customer charge per day-med voltage	1,095	$19.76010	$21,637	1,095	$19.76010	$21,637	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Energy charge-low voltage							
On-peak	2,700,099	$0.08530	$230,318	2,700,099	$0.09040	$244,089	5.98%
Off-peak	5,023,181	$0.06077	$305,259	5,023,181	$0.06441	$323,543	5.99%
Energy charge-med voltage							
On-peak	19,320,943	$0.08433	$1,629,335	19,320,943	$0.08937	$1,726,713	5.98%
Off-peak	28,353,706	$0.06006	$1,702,924	28,353,706	$0.06365	$1,804,713	5.98%
Energy charge-high voltage							
On-peak	0	$0.08351	$0	0	$0.08850	$0	5.98%
Off-peak	0	$0.05836	$0	0	$0.06184	$0	5.96%
Demand charge-low voltage							
On-peak	16,301	$16.80300	$273,906	16,301	$18.36200	$299,319	9.28%
Customer maximum	18,892	$2.33800	$44,169	18,892	$2.39600	$45,265	2.48%
Curtailable credit	16,301	-$2.00000	-$32,602	16,301	-$2.00000	-$32,602	0.00%
Demand charge-med voltage							
On-peak	120,915	$16.61200	$2,008,640	120,915	$18.15400	$2,195,091	9.28%
Customer maximum	153,202	$2.31100	$354,050	153,202	$2.36900	$362,936	2.51%
Curtailable credit	120,915	-$2.00000	-$241,830	120,915	-$2.00000	-$241,830	0.00%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.97800	$0	9.28%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Curtailable credit	0	-$2.00000	$0	0	-$2.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	55,397,929	$0.00000	$0	55,397,929	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	26,586,143	-$0.00227	-$60,351	26,586,143	-$0.00256	-$68,061	12.78%
Act 141 capped contribution	26,586,143	$0.00041	$10,968	26,586,143	$0.00041	$10,968	0.00%
Total Revenue: General Primary Seasonal Curtailable - Cp3S			**$6,260,849**			**$6,706,207**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
General Primary Combined Firm & NonFirm - CpFN							
Customer charge							
Customer charge per day-med voltage	6,935	$26.30137	$182,400	6,935	$26.30137	$182,400	0.00%
Customer charge per day-high voltage	365	$26.30137	$9,600	365	$26.30137	$9,600	0.00%
Energy charge-med voltage							
On-peak firm	7,527,270	$0.08433	$634,775	7,527,270	$0.08937	$672,712	5.98%
On-peak non-firm	140,327,910	$0.07845	$11,008,725	140,327,910	$0.08313	$11,665,459	5.97%
Off-peak firm	13,654,136	$0.05893	$804,638	13,654,136	$0.06246	$852,837	5.99%
Off-peak non-firm	225,152,440	$0.05482	$12,342,857	225,152,440	$0.05810	$13,081,357	5.98%
Energy charge-high voltage							
On-peak firm	2,502,689	$0.08351	$209,000	2,502,689	$0.08850	$221,488	5.98%
On-peak non-firm	29,932,179	$0.07768	$2,325,132	29,932,179	$0.08233	$2,464,316	5.99%
Off-peak firm	4,708,535	$0.05836	$274,790	4,708,535	$0.06185	$291,223	5.98%
Off-peak non-firm	59,522,037	$0.05429	$3,231,451	59,522,037	$0.05753	$3,424,303	5.97%
Demand charge-med voltage							
On-peak firm	30,983	$16.61200	$514,690	30,983	$18.15400	$562,465	9.28%
On-peak non-firm	736,891	$11.25200	$8,291,498	736,891	$12.79400	$9,427,783	13.70%
Customer maximum	912,908	$2.31100	$2,109,730	912,908	$2.36900	$2,162,679	2.51%
Demand charge-high voltage							
On-peak firm	9,913	$16.45100	$163,079	9,913	$17.97800	$178,216	9.28%
On-peak non-firm	218,487	$11.09100	$2,423,239	218,487	$12.61800	$2,756,869	13.77%
Customer maximum	250,542	$0.00000	$0	250,542	$0.00000	$0	0.00%
Fuel cost adjustment							
Adjustment	483,327,196	$0.00000	$0	483,327,196	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	460,886,290	-$0.00227	-$1,046,212	460,886,290	-$0.00256	-$1,179,869	12.78%
Act 141 capped contribution	460,886,290	$0.00027	$125,353	460,886,290	$0.00027	$125,353	0.00%
Total Revenue: General Primary Combined Firm & NonFirm - CpFN			**$43,604,744**			**$46,899,192**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
General Primary Service - Standby - Cp4							
Customer charge							
Customer charge per day-low voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-med voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Customer charge per day-high voltage	0	$19.76010	$0	0	$19.76010	$0	0.00%
Extra Meter per day	0	$3.14334	$0	0	$3.14334	$0	0.00%
Energy charge-low voltage							
On-peak	0	$0.08711	$0	0	$0.09040	$0	3.78%
Off-peak	0	$0.06206	$0	0	$0.06441	$0	3.79%
Energy charge-med voltage							
On-peak	0	$0.08612	$0	0	$0.08937	$0	3.77%
Off-peak	0	$0.06134	$0	0	$0.06365	$0	3.77%
Energy charge-high voltage							
On-peak	0	$0.08529	$0	0	$0.08850	$0	3.76%
Off-peak	0	$0.05960	$0	0	$0.06184	$0	3.76%
Demand charge-low voltage							
On-peak	0	$16.80300	$0	0	$18.36200	$0	9.28%
Customer maximum	0	$2.33800	$0	0	$2.39600	$0	2.48%
Reserved	0	$1.99300	$0	0	$1.99300	$0	0.00%
Demand charge-med voltage							
On-peak	0	$16.61200	$0	0	$18.15400	$0	9.28%
Customer maximum	0	$2.31100	$0	0	$2.36900	$0	2.51%
Reserved	0	$1.96400	$0	0	$1.96400	$0	0.00%
Demand charge-high voltage							
On-peak	0	$16.45100	$0	0	$17.97800	$0	9.28%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Reserved	0	$1.93900	$0	0	$1.93900	$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%
Act 141 capped credits	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped contribution	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Primary Service - Standby - Cp4			**$0**			**$0**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
General Primary Service - Real-Time Market Pricing (RTMP)							
Customer charge							
Administration per day	37,230	$5.75300	$214,184	37,230	$5.75300	$214,184	0.00%
Energy charge							
Hourly LMP	884,651,286	$0.03642	$32,217,727	884,651,286	$0.03642	$32,217,727	0.00%
Embedded cost adder	884,651,286	$0.00050	$442,326	884,651,286	$0.00050	$442,326	0.00%
Demand charge							
Transmission demand	850,932	$4.36000	$3,710,064	850,932	$5.75000	$4,892,859	31.88%
Customer maximum	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: General Primary Service - Real-Time Market Pricing (RTMP)			**$36,584,300**			**$37,767,096**	
General Primary Service - Real-Time Pricing (RTP)							
Customer charge							
Customer charge per day	365	$26.30137	$9,600	365	$26.30137	$9,600	0.00%
Extra meter per day	1,095	$3.14334	$3,442	1,095	$3.14334	$3,442	0.00%
Scheduling per month	12	$1,000.000	$12,000	12	$1,000.000	$12,000	0.00%
Energy charge							
Hourly LMP	388,216,002	$0.03666	$14,230,670	388,216,002	$0.03666	$14,230,670	0.00%
Embedded cost adder (firm)	32,576,138	$0.02050	$667,811	32,576,138	$0.02050	$667,811	0.00%
Embedded cost adder (non-firm)	355,639,864	$0.01350	$4,801,138	355,639,864	$0.01350	$4,801,138	0.00%
Demand charge							
On-peak (summer)	105	$20.23600	$2,125	105	$22.11500	$2,322	9.29%
On-peak (non-summer)	217	$14.55800	$3,159	217	$15.91000	$3,452	9.29%
Total Revenue: General Primary Service - Real-Time Pricing (RTP)			**$19,729,945**			**$19,730,436**	
Electronics and Information Technology Manufacturing (EITM)							
Customer charge							
EITM Zone	14	$44,947	$613,315	14	$44,947	$613,315	0.00%
Customer specific	13	$6,950	$93,684	13	$6,950	$93,684	0.00%
Energy charge	2,693,747,328	$0.03466	$93,359,014	2,693,747,328	$0.03466	$93,359,014	0.00%
Demand charge							
Firm service capacity	11,625,050	$3.19845	$37,182,156	11,625,050	$3.19845	$37,182,156	0.00%
Customer maximum	11,625,050	$4.26113	$49,535,867	11,625,050	$4.26113	$49,535,867	0.00%
Gross Receipts Tax	$180,784,036	3.190%	$5,767,011	$180,784,036	3.190%	$5,767,011	0.00%
Total Revenue: Electronics and Information Technology Manufacturing (EITM)			**$186,551,047**			**$186,551,047**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Area Lighting - Gl1							
Standard high pressure sodium							
50 Watt	36	$12.18000	$438	36	$13.72000	$494	12.64%
70 Watt	15,000	$14.45000	$216,750	15,000	$16.27000	$244,050	12.60%
100 Watt	48,000	$15.37000	$737,760	48,000	$17.31000	$830,880	12.62%
150 Watt	3,900	$17.89000	$69,771	3,900	$20.15000	$78,585	12.63%
200 Watt	40,200	$20.90000	$840,180	40,200	$23.53000	$945,906	12.58%
250 Watt	3,360	$23.68000	$79,565	3,360	$26.66000	$89,578	12.58%
400 Watt	40,200	$31.55000	$1,268,310	40,200	$35.53000	$1,428,306	12.61%
Flood high pressure sodium							
70 Watt	348	$14.96000	$5,206	348	$16.85000	$5,864	12.63%
100 Watt	3,120	$18.20000	$56,784	3,120	$20.49000	$63,929	12.58%
150 Watt	336	$19.63000	$6,596	336	$22.10000	$7,426	12.58%
200 Watt	9,780	$22.46000	$219,659	9,780	$25.29000	$247,336	12.60%
250 Watt	432	$25.19000	$10,882	432	$28.37000	$12,256	12.62%
400 Watt	15,000	$32.81000	$492,150	15,000	$36.95000	$554,250	12.62%
Standard metal halide							
175 Watt	60	$28.57000	$1,714	60	$32.17000	$1,930	12.60%
250 Watt	204	$30.01000	$6,122	204	$33.79000	$6,893	12.60%
400 Watt	660	$34.74000	$22,928	660	$39.12000	$25,819	12.61%
Flood metal halide							
175 Watt	204	$30.06000	$6,132	204	$33.85000	$6,905	12.61%
250 Watt	2,100	$31.65000	$66,465	2,100	$35.64000	$74,844	12.61%
400 Watt	11,100	$36.17000	$401,487	11,100	$40.73000	$452,103	12.61%
1000 Watt	120	$68.90000	$8,268	120	$77.58000	$9,310	12.60%
Poles	120,000	$2.80000	$336,000	120,000	$2.80000	$336,000	0.00%
Spans	132,000	$2.73000	$360,360	132,000	$2.73000	$360,360	0.00%
Fuel cost adjustment	18,750,323	$0.00000	$0	18,750,323	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	2,478,384	-$0.00227	-$5,626	2,478,384	-$0.00256	-$6,345	12.78%
Act 141 capped contribution	2,478,384	$0.00006	$158	2,478,384	$0.00006	$158	0.00%
Total Revenue: Area Lighting - Gl1			**$5,208,060**			**$5,776,837**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Street Lighting Small TOU - St1/St2							
Customer charge							
Single PH per day	155,855	$0.49315	$76,860	155,855	$0.49315	$76,860	0.00%
Three PH per day	13,505	$0.49315	$6,660	13,505	$0.49315	$6,660	0.00%
Extra Meter per day	0	$0.05951	$0	0	$0.05951	$0	0.00%
Energy charge-St1							
On-peak	881,423	$0.35386	$311,900	881,423	$0.39802	$350,824	12.48%
Off-peak	6,613,184	$0.06154	$406,975	6,613,184	$0.06922	$457,765	12.48%
Energy charge-St2							
On-Peak	4,740,922	$0.37047	$1,756,369	4,740,922	$0.41670	$1,975,542	12.48%
Off-Peak	35,570,434	$0.06443	$2,291,803	35,570,434	$0.07247	$2,577,789	12.48%
Fuel cost adjustment	47,805,963	$0.00000	$0	47,805,963	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	48,372,769	-$0.00227	-$109,806	48,372,769	-$0.00256	-$123,834	12.78%
Act 141 capped contribution	48,372,769	$0.00034	$16,382	48,372,769	$0.00034	$16,382	0.00%
Total Revenue: Street Lighting Small TOU - St1/St2			**$4,757,144**			**$5,337,988**	
Alley Lighting - Al1							
Lamp sizes							
0 - 10 Watt LED	0	$2.59000	$0	0	$2.91000	$0	12.36%
>10 - 20 Watt LED	0	$2.97000	$0	0	$3.34000	$0	12.46%
>20 - 30 Watt LED	2,100	$3.41000	$7,161	2,100	$3.84000	$8,064	12.61%
>30 - 40 Watt LED	1,464	$3.88000	$5,680	1,464	$4.37000	$6,398	12.63%
>40 - 50 Watt LED	384	$4.34000	$1,667	384	$4.88000	$1,874	12.44%
>50 - 60 Watt LED	0	$4.79000	$0	0	$5.39000	$0	12.53%
50 Watt HPS	0	$4.79000	$0	0	$5.39000	$0	12.53%
70 Watt HPS	111,600	$6.12000	$682,992	111,600	$6.89000	$768,924	12.58%
100 Watt HPS	2,160	$8.09000	$17,474	2,160	$9.10000	$19,656	12.48%
Fuel cost adjustment	2,705,043	$0.00000	$0	2,705,043	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,356,781	-$0.00227	-$7,620	3,356,781	-$0.00256	-$8,593	12.78%
Act 141 capped contribution	3,356,781	$0.00000	$0	3,356,781	$0.00000	$0	0.00%
Total Revenue: Alley Lighting - Al1			**$707,354**			**$796,322**	

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Street Lighting - Ms1							
Customer charge							
Flashers - <= 25 Watts	0	$3.40000	$0	0	$3.40000	$0	0.00%
Flashers - 25 to 75 Watts	1,548	$3.47000	$5,372	1,548	$3.47000	$5,372	0.00%
Flashers - Over 75 Watts	996	$5.57000	$5,548	996	$5.57000	$5,548	0.00%
Customer charge per day	165,600	$0.49315	$81,666	165,600	$0.49315	$81,666	0.00%
Energy charge	1,717,241	$0.15759	$270,620	1,717,241	$0.17621	$302,595	11.82%
Fuel cost adjustment	1,717,241	$0.00000	$0	1,717,241	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,290,244	-$0.00227	-$2,929	1,290,244	-$0.00256	-$3,303	12.78%
Act 141 capped contribution	1,290,244	$0.00075	$963	1,290,244	$0.00075	$963	0.00%
Total Revenue: Street Lighting - Ms1			**$361,239**			**$392,840**	
Street Lighting & Other - Ms2							
Energy charge	4,416,202	$0.14971	$661,150	4,416,202	$0.16916	$747,045	12.99%
Fuel cost adjustment	4,416,202	$0.00000	$0	4,416,202	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	1,880,718	-$0.00227	-$4,269	1,880,718	-$0.00256	-$4,815	12.78%
Act 141 capped contribution	1,880,718	$0.00068	$1,278	1,880,718	$0.00068	$1,278	0.00%
Total Revenue: Street Lighting & Other - Ms2			**$658,158**			**$743,508**	
Street Lighting - Ms3							
High pressure sodium lamps							
50 Watt	12,000	$12.18000	$146,160	12,000	$13.72000	$164,640	12.64%
70 Watt	16,800	$14.45000	$242,760	16,800	$16.27000	$273,336	12.60%
100 Watt	120,000	$15.37000	$1,844,400	120,000	$17.31000	$2,077,200	12.62%
150 Watt	90,000	$17.89000	$1,610,100	90,000	$20.15000	$1,813,500	12.63%
200 Watt	88,800	$20.90000	$1,855,920	88,800	$23.53000	$2,089,464	12.58%
250 Watt	20,400	$23.68000	$483,072	20,400	$26.66000	$543,864	12.58%
400 Watt	2,100	$31.55000	$66,255	2,100	$35.53000	$74,613	12.61%
Metal halide lamps							
175 Watt	0	$28.57000	$0	0	$32.17000	$0	12.60%
250 Watt	0	$30.01000	$0	0	$33.79000	$0	12.60%
400 Watt	0	$34.74000	$0	0	$39.12000	$0	12.61%
Fuel cost adjustment	26,150,659	$0.00000	$0	26,150,659	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	9,999,467	-$0.00227	-$22,699	9,999,467	-$0.00256	-$25,599	12.78%
Act 141 capped contribution	9,999,467	$0.00000	$0	9,999,467	$0.00000	$0	0.00%
Total Revenue: Street Lighting - Ms3			**$6,225,968**			**$7,011,018**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
Street Lighting - Ms4							
Customer charge							
Customer charge per Month			2,496,000			$2,496,000	
Non-standard lamps							
50 Watt HPS	0	$2.62000	$0	0	$3.05000	$0	16.41%
70 Watt HPS	3,300	$3.86000	$12,738	3,300	$4.49000	$14,817	16.32%
100 Watt HPS	50,400	$5.98000	$301,392	50,400	$6.96000	$350,784	16.39%
150 Watt HPS	90,000	$8.48000	$763,200	90,000	$9.87000	$888,300	16.39%
175 Watt MH	2,400	$9.62000	$23,088	2,400	$11.20000	$26,880	16.42%
200 Watt HPS	25,200	$11.22000	$282,744	25,200	$13.06000	$329,112	16.40%
250 Watt HPS	33,600	$13.96000	$469,056	33,600	$16.26000	$546,336	16.48%
400 Watt HPS	4,980	$21.59000	$107,518	4,980	$25.14000	$125,197	16.44%
1000 Watt HPS	0	$50.27000	$0	0	$58.53000	$0	16.43%
Fuel cost adjustment	12,294,156	$0.00000	$0	12,294,156	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	3,495,205	-$0.00227	-$7,934	3,495,205	-$0.00256	-$8,948	12.78%
Act 141 capped contribution	3,495,205	$0.00082	$2,876	3,495,205	$0.00082	$2,876	0.00%
Total Revenue: Street Lighting - Ms4			**$4,450,678**			**$4,771,355**	
LED Lighting - General Secondary - LED							
Customer charge							
Standard lighting fixture							
Category A	0	$8.44000	$0	0	$8.82000	$0	4.50%
Category B	26,400	$9.64000	$254,496	26,400	$10.07000	$265,848	4.46%
Category C	216,000	$11.06000	$2,388,960	216,000	$11.56000	$2,496,960	4.52%
Category D	57,600	$12.48000	$718,848	57,600	$13.04000	$751,104	4.49%
Category E	40,800	$13.90000	$567,120	40,800	$14.53000	$592,824	4.53%
Category F	8,400	$15.32000	$128,688	8,400	$16.01000	$134,484	4.50%
Category G	3,000	$16.74000	$50,220	3,000	$17.49000	$52,470	4.48%
Category H	3,600	$18.15000	$65,340	3,600	$18.97000	$68,292	4.52%
Category I	0	$19.58000	$0	0	$20.46000	$0	4.49%
Non-standard lighting fixture							
Category A	0	$5.65000	$0	0	$5.90000	$0	4.42%
Category B	0	$6.16000	$0	0	$6.44000	$0	4.55%
Category C	7,200	$6.76000	$48,672	7,200	$7.06000	$50,832	4.44%
Category D	7,200	$7.36000	$52,992	7,200	$7.69000	$55,368	4.48%
Category E	13,800	$7.94000	$109,572	13,800	$8.30000	$114,540	4.53%
Category F	4,800	$8.53000	$40,944	4,800	$8.91000	$42,768	4.45%
Category G	420	$9.13000	$3,835	420	$9.54000	$4,007	4.49%
Category H	10,200	$9.72000	$99,144	10,200	$10.16000	$103,632	4.53%
Category I	132	$10.31000	$1,361	132	$10.77000	$1,422	4.46%
Category J	0	$10.90000	$0	0	$11.39000	$0	4.50%
Category K	0	$11.49000	$0	0	$12.01000	$0	4.53%
Category L	2,820	$12.09000	$34,094	2,820	$12.63000	$35,617	4.47%
Category M	1,800	$12.68000	$22,824	1,800	$13.25000	$23,850	4.50%
Category N	0	$13.27000	$0	0	$13.87000	$0	4.52%
Category O	0	$13.86000	$0	0	$14.48000	$0	4.47%
Category P	0	$14.46000	$0	0	$15.11000	$0	4.50%
Category Q	0	$15.05000	$0	0	$15.73000	$0	4.52%
Category R	0	$15.63000	$0	0	$16.33000	$0	4.48%
Category S	0	$16.23000	$0	0	$16.96000	$0	4.50%
Category T	144	$16.83000	$2,424	144	$17.59000	$2,533	4.52%

Electric Rate Design - Test Year 2026
We Energies

	Current Rate - Year 2026			Authorized Rate - Year 2026			
Rate Schedule	Billing Component	Rate	Yield	Billing Component	Rate	Yield	2026
Energy charge							
0-3 kWh	0	$0.29000	$0	0	$0.30000	$0	3.45%
4-6 kWh	0	$0.58000	$0	0	$0.61000	$0	5.17%
7-9 kWh	0	$0.86000	$0	0	$0.90000	$0	4.65%
10-12 kWh	0	$1.15000	$0	0	$1.20000	$0	4.35%
13-15 kWh	18,000	$1.45000	$26,100	18,000	$1.52000	$27,360	4.83%
16-18 kWh	216,000	$1.73000	$373,680	216,000	$1.81000	$390,960	4.62%
19-21 kWh	3,600	$2.02000	$7,272	3,600	$2.11000	$7,596	4.46%
22-24 kWh	4,800	$2.32000	$11,136	4,800	$2.42000	$11,616	4.31%
25-27 kWh	0	$2.61000	$0	0	$2.73000	$0	4.60%
28-30 kWh	5,040	$2.89000	$14,566	5,040	$3.02000	$15,221	4.50%
31-33 kWh	11,640	$3.18000	$37,015	11,640	$3.32000	$38,645	4.40%
34-36 kWh	40,800	$3.47000	$141,576	40,800	$3.63000	$148,104	4.61%
37-39 kWh	8,400	$3.76000	$31,584	8,400	$3.93000	$33,012	4.52%
40-42 kWh	0	$4.05000	$0	0	$4.23000	$0	4.44%
43-45 kWh	2,568	$4.33000	$11,119	2,568	$4.52000	$11,607	4.39%
46-48 kWh	2,160	$4.62000	$9,979	2,160	$4.83000	$10,433	4.55%
49-51 kWh	0	$4.92000	$0	0	$5.14000	$0	4.47%
52-54 kWh	516	$5.20000	$2,683	516	$5.43000	$2,802	4.42%
55-57 kWh	8,400	$5.48000	$46,032	8,400	$5.73000	$48,132	4.56%
58-60 kWh	2,760	$5.79000	$15,980	2,760	$6.05000	$16,698	4.49%
61-63 kWh	0	$6.08000	$0	0	$6.35000	$0	4.44%
64-66 kWh	600	$6.36000	$3,816	600	$6.65000	$3,990	4.56%
67-69 kWh	0	$6.65000	$0	0	$6.95000	$0	4.51%
70-72 kWh	1,632	$6.94000	$11,326	1,632	$7.25000	$11,832	4.47%
73-75 kWh	0	$7.23000	$0	0	$7.56000	$0	4.56%
76-78 kWh	0	$7.52000	$0	0	$7.86000	$0	4.52%
79-81 kWh	0	$7.80000	$0	0	$8.15000	$0	4.49%
82-84 kWh	0	$8.10000	$0	0	$8.46000	$0	4.44%
85-87 kWh	0	$8.39000	$0	0	$8.77000	$0	4.53%
88-90 kWh	0	$8.67000	$0	0	$9.06000	$0	4.50%
91-93 kWh	0	$8.96000	$0	0	$9.36000	$0	4.46%
94-96 kWh	0	$9.25000	$0	0	$9.67000	$0	4.54%
97-99 kWh	0	$9.55000	$0	0	$9.98000	$0	4.50%
100-102 kWh	0	$9.83000	$0	0	$10.27000	$0	4.48%
103-105 kWh	0	$10.12000	$0	0	$10.58000	$0	4.55%
106-108 kWh	0	$10.41000	$0	0	$10.88000	$0	4.51%
109-111 kWh	0	$10.71000	$0	0	$11.19000	$0	4.48%
112-114 kWh	0	$10.99000	$0	0	$11.48000	$0	4.46%
115-117 kWh	0	$11.27000	$0	0	$11.78000	$0	4.53%
Fuel cost adjustment	6,763,132	$0.00000	$0	6,763,132	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Act 141 capped credits	979,887	-$0.00227	-$2,224	979,887	-$0.00256	-$2,509	12.78%
Act 141 capped contribution	979,887	$0.00002	$19	979,887	$0.00002	$19	0.00%
Total Revenue: LED Lighting - General Secondary - LED			**$5,331,193**			**$5,572,069**	

Electric Rate Design - Test Year 2026
We Energies

Rate Schedule	Current Rate - Year 2026 Billing Component	Rate	Yield	Authorized Rate - Year 2026 Billing Component	Rate	Yield	2026
Municipal Defense Sirens - Mg1							
Customer charge	120	$3.00000	$360	120	$3.00000	$360	0.00%
Energy charge	66,315	$0.15759	$10,451	66,315	$0.17621	$11,685	11.82%
Fuel cost adjustment	66,315	$0.00000	$0	66,315	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Municipal Defense Sirens - Mg1			**$10,811**			**$12,045**	
Telecom Equipment Service TE1							
Customer charge	864	$4.25000	$3,672	864	$4.25000	$3,672	0.00%
Energy charge	19,186	$0.15759	$3,024	19,186	$0.17621	$3,381	11.82%
Fuel cost adjustment	19,186	$0.00000	$0	19,186	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Telecom Equipment Service TE1			**$6,696**			**$7,053**	
Telecom Equipment Service TE2							
Customer charge	8,030	$0.49315	$3,960	8,030	$0.49315	$3,960	0.00%
Energy charge	144,614	$0.15759	$22,790	144,614	$0.17621	$25,482	11.82%
Fuel cost adjustment	144,614	$0.00000	$0	144,614	$0.00000	$0	0.00%
Other							
Other	0	$0.00000	$0	0	$0.00000	$0	0.00%
Total Revenue: Telecom Equipment Service TE2			**$26,750**			**$29,442**	
Energy For Tomorrow							
Energy for Tomorrow - Residential	49,570,704	$0.01158	$574,029	49,570,704	$0.01158	$574,029	0.00%
Energy for Tomorrow - Non-Residential	24,366,516	$0.01158	$282,164	24,366,516	$0.01158	$282,164	0.00%
Energy for Tomorrow - Non-Residential	12,157,056	$0.00995	$120,963	12,157,056	$0.00995	$120,963	0.00%
Total Revenue: Energy For Tomorrow			**$977,156**			**$977,156**	
Renewable Pathway							
Renewable Pathway (1 Year)	17,500,000	$0.00717	$125,475	17,500,000	$0.00717	$125,475	0.00%
Renewable Pathway (5 Year)	113,931,648	$0.00531	$604,977	113,931,648	$0.00531	$604,977	0.00%
Total Revenue: Renewable Pathway			**$730,452**			**$730,452**	
Dedicated Renewable Energy Rider							
Dedicated Renewable Energy Resource Cost	12	$51,300	$615,596	12	$51,300	$615,596	0.00%
Total Revenue: Dedicated Renewable Energy Rider			**$615,596**			**$615,596**	

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Rg1 -- Residential Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.17154	$0.19342	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Rg2 -- Residential Service TOU			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base	$0.23382	$0.30084	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.10628	$0.10028	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Fg1 -- Farm Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.17154	$0.19342	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
COEV-R -- Residential Electric Vehicle Charger Only			
Fixed service and administration charge			
Bundled service	$20.000	$20.000	per Month
Pre-paid service	$8.000	$8.000	per Month
Energy charge			
On-peak (summer)	$0.28733	$0.30862	per kWh
On-peak (non-summer)	$0.18007	$0.19342	per kWh
Intermediate-peak (summer)	$0.18007	$0.19342	per kWh
Intermediate-peak (non-summer)	$0.18007	$0.19342	per kWh
Off-peak (summer)	$0.07303	$0.07303	per kWh
Off-peak (non-summer)	$0.07303	$0.07303	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
Cg1 -- General Secondary Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cg2 -- General Secondary Service - Demand			
Customer Charge	$1.32000	$1.32000	per Day
Extra Meter Charge	$0.18542	$0.18542	per Day
On-Peak Energy Charge - Base	$0.12625	$0.13521	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.09018	$0.09658	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$7.783	$8.540	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.04799)	($0.05266)	per kW per HOU less than 100
Customer Demand Charge	$2.460	$2.700	per kW
Cg3 -- General Secondary Service - Demand/TOU			
Customer Charge	$2.00000	$2.00000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.09761	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.06000	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$20.095	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.12086)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.375	per kW
Cg3C -- Gen. Sec. - Experimental Curtailable			
Customer Charge	$3.85000	$3.85000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.09761	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.06000	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$20.095	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.12086)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.375	per kW
Curtailable Credit	$0.02080	$0.02080	per kWh curtailable on-peak
Cg3S -- Gen. Sec. - Seasonal Curtailable			
Customer Charge	$3.85000	$3.85000	per Day
Extra Meter Charge	$0.20000	$0.20000	per Day
On-Peak Energy Charge - Base	$0.09057	$0.09761	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.05660	$0.06000	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Regular On-Peak Demand Charge - Base	$18.313	$20.095	per kW
Regular On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Low Hours of Use Adjustment	($0.11014)	($0.12086)	per kW per HOU less than 100
Customer Demand Charge	$3.075	$3.375	per kW
Curtailable Credit	$2.00000	$2.00000	per kW curtailable demand

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cg6 -- General Secondary Service - TOU			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge - Base	$0.23324	$0.29475	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base	$0.10601	$0.09825	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TSSM - General Secondary Transmission Substations - Metered			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TSSU - General Secondary Transmission Substations - UnMetered			
Customer Charge	$4.25	$4.25	per Month
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TE1 - General Secondary Telecom Equipment - Small UnMetered			
Customer Charge	$4.25	$4.25	per Month
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
TE2 - General Secondary Telecom Equipment - Large UnMetered			
Customer Charge	$0.49315	$0.49315	per Day, per point of connection
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
ERER1 & ERER3 Renewable Rider			
Energy for Tomorrow - 25%	$0.00290	$0.00290	per kWh
Energy for Tomorrow - 50%	$0.00579	$0.00579	per kWh
Energy for Tomorrow - 100%	$0.01158	$0.01158	per kWh
ERER2 Renewable Rider			
Energy for Tomorrow - < 70,000 kWh per month	$0.01158	$0.01158	per kWh
Energy for Tomorrow - >= 70,000 kWh per month	$0.00995	$0.00995	per kWh
ERER4 Renewable Rider			
Energy for Tomorrow - 25%	$0.00249	$0.00249	per kWh
Energy for Tomorrow - 50%	$0.00498	$0.00498	per kWh
Energy for Tomorrow - 100%	$0.00995	$0.00995	per kWh
Renewable Pathway Pilot			
One year subscription	$0.01768	$0.01768	per kWh
Five year subscription	$0.01582	$0.01582	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cp1 -- General Primary Service - TOU			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Summer Base (Low Voltage)	$0.09552	$0.09912	per kWh
On-Peak Energy Charge - Summer Base (Medium Voltage)	$0.09444	$0.09800	per kWh
On-Peak Energy Charge - Summer Base (High Voltage)	$0.09353	$0.09705	per kWh
On-Peak Energy Charge - Non-summer Base (Low Voltage)	$0.08290	$0.08603	per kWh
On-Peak Energy Charge - Non-summer Base (Medium Voltage)	$0.08196	$0.08505	per kWh
On-Peak Energy Charge - Non-summer Base (High Voltage)	$0.08117	$0.08423	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Summer Base (Low Voltage)	$0.06206	$0.06440	per kWh
Off-Peak Energy Charge - Summer Base (Medium Voltage)	$0.06018	$0.06246	per kWh
Off-Peak Energy Charge - Summer Base (High Voltage)	$0.05960	$0.06185	per kWh
Off-Peak Energy Charge - Non-summer Base (Low Voltage)	$0.06206	$0.06440	per kWh
Off-Peak Energy Charge - Non-summer Base (Medium Voltage)	$0.06018	$0.06246	per kWh
Off-Peak Energy Charge - Non-summer Base (High Voltage)	$0.05960	$0.06185	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Summer Base (Low Voltage)	$20.669	$22.587	per kW
On-Peak Demand Charge - Summer Base (Meduim Voltage)	$20.434	$22.331	per kW
On-Peak Demand Charge - Summer Base (High Voltage)	$20.236	$22.115	per kW
On-Peak Demand Charge - Non-summer Base (Low Voltage)	$14.870	$16.250	per kW
On-Peak Demand Charge - Non-summer Base (Meduim Voltage)	$14.701	$16.066	per kW
On-Peak Demand Charge - Non-summer Base (High Voltage)	$14.558	$15.910	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.396	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.369	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Load Factor Credit	($0.010)	($0.010)	per kWh
SIC 4952 on-peak demand credit	$0.000	($9.077)	per kW
SIC 4952 customer maximum demand credit	$0.000	($0.592)	per kW

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cp3 -- Gen. Pri. Service - Curtailable			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08530	$0.09040	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08433	$0.08937	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08351	$0.08850	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06077	$0.00000	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06006	$0.06365	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05836	$0.06184	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$18.362	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$18.154	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.978	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.396	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.369	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$0.02028	$0.02028	per kWh curtailable on-peak
Curtailable Credit (Medium Voltage)	$0.02000	$0.02000	per kWh curtailable on-peak
Curtailable Credit (High Voltage)	$0.01970	$0.01970	per kWh curtailable on-peak
Cp3S -- Gen. Pri. - Seasonal Curtailable			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08530	$0.09040	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08433	$0.08937	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08351	$0.08850	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06077	$0.06441	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06006	$0.06365	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05836	$0.06184	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$18.362	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$18.154	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.978	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.396	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.369	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Curtailable Credit (Low Voltage)	$2.000	$2.000	per kW curtailable demand
Curtailable Credit (Medium Voltage)	$2.000	$2.000	per kW curtailable demand
Curtailable Credit (High Voltage)	$2.000	$2.000	per kW curtailable demand

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Cp4 -- Gen. Pri. Service - Standby Service			
Customer Charge - Low Voltage	$19.76010	$19.76010	per Day
Customer Charge - Medium Voltage	$19.76010	$19.76010	per Day
Customer Charge - High Voltage	$19.76010	$19.76010	per Day
Extra Meter Charge	$3.14334	$3.14334	per Day
On-Peak Energy Charge - Base (Low Voltage)	$0.08711	$0.09040	per kWh
On-Peak Energy Charge - Base (Medium Voltage)	$0.08612	$0.08937	per kWh
On-Peak Energy Charge - Base (High Voltage)	$0.08529	$0.08850	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge - Base (Low Voltage)	$0.06206	$0.06441	per kWh
Off-Peak Energy Charge - Base (Medium Voltage)	$0.06134	$0.06365	per kWh
Off-Peak Energy Charge - Base (High Voltage)	$0.05960	$0.06184	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Demand Charge - Base (Low Voltage)	$16.803	$18.362	per kW
On-Peak Demand Charge - Base (Medium Voltage)	$16.612	$18.154	per kW
On-Peak Demand Charge - Base (High Voltage)	$16.451	$17.978	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Low Voltage)	$2.338	$2.396	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.369	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW
Reserved Demand Charge (Low Voltage)	$1.993	$1.993	per kW
Reserved Demand Charge (Medium Voltage)	$1.964	$1.964	per kW
Reserved Demand Charge (High Voltage)	$1.939	$1.939	per kW
Minimum On-Peak Standby Energy Charge (Low Voltage)	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (Medium Voltage)	$0.03000	$0.03000	per kWh
Minimum On-Peak Standby Energy Charge (High Voltage)	$0.03000	$0.03000	per kWh
Minimum Off-Peak Standby Energy Charge (Low Voltage)	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (Medium Voltage)	$0.02000	$0.02000	per kWh
Minimum Off-Peak Standby Energy Charge (High Voltage)	$0.02000	$0.02000	per kWh
CpFN -- Gen Pri. Combined Firm & Non Firm			
Customer Charge - Medium Voltage	$26.30137	$26.30137	per Day
Customer Charge - High Voltage	$26.30137	$26.30137	per Day
On-Peak Firm Energy Charge - Base (Medium Voltage)	$0.08433	$0.08937	per kWh
On-Peak Firm Energy Charge - Base (High Voltage)	$0.08351	$0.08850	per kWh
On-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.07845	$0.08313	per kWh
On-Peak Non Firm Energy Charge - Base (High Voltage)	$0.07768	$0.08233	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Firm Energy Charge - Base (Medium Voltage)	$0.05893	$0.06246	per kWh
Off-Peak Firm Energy Charge - Base (High Voltage)	$0.05836	$0.06185	per kWh
Off-Peak Non Firm Energy Charge - Base (Medium Voltage)	$0.05482	$0.05810	per kWh
Off-Peak Non Firm Energy Charge - Base (High Voltage)	$0.05429	$0.05753	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
On-Peak Firm Demand Charge - Base (Medium Voltage)	$16.612	$18.154	per kW
On-Peak Firm Demand Charge - Base (High Voltage)	$16.451	$17.978	per kW
On-Peak Non Firm Demand Charge - Base (Medium Voltage)	$11.252	$12.794	per kW
On-Peak Non Firm Demand Charge - Base (High Voltage)	$11.091	$12.618	per kW
On-Peak Demand Charge - Fuel Cost Adjustment	NA	NA	per kW
Customer Demand Charge (Medium Voltage)	$2.311	$2.369	per kW
Customer Demand Charge (High Voltage)	$0.000	$0.000	per kW

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
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	$25.00000	$25.00000	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	$27.00000	$27.00000	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
Real Time Market Pricing (RTMP)			
Administration Charge	$5.75300	$5.75300	per Day
Embedded Cost Adder	$0.00050	$0.00050	per kWh
Transmission Demand	$4.36000	$5.75000	per kW
Real Time Pricing (RTP)			
Customer Charge	$26.30137	$26.30137	per Day
Extra Meter Charge	$3.14334	$3.14334	per Day
Scheduling Charge	$1,000.00	$1,000.00	per Month
Embedded Cost Adder (firm)	$0.02050	$0.02050	per kWh
Embedded Cost Adder (non-firm)	$0.01350	$0.01350	per kWh
On-Peak Demand Charge - Summer Base	$20.23600	$22.11500	per kW
On-Peak Demand Charge - Non-summer Base	$14.55800	$15.91000	per kW
Electronics and Information Technology Manufacturing (EITM)			
Customer Demand Charge	$3.10000	$3.10000	per kW
Experimental Short Term Productivity Rider (STPR)			
Administration Charge	$100.00000	$100.00000	per Month
Excess energy charge, 1,000 kWh or more billed in period	$0.10000	$0.10000	per kWh per Excess Period
Excess energy charge, less than 1,000 kWh billed in period	$0.12000	$0.12000	per kWh per Excess Period
Experimental Dollars for Power (DFP)			
Energy Credit Option 1	$0.40000	$0.40000	per kWh
Energy Credit Option 2	$0.80000	$0.80000	per kWh
Energy Credit Option 3	$1.25000	$1.25000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
St1 -- Optional TOU Street Lighting Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge	$0.35386	$0.39802	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge	$0.06154	$0.06922	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
St2 -- Optional TOU Street Lighting Service			
Customer Charge - Single Phase	$0.49315	$0.49315	per Day
Customer Charge - Three Phase	$0.49315	$0.49315	per Day
Extra Meter Charge	$0.05951	$0.05951	per Day
On-Peak Energy Charge	$0.37047	$0.41670	per kWh
On-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Off-Peak Energy Charge	$0.06443	$0.07247	per kWh
Off-Peak Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Gl1 - Area Lighting			
Standard High Pressure Sodium			
50 Watt	$12.18	$13.72	per Month
70 Watt	$14.45	$16.27	per Month
100 Watt	$15.37	$17.31	per Month
150 Watt	$17.89	$20.15	per Month
200 Watt	$20.90	$23.53	per Month
250 Watt	$23.68	$26.66	per Month
400 Watt	$31.55	$35.53	per Month
Flood High Presure Sodium			
70 Watt	$14.96	$16.85	per Month
100 Watt	$18.20	$20.49	per Month
150 Watt	$19.63	$22.10	per Month
200 Watt	$22.46	$25.29	per Month
250 Watt	$25.19	$28.37	per Month
400 Watt	$32.81	$36.95	per Month
Standard Metal Halide			
175 Watt	$28.57	$32.17	per Month
250 Watt	$30.01	$33.79	per Month
400 Watt	$34.74	$39.12	per Month
Flood Metal Halide			
175 Watt	$30.06	$33.85	per Month
250 Watt	$31.65	$35.64	per Month
400 Watt	$36.17	$40.73	per Month
1000 Watt	$68.90	$77.58	per Month
Poles	$2.80	$2.80	per Month
Spans	$2.73	$2.73	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Al1 - Alley Lighting			
0 - 10 Watt LED	$2.59	$2.91	per Month
>10 - 20 Watt LED	$2.97	$3.34	per Month
>20 - 30 Watt LED	$3.41	$3.84	per Month
>30 - 40 Watt LED	$3.88	$4.37	per Month
>40 - 50 Watt LED	$4.34	$4.88	per Month
>50 - 60 Watt LED	$4.79	$5.39	per Month
50 Watt HPS	$4.79	$5.39	per Month
70 Watt HPS	$6.12	$6.89	per Month
100 Watt HPS	$8.09	$9.10	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Ms1 - Highway Lighting			
Customer Charge	$0.49315	$0.49315	per Day
Flasher (per flasher) - 25 Watts or Less	$3.40	$3.40	per Month per Flasher
Flasher (per flasher) - 25 Watts to 75 Watts	$3.47	$3.47	per Month per Flasher
Flasher (per flasher) - Greater than 75 Watts	$5.57	$5.57	per Month per Flasher
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms2 - Street Lighting			
Energy Charge - Base	$0.14971	$0.16916	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms3 - Street Lighting			
High Pressure Sodium Lamps			
50 Watt	$12.18	$13.72	per Month
70 Watt	$14.45	$16.27	per Month
100 Watt	$15.37	$17.31	per Month
150 Watt	$17.89	$20.15	per Month
200 Watt	$20.90	$23.53	per Month
250 Watt	$23.68	$26.66	per Month
400 Watt	$31.55	$35.53	per Month
Metal Halide Lamps			
175 Watt	$28.57	$32.17	per Month
250 Watt	$30.01	$33.79	per Month
400 Watt	$34.74	$39.12	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Ms4 - Street Lighting			
Customer Charge - Option A	1.90%	1.90%	per Month of Installed Costs
Customer Charge - Option B	0.50%	0.50%	per Month of Installed Costs
Non-Standard Lamps			
50 Watt HPS	$2.62	$3.05	per Month
70 Watt HPS	$3.86	$4.49	per Month
100 Watt HPS	$5.98	$6.96	per Month
150 Watt HPS	$8.48	$9.87	per Month
175 Watt MH	$9.62	$11.20	per Month
200 Watt HPS	$11.22	$13.06	per Month
250 Watt HPS	$13.96	$16.26	per Month
400 Watt HPS	$21.59	$25.14	per Month
1000 Watt HPS	$50.27	$58.53	per Month
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh
Mg1 - Municipal Defense Sirens			
Customer Charge	$3.00	$3.00	per Year per every 2 horsepower
Energy Charge - Base	$0.15759	$0.17621	per kWh
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
LED			
Customer Charge			
Standard lighting fixture			
Category A	$8.44	$8.82	per Month, per Fixture
Category B	$9.64	$10.07	per Month, per Fixture
Category C	$11.06	$11.56	per Month, per Fixture
Category D	$12.48	$13.04	per Month, per Fixture
Category E	$13.90	$14.53	per Month, per Fixture
Category F	$15.32	$16.01	per Month, per Fixture
Category G	$16.74	$17.49	per Month, per Fixture
Category H	$18.15	$18.97	per Month, per Fixture
Category I	$19.58	$20.46	per Month, per Fixture
Category A (early removal)	$5.37	$5.50	per Month, per Fixture
Category B (early removal)	$6.06	$6.21	per Month, per Fixture
Category C (early removal)	$6.88	$7.08	per Month, per Fixture
Category D (early removal)	$7.70	$7.93	per Month, per Fixture
Category E (early removal)	$8.54	$8.81	per Month, per Fixture
Category F (early removal)	$9.37	$9.68	per Month, per Fixture
Category G (early removal)	$10.19	$10.53	per Month, per Fixture
Category H (early removal)	$11.01	$11.39	per Month, per Fixture
Category I (early removal)	$11.85	$12.27	per Month, per Fixture
Category A (after initial term)	$3.07	$3.32	per Month, per Fixture
Category B (after initial term)	$3.58	$3.86	per Month, per Fixture
Category C (after initial term)	$4.18	$4.48	per Month, per Fixture
Category D (after initial term)	$4.78	$5.11	per Month, per Fixture
Category E (after initial term)	$5.36	$5.72	per Month, per Fixture
Category F (after initial term)	$5.95	$6.33	per Month, per Fixture
Category G (after initial term)	$6.55	$6.96	per Month, per Fixture
Category H (after initial term)	$7.14	$7.58	per Month, per Fixture
Category I (after initial term)	$7.73	$8.19	per Month, per Fixture
Non-standard lighting fixture			
Category A	$5.65	$5.90	per Month, per Fixture
Category B	$6.16	$6.44	per Month, per Fixture
Category C	$6.76	$7.06	per Month, per Fixture
Category D	$7.36	$7.69	per Month, per Fixture
Category E	$7.94	$8.30	per Month, per Fixture
Category F	$8.53	$8.91	per Month, per Fixture
Category G	$9.13	$9.54	per Month, per Fixture
Category H	$9.72	$10.16	per Month, per Fixture
Category I	$10.31	$10.77	per Month, per Fixture
Category J	$10.90	$11.39	per Month, per Fixture
Category K	$11.49	$12.01	per Month, per Fixture
Category L	$12.09	$12.63	per Month, per Fixture
Category M	$12.68	$13.25	per Month, per Fixture
Category N	$13.27	$13.87	per Month, per Fixture
Category O	$13.86	$14.48	per Month, per Fixture
Category P	$14.46	$15.11	per Month, per Fixture
Category Q	$15.05	$15.73	per Month, per Fixture
Category R	$15.63	$16.33	per Month, per Fixture
Category S	$16.23	$16.96	per Month, per Fixture
Category T	$16.83	$17.59	per Month, per Fixture

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
LED (continued)			
Customer Charge (continued)			
Non-standard lighting fixture (continued)			
Category A (early removal)	$2.58	$2.58	per Month, per Fixture
Category B (early removal)	$2.58	$2.58	per Month, per Fixture
Category C (early removal)	$2.58	$2.58	per Month, per Fixture
Category D (early removal)	$2.58	$2.58	per Month, per Fixture
Category E (early removal)	$2.58	$2.58	per Month, per Fixture
Category F (early removal)	$2.58	$2.58	per Month, per Fixture
Category G (early removal)	$2.58	$2.58	per Month, per Fixture
Category H (early removal)	$2.58	$2.58	per Month, per Fixture
Category I (early removal)	$2.58	$2.58	per Month, per Fixture
Category J (early removal)	$2.58	$2.58	per Month, per Fixture
Category K (early removal)	$2.58	$2.58	per Month, per Fixture
Category L (early removal)	$2.58	$2.58	per Month, per Fixture
Category M (early removal)	$2.58	$2.58	per Month, per Fixture
Category N (early removal)	$2.58	$2.58	per Month, per Fixture
Category O (early removal)	$2.58	$2.58	per Month, per Fixture
Category P (early removal)	$2.58	$2.58	per Month, per Fixture
Category Q (early removal)	$2.58	$2.58	per Month, per Fixture
Category R (early removal)	$2.58	$2.58	per Month, per Fixture
Category S (early removal)	$2.58	$2.58	per Month, per Fixture
Category T (early removal)	$2.58	$2.58	per Month, per Fixture
Category A (after initial term)	$3.07	$3.32	per Month, per Fixture
Category B (after initial term)	$3.58	$3.86	per Month, per Fixture
Category C (after initial term)	$4.18	$4.48	per Month, per Fixture
Category D (after initial term)	$4.78	$5.11	per Month, per Fixture
Category E (after initial term)	$5.36	$5.72	per Month, per Fixture
Category F (after initial term)	$5.95	$6.33	per Month, per Fixture
Category G (after initial term)	$6.55	$6.96	per Month, per Fixture
Category H (after initial term)	$7.14	$7.58	per Month, per Fixture
Category I (after initial term)	$7.73	$8.19	per Month, per Fixture
Category J (after initial term)	$8.32	$8.81	per Month, per Fixture
Category K (after initial term)	$8.91	$9.43	per Month, per Fixture
Category L (after initial term)	$9.51	$10.05	per Month, per Fixture
Category M (after initial term)	$10.10	$10.67	per Month, per Fixture
Category N (after initial term)	$10.69	$11.29	per Month, per Fixture
Category O (after initial term)	$11.28	$11.90	per Month, per Fixture
Category P (after initial term)	$11.88	$12.53	per Month, per Fixture
Category Q (after initial term)	$12.47	$13.15	per Month, per Fixture
Category R (after initial term)	$13.05	$13.75	per Month, per Fixture
Category S (after initial term)	$13.65	$14.38	per Month, per Fixture
Category T (after initial term)	$14.25	$15.01	per Month, per Fixture

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
LED (continued)			
Energy Charge			
0-3 kWh	$0.29000	$0.30000	per Month, per Fixture
4-6 kWh	$0.58000	$0.61000	per Month, per Fixture
7-9 kWh	$0.86000	$0.90000	per Month, per Fixture
10-12 kWh	$1.15000	$1.20000	per Month, per Fixture
13-15 kWh	$1.45000	$1.52000	per Month, per Fixture
16-18 kWh	$1.73000	$1.81000	per Month, per Fixture
19-21 kWh	$2.02000	$2.11000	per Month, per Fixture
22-24 kWh	$2.32000	$2.42000	per Month, per Fixture
25-27 kWh	$2.61000	$2.73000	per Month, per Fixture
28-30 kWh	$2.89000	$3.02000	per Month, per Fixture
31-33 kWh	$3.18000	$3.32000	per Month, per Fixture
34-36 kWh	$3.47000	$3.63000	per Month, per Fixture
37-39 kWh	$3.76000	$3.93000	per Month, per Fixture
40-42 kWh	$4.05000	$4.23000	per Month, per Fixture
43-45 kWh	$4.33000	$4.52000	per Month, per Fixture
46-48 kWh	$4.62000	$4.83000	per Month, per Fixture
49-51 kWh	$4.92000	$5.14000	per Month, per Fixture
52-54 kWh	$5.20000	$5.43000	per Month, per Fixture
55-57 kWh	$5.48000	$5.73000	per Month, per Fixture
58-60 kWh	$5.79000	$6.05000	per Month, per Fixture
61-63 kWh	$6.08000	$6.35000	per Month, per Fixture
64-66 kWh	$6.36000	$6.65000	per Month, per Fixture
67-69 kWh	$6.65000	$6.95000	per Month, per Fixture
70-72 kWh	$6.94000	$7.25000	per Month, per Fixture
73-75 kWh	$7.23000	$7.56000	per Month, per Fixture
76-78 kWh	$7.52000	$7.86000	per Month, per Fixture
79-81 kWh	$7.80000	$8.15000	per Month, per Fixture
82-84 kWh	$8.10000	$8.46000	per Month, per Fixture
85-87 kWh	$8.39000	$8.77000	per Month, per Fixture
88-90 kWh	$8.67000	$9.06000	per Month, per Fixture
91-93 kWh	$8.96000	$9.36000	per Month, per Fixture
94-96 kWh	$9.25000	$9.67000	per Month, per Fixture
97-99 kWh	$9.55000	$9.98000	per Month, per Fixture
100-102 kWh	$9.83000	$10.27000	per Month, per Fixture
103-105 kWh	$10.12000	$10.58000	per Month, per Fixture
106-108 kWh	$10.41000	$10.88000	per Month, per Fixture
109-111 kWh	$10.71000	$11.19000	per Month, per Fixture
112-114 kWh	$10.99000	$11.48000	per Month, per Fixture
115-117 kWh	$11.27000	$11.78000	per Month, per Fixture
Energy Charge - Fuel Cost Adjustment	$0.00000	$0.00000	per kWh

Wisconsin Electric Power Company
Present and Proposed Electric Rates

Rate Schedule	Present Rate	Authorized Rate in 2026	
Embedded Credits for Line Extensions			
Rg1, Rg2 & Fg1 Single Phase	$1,757	$1,859	per Customer
Rg1, Rg2 & Fg1 Three Phase	$4,392	$4,648	per Customer
Cg1 & Cg6 Single Phase	$2,002	$2,121	per Customer
Cg1 & Cg6 Three Phase	$4,004	$4,242	per Customer
Cg2, Cg3, Cg3C & Cg3S	$148	$157.09	per kW
TE1 & TE2	$8	$8.13	per Customer
General Primary	$147	$155.24	per kW
Standard Street Lighting	$106	$112.24	per Lamp
Act 141 Costs Embedded in Base Rates			
Rg1, Rg2, Fg1	$0.00191	$0.00191	per kWh
Cg1, Cg2, Cg3, Cg3C, Cg6, TSSM, TSSU,	$0.00258	$0.00256	per kWh
Cp1, Cp3, Cp4, CpFN	$0.00258	$0.00256	per kWh
Gl1, St1, St2, Al1, Ms1, Ms2, Ms3, Ms4, Mg1, TE1, LED	$0.00258	$0.00256	per kWh

Comparison of Bills for Residential and Farm

A	B	C	D	E	F	G

Rg1

Monthly Use	Typical Bills					
	Current Rates		Authorized 2026		Authorized 2026 Change	
(kWh)	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$49.31	$591.72	$53.68	$644.16	8.86%	$4.37
300	$66.46	$797.52	$73.03	$876.36	9.89%	$6.57
500	$100.77	$1,209.24	$111.71	$1,340.52	10.86%	$10.94
660	**$128.22**	**$1,538.64**	**$142.66**	**$1,711.92**	**11.26%**	**$14.44**
700	$135.08	$1,620.96	$150.39	$1,804.68	11.33%	$15.31
1,000	$186.54	$2,238.48	$208.42	$2,501.04	11.73%	$21.88
2,000	$358.08	$4,296.96	$401.84	$4,822.08	12.22%	$43.76
3,000	$529.62	$6,355.44	$595.26	$7,143.12	12.39%	$65.64

Fg1

Monthly Use	Typical Bills					
	Current Rates		Authorized 2026		Authorized 2026 Change	
(kWh)	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$49.31	$591.72	$53.68	$644.16	8.86%	$4.37
300	$66.46	$797.52	$73.03	$876.36	9.89%	$6.57
500	$100.77	$1,209.24	$111.71	$1,340.52	10.86%	$10.94
600	$117.92	$1,415.04	$131.05	$1,572.60	11.13%	$13.13
700	$135.08	$1,620.96	$150.39	$1,804.68	11.33%	$15.31
1,000	$186.54	$2,238.48	$208.42	$2,501.04	11.73%	$21.88
2,000	$358.08	$4,296.96	$401.84	$4,822.08	12.22%	$43.76
3,000	$529.62	$6,355.44	$595.26	$7,143.12	12.39%	$65.64

Rg2

Monthly Use	Typical Bills					
	Current Rates		Authorized 2026		Authorized 2026 Change	
(kWh)	Monthly	Annual	Monthly	Annual	Monthly %	Monthly $
200	$44.57	$534.83	$48.13	$577.54	7.99%	$3.56
300	$59.35	$712.24	$64.69	$776.31	9.00%	$5.34
500	$88.92	$1,067.07	$97.82	$1,173.86	10.01%	$8.90
600	$103.71	$1,244.49	$114.39	$1,372.63	10.30%	$10.68
700	$118.49	$1,421.90	$130.95	$1,571.40	10.51%	$12.46
1,000	$162.85	$1,954.15	$180.64	$2,167.72	10.93%	$17.80
2,000	$310.69	$3,728.30	$346.29	$4,155.43	11.46%	$35.59
3,000	$458.54	$5,502.44	$511.93	$6,143.15	11.64%	$53.39

Wisconsin Electric - Gas Operations
Change of PSCW Adjusted 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	Final 2025 Total Revenues	Final Total Revenue $ Change	Final Revenue % Change
Residential Rg-1	473,416	409,328,297	$ 367,975,214	$ 394,172,221	$ 26,197,007	7.1%
Firm Comm. Ind. 0 to 3,999 Fg-1	29,683	42,146,665	$ 35,079,039	$ 37,548,836	$ 2,469,797	7.0%
Firm Comm. Ind. 4,000 to 39,999 Fg-2	10,753	124,426,033	$ 83,642,767	$ 90,187,578	$ 6,544,811	7.8%
Firm Comm. Ind. 40,000 to 99,999 Fg-3	524	31,911,952	$ 19,893,788	$ 21,782,974	$ 1,889,186	9.5%
Firm Comm. Ind. 100,000 to 499,999 Fg-4	157	25,841,265	$ 14,976,502	$ 16,457,207	$ 1,480,705	9.9%
Firm Comm. Ind. 500,000 to 999,999 Fg-5	8	5,766,302	$ 3,124,408	$ 3,400,615	$ 276,207	8.8%
Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6	1	1,500,000	$ 766,249	$ 848,952	$ 82,703	10.8%
Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7	-	-	$ -	$ -	$ -	0.0%
Firm Comm. Ind. 15,000,000 & Over Fg-8	-	-	$ -	$ -	$ -	0.0%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	161	1,023,323	$ 611,211	$ 630,245	$ 19,034	3.3%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	850,146	$ 471,225	$ 487,464	$ 16,239	3.3%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	353,073	$ 189,144	$ 196,064	$ 6,920	3.3%
Interrupt. Comm. Ind. 100000 to 499999 Ig-4	3	406,947	$ 202,642	$ 208,541	$ 5,899	2.9%
Interrupt Comm. Ind. 500000 to 999999 Ig-5	1	672,828	$ 323,284	$ 326,715	$ 3,431	1.1%
Interrupt. Comm. Ind. 1,000,000 to 7,999,999 Ig-6	-	-	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 8,000,000 to 14,999,999 Ig-7	-	-	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 15,000,000 & Over Ig-8	-	-	$ -	$ -	$ -	0.0%
Power Generation Pg-2	1	494,521	$ 508,469	$ 514,539	$ 6,070	1.2%
Power Generation Pg-6	1	-	$ 654,080	$ 655,175	$ 1,095	0.2%
Power Generation Pg-7	-	-	$ -	$ -	$ -	0.0%
Power Generation Pg-8	1	3,461,123	$ 1,635,319	$ 1,674,140	$ 38,821	2.4%
Power Generation Pg-9	1	768,875	$ 1,886,158	$ 1,895,233	$ 9,075	0.5%
Power Generation Pg-11	1	37,562,381	$ 13,211,583	$ 13,655,559	$ 443,976	3.4%
Power Generation Nominated Firm NFPg-2	-	10,539,650	$ 3,886,063	$ 4,450,989	$ 564,926	14.5%
Power Generation Nominated Firm NFPg-6	-	9,915,900	$ 3,835,586	$ 4,369,060	$ 533,474	13.9%
Power Generation Nominated Firm NFPg-8	-	-	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm NFPg-9	-	-	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm NFPg-11	-	7,754,061	$ 2,978,340	$ 3,401,715	$ 423,375	14.2%
Total - Sales Customers - All	514,711	714,723,342	$ 555,851,071	$ 596,863,822	$ 41,012,751	7.4%

Transportation Customers - All	Average Customer Counts	Total Therms	Current Rates 2025 Total Revenues	Final 2025 Total Revenues	Final Total Revenue $ Change	Final Revenue % Change
Residential Tr-1	-	-	$ -	$ -	$ -	0.0%
Firm Comm. Ind. 0 to 3,999 Tf-1	9	19,059	$ 12,805	$ 12,890	$ 85	0.7%
Firm Comm. Ind. 4,000 to 39,999 Tf-2	334	8,955,193	$ 1,913,714	$ 1,899,385	$ (14,329)	-0.8%
Firm Comm. Ind. 40,000 to 99,999 Tf-3	305	17,793,385	$ 3,034,222	$ 3,123,194	$ 88,972	2.9%
Firm Comm. Ind. 100,000 to 499,999 Tf-4	259	60,377,178	$ 7,458,305	$ 7,645,477	$ 187,172	2.5%
Firm Comm. Ind. 500,000 to 999,999 Tf-5	57	37,138,705	$ 4,303,931	$ 4,069,958	$ (233,973)	-5.4%
Firm Comm. Ind. 1,000,000 to 7,999,999 Tf-6	38	79,108,517	$ 6,501,057	$ 6,575,016	$ 73,959	1.1%
Firm Comm. Ind. 8,000,000 to 14,999,999 Tf-7	5	53,380,373	$ 3,076,973	$ 3,215,572	$ 138,599	4.5%
Firm Comm. Ind. 15,000,000 & Over Tf-8	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-2	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-6	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-7	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-8	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-9	-	-	$ -	$ -	$ -	0.0%
Power Generation Pt-11	-	-	$ -	$ -	$ -	0.0%
Other Transportation	-	-	$ -	$ -	$ -	0.0%
Total - Transportation Customers - All	1,007	256,772,410	$ 26,301,007	$ 26,541,492	$ 240,485	0.9%

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

Wisconsin Electric - Gas Operations
Change of PSCW Adjusted 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	Final 2025 Total Revenues	Final Total Revenue $ Change	Final Revenue % Change
Residential Rg-1		473,416	409,328,297	$ 367,975,214	$ 394,172,221	$ 26,197,007	7.1%
Firm Comm. Ind. 0 to 3,999		29,692	42,165,724	$ 35,091,844	$ 37,561,726	$ 2,469,882	7.0%
Firm Comm. Ind. 4,000 to 39,999		11,087	133,381,226	$ 85,556,481	$ 92,086,963	$ 6,530,482	7.6%
Firm Comm. Ind. 40,000 to 99,999		828	49,705,337	$ 22,928,010	$ 24,906,168	$ 1,978,158	8.6%
Firm Comm. Ind. 100,000 to 499,999		416	86,218,443	$ 22,434,807	$ 24,102,684	$ 1,667,877	7.4%
Firm Comm. Ind. 500,000 to 999,999		65	42,905,007	$ 7,428,339	$ 7,470,573	$ 42,234	0.6%
Firm Comm. Ind. 1,000,000 to 7,999,999		39	80,608,517	$ 7,267,306	$ 7,423,968	$ 156,662	2.2%
Firm Comm. Ind. 8,000,000 to 14,999,999		5	53,380,373	$ 3,076,973	$ 3,215,572	$ 138,599	4.5%
Firm Comm. Ind. 15,000,000 & Over		-	-	$ -	$ -	$ -	0.0%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999	Ag-1	161	1,023,323	$ 611,211	$ 630,245	$ 19,034	3.3%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999	Ag-1	-	850,146	$ 471,225	$ 487,464	$ 16,239	3.3%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999	Ag-1	-	353,073	$ 189,144	$ 196,064	$ 6,920	3.3%
Interrupt. Comm. Ind. 100000 to 499999	Ig-4	3	406,947	$ 202,642	$ 208,541	$ 5,899	2.9%
Interrupt Comm. Ind. 500000 to 999999	Ig-5	1	672,828	$ 323,284	$ 326,715	$ 3,431	1.1%
Interrupt. Comm. Ind. 1,000,000 to 7,999,999	Ig-6	-	-	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 8,000,000 to 14,999,999	Ig-7	-	-	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 15,000,000 & Over	Ig-8	-	-	$ -	$ -	$ -	0.0%
Power Generation	P_-2	1	494,521	$ 508,469	$ 514,539	$ 6,070	1.2%
Power Generation	P_-6	1	-	$ 654,080	$ 655,175	$ 1,095	0.2%
Power Generation	P_-7	-	-	$ -	$ -	$ -	0.0%
Power Generation	P_-8	1	3,461,123	$ 1,635,319	$ 1,674,140	$ 38,821	2.4%
Power Generation	P_-9	1	768,875	$ 1,886,158	$ 1,895,233	$ 9,075	0.5%
Power Generation	P_-11	1	37,562,381	$ 13,211,583	$ 13,655,559	$ 443,976	3.4%
Other		-	-	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm	NFPg-2	-	10,539,650	$ 3,886,063	$ 4,450,989	$ 564,926	14.5%
Power Generation Nominated Firm	NFPg-6	-	9,915,900	$ 3,835,586	$ 4,369,060	$ 533,474	13.9%
Power Generation Nominated Firm	NFPg-8	-	-	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm	NFPg-9	-	-	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm	NFPg-11	-	7,754,061	$ 2,978,340	$ 3,401,715	$ 423,375	14.2%
Total - All Customers - All		515,718	971,495,752	$ 582,152,078	$ 623,405,314	$ 41,253,236	7.1%

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

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Residential Service

Rates - Description	2025 Final Rates Firm Sales	2025 Final Rates Interruptible Sales	2025 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.2965	NA	$ 0.2965	$ 0.2871	NA	$ 0.2871	$ 0.0094	NA	$ 0.0094
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0510	NA	$ -	$ 0.0082	NA	$ -	$ 0.0428	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.3882	NA	$ 0.2977	$ 0.3242	NA	$ 0.2879	$ 0.0640	NA	$ 0.0098
Peak Demand	$ 0.1025	NA	$ -	$ 0.1025	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0083	NA	$ -	$ 0.0083	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3394	NA	$ -	$ 0.3394	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	NA	$ -	$ 0.4502	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8384	NA	$ 0.2977	$ 0.7744	NA	$ 0.2879	$ 0.0640	NA	$ 0.0098
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0072	NA	$ 0.0072	$ 0.0056	NA	$ 0.0056	$ 0.0016	NA	$ 0.0016

Commercial / Industrial Class 1 0 to 3,999 Therms Annually

Rates - Description	2025 Final Rates Firm Sales	2025 Final Rates Interruptible Sales	2025 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.2736	NA	$ 0.2736	$ 0.2696	NA	$ 0.2696	$ 0.0040	NA	$ 0.0040
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0510	NA	$ -	$ 0.0082	NA	$ -	$ 0.0428	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.3653	NA	$ 0.2748	$ 0.3067	NA	$ 0.2704	$ 0.0586	NA	$ 0.0044
Peak Demand	$ 0.1025	NA	$ -	$ 0.1025	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0083	NA	$ -	$ 0.0083	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3394	NA	$ -	$ 0.3394	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	NA	$ -	$ 0.4502	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8155	NA	$ 0.2748	$ 0.7569	NA	$ 0.2704	$ 0.0586	NA	$ 0.0044
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	NA	$ 0.0123	$ 0.0096	NA	$ 0.0096	$ 0.0027	NA	$ 0.0027

NA = Not Available

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Commercial / Industrial Class 2 4,000 to 39,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.85	NA	$ 0.85	$ 0.85	NA	$ 0.85	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.1721	NA	$ 0.1721	$ 0.1741	NA	$ 0.1741	$ (0.0020)	NA	$ (0.0020)
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0510	NA	$ -	$ 0.0082	NA	$ -	$ 0.0428	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.2638	NA	$ 0.1733	$ 0.2112	NA	$ 0.1749	$ 0.0526	NA	$ (0.0016)
Peak Demand	$ 0.1025	NA	$ -	$ 0.1025	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0083	NA	$ -	$ 0.0083	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3394	NA	$ -	$ 0.3394	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	NA	$ -	$ 0.4502	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.7140	NA	$ 0.1733	$ 0.6614	NA	$ 0.1749	$ 0.0526	NA	$ (0.0016)
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	NA	$ 0.0123	$ 0.0096	NA	$ 0.0096	$ 0.0027	NA	$ 0.0027

NA = Not Available   NA = Not Available

Commercial / Industrial Class 3 40,000 to 99,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 6.00	NA	$ 6.00	$ 6.00	NA	$ 6.00	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.1243	NA	$ 0.1243	$ 0.1197	NA	$ 0.1197	$ 0.0046	NA	$ 0.0046
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0510	NA	$ -	$ 0.0082	NA	$ -	$ 0.0428	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.2160	NA	$ 0.1255	$ 0.1568	NA	$ 0.1205	$ 0.0592	NA	$ 0.0050
Peak Demand	$ 0.1025	NA	$ -	$ 0.1025	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0083	NA	$ -	$ 0.0083	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3394	NA	$ -	$ 0.3394	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	NA	$ -	$ 0.4502	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.6662	NA	$ 0.1255	$ 0.6070	NA	$ 0.1205	$ 0.0592	NA	$ 0.0050
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	NA	$ 0.0123	$ 0.0096	NA	$ 0.0096	$ 0.0027	NA	$ 0.0027

NA = Not Available   NA = Not Available   NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Commercial / Industrial Class 4 100,000 to 499,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1051	$ 0.1051	$ 0.1051	$ 0.1024	$ 0.1024	$ 0.1024	$ 0.0027	$ 0.0027	$ 0.0027
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0428	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1968	$ 0.1458	$ 0.1063	$ 0.1395	$ 0.1313	$ 0.1032	$ 0.0573	$ 0.0145	$ 0.0031
Peak Demand	$ 0.1025	$ -	$ -	$ 0.1025	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ -	$ 0.0083	$ 0.0083	$ -	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ -	$ 0.3394	$ 0.3394	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.3477	$ -	$ 0.4502	$ 0.3477	$ -	$ -	$ -	$ -
Total Rate	$ 0.6470	$ 0.4935	$ 0.1063	$ 0.5897	$ 0.4790	$ 0.1032	$ 0.0573	$ 0.0145	$ 0.0031
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	$ 0.0123	$ 0.0123	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0027	$ 0.0027	$ 0.0027

Commercial / Industrial Class 5 500,000 to 999,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0876	$ 0.0876	$ 0.0876	$ 0.0943	$ 0.0943	$ 0.0943	$ (0.0067)	$ (0.0067)	$ (0.0067)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0428	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1793	$ 0.1283	$ 0.0888	$ 0.1314	$ 0.1232	$ 0.0951	$ 0.0479	$ 0.0051	$ (0.0063)
Peak Demand	$ 0.1025	$ -	$ -	$ 0.1025	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ -	$ 0.0083	$ 0.0083	$ -	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ -	$ 0.3394	$ 0.3394	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.3477	$ -	$ 0.4502	$ 0.3477	$ -	$ -	$ -	$ -
Total Rate	$ 0.6295	$ 0.4760	$ 0.0888	$ 0.5816	$ 0.4709	$ 0.0951	$ 0.0479	$ 0.0051	$ (0.0063)
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	$ 0.0123	$ 0.0123	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0027	$ 0.0027	$ 0.0027

NA = Not Available NA = Not Available NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Commercial / Industrial Class 6 1,000,000 to 7,999,999 Therms Annually

Rates - Description	2025 Final Rates Firm Sales	2025 Final Rates Interruptible Sales	2025 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0036	$ 0.0036	$ 0.0036	$ 0.0010	$ 0.0010	$ 0.0010
Distribution Margin per therm	$ 0.0525	$ 0.0525	$ 0.0525	$ 0.0539	$ 0.0539	$ 0.0539	$ (0.0014)	$ (0.0014)	$ (0.0014)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0428	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1442	$ 0.0932	$ 0.0537	$ 0.0910	$ 0.0828	$ 0.0547	$ 0.0532	$ 0.0104	$ (0.0010)
Peak Demand	$ 0.1025	$ -	$ -	$ 0.1025	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ -	$ 0.0083	$ 0.0083	$ -	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ -	$ 0.3394	$ 0.3394	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.3477	$ -	$ 0.4502	$ 0.3477	$ -	$ -	$ -	$ -
Total Rate	$ 0.5944	$ 0.4409	$ 0.0537	$ 0.5412	$ 0.4305	$ 0.0547	$ 0.0532	$ 0.0104	$ (0.0010)
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

Commercial / Industrial Class 7 8,000,000 Therms to 14,999,999 Annually

Rates - Description	2025 Final Rates Firm Sales	2025 Final Rates Interruptible Sales	2025 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0040	$ 0.0040	$ 0.0040	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0010	$ 0.0010	$ 0.0010
Distribution Margin per therm	$ 0.0384	$ 0.0384	$ 0.0384	$ 0.0375	$ 0.0375	$ 0.0375	$ 0.0009	$ 0.0009	$ 0.0009
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0428	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1301	$ 0.0791	$ 0.0396	$ 0.0746	$ 0.0664	$ 0.0383	$ 0.0555	$ 0.0127	$ 0.0013
Peak Demand	$ 0.1025	$ -	$ -	$ 0.1025	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ -	$ 0.0083	$ 0.0083	$ -	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ -	$ 0.3394	$ 0.3394	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.3477	$ -	$ 0.4502	$ 0.3477	$ -	$ -	$ -	$ -
Total Rate	$ 0.5803	$ 0.4268	$ 0.0396	$ 0.5248	$ 0.4141	$ 0.0383	$ 0.0555	$ 0.0127	$ 0.0013
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

NA = Not Available (2025 Final Rates)
NA = Not Available (2024 Current Rates)
NA = Not Available (Final Change in Rates)

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Commercial / Industrial Class 8 15,000,000 Therms Annually & Over

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0031	$ 0.0031	$ 0.0031	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0010	$ 0.0010	$ 0.0010
Distribution Margin per therm	$ 0.0164	$ 0.0164	$ 0.0164	$ 0.0152	$ 0.0152	$ 0.0152	$ 0.0012	$ 0.0012	$ 0.0012
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0428	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1081	$ 0.0571	$ 0.0176	$ 0.0523	$ 0.0441	$ 0.0160	$ 0.0558	$ 0.0130	$ 0.0016
Peak Demand	$ 0.1025	$ -	$ -	$ 0.1025	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ -	$ 0.0083	$ 0.0083	$ -	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ -	$ 0.3394	$ 0.3394	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.3477	$ -	$ 0.4502	$ 0.3477	$ -	$ -	$ -	$ -
Total Rate	$ 0.5583	$ 0.4048	$ 0.0176	$ 0.5025	$ 0.3918	$ 0.0160	$ 0.0558	$ 0.0130	$ 0.0016
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

Agricultural Seasonal Use Sales Service Ag-1

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3
Daily Facitilties Charge	$ 0.50	$ -	$ -	$ 0.50	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1462	$ 0.1394	$ 0.1269	$ 0.1822	$ 0.1749	$ 0.1619	$ (0.0360)	$ (0.0355)	$ (0.0350)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ 0.0395	$ 0.0281	$ 0.0281	$ 0.0281	$ 0.0114	$ 0.0114	$ 0.0114
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0510	$ 0.0510	$ 0.0510	$ 0.0082	$ 0.0082	$ 0.0082	$ 0.0428	$ 0.0428	$ 0.0428
Other Margin									
Total All Margin Rates	$ 0.2379	$ 0.2311	$ 0.2186	$ 0.2193	$ 0.2120	$ 0.1990	$ 0.0186	$ 0.0191	$ 0.0196
Peak Demand	$ 0.1025	$ 0.1025	$ 0.1025	$ 0.1025	$ 0.1025	$ 0.1025	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4502	$ 0.4502	$ 0.4502	$ 0.4502	$ 0.4502	$ 0.4502	$ -	$ -	$ -
Total Rate	$ 0.6881	$ 0.6813	$ 0.6688	$ 0.6695	$ 0.6622	$ 0.6492	$ 0.0186	$ 0.0191	$ 0.0196
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0123	$ 0.0123	$ 0.0123	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0027	$ 0.0027	$ 0.0027

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2025

Power Generation

Rates - Description	2025 Final Rates Pg-2	2025 Final Rates Pg-6	2025 Final Rates Pg-8	2024 Current Rates Pg-2	2024 Current Rates Pg-6	2024 Current Rates Pg-8	Final Change in Rates Pg-2	Final Change in Rates Pg-6	Final Change in Rates Pg-8
Daily Facitilties Charge	$ 900.00	$ 1,795.00	$ 682.00	$ 898.00	$ 1,792.00	$ 679.00	$ 2.00	$ 3.00	$ 3.00
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0089	$ 0.0269	$ 0.0259	$ 0.0099	$ 0.0277	$ 0.0268	$ (0.0010)	$ (0.0008)	$ (0.0009)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ 0.0395	$ 0.0281	$ 0.0281	$ 0.0281	$ 0.0114	$ 0.0114	$ 0.0114
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0496	$ 0.0676	$ 0.0666	$ 0.0388	$ 0.0566	$ 0.0557	$ 0.0108	$ 0.0110	$ 0.0109
Peak Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ 0.0083	$ -	$ -	$ -
Commodity	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ 0.3394	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.3477	$ 0.3477	$ 0.3477	$ 0.3477	$ 0.3477	$ 0.3477	$ -	$ -	$ -
Total Rate	$ 0.3973	$ 0.4153	$ 0.4143	$ 0.3865	$ 0.4043	$ 0.4034	$ 0.0108	$ 0.0110	$ 0.0109
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA

Power Generation

Rates - Description	2025 Final Rates Pg-9	2025 Final Rates Pg-11	2025 Final Rates NA	2024 Current Rates Pg-9	2024 Current Rates Pg-11	2024 Current Rates NA	Final Change in Rates Pg-9	Final Change in Rates Pg-11	Final Change in Rates NA
Daily Facitilties Charge	$ 251.20	$ 422.00	NA	$ 251.20	$ 419.97	NA	$ -	$ 2.03	NA
Transportation Administrative	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Daily Demand Charge	$ 0.0150	$ -	NA	$ 0.0150	$ -	NA	$ -	$ -	NA
Distribution Margin per therm	$ 0.0015	$ 0.0003	NA	$ 0.0015	$ 0.0003	NA	$ -	$ -	NA
Competitive Supply Margin	$ 0.0395	$ 0.0395	NA	$ 0.0281	$ 0.0281	NA	$ 0.0114	$ 0.0114	NA
Daily Balancing Margin	$ 0.0012	$ 0.0012	NA	$ 0.0008	$ 0.0008	NA	$ 0.0004	$ 0.0004	NA
Peak Day Margin	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Other Margin									
Total All Margin Rates	$ 0.0422	$ 0.0410	NA	$ 0.0304	$ 0.0292	NA	$ 0.0118	$ 0.0118	NA
Peak Demand	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Annual Demand	$ 0.0083	$ 0.0083	NA	$ 0.0083	$ 0.0083	NA	$ -	$ -	NA
Commodity	$ 0.3394	$ 0.3394	NA	$ 0.3394	$ 0.3394	NA	$ -	$ -	NA
Total Natural Gas Rate Per Therm	$ 0.3477	$ 0.3477	NA	$ 0.3477	$ 0.3477	NA	$ -	$ -	NA
Total Rate	$ 0.3899	$ 0.3887	NA	$ 0.3781	$ 0.3769	NA	$ 0.0118	$ 0.0118	NA
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not Available

NA = Not Available

NA = Not Available

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Residential Rg-1

Transportation Service / **Sales Service**

	Transportation: Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change		Sales: Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -		$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -	
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -		$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -	
$/Therm-Winter	$ 0.2879	$ 0.2977	$ 0.0098		$/Therm-Winter	$ 0.7744	$ 0.8384	$ 0.0640	
$/Therm-Summer	$ 0.2879	$ 0.2977	$ 0.0098		$/Therm-Summer	$ 0.6719	$ 0.7359	$ 0.0640	

Usage in Therms	# of Customers & Class Average Use	Transportation: Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Sales: Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
300		$ 936.85	$ 939.80	$ 2.95	0.31%		$ 347.49	$ 366.70	$ 19.21	5.53%
600		$ 1,023.26	$ 1,029.14	$ 5.88	0.57%		$ 574.53	$ 612.95	$ 38.42	6.69%
865		$ 1,099.48	$ 1,107.96	$ 8.48	0.77%		$ 774.83	$ 830.19	$ 55.36	7.14%
1,096		$ 1,166.07	$ 1,176.82	$ 10.75	0.92%		$ 949.80	$ 1,019.96	$ 70.16	7.39%
1,332		$ 1,233.81	$ 1,246.86	$ 13.05	1.06%		$ 1,127.80	$ 1,213.02	$ 85.22	7.56%
1,567		$ 1,301.56	$ 1,316.91	$ 15.35	1.18%		$ 1,305.80	$ 1,406.08	$ 100.28	7.68%
1,802		$ 1,369.30	$ 1,386.96	$ 17.66	1.29%		$ 1,483.80	$ 1,599.14	$ 115.34	7.77%
2,037		$ 1,437.04	$ 1,457.00	$ 19.96	1.39%		$ 1,661.80	$ 1,792.20	$ 130.40	7.85%
2,273		$ 1,504.78	$ 1,527.05	$ 22.27	1.48%		$ 1,839.80	$ 1,985.26	$ 145.46	7.91%
2,508		$ 1,572.52	$ 1,597.10	$ 24.58	1.56%		$ 2,017.81	$ 2,178.32	$ 160.51	7.95%
2,743		$ 1,640.26	$ 1,667.15	$ 26.89	1.64%		$ 2,195.81	$ 2,371.38	$ 175.57	8.00%
2,979		$ 1,708.00	$ 1,737.19	$ 29.19	1.71%		$ 2,373.81	$ 2,564.44	$ 190.63	8.03%
3,214		$ 1,775.74	$ 1,807.24	$ 31.50	1.77%		$ 2,551.81	$ 2,757.50	$ 205.69	8.06%
3,449		$ 1,843.48	$ 1,877.29	$ 33.81	1.83%		$ 2,729.81	$ 2,950.56	$ 220.75	8.09%
3,685		$ 1,911.23	$ 1,947.33	$ 36.10	1.89%		$ 2,907.81	$ 3,143.62	$ 235.81	8.11%
3,920		$ 1,978.97	$ 2,017.38	$ 38.41	1.94%		$ 3,085.81	$ 3,336.68	$ 250.87	8.13%
4,095		$ 2,029.43	$ 2,069.57	$ 40.14	1.98%		$ 3,218.42	$ 3,480.51	$ 262.09	8.14%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	82.54%	82.54%	Winter Qty %	82.54%	82.54%
Summer QTY %	17.46%	17.46%	Summer QTY %	17.46%	17.46%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477
Transportation Administrative Charge:	$ 2.00	

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Agricultural Use Crop Drying Step 1 0 to 2,999 Ag-1

	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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equ	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Out of Se	NA	NA	NA		$/Therm-Out of Season Step	$ 0.6695	$ 0.6881	$ 0.0186	
						$/Therm-Out of Season Step	$ 0.6622	$ 0.6813	$ 0.0191	
						$/Therm-Out of Season Step	$ 0.6492	$ 0.6688	$ 0.0196	
	$/Therm-In Seasor	NA	NA	NA		$/Therm-In Season Step 1	$ 0.5670	$ 0.5856	$ 0.0186	
						$/Therm-In Season Step 2	$ 0.5597	$ 0.5788	$ 0.0191	
						$/Therm-In Season Step 3	$ 0.5467	$ 0.5663	$ 0.0196	

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		NA	NA	NA	NA		$ 316.95	$ 321.32	$ 4.37	1.38%
294	57	NA	NA	NA	NA		$ 350.70	$ 356.17	$ 5.47	1.56%
470		NA	NA	NA	NA		$ 451.40	$ 460.14	$ 8.74	1.94%
940		NA	NA	NA	NA		$ 720.30	$ 737.78	$ 17.48	2.43%
1,175		NA	NA	NA	NA		$ 854.75	$ 876.60	$ 21.85	2.56%
1,350		NA	NA	NA	NA		$ 954.87	$ 979.98	$ 25.11	2.63%
1,515		NA	NA	NA	NA		$ 1,049.27	$ 1,077.45	$ 28.18	2.69%
1,690		NA	NA	NA	NA		$ 1,149.39	$ 1,180.83	$ 31.44	2.73%
1,830		NA	NA	NA	NA		$ 1,229.49	$ 1,263.53	$ 34.04	2.77%
1,970		NA	NA	NA	NA		$ 1,309.59	$ 1,346.23	$ 36.64	2.80%
2,110		NA	NA	NA	NA		$ 1,389.68	$ 1,428.93	$ 39.25	2.82%
2,250		NA	NA	NA	NA		$ 1,469.78	$ 1,511.63	$ 41.85	2.85%
2,390		NA	NA	NA	NA		$ 1,549.88	$ 1,594.33	$ 44.45	2.87%
2,530		NA	NA	NA	NA		$ 1,629.98	$ 1,677.03	$ 47.05	2.89%
2,670		NA	NA	NA	NA		$ 1,710.07	$ 1,759.74	$ 49.67	2.90%
2,810		NA	NA	NA	NA		$ 1,790.17	$ 1,842.44	$ 52.27	2.92%
2,950		NA	NA	NA	NA		$ 1,870.27	$ 1,925.14	$ 54.87	2.93%

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:	$ 0.3394	$ 0.3394
1175	Base Average Peak Demand Cost:	$ 0.1025	$ -
4	Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
293.75	Base Average Balancing Cost:	$ -	$ -
	Base Average Surcharge Cost:	$ -	$ -
	Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Agricultural Use Crop Drying Step 2 3,000 to 9,999 Ag-1

		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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Out of Seasor	NA	NA	NA		$/Therm-Out of Season S	$ 0.6695	$ 0.6881	$ 0.0186	
						$/Therm-Out of Season S	$ 0.6622	$ 0.6813	$ 0.0191	
						$/Therm-Out of Season S	$ 0.6492	$ 0.6688	$ 0.0196	
	$/Therm-In Season	NA	NA	NA		$/Therm-In Season Step	$ 0.5670	$ 0.5856	$ 0.0186	
						$/Therm-In Season Step	$ 0.5597	$ 0.5788	$ 0.0191	
						$/Therm-In Season Step	$ 0.5467	$ 0.5663	$ 0.0196	

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
3,123	94	NA	NA	NA	NA		$ 1,954.84	$ 2,012.93	$ 58.09	2.97%
4,400		NA	NA	NA	NA		$ 2,679.56	$ 2,761.40	$ 81.83	3.05%
4,800		NA	NA	NA	NA		$ 2,906.56	$ 2,995.84	$ 89.28	3.07%
5,200		NA	NA	NA	NA		$ 3,133.57	$ 3,230.29	$ 96.71	3.09%
5,600		NA	NA	NA	NA		$ 3,360.57	$ 3,464.73	$ 104.16	3.10%
6,000		NA	NA	NA	NA		$ 3,587.58	$ 3,699.18	$ 111.59	3.11%
6,400		NA	NA	NA	NA		$ 3,814.58	$ 3,933.62	$ 119.04	3.12%
6,800		NA	NA	NA	NA		$ 4,041.59	$ 4,168.07	$ 126.47	3.13%
7,200		NA	NA	NA	NA		$ 4,268.59	$ 4,402.51	$ 133.92	3.14%
7,600		NA	NA	NA	NA		$ 4,495.60	$ 4,636.96	$ 141.35	3.14%
8,000		NA	NA	NA	NA		$ 4,722.60	$ 4,871.40	$ 148.80	3.15%
8,400		NA	NA	NA	NA		$ 4,949.61	$ 5,105.85	$ 156.24	3.16%
8,800		NA	NA	NA	NA		$ 5,176.61	$ 5,340.29	$ 163.68	3.16%
9,000		NA	NA	NA	NA		$ 5,290.11	$ 5,457.51	$ 167.40	3.16%
9,400		NA	NA	NA	NA		$ 5,517.12	$ 5,691.96	$ 174.84	3.17%
9,800		NA	NA	NA	NA		$ 5,744.12	$ 5,926.40	$ 182.28	3.17%
9,950		NA	NA	NA	NA		$ 5,829.25	$ 6,014.32	$ 185.07	3.17%
	Winter Qty %	NA	NA			Winter Qty %	0.50%	0.50%		
	Summer QTY %	NA	NA			Drying Season QTY %	99.50%	99.50%		

			Firm	Interruptible
12492	Gas Cost Rates:			
4	Base Average Commodity Cost:		$ 0.3394	$ 0.3394
3123	Base Average Peak Demand Cost:		$ 0.1025	$ -
	Base Average Annual Demand Cost:		$ 0.0083	$ 0.0083
	Base Average Balancing Cost:		$ -	$ -
	Base Average Surcharge Cost:		$ -	$ -
		Totals:	$ 0.4502	$ 0.3477
	Transportation Administrative Charge:		$ 2.00	

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Agricultural Use Crop Drying Step 3 Over 9,999 Ag-1

		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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Out of Se	NA	NA	NA		$/Therm-Out of Season S	$ 0.6695	$ 0.6881	$ 0.0186	
						$/Therm-Out of Season S	$ 0.6622	$ 0.6813	$ 0.0191	
						$/Therm-Out of Season S	$ 0.6492	$ 0.6688	$ 0.0196	
	$/Therm-In Seasor	NA	NA	NA		$/Therm-In Season Step	$ 0.5670	$ 0.5856	$ 0.0186	
						$/Therm-In Season Step	$ 0.5597	$ 0.5788	$ 0.0191	
						$/Therm-In Season Step	$ 0.5467	$ 0.5663	$ 0.0196	

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
10,000		NA	NA	NA	NA		$ 5,857.63	$ 6,043.63	$ 185.99	3.18%
17,500		NA	NA	NA	NA		$ 10,074.43	$ 10,402.64	$ 328.21	3.26%
22,351	13	NA	NA	NA	NA		$ 12,792.20	$ 13,213.05	$ 420.85	3.29%
32,500		NA	NA	NA	NA		$ 18,478.17	$ 19,092.83	$ 614.67	3.33%
40,000		NA	NA	NA	NA		$ 22,680.03	$ 23,437.93	$ 757.90	3.34%
37,851	1	NA	NA	NA	NA		$ 21,476.06	$ 22,192.92	$ 716.86	3.34%
45,351		NA	NA	NA	NA		$ 25,611.26	$ 26,473.91	$ 862.65	3.37%
52,851		NA	NA	NA	NA		$ 29,716.12	$ 30,725.73	$ 1,009.62	3.40%
60,351		NA	NA	NA	NA		$ 33,820.97	$ 34,977.55	$ 1,156.58	3.42%
67,851		NA	NA	NA	NA		$ 37,925.83	$ 39,229.37	$ 1,303.54	3.44%
75,351		NA	NA	NA	NA		$ 42,030.68	$ 43,481.18	$ 1,450.50	3.45%
82,851		NA	NA	NA	NA		$ 46,135.54	$ 47,733.00	$ 1,597.46	3.46%
90,351		NA	NA	NA	NA		$ 50,240.39	$ 51,984.82	$ 1,744.43	3.47%
97,851		NA	NA	NA	NA		$ 54,345.25	$ 56,236.64	$ 1,891.39	3.48%
105,351		NA	NA	NA	NA		$ 58,450.10	$ 60,488.45	$ 2,038.35	3.49%
112,851		NA	NA	NA	NA		$ 62,554.96	$ 64,740.27	$ 2,185.31	3.49%
120,351		NA	NA	NA	NA		$ 66,659.82	$ 68,992.09	$ 2,332.27	3.50%
	Winter Qty %	NA	NA			Winter Qty %	0.50%	0.50%		
	Summer QTY %	NA	NA			Drying Season QTY %	99.50%	99.50%		

			Firm	Interruptible
		Gas Cost Rates:		
151403		Base Average Commodity Cost:	$ 0.3394	$ 0.3394
4		Base Average Peak Demand Cost:	$ 0.1025	$ -
37850.75	89406	Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
	4	Base Average Balancing Cost:	$ -	$ -
	22351.5	Base Average Surcharge Cost:	$ -	$ -
		Totals:	$ 0.4502	$ 0.3477
		Transportation Administrative Charge:	$ 2.00	

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 0 to 3,999 Fg-1 & Tf-1

Transportation Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -
Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.2704	$ 0.2748	$ 0.0044
$/Therm-Summer	$ 0.2704	$ 0.2748	$ 0.0044

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -
$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -
Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.7569	$ 0.8155	$ 0.0586
$/Therm-Summer	$ 0.6544	$ 0.7130	$ 0.0586

Usage in Therms	# of Customers & Class Average Use	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	# of Customers & Class Average Use	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
250		$ 918.03	$ 919.13	$ 1.10	0.12%		$ 306.14	$ 320.79	$ 14.65	4.79%
500		$ 985.62	$ 987.82	$ 2.20	0.22%		$ 491.84	$ 521.13	$ 29.29	5.96%
750		$ 1,053.20	$ 1,056.50	$ 3.30	0.31%		$ 677.53	$ 721.47	$ 43.94	6.49%
1,000		$ 1,120.78	$ 1,125.18	$ 4.40	0.39%		$ 863.22	$ 921.81	$ 58.59	6.79%
1,398		$ 1,228.47	$ 1,234.62	$ 6.15	0.50%		$ 1,159.11	$ 1,241.03	$ 81.92	7.07%
1,500		$ 1,256.05	$ 1,262.65	$ 6.60	0.53%		$ 1,234.89	$ 1,322.79	$ 87.90	7.12%
1,750		$ 1,323.63	$ 1,331.33	$ 7.70	0.58%		$ 1,420.58	$ 1,523.13	$ 102.55	7.22%
1,900		$ 1,364.18	$ 1,372.54	$ 8.36	0.61%		$ 1,531.98	$ 1,643.31	$ 111.33	7.27%
2,151		$ 1,432.03	$ 1,441.49	$ 9.46	0.66%		$ 1,718.42	$ 1,844.46	$ 126.04	7.33%
2,401		$ 1,499.61	$ 1,510.18	$ 10.57	0.70%		$ 1,904.11	$ 2,044.80	$ 140.69	7.39%
2,651		$ 1,567.20	$ 1,578.86	$ 11.66	0.74%		$ 2,089.80	$ 2,245.14	$ 155.34	7.43%
2,901		$ 1,634.78	$ 1,647.54	$ 12.76	0.78%		$ 2,275.50	$ 2,445.47	$ 169.97	7.47%
3,151		$ 1,702.36	$ 1,716.22	$ 13.86	0.81%		$ 2,461.19	$ 2,645.81	$ 184.62	7.50%
3,401		$ 1,769.95	$ 1,784.91	$ 14.96	0.85%		$ 2,646.89	$ 2,846.15	$ 199.26	7.53%
3,650		$ 1,837.53	$ 1,853.59	$ 16.06	0.87%		$ 2,832.58	$ 3,046.49	$ 213.91	7.55%
3,899		$ 1,904.84	$ 1,922.00	$ 17.16	0.90%		$ 3,017.53	$ 3,246.03	$ 228.50	7.57%

	Transportation Old	Transportation New	Sales Old	Sales New
Winter Qty %	86.40%	86.40%	86.40%	86.40%
Summer QTY %	13.60%	13.60%	13.60%	13.60%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 4,000 to 39,999 Fg-2 & Tf-2

		Transportation Service Without Telemetry Fee					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	$ 86.69	$ 86.69	$ -		$/Mo. Fixed or equ	$ 25.85	$ 25.85	$ -	
	$/Day Fixed or equ	$ 2.85	$ 2.85	$ -		$/Day Fixed or equ	$ 0.85	$ 0.85	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1749	$ 0.1733	$ (0.0016)		$/Therm-Winter	$ 0.6614	$ 0.7140	$ 0.0526	
	$/Therm-Summer	$ 0.1749	$ 0.1733	$ (0.0016)		$/Therm-Summer	$ 0.5589	$ 0.6115	$ 0.0526	

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
4,000		$ 1,739.85	$ 1,733.45	$ (6.40)	-0.37%		$ 2,877.87	$ 3,088.27	$ 210.40	7.31%
6,400		$ 2,159.61	$ 2,149.37	$ (10.24)	-0.47%		$ 4,418.44	$ 4,755.08	$ 336.64	7.62%
8,800		$ 2,579.37	$ 2,565.29	$ (14.08)	-0.55%		$ 5,959.01	$ 6,421.89	$ 462.88	7.77%
11,392		$ 3,032.71	$ 3,014.48	$ (18.23)	-0.60%		$ 7,622.83	$ 8,222.05	$ 599.22	7.86%
13,600		$ 3,418.89	$ 3,397.13	$ (21.76)	-0.64%		$ 9,040.15	$ 9,755.51	$ 715.36	7.91%
16,000		$ 3,838.65	$ 3,813.05	$ (25.60)	-0.67%		$ 10,580.72	$ 11,422.32	$ 841.60	7.95%
18,400		$ 4,258.41	$ 4,228.97	$ (29.44)	-0.69%		$ 12,121.29	$ 13,089.13	$ 967.84	7.98%
20,800		$ 4,678.17	$ 4,644.89	$ (33.28)	-0.71%		$ 13,661.86	$ 14,755.94	$ 1,094.08	8.01%
23,200		$ 5,097.93	$ 5,060.81	$ (37.12)	-0.73%		$ 15,202.43	$ 16,422.75	$ 1,220.32	8.03%
25,600		$ 5,517.69	$ 5,476.73	$ (40.96)	-0.74%		$ 16,743.01	$ 18,089.57	$ 1,346.56	8.04%
28,000		$ 5,937.45	$ 5,892.65	$ (44.80)	-0.75%		$ 18,283.58	$ 19,756.38	$ 1,472.80	8.06%
30,400		$ 6,357.21	$ 6,308.57	$ (48.64)	-0.77%		$ 19,824.15	$ 21,423.19	$ 1,599.04	8.07%
32,800		$ 6,776.97	$ 6,724.49	$ (52.48)	-0.77%		$ 21,364.72	$ 23,090.00	$ 1,725.28	8.08%
35,200		$ 7,196.73	$ 7,140.41	$ (56.32)	-0.78%		$ 22,905.29	$ 24,756.81	$ 1,851.52	8.08%
37,600		$ 7,616.49	$ 7,556.33	$ (60.16)	-0.79%		$ 24,445.86	$ 26,423.62	$ 1,977.76	8.09%
39,999		$ 8,036.08	$ 7,972.08	$ (64.00)	-0.80%		$ 25,985.79	$ 28,089.74	$ 2,103.95	8.10%
	Winter Qty %	81.39%	81.39%			Winter Qty %	80.98%	80.98%		
	Summer QTY %	18.61%	18.61%			Summer QTY %	19.02%	19.02%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 40,000 to 99,999 Fg-3 & Tf-3

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.	$ 243.33	$ 243.33	$ -		$/Mo. Fixed or equiv.	$ 182.50	$ 182.50	$ -	
	$/Day Fixed or equiv.	$ 8.00	$ 8.00	$ -		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1205	$ 0.1255	$ 0.0050		$/Therm-Winter	$ 0.6070	$ 0.6662	$ 0.0592	
	$/Therm-Summer	$ 0.1205	$ 0.1255	$ 0.0050		$/Therm-Summer	$ 0.5045	$ 0.5637	$ 0.0592	

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
40,000		$ 7,740.00	$ 7,940.00	$ 200.00	2.58%		$ 25,590.55	$ 27,958.55	$ 2,368.00	9.25%
44,000		$ 8,222.00	$ 8,442.00	$ 220.00	2.68%		$ 27,930.61	$ 30,535.41	$ 2,604.80	9.33%
48,000		$ 8,704.00	$ 8,944.00	$ 240.00	2.76%		$ 30,270.66	$ 33,112.26	$ 2,841.60	9.39%
52,000		$ 9,186.00	$ 9,446.00	$ 260.00	2.83%		$ 32,610.72	$ 35,689.12	$ 3,078.40	9.44%
56,000		$ 9,668.00	$ 9,948.00	$ 280.00	2.90%		$ 34,950.77	$ 38,265.97	$ 3,315.20	9.49%
59,991		$ 10,148.92	$ 10,448.87	$ 299.95	2.96%		$ 37,285.56	$ 40,837.03	$ 3,551.47	9.53%
64,000		$ 10,632.00	$ 10,952.00	$ 320.00	3.01%		$ 39,630.88	$ 43,419.68	$ 3,788.80	9.56%
68,000		$ 11,114.00	$ 11,454.00	$ 340.00	3.06%		$ 41,970.94	$ 45,996.54	$ 4,025.60	9.59%
72,000		$ 11,596.00	$ 11,956.00	$ 360.00	3.10%		$ 44,310.99	$ 48,573.39	$ 4,262.40	9.62%
76,000		$ 12,078.00	$ 12,458.00	$ 380.00	3.15%		$ 46,651.05	$ 51,150.25	$ 4,499.20	9.64%
80,000		$ 12,560.00	$ 12,960.00	$ 400.00	3.18%		$ 48,991.10	$ 53,727.10	$ 4,736.00	9.67%
84,000		$ 13,042.00	$ 13,462.00	$ 420.00	3.22%		$ 51,331.16	$ 56,303.96	$ 4,972.80	9.69%
88,000		$ 13,524.00	$ 13,964.00	$ 440.00	3.25%		$ 53,671.21	$ 58,880.81	$ 5,209.60	9.71%
92,000		$ 14,006.00	$ 14,466.00	$ 460.00	3.28%		$ 56,011.27	$ 61,457.67	$ 5,446.40	9.72%
96,000		$ 14,488.00	$ 14,968.00	$ 480.00	3.31%		$ 58,351.32	$ 64,034.52	$ 5,683.20	9.74%
99,999		$ 14,969.88	$ 15,469.87	$ 499.99	3.34%		$ 60,690.79	$ 66,610.73	$ 5,919.94	9.75%
	Winter Qty %	77.64%	77.64%			Winter Qty %	78.55%	78.55%		
	Summer QTY %	22.36%	22.36%			Summer QTY %	21.45%	21.45%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 100,000 to 499,999 Fg-4 & Tf-4

	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	$ 395.42	$ 395.42	$ -		$/Mo. Fixed or equ	$ 334.58	$ 334.58	$ -	
	$/Day Fixed or equ	$ 13.00	$ 13.00	$ -		$/Day Fixed or equ	$ 11.00	$ 11.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1032	$ 0.1063	$ 0.0031		$/Therm-Winter	$ 0.5897	$ 0.6470	$ 0.0573	
	$/Therm-Summer	$ 0.1032	$ 0.1063	$ 0.0031		$/Therm-Summer	$ 0.4872	$ 0.5445	$ 0.0573	

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
100,000		$ 15,065.00	$ 15,375.00	$ 310.00	2.06%		$ 59,785.98	$ 65,515.98	$ 5,730.00	9.58%
126,667		$ 17,817.00	$ 18,209.67	$ 392.67	2.20%		$ 74,658.24	$ 81,916.24	$ 7,258.00	9.72%
162,033		$ 21,466.81	$ 21,969.11	$ 502.30	2.34%		$ 94,382.38	$ 103,666.87	$ 9,284.49	9.84%
180,000		$ 23,321.00	$ 23,879.00	$ 558.00	2.39%		$ 104,402.76	$ 114,716.76	$ 10,314.00	9.88%
206,667		$ 26,073.00	$ 26,713.67	$ 640.67	2.46%		$ 119,275.02	$ 131,117.02	$ 11,842.00	9.93%
233,333		$ 28,825.00	$ 29,548.33	$ 723.33	2.51%		$ 134,147.28	$ 147,517.28	$ 13,370.00	9.97%
260,000		$ 31,577.00	$ 32,383.00	$ 806.00	2.55%		$ 149,019.54	$ 163,917.54	$ 14,898.00	10.00%
286,667		$ 34,329.00	$ 35,217.67	$ 888.67	2.59%		$ 163,891.80	$ 180,317.80	$ 16,426.00	10.02%
313,333		$ 37,081.00	$ 38,052.33	$ 971.33	2.62%		$ 178,764.06	$ 196,718.06	$ 17,954.00	10.04%
340,000		$ 39,833.00	$ 40,887.00	$ 1,054.00	2.65%		$ 193,636.32	$ 213,118.32	$ 19,482.00	10.06%
366,667		$ 42,585.00	$ 43,721.67	$ 1,136.67	2.67%		$ 208,508.58	$ 229,518.58	$ 21,010.00	10.08%
393,333		$ 45,337.00	$ 46,556.33	$ 1,219.33	2.69%		$ 223,380.84	$ 245,918.84	$ 22,538.00	10.09%
420,000		$ 48,089.00	$ 49,391.00	$ 1,302.00	2.71%		$ 238,253.10	$ 262,319.10	$ 24,066.00	10.10%
446,667		$ 50,841.00	$ 52,225.67	$ 1,384.67	2.72%		$ 253,125.36	$ 278,719.36	$ 25,594.00	10.11%
473,333		$ 53,593.00	$ 55,060.33	$ 1,467.33	2.74%		$ 267,997.62	$ 295,119.62	$ 27,122.00	10.12%
499,999		$ 56,344.90	$ 57,894.89	$ 1,549.99	2.75%		$ 282,869.32	$ 311,519.26	$ 28,649.94	10.13%
	Winter Qty %	69.34%	69.34%			Winter Qty %	68.79%	68.79%		
	Summer QTY %	30.66%	30.66%			Summer QTY %	31.21%	31.21%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 500,000 to 999,999 Fg-5 & Tf-5

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	$ 1,125.42	$ 1,125.42	$ -		$/Mo. Fixed or equ	$ 1,064.58	$ 1,064.58	$ -	
	$/Day Fixed or equ	$ 37.00	$ 37.00	$ -		$/Day Fixed or equ	$ 35.00	$ 35.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.0951	$ 0.0888	$ (0.0063)		$/Therm-Winter	$ 0.5816	$ 0.6295	$ 0.0479	
	$/Therm-Summer	$ 0.0951	$ 0.0888	$ (0.0063)		$/Therm-Summer	$ 0.4791	$ 0.5270	$ 0.0479	

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
500,000		$ 61,055.00	$ 57,905.00	$ (3,150.00)	-5.16%		$ 279,041.63	$ 302,991.63	$ 23,950.00	8.58%
533,333		$ 64,224.99	$ 60,864.99	$ (3,360.00)	-5.23%		$ 296,792.70	$ 322,339.36	$ 25,546.66	8.61%
566,667		$ 67,394.99	$ 63,824.99	$ (3,570.00)	-5.30%		$ 314,543.77	$ 341,687.10	$ 27,143.33	8.63%
600,000		$ 70,564.98	$ 66,784.98	$ (3,780.00)	-5.36%		$ 332,294.84	$ 361,034.83	$ 28,739.99	8.65%
633,333		$ 73,734.97	$ 69,744.98	$ (3,989.99)	-5.41%		$ 350,045.92	$ 380,382.57	$ 30,336.65	8.67%
666,666		$ 76,904.97	$ 72,704.97	$ (4,200.00)	-5.46%		$ 367,796.99	$ 399,730.31	$ 31,933.32	8.68%
700,531		$ 80,125.50	$ 75,712.15	$ (4,413.35)	-5.51%		$ 385,831.05	$ 419,386.49	$ 33,555.44	8.70%
733,333		$ 83,244.97	$ 78,624.97	$ (4,620.00)	-5.55%		$ 403,299.21	$ 438,425.86	$ 35,126.65	8.71%
766,666		$ 86,414.96	$ 81,584.96	$ (4,830.00)	-5.59%		$ 421,050.28	$ 457,773.59	$ 36,723.31	8.72%
800,000		$ 89,584.96	$ 84,544.96	$ (5,040.00)	-5.63%		$ 438,801.35	$ 477,121.33	$ 38,319.98	8.73%
833,333		$ 92,754.95	$ 87,504.95	$ (5,250.00)	-5.66%		$ 456,552.42	$ 496,469.07	$ 39,916.65	8.74%
866,666		$ 95,924.94	$ 90,464.95	$ (5,459.99)	-5.69%		$ 474,303.50	$ 515,816.80	$ 41,513.30	8.75%
899,999		$ 99,094.94	$ 93,424.94	$ (5,670.00)	-5.72%		$ 492,054.57	$ 535,164.54	$ 43,109.97	8.76%
933,333		$ 102,264.93	$ 96,384.93	$ (5,880.00)	-5.75%		$ 509,805.64	$ 554,512.27	$ 44,706.63	8.77%
966,666		$ 105,434.92	$ 99,344.93	$ (6,089.99)	-5.78%		$ 527,556.72	$ 573,860.01	$ 46,303.29	8.78%
999,999		$ 108,604.92	$ 102,304.92	$ (6,300.00)	-5.80%		$ 545,307.79	$ 593,207.75	$ 47,899.96	8.78%
	Winter Qty %	57.50%	57.50%			Winter Qty %	52.13%	52.13%		
	Summer QTY %	42.50%	42.50%			Summer QTY %	47.87%	47.87%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6 & Tf-6

	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.	$ 3,558.75	$ 3,558.75	$ -		$/Mo. Fixed or equiv.	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or equiv.	$ 117.00	$ 117.00	$ -		$/Day Fixed or equiv.	$ 115.00	$ 115.00	$ -	
	Demand Charge	$ 0.0036	$ 0.0046	$ 0.0010		Demand Charge	$ 0.0036	$ 0.0046	$ 0.0010	
	$/Therm-Winter	$ 0.0547	$ 0.0537	$ (0.0010)		$/Therm-Winter	$ 0.5412	$ 0.5944	$ 0.0532	
	$/Therm-Summer	$ 0.0547	$ 0.0537	$ (0.0010)		$/Therm-Summer	$ 0.4387	$ 0.4919	$ 0.0532	

Usage in Therms	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
1,000,000	10,957	$ 111,801.93	$ 114,801.08	$ 2,999.15	2.68%	10,957	$ 536,977.68	$ 593,043.67	$ 56,065.99	10.44%
1,466,667	10,957	$ 137,328.60	$ 139,861.07	$ 2,532.47	1.84%	10,957	$ 761,260.30	$ 841,624.15	$ 80,363.85	10.56%
1,933,333	10,957	$ 162,855.26	$ 164,921.07	$ 2,065.81	1.27%	10,957	$ 985,542.93	$ 1,090,204.63	$ 104,661.70	10.62%
2,400,000	10,957	$ 188,381.92	$ 189,981.07	$ 1,599.15	0.85%	10,957	$ 1,209,825.55	$ 1,338,785.11	$ 128,959.56	10.66%
2,866,667	10,957	$ 213,908.58	$ 215,041.06	$ 1,132.48	0.53%	10,957	$ 1,434,108.17	$ 1,587,365.59	$ 153,257.42	10.69%
3,333,333	10,957	$ 239,435.25	$ 240,101.06	$ 665.81	0.28%	10,957	$ 1,658,390.80	$ 1,835,946.06	$ 177,555.26	10.71%
3,800,000	10,957	$ 264,961.91	$ 265,161.06	$ 199.15	0.08%	10,957	$ 1,882,673.42	$ 2,084,526.54	$ 201,853.12	10.72%
4,266,666	10,957	$ 290,488.57	$ 290,221.05	$ (267.52)	-0.09%	10,957	$ 2,106,956.04	$ 2,333,107.02	$ 226,150.98	10.73%
4,733,333	10,957	$ 316,015.24	$ 315,281.05	$ (734.19)	-0.23%	10,957	$ 2,331,238.67	$ 2,581,687.50	$ 250,448.83	10.74%
5,200,000	10,957	$ 341,541.90	$ 340,341.05	$ (1,200.85)	-0.35%	10,957	$ 2,555,521.29	$ 2,830,267.98	$ 274,746.69	10.75%
5,666,666	10,957	$ 367,068.56	$ 365,401.04	$ (1,667.52)	-0.45%	10,957	$ 2,779,803.91	$ 3,078,848.46	$ 299,044.55	10.76%
6,000,000	10,957	$ 385,301.93	$ 383,301.07	$ (2,000.86)	-0.52%	10,957	$ 2,940,006.07	$ 3,256,406.25	$ 316,400.18	10.76%
6,466,667	10,957	$ 410,828.59	$ 408,361.07	$ (2,467.52)	-0.60%	10,957	$ 3,164,288.69	$ 3,504,986.73	$ 340,698.04	10.77%
6,933,333	10,957	$ 436,355.25	$ 433,421.06	$ (2,934.19)	-0.67%	10,957	$ 3,388,571.31	$ 3,753,567.21	$ 364,995.90	10.77%
7,400,000	10,957	$ 461,881.91	$ 458,481.06	$ (3,400.85)	-0.74%	10,957	$ 3,612,853.94	$ 4,002,147.69	$ 389,293.75	10.78%
7,866,666	10,957	$ 487,408.58	$ 483,541.06	$ (3,867.52)	-0.79%	10,957	$ 3,837,136.56	$ 4,250,728.17	$ 413,591.61	10.78%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	57.08%	57.08%	Winter Qty %	50.00%	50.00%
Summer QTY %	42.92%	42.92%	Summer QTY %	47.87%	47.87%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7 & Tf-7

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.	$ 13,748.33	$ 13,748.33	$ -		$/Mo. Fixed or equiv.	$ 13,687.50	$ 13,687.50	$ -	
	$/Day Fixed or equiv.	$ 452.00	$ 452.00	$ -		$/Day Fixed or equiv.	$ 450.00	$ 450.00	$ -	
	Demand Charge	$ 0.0030	$ 0.0040	$ 0.0010		Demand Charge	$ 0.0030	$ 0.0040	$ 0.0010	
	$/Therm-Winter	$ 0.0383	$ 0.0396	$ 0.0013		$/Therm-Winter	$ 0.5248	$ 0.5803	$ 0.0555	
	$/Therm-Summer	$ 0.0383	$ 0.0396	$ 0.0013		$/Therm-Summer	$ 0.4223	$ 0.4778	$ 0.0555	

Usage in Therms	# of Customers & Class Average Use	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
8,000,000	37,919	$ 512,901.31	$ 537,141.74	$ 24,240.43	4.73%	37,919	$ 4,026,397.31	$ 4,484,237.74	$ 457,840.43	11.37%
8,466,667	37,919	$ 530,774.64	$ 555,621.74	$ 24,847.10	4.68%	37,919	$ 4,249,267.12	$ 4,733,007.55	$ 483,740.43	11.38%
8,933,333	37,919	$ 548,647.97	$ 574,101.73	$ 25,453.76	4.64%	37,919	$ 4,472,136.94	$ 4,981,777.37	$ 509,640.43	11.40%
9,400,000	37,919	$ 566,521.30	$ 592,581.73	$ 26,060.43	4.60%	37,919	$ 4,695,006.76	$ 5,230,547.18	$ 535,540.42	11.41%
9,866,666	37,919	$ 584,394.63	$ 611,061.73	$ 26,667.10	4.56%	37,919	$ 4,917,876.58	$ 5,479,317.00	$ 561,440.42	11.42%
10,333,333	37,919	$ 602,267.96	$ 629,541.73	$ 27,273.77	4.53%	37,919	$ 5,140,746.40	$ 5,728,086.81	$ 587,340.41	11.43%
10,800,000	37,919	$ 620,141.29	$ 648,021.72	$ 27,880.43	4.50%	37,919	$ 5,363,616.21	$ 5,976,856.63	$ 613,240.42	11.43%
11,266,666	37,919	$ 638,014.62	$ 666,501.72	$ 28,487.10	4.46%	37,919	$ 5,586,486.03	$ 6,225,626.44	$ 639,140.41	11.44%
11,733,333	37,919	$ 655,887.95	$ 684,981.72	$ 29,093.77	4.44%	37,919	$ 5,809,355.85	$ 6,474,396.26	$ 665,040.41	11.45%
12,199,999	37,919	$ 673,761.28	$ 703,461.72	$ 29,700.44	4.41%	37,919	$ 6,032,225.67	$ 6,723,166.07	$ 690,940.40	11.45%
12,666,666	37,919	$ 691,634.61	$ 721,941.71	$ 30,307.10	4.38%	37,919	$ 6,255,095.49	$ 6,971,935.88	$ 716,840.39	11.46%
13,133,333	37,919	$ 709,507.94	$ 740,421.71	$ 30,913.77	4.36%	37,919	$ 6,477,965.30	$ 7,220,705.70	$ 742,740.40	11.47%
13,599,999	37,919	$ 727,381.27	$ 758,901.71	$ 31,520.44	4.33%	37,919	$ 6,700,835.12	$ 7,469,475.51	$ 768,640.39	11.47%
14,066,666	37,919	$ 745,254.61	$ 777,381.71	$ 32,127.10	4.31%	37,919	$ 6,923,704.94	$ 7,718,245.33	$ 794,540.39	11.48%
14,533,332	37,919	$ 763,127.94	$ 795,861.70	$ 32,733.76	4.29%	37,919	$ 7,146,574.76	$ 7,967,015.14	$ 820,440.38	11.48%
14,999,999	37,919	$ 781,001.27	$ 814,341.70	$ 33,340.43	4.27%	37,919	$ 7,369,444.58	$ 8,215,784.96	$ 846,340.38	11.48%

	Old	New		Old	New
Winter Qty %	53.93%	53.93%	Winter Qty %	53.93%	53.93%
Summer QTY %	46.07%	46.07%	Summer QTY %	46.07%	46.07%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ 0.1025	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4502	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 15,000,000 & Over Fg-8 & Tf-8

		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.	$ 43,556.67	$ 43,556.67	$ -		$/Mo. Fixed or ‹	$ 43,495.83	$ 43,495.83	$ -	
	$/Day Fixed or equiv.	$ 1,432.00	$ 1,432.00	$ -		$/Day Fixed or ‹	$ 1,430.00	$ 1,430.00	$ -	
	Demand Charge	$ 0.0021	$ 0.0031	$ 0.0010		Demand Charg	$ 0.0021	$ 0.0031	$ 0.0010	
	$/Therm-Winter	$ 0.0160	$ 0.0176	$ 0.0016		$/Therm-Winte	$ 0.4000	$ 0.4558	$ 0.0558	
	$/Therm-Summer	$ 0.0160	$ 0.0176	$ 0.0016		$/Therm-Summ	$ 0.4000	$ 0.4558	$ 0.0558	

Usage in Therms	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Class laximum Demar	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
15,000,000	37,919	$ 791,744.91	$ 829,585.35	$ 37,840.44	4.78%	37,919	$ 6,423,214.91	$ 7,256,227.25	$ 833,012.34	12.97%
15,466,667	37,919	$ 799,211.58	$ 837,798.68	$ 38,587.10	4.83%	37,919	$ 6,605,905.55	$ 7,464,403.23	$ 858,497.68	13.00%
15,933,333	37,919	$ 806,678.24	$ 846,012.01	$ 39,333.77	4.88%	37,919	$ 6,788,596.19	$ 7,672,579.22	$ 883,983.03	13.02%
16,400,000	37,919	$ 814,144.91	$ 854,225.34	$ 40,080.43	4.92%	37,919	$ 6,971,286.84	$ 7,880,755.20	$ 909,468.36	13.05%
16,866,666	37,919	$ 821,611.58	$ 862,438.68	$ 40,827.10	4.97%	37,919	$ 7,153,977.48	$ 8,088,931.19	$ 934,953.71	13.07%
17,333,333	37,919	$ 829,078.24	$ 870,652.01	$ 41,573.77	5.01%	37,919	$ 7,336,668.12	$ 8,297,107.17	$ 960,439.05	13.09%
17,800,000	37,919	$ 836,544.91	$ 878,865.34	$ 42,320.43	5.06%	37,919	$ 7,519,358.76	$ 8,505,283.16	$ 985,924.40	13.11%
18,266,666	37,919	$ 844,011.57	$ 887,078.67	$ 43,067.10	5.10%	37,919	$ 7,702,049.40	$ 8,713,459.14	$ 1,011,409.74	13.13%
18,733,333	37,919	$ 851,478.24	$ 895,292.01	$ 43,813.77	5.15%	37,919	$ 7,884,740.04	$ 8,921,635.13	$ 1,036,895.09	13.15%
19,199,999	37,919	$ 858,944.90	$ 903,505.34	$ 44,560.44	5.19%	37,919	$ 8,067,430.68	$ 9,129,811.11	$ 1,062,380.43	13.17%
19,666,666	37,919	$ 866,411.57	$ 911,718.67	$ 45,307.10	5.23%	37,919	$ 8,250,121.32	$ 9,337,987.10	$ 1,087,865.78	13.19%
20,133,333	37,919	$ 873,878.24	$ 919,932.00	$ 46,053.76	5.27%	37,919	$ 8,432,811.96	$ 9,546,163.08	$ 1,113,351.12	13.20%
20,599,999	37,919	$ 881,344.90	$ 928,145.33	$ 46,800.43	5.31%	37,919	$ 8,615,502.60	$ 9,754,339.07	$ 1,138,836.47	13.22%
21,066,666	37,919	$ 888,811.57	$ 936,358.67	$ 47,547.10	5.35%	37,919	$ 8,798,193.24	$ 9,962,515.05	$ 1,164,321.81	13.23%
21,533,332	37,919	$ 896,278.23	$ 944,572.00	$ 48,293.77	5.39%	37,919	$ 8,980,883.88	$ 10,170,691.04	$ 1,189,807.16	13.25%
21,999,999	37,919	$ 903,744.90	$ 952,785.33	$ 49,040.43	5.43%	37,919	$ 9,163,574.52	$ 10,378,867.02	$ 1,215,292.50	13.26%

	Old	New		Old	New
Winter Qty %	57.08%	57.08%	Winter Qty %	50.00%	50.00%
Summer QTY %	42.92%	42.92%	Summer QTY ‹	47.87%	47.87%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt. Comm. Ind. 100000 to 499999 Ig-4

		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.	N/A	N/A	N/A		$/Mo. Fixed or equiv.	$ 334.58	$ 334.58	$ -	
	$/Day Fixed or equiv.	N/A	N/A	N/A		$/Day Fixed or equiv.	$ 11.00	$ 11.00	$ -	
	$/Therm-Winter	N/A	N/A	N/A		$/Therm-Winter	$ 0.4790	$ 0.4935	$ 0.0145	
	$/Therm-Summer	N/A	N/A	N/A		$/Therm-Summer	$ 0.4790	$ 0.4935	$ 0.0145	

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
100,000		N/A	N/A	N/A	N/A		$ 51,915.00	$ 53,365.00	$ 1,450.00	2.79%
123,529		N/A	N/A	N/A	N/A		$ 63,185.56	$ 64,976.74	$ 1,791.18	2.83%
147,059		N/A	N/A	N/A	N/A		$ 74,456.12	$ 76,588.47	$ 2,132.35	2.86%
170,588		N/A	N/A	N/A	N/A		$ 85,726.68	$ 88,200.21	$ 2,473.53	2.89%
194,117		N/A	N/A	N/A	N/A		$ 96,997.24	$ 99,811.94	$ 2,814.70	2.90%
217,647		N/A	N/A	N/A	N/A		$ 108,267.80	$ 111,423.68	$ 3,155.88	2.91%
241,176		N/A	N/A	N/A	N/A		$ 119,538.36	$ 123,035.41	$ 3,497.05	2.93%
264,705		N/A	N/A	N/A	N/A		$ 130,808.92	$ 134,647.15	$ 3,838.23	2.93%
288,235		N/A	N/A	N/A	N/A		$ 142,079.48	$ 146,258.89	$ 4,179.41	2.94%
311,764		N/A	N/A	N/A	N/A		$ 153,350.04	$ 157,870.62	$ 4,520.58	2.95%
335,294		N/A	N/A	N/A	N/A		$ 164,620.60	$ 169,482.36	$ 4,861.76	2.95%
358,823		N/A	N/A	N/A	N/A		$ 175,891.16	$ 181,094.09	$ 5,202.93	2.96%
382,352		N/A	N/A	N/A	N/A		$ 187,161.72	$ 192,705.83	$ 5,544.11	2.96%
405,882		N/A	N/A	N/A	N/A		$ 198,432.28	$ 204,317.56	$ 5,885.28	2.97%
429,411		N/A	N/A	N/A	N/A		$ 209,702.84	$ 215,929.30	$ 6,226.46	2.97%
452,940		N/A	N/A	N/A	N/A		$ 220,973.40	$ 227,541.04	$ 6,567.64	2.97%
476,470		N/A	N/A	N/A	N/A		$ 232,243.96	$ 239,152.77	$ 6,908.81	2.97%
	Winter Qty %	N/A	N/A			Winter Qty %	62.07%	62.07%		
	Summer QTY %	N/A	N/A			Summer QTY %	37.93%	37.93%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

0

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt Comm. Ind. 500000 to 999999 Ig-5

	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.	N/A	N/A	N/A		$/Mo. Fixed or equiv.	$ 1,064.58	$ 1,064.58	$ -	
	$/Day Fixed or equiv.	N/A	N/A	N/A		$/Day Fixed or equiv.	$ 35.00	$ 35.00	$ -	
	$/Therm-Winter	N/A	N/A	N/A		$/Therm-Winter	$ 0.4709	$ 0.4760	$ 0.0051	
	$/Therm-Summer	N/A	N/A	N/A		$/Therm-Summer	$ 0.4709	$ 0.4760	$ 0.0051	

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
500,000		N/A	N/A	N/A	N/A		$ 248,225.00	$ 250,775.00	$ 2,550.00	1.03%
529,412		N/A	N/A	N/A	N/A		$ 262,074.97	$ 264,774.97	$ 2,700.00	1.03%
558,823		N/A	N/A	N/A	N/A		$ 275,924.94	$ 278,774.94	$ 2,850.00	1.03%
588,235		N/A	N/A	N/A	N/A		$ 289,774.92	$ 292,774.92	$ 3,000.00	1.04%
617,647		N/A	N/A	N/A	N/A		$ 303,624.89	$ 306,774.89	$ 3,150.00	1.04%
647,059		N/A	N/A	N/A	N/A		$ 317,474.86	$ 320,774.86	$ 3,300.00	1.04%
676,470		N/A	N/A	N/A	N/A		$ 331,324.83	$ 334,774.83	$ 3,450.00	1.04%
705,882		N/A	N/A	N/A	N/A		$ 345,174.81	$ 348,774.80	$ 3,599.99	1.04%
735,294		N/A	N/A	N/A	N/A		$ 359,024.78	$ 362,774.78	$ 3,750.00	1.04%
764,705		N/A	N/A	N/A	N/A		$ 372,874.75	$ 376,774.75	$ 3,900.00	1.05%
794,117		N/A	N/A	N/A	N/A		$ 386,724.72	$ 390,774.72	$ 4,050.00	1.05%
823,529		N/A	N/A	N/A	N/A		$ 400,574.70	$ 404,774.69	$ 4,199.99	1.05%
852,940		N/A	N/A	N/A	N/A		$ 414,424.67	$ 418,774.66	$ 4,349.99	1.05%
882,352		N/A	N/A	N/A	N/A		$ 428,274.64	$ 432,774.64	$ 4,500.00	1.05%
911,764		N/A	N/A	N/A	N/A		$ 442,124.61	$ 446,774.61	$ 4,650.00	1.05%
941,176		N/A	N/A	N/A	N/A		$ 455,974.58	$ 460,774.58	$ 4,800.00	1.05%
970,587		N/A	N/A	N/A	N/A		$ 469,824.56	$ 474,774.55	$ 4,949.99	1.05%
	Winter Qty %	N/A	N/A			Winter Qty %	62.07%	62.07%		
	Summer QTY %	N/A	N/A			Summer QTY %	37.93%	37.93%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

0

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Power Generation

Pg-2 and Pt-2

	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.	$ 27,375.00	$ 27,435.83	$ 60.83		$/Mo. Fixed or equ	$ 27,314.17	$ 27,375.00	$ 60.83	
$/Day Fixed or equiv.	$ 900.00	$ 902.00	$ 2.00		$/Day Fixed or equ	$ 898.00	$ 900.00	$ 2.00	
Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0107	$ 0.0101	$ (0.0006)		$/Therm-Winter	$ 0.3865	$ 0.3973	$ 0.0108	
$/Therm-Summer	$ 0.0107	$ 0.0101	$ (0.0006)		$/Therm-Summer	$ 0.3865	$ 0.3973	$ 0.0108	

Usage in Therms	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
90,000	$ 329,463.00	$ 330,139.00	$ 676.00	0.21%	$ 362,555.03	$ 364,257.04	$ 1,702.01	0.47%
177,600	$ 330,400.32	$ 331,023.76	$ 623.44	0.19%	$ 396,412.47	$ 399,060.55	$ 2,648.08	0.67%
265,200	$ 331,337.64	$ 331,908.52	$ 570.88	0.17%	$ 430,269.90	$ 433,864.07	$ 3,594.17	0.84%
352,800	$ 332,274.96	$ 332,793.28	$ 518.32	0.16%	$ 464,127.34	$ 468,667.58	$ 4,540.24	0.98%
440,400	$ 333,212.28	$ 333,678.04	$ 465.76	0.14%	$ 497,984.77	$ 503,471.09	$ 5,486.32	1.10%
528,000	$ 334,149.61	$ 334,562.81	$ 413.20	0.12%	$ 531,842.20	$ 538,274.61	$ 6,432.41	1.21%
615,600	$ 335,086.93	$ 335,447.57	$ 360.64	0.11%	$ 565,699.64	$ 573,078.12	$ 7,378.48	1.30%
703,200	$ 336,024.25	$ 336,332.33	$ 308.08	0.09%	$ 599,557.07	$ 607,881.64	$ 8,324.57	1.39%
790,800	$ 336,961.57	$ 337,217.09	$ 255.52	0.08%	$ 633,414.51	$ 642,685.15	$ 9,270.64	1.46%
878,400	$ 337,898.89	$ 338,101.85	$ 202.96	0.06%	$ 667,271.94	$ 677,488.67	$ 10,216.73	1.53%
966,000	$ 338,836.21	$ 338,986.61	$ 150.40	0.04%	$ 701,129.37	$ 712,292.18	$ 11,162.81	1.59%
1,053,600	$ 339,773.53	$ 339,871.37	$ 97.84	0.03%	$ 734,986.81	$ 747,095.70	$ 12,108.89	1.65%
1,141,200	$ 340,710.85	$ 340,756.13	$ 45.28	0.01%	$ 768,844.24	$ 781,899.21	$ 13,054.97	1.70%
1,228,800	$ 341,648.17	$ 341,640.89	$ (7.28)	0.00%	$ 802,701.67	$ 816,702.73	$ 14,001.06	1.74%
1,316,400	$ 342,585.49	$ 342,525.65	$ (59.84)	-0.02%	$ 836,559.11	$ 851,506.24	$ 14,947.13	1.79%
1,404,000	$ 343,522.82	$ 343,410.41	$ (112.41)	-0.03%	$ 870,416.54	$ 886,309.76	$ 15,893.22	1.83%
1,491,600	$ 344,460.14	$ 344,295.18	$ (164.96)	-0.05%	$ 904,273.98	$ 921,113.27	$ 16,839.29	1.86%

	Transportation Old	Transportation New		Sales Old	Sales 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:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Power Generation

Pg-6 and Pt-6

Transportation Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 54,567.50	$ 54,658.75	$ 91.25	
$/Day Fixed or equ	$ 1,794.00	$ 1,797.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0285	$ 0.0281	$ (0.0004)	
$/Therm-Summer	$ 0.0285	$ 0.0281	$ (0.0004)	

Sales Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 54,506.67	$ 54,597.92	$ 91.25	
$/Day Fixed or equ	$ 1,792.00	$ 1,795.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.4043	$ 0.4153	$ 0.0110	
$/Therm-Summer	$ 0.4043	$ 0.4153	$ 0.0110	

Usage in Therms	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
100,000	$ 654,810.00	$ 655,905.00	$ 1,095.00	0.17%	$ 654,080.04	$ 655,175.04	$ 1,095.00	0.17%
200,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.08	$ 655,175.08	$ 1,095.00	0.17%
300,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.12	$ 655,175.12	$ 1,095.00	0.17%
400,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.16	$ 655,175.17	$ 1,095.01	0.17%
500,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.20	$ 655,175.21	$ 1,095.01	0.17%
600,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.24	$ 655,175.25	$ 1,095.01	0.17%
700,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.28	$ 655,175.29	$ 1,095.01	0.17%
800,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.32	$ 655,175.33	$ 1,095.01	0.17%
900,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.36	$ 655,175.37	$ 1,095.01	0.17%
1,000,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.40	$ 655,175.42	$ 1,095.02	0.17%
1,100,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.44	$ 655,175.46	$ 1,095.02	0.17%
1,200,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.49	$ 655,175.50	$ 1,095.01	0.17%
1,300,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.53	$ 655,175.54	$ 1,095.01	0.17%
1,400,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.57	$ 655,175.58	$ 1,095.01	0.17%
1,500,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.61	$ 655,175.62	$ 1,095.01	0.17%
1,600,000	$ 654,810.05	$ 655,905.04	$ 1,094.99	0.17%	$ 654,080.65	$ 655,175.66	$ 1,095.01	0.17%
1,700,000	$ 654,810.05	$ 655,905.05	$ 1,095.00	0.17%	$ 654,080.69	$ 655,175.71	$ 1,095.02	0.17%

	Transportation Old	Transportation New	Sales Old	Sales New
Winter Qty %	0.00%	0.00%	0.00%	0.00%
Summer QTY %	0.00%	0.00%	0.00%	0.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Power Generation

Pg-8 and Pt-8

Transportation Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 20,713.75	$ 20,805.00	$ 91.25	
$/Day Fixed or equ	$ 681.00	$ 684.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0276	$ 0.0271	$ (0.0005)	
$/Therm-Summer	$ 0.0276	$ 0.0271	$ (0.0005)	

Sales Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 20,652.92	$ 20,744.17	$ 91.25	
$/Day Fixed or equ	$ 679.00	$ 682.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.4034	$ 0.4143	$ 0.0109	
$/Therm-Summer	$ 0.4034	$ 0.4143	$ 0.0109	

Usage in Therms	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
100,000	$ 251,325.00	$ 252,370.00	$ 1,045.00	0.42%	$ 288,175.04	$ 290,360.04	$ 2,185.00	0.76%
512,000	$ 262,696.21	$ 263,535.21	$ 839.00	0.32%	$ 454,376.01	$ 461,051.81	$ 6,675.80	1.47%
924,000	$ 274,067.43	$ 274,700.43	$ 633.00	0.23%	$ 620,576.97	$ 631,743.58	$ 11,166.61	1.80%
1,336,000	$ 285,438.64	$ 285,865.64	$ 427.00	0.15%	$ 786,777.94	$ 802,435.35	$ 15,657.41	1.99%
1,748,000	$ 296,809.85	$ 297,030.85	$ 221.00	0.07%	$ 952,978.91	$ 973,127.12	$ 20,148.21	2.11%
2,160,000	$ 308,181.06	$ 308,196.06	$ 15.00	0.00%	$ 1,119,179.87	$ 1,143,818.89	$ 24,639.02	2.20%
2,572,000	$ 319,552.27	$ 319,361.27	$ (191.00)	-0.06%	$ 1,285,380.84	$ 1,314,510.67	$ 29,129.83	2.27%
2,984,000	$ 330,923.48	$ 330,526.48	$ (397.00)	-0.12%	$ 1,451,581.80	$ 1,485,202.44	$ 33,620.64	2.32%
3,396,000	$ 342,294.69	$ 341,691.69	$ (603.00)	-0.18%	$ 1,617,782.77	$ 1,655,894.21	$ 38,111.44	2.36%
3,808,000	$ 353,665.91	$ 352,856.90	$ (809.01)	-0.23%	$ 1,783,983.74	$ 1,826,585.98	$ 42,602.24	2.39%
4,220,000	$ 365,037.12	$ 364,022.11	$ (1,015.01)	-0.28%	$ 1,950,184.70	$ 1,997,277.75	$ 47,093.05	2.41%
4,632,000	$ 376,408.33	$ 375,187.33	$ (1,221.00)	-0.32%	$ 2,116,385.67	$ 2,167,969.52	$ 51,583.85	2.44%
5,044,000	$ 387,779.54	$ 386,352.54	$ (1,427.00)	-0.37%	$ 2,282,586.63	$ 2,338,661.29	$ 56,074.66	2.46%
5,456,000	$ 399,150.75	$ 397,517.75	$ (1,633.00)	-0.41%	$ 2,448,787.60	$ 2,509,353.06	$ 60,565.46	2.47%
5,868,000	$ 410,521.96	$ 408,682.96	$ (1,839.00)	-0.45%	$ 2,614,988.57	$ 2,680,044.83	$ 65,056.26	2.49%
6,280,000	$ 421,893.17	$ 419,848.17	$ (2,045.00)	-0.48%	$ 2,781,189.53	$ 2,850,736.60	$ 69,547.07	2.50%
6,692,000	$ 433,264.38	$ 431,013.38	$ (2,251.00)	-0.52%	$ 2,947,390.50	$ 3,021,428.37	$ 74,037.87	2.51%

	Transportation Old	Transportation New	Sales Old	Sales New
Winter Qty %	32.22%	32.22%	32.22%	32.22%
Summer QTY %	67.78%	67.78%	67.78%	67.78%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Power Generation

Pg-9 and Pt-9

Transportation Service | **Sales Service**

	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change		Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
$/Mo. Fixed or equ	$ 7,701.50	$ 7,701.50	$ -		$/Mo. Fixed or equ	$ 7,640.67	$ 7,640.67	$ -	
$/Day Fixed or equ	$ 253.20	$ 253.20	$ -		$/Day Fixed or equ	$ 251.20	$ 251.20	$ -	
Demand Charge	$ 0.0150	$ 0.0150	$ -		Demand Charge	$ 0.0150	$ 0.0150	$ -	
$/Therm-Winter	$ 0.0015	$ 0.0015	$ -		$/Therm-Winter	$ 0.3781	$ 0.3899	$ 0.0118	
$/Therm-Summer	$ 0.0015	$ 0.0015	$ -		$/Therm-Summer	$ 0.3781	$ 0.3899	$ 0.0118	

Usage in Therms	Demand Charge Quantity	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
100,000	-	$ 92,568.00	$ 92,568.00	$ -	0.00%	$ 129,498.00	$ 130,678.00	$ 1,180.00	0.91%
512,000	-	$ 93,186.00	$ 93,186.00	$ -	0.00%	$ 285,275.20	$ 291,316.80	$ 6,041.60	2.12%
924,000	-	$ 93,804.00	$ 93,804.00	$ -	0.00%	$ 441,052.40	$ 451,955.60	$ 10,903.20	2.47%
1,336,000	-	$ 94,422.00	$ 94,422.00	$ -	0.00%	$ 596,829.60	$ 612,594.40	$ 15,764.80	2.64%
1,748,000	-	$ 95,040.00	$ 95,040.00	$ -	0.00%	$ 752,606.80	$ 773,233.20	$ 20,626.40	2.74%
2,160,000	-	$ 95,658.00	$ 95,658.00	$ -	0.00%	$ 908,384.00	$ 933,872.00	$ 25,488.00	2.81%
2,572,000	-	$ 96,276.00	$ 96,276.00	$ -	0.00%	$ 1,064,161.20	$ 1,094,510.80	$ 30,349.60	2.85%
2,984,000	-	$ 96,894.00	$ 96,894.00	$ -	0.00%	$ 1,219,938.40	$ 1,255,149.60	$ 35,211.20	2.89%
3,396,000	-	$ 97,512.00	$ 97,512.00	$ -	0.00%	$ 1,375,715.60	$ 1,415,788.40	$ 40,072.80	2.91%
3,808,000	-	$ 98,130.00	$ 98,130.00	$ -	0.00%	$ 1,531,492.80	$ 1,576,427.20	$ 44,934.40	2.93%
4,220,000	-	$ 98,748.00	$ 98,748.00	$ -	0.00%	$ 1,687,270.00	$ 1,737,066.00	$ 49,796.00	2.95%
4,632,000	-	$ 99,366.00	$ 99,366.00	$ -	0.00%	$ 1,843,047.20	$ 1,897,704.80	$ 54,657.60	2.97%
5,044,000	-	$ 99,984.00	$ 99,984.00	$ -	0.00%	$ 1,998,824.40	$ 2,058,343.60	$ 59,519.20	2.98%
5,456,000	-	$ 100,602.00	$ 100,602.00	$ -	0.00%	$ 2,154,601.60	$ 2,218,982.40	$ 64,380.80	2.99%
5,868,000	-	$ 101,220.00	$ 101,220.00	$ -	0.00%	$ 2,310,378.80	$ 2,379,621.20	$ 69,242.40	3.00%
6,280,000	-	$ 101,838.00	$ 101,838.00	$ -	0.00%	$ 2,466,156.00	$ 2,540,260.00	$ 74,104.00	3.00%
6,692,000	-	$ 102,456.00	$ 102,456.00	$ -	0.00%	$ 2,621,933.20	$ 2,700,898.80	$ 78,965.60	3.01%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	63.16%	63.16%	Winter Qty %	63.16%	63.16%
Summer QTY %	36.84%	36.84%	Summer QTY %	36.84%	36.84%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Power Generation — Pg-11 and Pt-11

	Transportation Service Old Annual Bill	Transportation Service New Annual Bill	Transportation Service Increase (Decrease)	Transportation Service Percent of Change		Sales Service Old Annual Bill	Sales Service New Annual Bill	Sales Service Increase (Decrease)	Sales Service Percent of Change
$/Mo. Fixed or equ	$ 12,834.92	$ 12,896.67	$ 61.75		$/Mo. Fixed or equ	$ 12,774.09	$ 12,835.83	$ 61.74	
$/Day Fixed or equ	$ 421.97	$ 424.00	$ 2.03		$/Day Fixed or equ	$ 419.97	$ 422.00	$ 2.03	
Demand Charge	$ -	$ -	$ -		Demand Charge	$ -	$ -	$ -	
$/Therm-Winter	$ 0.0011	$ 0.0015	$ 0.0004		$/Therm-Winter	$ 0.3769	$ 0.3887	$ 0.0118	
$/Therm-Summer	$ 0.0011	$ 0.0015	$ 0.0004		$/Therm-Summer	$ 0.3769	$ 0.3887	$ 0.0118	

Usage in Therms	Demand Charge Quantity	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
100,000	-	$ 154,129.05	$ 154,910.00	$ 780.95	0.51%	$ 190,979.05	$ 192,900.00	$ 1,920.95	1.01%
512,000	-	$ 154,582.25	$ 155,528.00	$ 945.75	0.61%	$ 346,261.85	$ 353,044.40	$ 6,782.55	1.96%
924,000	-	$ 155,035.45	$ 156,146.00	$ 1,110.55	0.72%	$ 501,544.65	$ 513,188.80	$ 11,644.15	2.32%
1,336,000	-	$ 155,488.65	$ 156,764.00	$ 1,275.35	0.82%	$ 656,827.45	$ 673,333.20	$ 16,505.75	2.51%
1,748,000	-	$ 155,941.85	$ 157,382.00	$ 1,440.15	0.92%	$ 812,110.25	$ 833,477.60	$ 21,367.35	2.63%
2,160,000	-	$ 156,395.05	$ 158,000.00	$ 1,604.95	1.03%	$ 967,393.05	$ 993,622.00	$ 26,228.95	2.71%
2,572,000	-	$ 156,848.25	$ 158,618.00	$ 1,769.75	1.13%	$ 1,122,675.85	$ 1,153,766.40	$ 31,090.55	2.77%
2,984,000	-	$ 157,301.45	$ 159,236.00	$ 1,934.55	1.23%	$ 1,277,958.65	$ 1,313,910.80	$ 35,952.15	2.81%
3,396,000	-	$ 157,754.65	$ 159,854.00	$ 2,099.35	1.33%	$ 1,433,241.45	$ 1,474,055.20	$ 40,813.75	2.85%
3,808,000	-	$ 158,207.85	$ 160,472.00	$ 2,264.15	1.43%	$ 1,588,524.25	$ 1,634,199.60	$ 45,675.35	2.88%
4,220,000	-	$ 158,661.05	$ 161,090.00	$ 2,428.95	1.53%	$ 1,743,807.05	$ 1,794,344.00	$ 50,536.95	2.90%
4,632,000	-	$ 159,114.25	$ 161,708.00	$ 2,593.75	1.63%	$ 1,899,089.85	$ 1,954,488.40	$ 55,398.55	2.92%
5,044,000	-	$ 159,567.45	$ 162,326.00	$ 2,758.55	1.73%	$ 2,054,372.65	$ 2,114,632.80	$ 60,260.15	2.93%
5,456,000	-	$ 160,020.65	$ 162,944.00	$ 2,923.35	1.83%	$ 2,209,655.45	$ 2,274,777.20	$ 65,121.75	2.95%
5,868,000	-	$ 160,473.85	$ 163,562.00	$ 3,088.15	1.92%	$ 2,364,938.25	$ 2,434,921.60	$ 69,983.35	2.96%
6,280,000	-	$ 160,927.05	$ 164,180.00	$ 3,252.95	2.02%	$ 2,520,221.05	$ 2,595,066.00	$ 74,844.95	2.97%
6,692,000	-	$ 161,380.25	$ 164,798.00	$ 3,417.75	2.12%	$ 2,675,503.85	$ 2,755,210.40	$ 79,706.55	2.98%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	63.16%	63.16%	Winter Qty %	63.16%	63.16%
Summer QTY %	36.84%	36.84%	Summer QTY %	36.84%	36.84%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3394	$ 0.3394
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0083	$ 0.0083
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3477	$ 0.3477

Transportation Administrative Charge: $ 2.00

Wisconsin Electric - Gas Operations
PSCW Adjusted 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 Revenue % Change
Residential	Rg-1	476,884	411,283,016	$ 383,644,885	$ 192,865,528	$ 190,779,357	$ 435,014,130	$ 192,865,528	$ 242,148,602	$ 51,369,245	13.4%
Firm Comm. Ind. 0 to 3,999	Fg-1	29,841	42,577,422	$ 36,923,096	$ 20,270,299	$ 16,652,797	$ 39,524,576	$ 20,270,299	$ 19,254,277	$ 2,601,480	7.1%
Firm Comm. Ind. 4,000 to 39,999	Fg-2	10,810	125,761,567	$ 88,680,258	$ 58,765,664	$ 29,914,594	$ 97,332,653	$ 58,765,664	$ 38,566,989	$ 8,652,395	9.8%
Firm Comm. Ind. 40,000 to 99,999	Fg-3	526	32,260,888	$ 21,144,991	$ 14,933,809	$ 6,211,182	$ 23,180,651	$ 14,933,809	$ 8,246,842	$ 2,035,660	9.6%
Firm Comm. Ind. 100,000 to 499,999	Fg-4	158	26,148,890	$ 15,929,433	$ 11,649,316	$ 4,280,117	$ 17,568,966	$ 11,649,316	$ 5,919,650	$ 1,639,533	10.3%
Firm Comm. Ind. 500,000 to 999,999	Fg-5	8	5,842,899	$ 3,319,598	$ 2,449,642	$ 869,956	$ 3,597,139	$ 2,449,642	$ 1,147,497	$ 277,541	8.4%
Firm Comm. Ind. 1,000,000 to 7,999,999	Fg-6	1	2,100,000	$ 1,106,041	$ 862,507	$ 243,534	$ 1,247,964	$ 862,507	$ 385,457	$ 141,923	12.8%
Firm Comm. Ind. 8,000,000 to 14,999,999	Fg-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Firm Comm. Ind. 15,000,000 & Over	Fg-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999	Ag-1	161	1,023,323	$ 635,103	$ 381,319	$ 253,784	$ 639,912	$ 381,319	$ 258,593	$ 4,809	0.9%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999	Ag-1	-	850,146	$ 490,898	$ 310,667	$ 180,231	$ 495,319	$ 310,667	$ 184,652	$ 4,421	0.9%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999	Ag-1	-	353,073	$ 197,412	$ 127,151	$ 70,261	$ 199,423	$ 127,151	$ 72,272	$ 2,011	0.9%
Interrupt. Comm. Ind. 100000 to 499999	Ig-4	3	406,947	$ 215,867	$ 150,389	$ 65,478	$ 223,881	$ 150,389	$ 73,492	$ 8,014	3.7%
Interrupt Comm. Ind. 500000 to 999999	Ig-5	1	672,828	$ 343,962	$ 248,297	$ 95,665	$ 346,989	$ 248,297	$ 98,692	$ 3,027	0.9%
Interrupt. Comm. Ind. 1,000,000 to 7,999,999	Ig-6	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 8,000,000 to 14,999,999	Ig-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 15,000,000 & Over	Ig-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pg-2	1	-	$ 327,770	$ -	$ 327,770	$ 329,230	$ -	$ 329,230	$ 1,460	0.5%
Power Generation	Pg-6	1	-	$ 654,080	$ -	$ 654,080	$ 655,175	$ -	$ 655,175	$ 1,095	0.2%
Power Generation	Pg-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pg-8	1	3,461,123	$ 1,735,273	$ 1,294,654	$ 440,619	$ 1,774,824	$ 1,294,654	$ 480,170	$ 39,551	2.3%
Power Generation	Pg-9	1	768,875	$ 1,905,197	$ 281,254	$ 1,623,943	$ 1,914,272	$ 281,254	$ 1,633,018	$ 9,075	0.5%
Power Generation Nominated Firm	NFPg-2	-	2,558,978	$ 995,386	$ 875,115	$ 120,271	$ 1,133,059	$ 875,115	$ 257,944	$ 137,673	13.8%
Power Generation Nominated Firm	NFPg-6	-	11,959,643	$ 4,846,522	$ 4,071,535	$ 774,987	$ 5,492,340	$ 4,071,535	$ 1,420,805	$ 645,818	13.3%
Power Generation Nominated Firm	NFPg-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm	NFPg-9	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm	NFPg-11	-	9,282,000	$ 3,924,543	$ 3,577,399	$ 347,144	$ 4,433,200	$ 3,577,399	$ 855,801	$ 508,657	13.0%
NA- 6		-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
NA- 7		-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
NA- 8		-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
NA- 9		-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
NA- 10		-	-	$ -	$ -	$ -	$ -			$ -	0.0%
Total - Sales Customers - All		518,397	734,440,875	$ 588,251,058	$ 332,523,827	$ 255,727,231	$ 657,010,409	$ 332,523,827	$ 324,486,582	$ 68,759,351	11.7%

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 Revenue % Change
Residential	Tr-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Firm Comm. Ind. 0 to 3,999	Tf-1	9	19,059	$ 12,947	$ -	$ 12,947	$ 13,075	$ -	$ 13,075	$ 128	1.0%
Firm Comm. Ind. 4,000 to 39,999	Tf-2	340	9,132,181	$ 1,950,735	$ -	$ 1,950,735	$ 2,082,240	$ -	$ 2,082,240	$ 131,505	6.7%
Firm Comm. Ind. 40,000 to 99,999	Tf-3	310	18,146,376	$ 3,091,357	$ -	$ 3,091,357	$ 3,249,231	$ -	$ 3,249,231	$ 157,874	5.1%
Firm Comm. Ind. 100,000 to 499,999	Tf-4	263	61,570,700	$ 7,600,456	$ -	$ 7,600,456	$ 8,111,494	$ -	$ 8,111,494	$ 511,038	6.7%
Firm Comm. Ind. 500,000 to 999,999	Tf-5	58	37,876,663	$ 4,387,617	$ -	$ 4,387,617	$ 4,126,268	$ -	$ 4,126,268	$ (261,349)	-6.0%
Firm Comm. Ind. 1,000,000 to 7,999,999	Tf-6	38	79,108,517	$ 6,501,057	$ -	$ 6,501,057	$ 7,587,604	$ -	$ 7,587,604	$ 1,086,547	16.7%
Firm Comm. Ind. 8,000,000 to 14,999,999	Tf-7	5	58,380,370	$ 3,268,475	$ -	$ 3,268,475	$ 3,985,700	$ -	$ 3,985,700	$ 717,225	21.9%
Firm Comm. Ind. 15,000,000 & Over	Tf-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-6	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-9	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation	Pt-11	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Other Transportation		-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Total - Transportation Customers - All		1,023	264,233,866	$ 26,812,644	$ -	$ 26,812,644	$ 29,155,612	$ -	$ 29,155,612	$ 2,342,968	8.7%

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

Wisconsin Electric - Gas Operations
PSCW Adjusted 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 Revenue % Change
Residential Rg-1	476,884	411,283,016	$ 383,644,885	$ 192,865,528	$ 190,779,357	$ 435,014,130	$ 192,865,528	$ 242,148,602	$ 51,369,245	13.4%
Firm Comm. Ind. 0 to 3,999	29,850	42,596,481	$ 36,936,043	$ 20,270,299	$ 16,665,744	$ 39,537,651	$ 20,270,299	$ 19,267,352	$ 2,601,608	7.0%
Firm Comm. Ind. 4,000 to 39,999	11,150	134,893,748	$ 90,630,993	$ 58,765,664	$ 31,865,329	$ 99,414,893	$ 58,765,664	$ 40,649,229	$ 8,783,900	9.7%
Firm Comm. Ind. 40,000 to 99,999	836	50,407,264	$ 24,236,348	$ 14,933,809	$ 9,302,539	$ 26,429,882	$ 14,933,809	$ 11,496,073	$ 2,193,534	9.1%
Firm Comm. Ind. 100,000 to 499,999	420	87,719,590	$ 23,529,889	$ 11,649,316	$ 11,880,573	$ 25,680,460	$ 11,649,316	$ 14,031,144	$ 2,150,571	9.1%
Firm Comm. Ind. 500,000 to 999,999	66	43,719,562	$ 7,707,215	$ 2,449,642	$ 5,257,573	$ 7,723,407	$ 2,449,642	$ 5,273,765	$ 16,192	0.2%
Firm Comm. Ind. 1,000,000 to 7,999,999	39	81,208,517	$ 7,607,098	$ 862,507	$ 6,744,591	$ 8,835,568	$ 862,507	$ 7,973,061	$ 1,228,470	16.2%
Firm Comm. Ind. 8,000,000 to 14,999,999	5	58,380,370	$ 3,268,475	$ -	$ 3,268,475	$ 3,985,700	$ -	$ 3,985,700	$ 717,225	21.9%
Firm Comm. Ind. 15,000,000 & Over	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	161	1,023,323	$ 635,103	$ 381,319	$ 253,784	$ 639,912	$ 381,319	$ 258,593	$ 4,809	0.9%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	850,146	$ 490,898	$ 310,667	$ 180,231	$ 495,319	$ 310,667	$ 184,652	$ 4,421	0.9%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	353,073	$ 197,412	$ 127,151	$ 70,261	$ 199,423	$ 127,151	$ 72,272	$ 2,011	0.9%
Interrupt. Comm. Ind. 100000 to 499999 Ig-4	3	406,947	$ 215,867	$ 150,389	$ 65,478	$ 223,881	$ 150,389	$ 73,492	$ 8,014	3.7%
Interrupt Comm. Ind. 500000 to 999999 Ig-5	1	672,828	$ 343,962	$ 248,297	$ 95,665	$ 346,989	$ 248,297	$ 98,692	$ 3,027	0.9%
Interrupt. Comm. Ind. 1,000,000 to 7,999,999 Ig-6	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 8,000,000 to 14,999,999 Ig-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Interrupt. Comm. Ind. 15,000,000 & Over Ig-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation P_-2	1	-	$ 327,770	$ -	$ 327,770	$ 329,230	$ -	$ 329,230	$ 1,460	0.5%
Power Generation P_-6	1	-	$ 654,080	$ -	$ 654,080	$ 655,175	$ -	$ 655,175	$ 1,095	0.2%
Power Generation P_-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation P_-8	1	3,461,123	$ 1,735,273	$ 1,294,654	$ 440,619	$ 1,774,824	$ 1,294,654	$ 480,170	$ 39,551	2.3%
Power Generation P_-9	1	768,875	$ 1,905,197	$ 281,254	$ 1,623,943	$ 1,914,272	$ 281,254	$ 1,633,018	$ 9,075	0.5%
Power Generation P_-11	1	57,129,257	$ 21,230,743	$ 19,409,282	$ 1,821,461	$ 21,906,706	$ 19,409,282	$ 2,497,424	$ 675,963	3.2%
Other	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm NFPg-2	-	2,558,978	$ 995,386	$ 875,115	$ 120,271	$ 1,133,059	$ 875,115	$ 257,944	$ 137,673	13.8%
Power Generation Nominated Firm NFPg-6	-	11,959,643	$ 4,846,522	$ 4,071,535	$ 774,987	$ 5,492,340	$ 4,071,535	$ 1,420,805	$ 645,818	13.3%
Power Generation Nominated Firm NFPg-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm NFPg-9	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.0%
Power Generation Nominated Firm NFPg-11	-	9,282,000	$ 3,924,543	$ 3,577,399	$ 347,144	$ 4,433,200	$ 3,577,399	$ 855,801	$ 508,657	13.0%
Total - All Customers - All	519,420	998,674,741	$ 615,063,702	$ 332,523,827	$ 282,539,875	$ 686,166,021	$ 332,523,827	$ 353,642,194	$ 71,102,319	11.6%

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

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

Residential Service

Rates - Description	2026 Final Rates Firm Sales	Interruptible Sales	Transportation	2024 Current Rates Firm Sales	Interruptible Sales	Transportation	Final Change in Rates Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.3572	NA	$ 0.3572	$ 0.2871	NA	$ 0.2871	$ 0.0701	NA	$ 0.0701
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0512	NA	$ -	$ 0.0082	NA	$ -	$ 0.0430	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.4491	NA	$ 0.3584	$ 0.3242	NA	$ 0.2879	$ 0.1249	NA	$ 0.0705
Peak Demand	$ 0.1014	NA	$ -	$ 0.1014	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0081	NA	$ -	$ 0.0081	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3717	NA	$ -	$ 0.3717	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	NA	$ -	$ 0.4812	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.9303	NA	$ 0.3584	$ 0.8054	NA	$ 0.2879	$ 0.1249	NA	$ 0.0705
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0072	NA	$ 0.0072	$ 0.0056	NA	$ 0.0056	$ 0.0016	NA	$ 0.0016

Commercial / Industrial Class 1 0 to 3,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	Interruptible Sales	Transportation	2024 Current Rates Firm Sales	Interruptible Sales	Transportation	Final Change in Rates Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.2759	NA	$ 0.2759	$ 0.2696	NA	$ 0.2696	$ 0.0063	NA	$ 0.0063
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0512	NA	$ -	$ 0.0082	NA	$ -	$ 0.0430	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.3678	NA	$ 0.2771	$ 0.3067	NA	$ 0.2704	$ 0.0611	NA	$ 0.0067
Peak Demand	$ 0.1014	NA	$ -	$ 0.1014	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0081	NA	$ -	$ 0.0081	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3717	NA	$ -	$ 0.3717	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	NA	$ -	$ 0.4812	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8490	NA	$ 0.2771	$ 0.7879	NA	$ 0.2704	$ 0.0611	NA	$ 0.0067
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	NA	$ 0.0122	$ 0.0096	NA	$ 0.0096	$ 0.0026	NA	$ 0.0026

NA = Not Available

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

Commercial / Industrial Class 2 4,000 to 39,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.85	NA	$ 0.85	$ 0.85	NA	$ 0.85	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.1881	NA	$ 0.1881	$ 0.1741	NA	$ 0.1741	$ 0.0140	NA	$ 0.0140
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0512	NA	$ -	$ 0.0082	NA	$ -	$ 0.0430	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.2800	NA	$ 0.1893	$ 0.2112	NA	$ 0.1749	$ 0.0688	NA	$ 0.0144
Peak Demand	$ 0.1014	NA	$ -	$ 0.1014	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0081	NA	$ -	$ 0.0081	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3717	NA	$ -	$ 0.3717	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	NA	$ -	$ 0.4812	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.7612	NA	$ 0.1893	$ 0.6924	NA	$ 0.1749	$ 0.0688	NA	$ 0.0144
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	NA	$ 0.0122	$ 0.0096	NA	$ 0.0096	$ 0.0026	NA	$ 0.0026

NA = Not Available

NA = Not Available

Commercial / Industrial Class 3 40,000 to 99,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 6.00	NA	$ 6.00	$ 6.00	NA	$ 6.00	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.1280	NA	$ 0.1280	$ 0.1197	NA	$ 0.1197	$ 0.0083	NA	$ 0.0083
Competitive Supply Margin	$ 0.0395	NA	$ -	$ 0.0281	NA	$ -	$ 0.0114	NA	$ -
Daily Balancing Margin	$ 0.0012	NA	$ 0.0012	$ 0.0008	NA	$ 0.0008	$ 0.0004	NA	$ 0.0004
Peak Day Margin	$ 0.0512	NA	$ -	$ 0.0082	NA	$ -	$ 0.0430	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.2199	NA	$ 0.1292	$ 0.1568	NA	$ 0.1205	$ 0.0631	NA	$ 0.0087
Peak Demand	$ 0.1014	NA	$ -	$ 0.1014	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0081	NA	$ -	$ 0.0081	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3717	NA	$ -	$ 0.3717	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	NA	$ -	$ 0.4812	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.7011	NA	$ 0.1292	$ 0.6380	NA	$ 0.1205	$ 0.0631	NA	$ 0.0087
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	NA	$ 0.0122	$ 0.0096	NA	$ 0.0096	$ 0.0026	NA	$ 0.0026

NA = Not Available

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

Commercial / Industrial Class 4 100,000 to 499,999 Therms Annually

	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1103	$ 0.1103	$ 0.1103	$ 0.1024	$ 0.1024	$ 0.1024	$ 0.0079	$ 0.0079	$ 0.0079
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0430	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.2022	$ 0.1510	$ 0.1115	$ 0.1395	$ 0.1313	$ 0.1032	$ 0.0627	$ 0.0197	$ 0.0083
Peak Demand	$ 0.1014	$ -	$ -	$ 0.1014	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ -	$ 0.0081	$ 0.0081	$ -	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ -	$ 0.3717	$ 0.3717	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.3798	$ -	$ 0.4812	$ 0.3798	$ -	$ -	$ -	$ -
Total Rate	$ 0.6834	$ 0.5308	$ 0.1115	$ 0.6207	$ 0.5111	$ 0.1032	$ 0.0627	$ 0.0197	$ 0.0083
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0026	$ 0.0026	$ 0.0026

Commercial / Industrial Class 5 500,000 to 999,999 Therms Annually

	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ 35.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0870	$ 0.0870	$ 0.0870	$ 0.0943	$ 0.0943	$ 0.0943	$ (0.0073)	$ (0.0073)	$ (0.0073)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0430	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1789	$ 0.1277	$ 0.0882	$ 0.1314	$ 0.1232	$ 0.0951	$ 0.0475	$ 0.0045	$ (0.0069)
Peak Demand	$ 0.1014	$ -	$ -	$ 0.1014	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ -	$ 0.0081	$ 0.0081	$ -	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ -	$ 0.3717	$ 0.3717	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.3798	$ -	$ 0.4812	$ 0.3798	$ -	$ -	$ -	$ -
Total Rate	$ 0.6601	$ 0.5075	$ 0.0882	$ 0.6126	$ 0.5030	$ 0.0951	$ 0.0475	$ 0.0045	$ (0.0069)
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0026	$ 0.0026	$ 0.0026

NA = Not Available

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

Commercial / Industrial Class 6 1,000,000 to 7,999,999 Therms Annually

	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0036	$ 0.0036	$ 0.0036	$ 0.0010	$ 0.0010	$ 0.0010
Distribution Margin per therm	$ 0.0653	$ 0.0653	$ 0.0653	$ 0.0539	$ 0.0539	$ 0.0539	$ 0.0114	$ 0.0114	$ 0.0114
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0430	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1572	$ 0.1060	$ 0.0665	$ 0.0910	$ 0.0828	$ 0.0547	$ 0.0662	$ 0.0232	$ 0.0118
Peak Demand	$ 0.1014	$ -	$ -	$ 0.1014	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ -	$ 0.0081	$ 0.0081	$ -	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ -	$ 0.3717	$ 0.3717	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.3798	$ -	$ 0.4812	$ 0.3798	$ -	$ -	$ -	$ -
Total Rate	$ 0.6384	$ 0.4858	$ 0.0665	$ 0.5722	$ 0.4626	$ 0.0547	$ 0.0662	$ 0.0232	$ 0.0118
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

Commercial / Industrial Class 7 8,000,000 Therms to 14,999,999 Annually

	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0040	$ 0.0040	$ 0.0040	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0010	$ 0.0010	$ 0.0010
Distribution Margin per therm	$ 0.0482	$ 0.0482	$ 0.0482	$ 0.0375	$ 0.0375	$ 0.0375	$ 0.0107	$ 0.0107	$ 0.0107
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0430	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1401	$ 0.0889	$ 0.0494	$ 0.0746	$ 0.0664	$ 0.0383	$ 0.0655	$ 0.0225	$ 0.0111
Peak Demand	$ 0.1014	$ -	$ -	$ 0.1014	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ -	$ 0.0081	$ 0.0081	$ -	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ -	$ 0.3717	$ 0.3717	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.3798	$ -	$ 0.4812	$ 0.3798	$ -	$ -	$ -	$ -
Total Rate	$ 0.6213	$ 0.4687	$ 0.0494	$ 0.5558	$ 0.4462	$ 0.0383	$ 0.0655	$ 0.0225	$ 0.0111
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

NA = Not Available

NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

	Commercial / Industrial Class 8 15,000,000 Therms Annually & Over								
	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ 1,430.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0032	$ 0.0032	$ 0.0032	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0011	$ 0.0011	$ 0.0011
Distribution Margin per therm	$ 0.0252	$ 0.0252	$ 0.0252	$ 0.0152	$ 0.0152	$ 0.0152	$ 0.0100	$ 0.0100	$ 0.0100
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ -	$ 0.0281	$ 0.0281	$ -	$ 0.0114	$ 0.0114	$ -
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ -	$ -	$ 0.0082	$ -	$ -	$ 0.0430	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1171	$ 0.0659	$ 0.0264	$ 0.0523	$ 0.0441	$ 0.0160	$ 0.0648	$ 0.0218	$ 0.0104
Peak Demand	$ 0.1014	$ -	$ -	$ 0.1014	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ -	$ 0.0081	$ 0.0081	$ -	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ -	$ 0.3717	$ 0.3717	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.3798	$ -	$ 0.4812	$ 0.3798	$ -	$ -	$ -	$ -
Total Rate	$ 0.5983	$ 0.4457	$ 0.0264	$ 0.5335	$ 0.4239	$ 0.0160	$ 0.0648	$ 0.0218	$ 0.0104
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

	Agricultural Seasonal Use Sales Service Ag-1								
	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3	Firm Sales Step 1	Firm Sales Step 2	Firm Sales Step 3
Daily Facitilties Charge	$ 0.50	$ -	$ -	$ 0.50	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1321	$ 0.1253	$ 0.1128	$ 0.1822	$ 0.1749	$ 0.1619	$ (0.0501)	$ (0.0496)	$ (0.0491)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ 0.0395	$ 0.0281	$ 0.0281	$ 0.0281	$ 0.0114	$ 0.0114	$ 0.0114
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ 0.0512	$ 0.0512	$ 0.0512	$ 0.0082	$ 0.0082	$ 0.0082	$ 0.0430	$ 0.0430	$ 0.0430
Other Margin									
Total All Margin Rates	$ 0.2240	$ 0.2172	$ 0.2047	$ 0.2193	$ 0.2120	$ 0.1990	$ 0.0047	$ 0.0052	$ 0.0057
Peak Demand	$ 0.1014	$ 0.1014	$ 0.1014	$ 0.1014	$ 0.1014	$ 0.1014	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4812	$ 0.4812	$ 0.4812	$ 0.4812	$ 0.4812	$ 0.4812	$ -	$ -	$ -
Total Rate	$ 0.7052	$ 0.6984	$ 0.6859	$ 0.7005	$ 0.6932	$ 0.6802	$ 0.0047	$ 0.0052	$ 0.0057
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0096	$ 0.0096	$ 0.0096	$ 0.0026	$ 0.0026	$ 0.0026

NA = Not Available　NA = Not Available　NA = Not Available

Wisconsin Electric - Gas Operations
PSCW Adjusted Final and Current Rates
for the Test Year ended December 31, 2026

Power Generation

Rates - Description	2026 Final Rates Pg-2	2026 Final Rates Pg-6	2026 Final Rates Pg-8	2024 Current Rates Pg-2	2024 Current Rates Pg-6	2024 Current Rates Pg-8	Final Change in Rates Pg-2	Final Change in Rates Pg-6	Final Change in Rates Pg-8
Daily Facitilties Charge	$ 902.00	$ 1,795.00	$ 684.00	$ 898.00	$ 1,792.00	$ 679.00	$ 4.00	$ 3.00	$ 5.00
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0089	$ 0.0269	$ 0.0259	$ 0.0099	$ 0.0277	$ 0.0268	$ (0.0010)	$ (0.0008)	$ (0.0009)
Competitive Supply Margin	$ 0.0395	$ 0.0395	$ 0.0395	$ 0.0281	$ 0.0281	$ 0.0281	$ 0.0114	$ 0.0114	$ 0.0114
Daily Balancing Margin	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0008	$ 0.0008	$ 0.0008	$ 0.0004	$ 0.0004	$ 0.0004
Peak Day Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0496	$ 0.0676	$ 0.0666	$ 0.0388	$ 0.0566	$ 0.0557	$ 0.0108	$ 0.0110	$ 0.0109
Peak Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ 0.0081	$ -	$ -	$ -
Commodity	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ 0.3717	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.3798	$ 0.3798	$ 0.3798	$ 0.3798	$ 0.3798	$ 0.3798	$ -	$ -	$ -
Total Rate	$ 0.4294	$ 0.4474	$ 0.4464	$ 0.4186	$ 0.4364	$ 0.4355	$ 0.0108	$ 0.0110	$ 0.0109
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA

Power Generation

Rates - Description	2026 Final Rates Pg-9	2026 Final Rates Pg-11	2026 Final Rates NA	2024 Current Rates Pg-9	2024 Current Rates Pg-11	2024 Current Rates NA	Final Change in Rates Pg-9	Final Change in Rates Pg-11	Final Change in Rates NA
Daily Facitilties Charge	$ 251.20	$ 425.00	NA	$ 251.20	$ 419.97	NA	$ -	$ 5.03	NA
Transportation Administrative	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Daily Demand Charge	$ 0.0150	$ -	NA	$ 0.0150	$ -	NA	$ -	$ -	NA
Distribution Margin per therm	$ 0.0015	$ 0.0003	NA	$ 0.0015	$ 0.0003	NA	$ -	$ -	NA
Competitive Supply Margin	$ 0.0395	$ 0.0395	NA	$ 0.0281	$ 0.0281	NA	$ 0.0114	$ 0.0114	NA
Daily Balancing Margin	$ 0.0012	$ 0.0012	NA	$ 0.0008	$ 0.0008	NA	$ 0.0004	$ 0.0004	NA
Peak Day Margin	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Other Margin									
Total All Margin Rates	$ 0.0422	$ 0.0410	NA	$ 0.0304	$ 0.0292	NA	$ 0.0118	$ 0.0118	NA
Peak Demand	$ -	$ -	NA	$ -	$ -	NA	$ -	$ -	NA
Annual Demand	$ 0.0081	$ 0.0081	NA	$ 0.0081	$ 0.0081	NA	$ -	$ -	NA
Commodity	$ 0.3717	$ 0.3717	NA	$ 0.3717	$ 0.3717	NA	$ -	$ -	NA
Total Natural Gas Rate Per Therm	$ 0.3798	$ 0.3798	NA	$ 0.3798	$ 0.3798	NA	$ -	$ -	NA
Total Rate	$ 0.4220	$ 0.4208	NA	$ 0.4102	$ 0.4090	NA	$ 0.0118	$ 0.0118	NA
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not Available

NA = Not Available

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Residential Rg-1

Transportation Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -	
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -	
$/Therm-Winter	$ 0.2879	$ 0.3584	$ 0.0705	
$/Therm-Summer	$ 0.2879	$ 0.3584	$ 0.0705	

Sales Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -	
$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -	
$/Therm-Winter	$ 0.8054	$ 0.9303	$ 0.1249	
$/Therm-Summer	$ 0.7040	$ 0.8289	$ 0.1249	

Usage in Therms	# of Customers & Class Average Use	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	# of Customers & Class Average Use	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
300		$ 936.85	$ 958.01	$ 21.16	2.26%		$ 356.88	$ 394.37	$ 37.49	10.50%
600		$ 1,023.26	$ 1,065.57	$ 42.31	4.13%		$ 593.31	$ 668.28	$ 74.97	12.64%
865		$ 1,099.48	$ 1,160.47	$ 60.99	5.55%		$ 801.89	$ 909.93	$ 108.04	13.47%
1,096		$ 1,166.07	$ 1,243.36	$ 77.29	6.63%		$ 984.11	$ 1,121.03	$ 136.92	13.91%
1,332		$ 1,233.81	$ 1,327.69	$ 93.88	7.61%		$ 1,169.47	$ 1,335.79	$ 166.32	14.22%
1,567		$ 1,301.56	$ 1,412.02	$ 110.46	8.49%		$ 1,354.84	$ 1,550.54	$ 195.70	14.44%
1,802		$ 1,369.30	$ 1,496.35	$ 127.05	9.28%		$ 1,540.20	$ 1,765.29	$ 225.09	14.61%
2,037		$ 1,437.04	$ 1,580.68	$ 143.64	10.00%		$ 1,725.56	$ 1,980.04	$ 254.48	14.75%
2,273		$ 1,504.78	$ 1,665.01	$ 160.23	10.65%		$ 1,910.93	$ 2,194.80	$ 283.87	14.86%
2,508		$ 1,572.52	$ 1,749.34	$ 176.82	11.24%		$ 2,096.29	$ 2,409.55	$ 313.26	14.94%
2,743		$ 1,640.26	$ 1,833.67	$ 193.41	11.79%		$ 2,281.66	$ 2,624.30	$ 342.64	15.02%
2,979		$ 1,708.00	$ 1,918.00	$ 210.00	12.30%		$ 2,467.02	$ 2,839.05	$ 372.03	15.08%
3,214		$ 1,775.74	$ 2,002.33	$ 226.59	12.76%		$ 2,652.38	$ 3,053.80	$ 401.42	15.13%
3,449		$ 1,843.48	$ 2,086.66	$ 243.18	13.19%		$ 2,837.75	$ 3,268.56	$ 430.81	15.18%
3,685		$ 1,911.23	$ 2,170.99	$ 259.76	13.59%		$ 3,023.11	$ 3,483.31	$ 460.20	15.22%
3,920		$ 1,978.97	$ 2,255.31	$ 276.34	13.96%		$ 3,208.48	$ 3,698.06	$ 489.58	15.26%
4,095		$ 2,029.43	$ 2,318.14	$ 288.71	14.23%		$ 3,346.57	$ 3,858.05	$ 511.48	15.28%

	Transportation Old	Transportation New	Sales Old	Sales New
Winter Qty %	82.64%	82.64%	82.64%	82.64%
Summer QTY %	17.36%	17.36%	17.36%	17.36%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798
Transportation Administrative Charge:	$ 2.00	

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Agricultural Use Crop Drying Step 1 0 to 2,999 Ag-1

	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.	$	15.21	$	15.21	$	-	
	$/Day Fixed or equ	NA	NA	NA		$/Day Fixed or equiv.	$	0.50	$	0.50	$	-	
	Demand Charge	NA	NA	NA		Demand Charge		NA		NA		NA	
	$/Therm-Out of Se	NA	NA	NA		$/Therm-Out of Season Step	$	0.7005	$	0.7052	$	0.0047	
						$/Therm-Out of Season Step	$	0.6932	$	0.6984	$	0.0052	
						$/Therm-Out of Season Step	$	0.6802	$	0.6859	$	0.0057	
	$/Therm-In Seasor	NA	NA	NA		$/Therm-In Season Step 1	$	0.5991	$	0.6038	$	0.0047	
						$/Therm-In Season Step 2	$	0.5918	$	0.5970	$	0.0052	
						$/Therm-In Season Step 3	$	0.5788	$	0.5845	$	0.0057	

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		NA	NA	NA	NA		$	324.48	$	325.58	$	1.10	0.34%
294	57	NA	NA	NA	NA		$	360.13	$	361.51	$	1.38	0.38%
470		NA	NA	NA	NA		$	466.46	$	468.67	$	2.21	0.47%
940		NA	NA	NA	NA		$	750.42	$	754.84	$	4.42	0.59%
1,175		NA	NA	NA	NA		$	892.40	$	897.92	$	5.52	0.62%
1,350		NA	NA	NA	NA		$	998.13	$	1,004.47	$	6.34	0.64%
1,515		NA	NA	NA	NA		$	1,097.82	$	1,104.94	$	7.12	0.65%
1,690		NA	NA	NA	NA		$	1,203.55	$	1,211.49	$	7.94	0.66%
1,830		NA	NA	NA	NA		$	1,288.13	$	1,296.73	$	8.60	0.67%
1,970		NA	NA	NA	NA		$	1,372.72	$	1,381.97	$	9.25	0.67%
2,110		NA	NA	NA	NA		$	1,457.30	$	1,467.22	$	9.92	0.68%
2,250		NA	NA	NA	NA		$	1,541.88	$	1,552.46	$	10.58	0.69%
2,390		NA	NA	NA	NA		$	1,626.47	$	1,637.70	$	11.23	0.69%
2,530		NA	NA	NA	NA		$	1,711.05	$	1,722.94	$	11.89	0.69%
2,670		NA	NA	NA	NA		$	1,795.63	$	1,808.18	$	12.55	0.70%
2,810		NA	NA	NA	NA		$	1,880.22	$	1,893.42	$	13.20	0.70%
2,950		NA	NA	NA	NA		$	1,964.80	$	1,978.67	$	13.87	0.71%
	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:	$	0.3717	$	0.3717
1175	Base Average Peak Demand Cost:	$	0.1014	$	-
4	Base Average Annual Demand Cost:	$	0.0081	$	0.0081
293.75	Base Average Balancing Cost:	$	-	$	-
	Base Average Surcharge Cost:	$	-	$	-
	Totals:	$	0.4812	$	0.3798
	Transportation Administrative Charge:	$	2.00		

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Agricultural Use Crop Drying Step 2 3,000 to 9,999 Ag-1

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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Out of Seasor	NA	NA	NA		$/Therm-Out of Season S	$ 0.7005	$ 0.7052	$ 0.0047	
						$/Therm-Out of Season S	$ 0.6932	$ 0.6984	$ 0.0052	
						$/Therm-Out of Season S	$ 0.6802	$ 0.6859	$ 0.0057	
	$/Therm-In Season	NA	NA	NA		$/Therm-In Season Step	$ 0.5991	$ 0.6038	$ 0.0047	
						$/Therm-In Season Step	$ 0.5918	$ 0.5970	$ 0.0052	
						$/Therm-In Season Step	$ 0.5788	$ 0.5845	$ 0.0057	

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
3,123	94	NA	NA	NA	NA		$ 2,055.07	$ 2,069.75	$ 14.68	0.71%
4,400		NA	NA	NA	NA		$ 2,820.77	$ 2,841.45	$ 20.68	0.73%
4,800		NA	NA	NA	NA		$ 3,060.61	$ 3,083.17	$ 22.56	0.74%
5,200		NA	NA	NA	NA		$ 3,300.46	$ 3,324.90	$ 24.44	0.74%
5,600		NA	NA	NA	NA		$ 3,540.30	$ 3,566.62	$ 26.32	0.74%
6,000		NA	NA	NA	NA		$ 3,780.14	$ 3,808.34	$ 28.20	0.75%
6,400		NA	NA	NA	NA		$ 4,019.99	$ 4,050.06	$ 30.07	0.75%
6,800		NA	NA	NA	NA		$ 4,259.83	$ 4,291.79	$ 31.96	0.75%
7,200		NA	NA	NA	NA		$ 4,499.67	$ 4,533.51	$ 33.84	0.75%
7,600		NA	NA	NA	NA		$ 4,739.51	$ 4,775.23	$ 35.72	0.75%
8,000		NA	NA	NA	NA		$ 4,979.36	$ 5,016.96	$ 37.60	0.76%
8,400		NA	NA	NA	NA		$ 5,219.20	$ 5,258.68	$ 39.48	0.76%
8,800		NA	NA	NA	NA		$ 5,459.04	$ 5,500.40	$ 41.36	0.76%
9,000		NA	NA	NA	NA		$ 5,578.96	$ 5,621.26	$ 42.30	0.76%
9,400		NA	NA	NA	NA		$ 5,818.81	$ 5,862.99	$ 44.18	0.76%
9,800		NA	NA	NA	NA		$ 6,058.65	$ 6,104.71	$ 46.06	0.76%
9,950		NA	NA	NA	NA		$ 6,148.59	$ 6,195.35	$ 46.76	0.76%
	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
12492			
4	Base Average Commodity Cost:	$ 0.3717	$ 0.3717
3123	Base Average Peak Demand Cost:	$ 0.1014	$ -
	Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
	Base Average Balancing Cost:	$ -	$ -
	Base Average Surcharge Cost:	$ -	$ -
	Totals:	$ 0.4812	$ 0.3798
	Transportation Administrative Charge:	$ 2.00	

Wisconsin Electric - Gas Operations
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Agricultural Use Crop Drying Step 3 Over 9,999 Ag-1

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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Out of Se	NA	NA	NA		$/Therm-Out of Season S	$ 0.7005	$ 0.7052	$ 0.0047	
						$/Therm-Out of Season S	$ 0.6932	$ 0.6984	$ 0.0052	
						$/Therm-Out of Season S	$ 0.6802	$ 0.6859	$ 0.0057	
	$/Therm-In Seasor	NA	NA	NA		$/Therm-In Season Step	$ 0.5991	$ 0.6038	$ 0.0047	
						$/Therm-In Season Step	$ 0.5918	$ 0.5970	$ 0.0052	
						$/Therm-In Season Step	$ 0.5788	$ 0.5845	$ 0.0057	

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
10,000		NA	NA	NA	NA		$ 6,178.57	$ 6,225.57	$ 47.00	0.76%
17,500		NA	NA	NA	NA		$ 10,636.08	$ 10,721.04	$ 84.96	0.80%
22,351	13	NA	NA	NA	NA		$ 13,509.54	$ 13,619.71	$ 110.17	0.82%
32,500		NA	NA	NA	NA		$ 19,521.24	$ 19,684.16	$ 162.92	0.83%
40,000		NA	NA	NA	NA		$ 23,963.81	$ 24,165.71	$ 201.90	0.84%
37,851	1	NA	NA	NA	NA		$ 22,690.87	$ 22,881.60	$ 190.73	0.84%
45,351		NA	NA	NA	NA		$ 27,066.78	$ 27,299.05	$ 232.27	0.86%
52,851		NA	NA	NA	NA		$ 31,412.34	$ 31,687.33	$ 274.99	0.88%
60,351		NA	NA	NA	NA		$ 35,757.91	$ 36,075.60	$ 317.70	0.89%
67,851		NA	NA	NA	NA		$ 40,103.47	$ 40,463.88	$ 360.41	0.90%
75,351		NA	NA	NA	NA		$ 44,449.03	$ 44,852.16	$ 403.12	0.91%
82,851		NA	NA	NA	NA		$ 48,794.60	$ 49,240.43	$ 445.83	0.91%
90,351		NA	NA	NA	NA		$ 53,140.16	$ 53,628.71	$ 488.55	0.92%
97,851		NA	NA	NA	NA		$ 57,485.73	$ 58,016.99	$ 531.26	0.92%
105,351		NA	NA	NA	NA		$ 61,831.29	$ 62,405.26	$ 573.97	0.93%
112,851		NA	NA	NA	NA		$ 66,176.86	$ 66,793.54	$ 616.68	0.93%
120,351		NA	NA	NA	NA		$ 70,522.42	$ 71,181.81	$ 659.39	0.94%
	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
151403		Base Average Commodity Cost:	$ 0.3717	$ 0.3717
4		Base Average Peak Demand Cost:	$ 0.1014	$ -
37850.75	89406	Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
	4	Base Average Balancing Cost:	$ -	$ -
	22351.5	Base Average Surcharge Cost:	$ -	$ -
		Totals:	$ 0.4812	$ 0.3798
		Transportation Administrative Charge:	$ 2.00	

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 0 to 3,999 Fg-1 & Tf-1

Transportation Service | **Sales Service**

	Transportation Old Annual Rate	Transportation New Annual Rate	Transportation Increase (Decrease)		Sales Old Annual Rate	Sales New Annual Rate	Sales Increase (Decrease)
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -	$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -	$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -
Demand Charge	N/A	N/A	N/A	Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.2704	$ 0.2771	$ 0.0067	$/Therm-Winter	$ 0.7879	$ 0.8490	$ 0.0611
$/Therm-Summer	$ 0.2704	$ 0.2771	$ 0.0067	$/Therm-Summer	$ 0.6865	$ 0.7476	$ 0.0611

Usage in Therms	# of Customers & Class Average Use	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Percent of Change	# of Customers & Class Average Use	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Percent of Change
250		$ 918.03	$ 919.71	$ 1.68	0.18%		$ 313.90	$ 329.17	$ 15.27	4.86%
500		$ 985.62	$ 988.97	$ 3.35	0.34%		$ 507.35	$ 537.89	$ 30.54	6.02%
750		$ 1,053.20	$ 1,058.22	$ 5.02	0.48%		$ 700.80	$ 746.62	$ 45.82	6.54%
1,000		$ 1,120.78	$ 1,127.48	$ 6.70	0.60%		$ 894.25	$ 955.34	$ 61.09	6.83%
1,250		$ 1,188.37	$ 1,196.74	$ 8.37	0.70%		$ 1,087.71	$ 1,164.06	$ 76.35	7.02%
1,500		$ 1,255.95	$ 1,266.00	$ 10.05	0.80%		$ 1,281.16	$ 1,372.78	$ 91.62	7.15%
1,750		$ 1,323.53	$ 1,335.25	$ 11.72	0.89%		$ 1,474.61	$ 1,581.51	$ 106.90	7.25%
1,900		$ 1,364.07	$ 1,376.80	$ 12.73	0.93%		$ 1,590.66	$ 1,706.72	$ 116.06	7.30%
2,150		$ 1,431.93	$ 1,446.34	$ 14.41	1.01%		$ 1,784.88	$ 1,916.28	$ 131.40	7.36%
2,400		$ 1,499.51	$ 1,515.59	$ 16.08	1.07%		$ 1,978.34	$ 2,125.00	$ 146.66	7.41%
2,650		$ 1,567.09	$ 1,584.85	$ 17.76	1.13%		$ 2,171.79	$ 2,333.72	$ 161.93	7.46%
2,900		$ 1,634.68	$ 1,654.11	$ 19.43	1.19%		$ 2,365.24	$ 2,542.44	$ 177.20	7.49%
3,150		$ 1,702.26	$ 1,723.37	$ 21.11	1.24%		$ 2,558.69	$ 2,751.17	$ 192.48	7.52%
3,400		$ 1,769.84	$ 1,792.62	$ 22.78	1.29%		$ 2,752.14	$ 2,959.89	$ 207.75	7.55%
3,650		$ 1,837.43	$ 1,861.88	$ 24.45	1.33%		$ 2,945.59	$ 3,168.61	$ 223.02	7.57%
3,899		$ 1,904.74	$ 1,930.86	$ 26.12	1.37%		$ 3,138.27	$ 3,376.50	$ 238.23	7.59%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	86.29%	86.29%	Winter Qty %	86.29%	86.29%
Summer QTY %	13.71%	13.71%	Summer QTY %	13.71%	13.71%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 4,000 to 39,999 Fg-2 & Tf-2

Usage in Therms		Transportation Service (Without Telemetry Fee) 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	$ 86.69	$ 86.69	$ -		$/Mo. Fixed or equ	$ 25.85	$ 25.85	$ -	
	$/Day Fixed or equ	$ 2.85	$ 2.85	$ -		$/Day Fixed or equ	$ 0.85	$ 0.85	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1749	$ 0.1893	$ 0.0144		$/Therm-Winter	$ 0.6924	$ 0.7612	$ 0.0688	
	$/Therm-Summer	$ 0.1749	$ 0.1893	$ 0.0144		$/Therm-Summer	$ 0.5910	$ 0.6598	$ 0.0688	

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
4,000		$ 1,739.85	$ 1,797.45	$ 57.60	3.31%		$ 3,002.14	$ 3,277.34	$ 275.20	9.17%
6,400		$ 2,159.61	$ 2,251.77	$ 92.16	4.27%		$ 4,617.27	$ 5,057.59	$ 440.32	9.54%
8,800		$ 2,579.37	$ 2,706.09	$ 126.72	4.91%		$ 6,232.40	$ 6,837.84	$ 605.44	9.71%
11,200		$ 2,999.13	$ 3,160.41	$ 161.28	5.38%		$ 7,847.53	$ 8,618.09	$ 770.56	9.82%
13,600		$ 3,418.89	$ 3,614.73	$ 195.84	5.73%		$ 9,462.67	$ 10,398.35	$ 935.68	9.89%
16,000		$ 3,838.65	$ 4,069.05	$ 230.40	6.00%		$ 11,077.80	$ 12,178.60	$ 1,100.80	9.94%
18,400		$ 4,258.41	$ 4,523.37	$ 264.96	6.22%		$ 12,692.93	$ 13,958.85	$ 1,265.92	9.97%
20,800		$ 4,678.17	$ 4,977.69	$ 299.52	6.40%		$ 14,308.06	$ 15,739.10	$ 1,431.04	10.00%
23,200		$ 5,097.93	$ 5,432.01	$ 334.08	6.55%		$ 15,923.19	$ 17,519.35	$ 1,596.16	10.02%
25,600		$ 5,517.69	$ 5,886.33	$ 368.64	6.68%		$ 17,538.33	$ 19,299.61	$ 1,761.28	10.04%
28,000		$ 5,937.45	$ 6,340.65	$ 403.20	6.79%		$ 19,153.46	$ 21,079.86	$ 1,926.40	10.06%
30,400		$ 6,357.21	$ 6,794.97	$ 437.76	6.89%		$ 20,768.59	$ 22,860.11	$ 2,091.52	10.07%
32,800		$ 6,776.97	$ 7,249.29	$ 472.32	6.97%		$ 22,383.72	$ 24,640.36	$ 2,256.64	10.08%
35,200		$ 7,196.73	$ 7,703.61	$ 506.88	7.04%		$ 23,998.86	$ 26,420.62	$ 2,421.76	10.09%
37,600		$ 7,616.49	$ 8,157.93	$ 541.44	7.11%		$ 25,613.99	$ 28,200.87	$ 2,586.88	10.10%
39,999		$ 8,036.08	$ 8,612.06	$ 575.98	7.17%		$ 27,228.45	$ 29,980.38	$ 2,751.93	10.11%
	Winter Qty %	81.43%	81.43%			Winter Qty %	80.84%	80.84%		
	Summer QTY %	18.57%	18.57%			Summer QTY %	19.16%	19.16%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 40,000 to 99,999 Fg-3 & Tf-3

	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.	$ 243.33	$ 243.33	$ -		$/Mo. Fixed or equiv.	$ 182.50	$ 182.50	$ -	
	$/Day Fixed or equiv.	$ 8.00	$ 8.00	$ -		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1205	$ 0.1292	$ 0.0087		$/Therm-Winter	$ 0.6380	$ 0.7011	$ 0.0631	
	$/Therm-Summer	$ 0.1205	$ 0.1292	$ 0.0087		$/Therm-Summer	$ 0.5366	$ 0.5997	$ 0.0631	

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
40,000		$ 7,740.00	$ 8,088.00	$ 348.00	4.50%		$ 26,833.90	$ 29,357.90	$ 2,524.00	9.41%
44,000		$ 8,222.00	$ 8,604.80	$ 382.80	4.66%		$ 29,298.29	$ 32,074.69	$ 2,776.40	9.48%
48,000		$ 8,704.00	$ 9,121.60	$ 417.60	4.80%		$ 31,762.68	$ 34,791.48	$ 3,028.80	9.54%
52,000		$ 9,186.00	$ 9,638.40	$ 452.40	4.92%		$ 34,227.08	$ 37,508.28	$ 3,281.20	9.59%
56,000		$ 9,668.00	$ 10,155.20	$ 487.20	5.04%		$ 36,691.47	$ 40,225.07	$ 3,533.60	9.63%
60,000		$ 10,150.00	$ 10,672.00	$ 522.00	5.14%		$ 39,155.86	$ 42,941.86	$ 3,786.00	9.67%
64,000		$ 10,632.00	$ 11,188.80	$ 556.80	5.24%		$ 41,620.25	$ 45,658.65	$ 4,038.40	9.70%
68,000		$ 11,114.00	$ 11,705.60	$ 591.60	5.32%		$ 44,084.64	$ 48,375.44	$ 4,290.80	9.73%
72,000		$ 11,596.00	$ 12,222.40	$ 626.40	5.40%		$ 46,549.03	$ 51,092.23	$ 4,543.20	9.76%
76,000		$ 12,078.00	$ 12,739.20	$ 661.20	5.47%		$ 49,013.42	$ 53,809.02	$ 4,795.60	9.78%
80,000		$ 12,560.00	$ 13,256.00	$ 696.00	5.54%		$ 51,477.81	$ 56,525.81	$ 5,048.00	9.81%
84,000		$ 13,042.00	$ 13,772.80	$ 730.80	5.60%		$ 53,942.20	$ 59,242.60	$ 5,300.40	9.83%
88,000		$ 13,524.00	$ 14,289.60	$ 765.60	5.66%		$ 56,406.59	$ 61,959.39	$ 5,552.80	9.84%
92,000		$ 14,006.00	$ 14,806.40	$ 800.40	5.71%		$ 58,870.98	$ 64,676.18	$ 5,805.20	9.86%
96,000		$ 14,488.00	$ 15,323.20	$ 835.20	5.76%		$ 61,335.37	$ 67,392.97	$ 6,057.60	9.88%
99,999		$ 14,969.88	$ 15,839.87	$ 869.99	5.81%		$ 63,799.14	$ 70,109.08	$ 6,309.94	9.89%
	Winter Qty %	77.68%	77.68%			Winter Qty %	78.40%	78.40%		
	Summer QTY %	22.32%	22.32%			Summer QTY %	21.60%	21.60%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 100,000 to 499,999 Fg-4 & Tf-4

	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	$ 395.42	$ 395.42	$ -		$/Mo. Fixed or equ	$ 334.58	$ 334.58	$ -	
	$/Day Fixed or equ	$ 13.00	$ 13.00	$ -		$/Day Fixed or equ	$ 11.00	$ 11.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1032	$ 0.1115	$ 0.0083		$/Therm-Winter	$ 0.6207	$ 0.6834	$ 0.0627	
	$/Therm-Summer	$ 0.1032	$ 0.1115	$ 0.0083		$/Therm-Summer	$ 0.5193	$ 0.5820	$ 0.0627	

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
100,000		$ 15,065.00	$ 15,895.00	$ 830.00	5.51%		$ 62,901.04	$ 69,171.04	$ 6,270.00	9.97%
126,667		$ 17,817.00	$ 18,868.33	$ 1,051.33	5.90%		$ 78,603.98	$ 86,545.98	$ 7,942.00	10.10%
153,333		$ 20,569.00	$ 21,841.67	$ 1,272.67	6.19%		$ 94,306.93	$ 103,920.93	$ 9,614.00	10.19%
180,000		$ 23,321.00	$ 24,815.00	$ 1,494.00	6.41%		$ 110,009.87	$ 121,295.87	$ 11,286.00	10.26%
206,667		$ 26,073.00	$ 27,788.33	$ 1,715.33	6.58%		$ 125,712.82	$ 138,670.82	$ 12,958.00	10.31%
233,333		$ 28,825.00	$ 30,761.67	$ 1,936.67	6.72%		$ 141,415.76	$ 156,045.76	$ 14,630.00	10.35%
260,000		$ 31,577.00	$ 33,735.00	$ 2,158.00	6.83%		$ 157,118.70	$ 173,420.70	$ 16,302.00	10.38%
286,667		$ 34,329.00	$ 36,708.33	$ 2,379.33	6.93%		$ 172,821.65	$ 190,795.65	$ 17,974.00	10.40%
313,333		$ 37,081.00	$ 39,681.67	$ 2,600.67	7.01%		$ 188,524.59	$ 208,170.59	$ 19,646.00	10.42%
340,000		$ 39,833.00	$ 42,655.00	$ 2,822.00	7.08%		$ 204,227.54	$ 225,545.54	$ 21,318.00	10.44%
366,667		$ 42,585.00	$ 45,628.33	$ 3,043.33	7.15%		$ 219,930.48	$ 242,920.48	$ 22,990.00	10.45%
393,333		$ 45,337.00	$ 48,601.67	$ 3,264.67	7.20%		$ 235,633.42	$ 260,295.42	$ 24,662.00	10.47%
420,000		$ 48,089.00	$ 51,575.00	$ 3,486.00	7.25%		$ 251,336.37	$ 277,670.37	$ 26,334.00	10.48%
446,667		$ 50,841.00	$ 54,548.33	$ 3,707.33	7.29%		$ 267,039.31	$ 295,045.31	$ 28,006.00	10.49%
473,333		$ 53,593.00	$ 57,521.67	$ 3,928.67	7.33%		$ 282,742.26	$ 312,420.26	$ 29,678.00	10.50%
499,999		$ 56,344.90	$ 60,494.89	$ 4,149.99	7.37%		$ 298,444.61	$ 329,794.55	$ 31,349.94	10.50%
	Winter Qty %	69.37%	69.37%			Winter Qty %	68.60%	68.60%		
	Summer QTY %	30.63%	30.63%			Summer QTY %	31.40%	31.40%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 500,000 to 999,999 Fg-5 & Tf-5

	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	$ 1,125.42	$ 1,125.42	$ -		$/Mo. Fixed or equ	$ 1,064.58	$ 1,064.58	$ -	
	$/Day Fixed or equ	$ 37.00	$ 37.00	$ -		$/Day Fixed or equ	$ 35.00	$ 35.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.0951	$ 0.0882	$ (0.0069)		$/Therm-Winter	$ 0.6126	$ 0.6601	$ 0.0475	
	$/Therm-Summer	$ 0.0951	$ 0.0882	$ (0.0069)		$/Therm-Summer	$ 0.5112	$ 0.5587	$ 0.0475	

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
500,000		$ 61,055.00	$ 57,605.00	$ (3,450.00)	-5.65%		$ 294,703.51	$ 318,453.51	$ 23,750.00	8.06%
533,333		$ 64,224.99	$ 60,544.99	$ (3,680.00)	-5.73%		$ 313,498.71	$ 338,832.04	$ 25,333.33	8.08%
566,667		$ 67,394.99	$ 63,484.99	$ (3,910.00)	-5.80%		$ 332,293.90	$ 359,210.56	$ 26,916.66	8.10%
600,000		$ 70,564.98	$ 66,424.98	$ (4,140.00)	-5.87%		$ 351,089.10	$ 379,589.09	$ 28,499.99	8.12%
633,333		$ 73,734.97	$ 69,364.98	$ (4,369.99)	-5.93%		$ 369,884.30	$ 399,967.62	$ 30,083.32	8.13%
666,666		$ 76,904.97	$ 72,304.97	$ (4,600.00)	-5.98%		$ 388,679.49	$ 420,346.14	$ 31,666.65	8.15%
700,000		$ 80,074.96	$ 75,244.96	$ (4,830.00)	-6.03%		$ 407,474.69	$ 440,724.67	$ 33,249.98	8.16%
733,333		$ 83,244.96	$ 78,184.96	$ (5,060.00)	-6.08%		$ 426,269.88	$ 461,103.20	$ 34,833.32	8.17%
766,666		$ 86,414.95	$ 81,124.95	$ (5,290.00)	-6.12%		$ 445,065.08	$ 481,481.72	$ 36,416.64	8.18%
799,999		$ 89,584.94	$ 84,064.95	$ (5,519.99)	-6.16%		$ 463,860.28	$ 501,860.25	$ 37,999.97	8.19%
833,333		$ 92,754.94	$ 87,004.94	$ (5,750.00)	-6.20%		$ 482,655.47	$ 522,238.78	$ 39,583.31	8.20%
866,666		$ 95,924.93	$ 89,944.94	$ (5,979.99)	-6.23%		$ 501,450.67	$ 542,617.30	$ 41,166.63	8.21%
899,999		$ 99,094.92	$ 92,884.93	$ (6,209.99)	-6.27%		$ 520,245.87	$ 562,995.83	$ 42,749.96	8.22%
933,332		$ 102,264.92	$ 95,824.92	$ (6,440.00)	-6.30%		$ 539,041.06	$ 583,374.36	$ 44,333.30	8.22%
966,666		$ 105,434.91	$ 98,764.92	$ (6,669.99)	-6.33%		$ 557,836.26	$ 603,752.88	$ 45,916.62	8.23%
999,999		$ 108,604.90	$ 101,704.91	$ (6,899.99)	-6.35%		$ 576,631.46	$ 624,131.41	$ 47,499.95	8.24%
	Winter Qty %	57.53%	57.53%			Winter Qty %	51.93%	51.93%		
	Summer QTY %	42.47%	42.47%			Summer QTY %	48.07%	48.07%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6 & Tf-6

	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.	$ 3,558.75	$ 3,558.75	$ -		$/Mo. Fixed or equiv.	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or equiv.	$ 117.00	$ 117.00	$ -		$/Day Fixed or equiv.	$ 115.00	$ 115.00	$ -	
	Demand Charge	$ 0.0036	$ 0.0046	$ 0.0010		Demand Charge	$ 0.0036	$ 0.0046	$ 0.0010	
	$/Therm-Winter	$ 0.0547	$ 0.0665	$ 0.0118		$/Therm-Winter	$ 0.5722	$ 0.6384	$ 0.0662	
	$/Therm-Summer	$ 0.0547	$ 0.0665	$ 0.0118		$/Therm-Summer	$ 0.4708	$ 0.5370	$ 0.0662	

Usage in Therms	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
1,000,000	10,957	$ 111,801.93	$ 127,601.07	$ 15,799.14	14.13%	10,957	$ 568,785.49	$ 637,706.97	$ 68,921.48	12.12%
1,466,667	10,957	$ 137,328.59	$ 158,634.40	$ 21,305.81	15.51%	10,957	$ 807,911.78	$ 907,130.35	$ 99,218.57	12.28%
1,933,333	10,957	$ 162,855.25	$ 189,667.73	$ 26,812.48	16.46%	10,957	$ 1,047,038.07	$ 1,176,553.73	$ 129,515.66	12.37%
2,400,000	10,957	$ 188,381.91	$ 220,701.06	$ 32,319.15	17.16%	10,957	$ 1,286,164.37	$ 1,445,977.12	$ 159,812.75	12.43%
2,866,666	10,957	$ 213,908.58	$ 251,734.39	$ 37,825.81	17.68%	10,957	$ 1,525,290.66	$ 1,715,400.50	$ 190,109.84	12.46%
3,333,333	10,957	$ 239,435.24	$ 282,767.72	$ 43,332.48	18.10%	10,957	$ 1,764,416.95	$ 1,984,823.88	$ 220,406.93	12.49%
3,800,000	10,957	$ 264,961.90	$ 313,801.04	$ 48,839.14	18.43%	10,957	$ 2,003,543.25	$ 2,254,247.26	$ 250,704.01	12.51%
4,266,666	10,957	$ 290,488.57	$ 344,834.37	$ 54,345.80	18.71%	10,957	$ 2,242,669.54	$ 2,523,670.64	$ 281,001.10	12.53%
4,733,333	10,957	$ 316,015.23	$ 375,867.70	$ 59,852.47	18.94%	10,957	$ 2,481,795.84	$ 2,793,094.02	$ 311,298.18	12.54%
5,199,999	10,957	$ 341,541.89	$ 406,901.03	$ 65,359.14	19.14%	10,957	$ 2,720,922.13	$ 3,062,517.40	$ 341,595.27	12.55%
5,666,666	10,957	$ 367,068.56	$ 437,934.36	$ 70,865.80	19.31%	10,957	$ 2,960,048.42	$ 3,331,940.79	$ 371,892.37	12.56%
6,000,000	10,957	$ 385,301.93	$ 460,101.07	$ 74,799.14	19.41%	10,957	$ 3,130,853.29	$ 3,524,386.47	$ 393,533.18	12.57%
6,466,667	10,957	$ 410,828.59	$ 491,134.40	$ 80,305.81	19.55%	10,957	$ 3,369,979.58	$ 3,793,809.85	$ 423,830.27	12.58%
6,933,333	10,957	$ 436,355.25	$ 522,167.73	$ 85,812.48	19.67%	10,957	$ 3,609,105.87	$ 4,063,233.23	$ 454,127.36	12.58%
7,400,000	10,957	$ 461,881.91	$ 553,201.06	$ 91,319.15	19.77%	10,957	$ 3,848,232.17	$ 4,332,656.62	$ 484,424.45	12.59%
7,866,666	10,957	$ 487,408.58	$ 584,234.39	$ 96,825.81	19.87%	10,957	$ 4,087,358.46	$ 4,602,080.00	$ 514,721.54	12.59%

Winter Qty %	57.08%	57.08%	Winter Qty %	50.00%	50.00%
Summer QTY %	42.92%	42.92%	Summer QTY %	48.07%	48.07%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ 0.1014	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4812	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7 & Tf-7

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.	$	13,748.33	$	13,748.33	$	-		$/Mo. Fixed or equiv.	$	13,687.50	$	13,687.50	$	-	
	$/Day Fixed or equiv.	$	452.00	$	452.00	$	-		$/Day Fixed or equiv.	$	450.00	$	450.00	$	-	
	Demand Charge	$	0.0030	$	0.0040	$	0.0010		Demand Charge	$	0.0030	$	0.0040	$	0.0010	
	$/Therm-Winter	$	0.0383	$	0.0494	$	0.0111		$/Therm-Winter	$	0.5558	$	0.6213	$	0.0655	
	$/Therm-Summer	$	0.0383	$	0.0494	$	0.0111		$/Therm-Summer	$	0.4544	$	0.5199	$	0.0655	

Usage in Therms	# of Customers & Class Average Use		Old Annual Bill		New Annual Bill		Increase (Decrease)	Percent of Change	Class Maximum Demand		Old Annual Bill		New Annual Bill		Increase (Decrease)	Percent of Change
8,000,000	37,919	$	512,901.31	$	615,541.74	$	102,640.43	20.01%	37,919	$	4,275,774.51	$	4,813,614.94	$	537,840.43	12.58%
8,466,667	37,919	$	530,774.64	$	638,595.07	$	107,820.43	20.31%	37,919	$	4,513,191.32	$	5,081,598.42	$	568,407.10	12.59%
8,933,333	37,919	$	548,647.97	$	661,648.40	$	113,000.43	20.60%	37,919	$	4,750,608.14	$	5,349,581.90	$	598,973.76	12.61%
9,400,000	37,919	$	566,521.30	$	684,701.73	$	118,180.43	20.86%	37,919	$	4,988,024.96	$	5,617,565.39	$	629,540.43	12.62%
9,866,666	37,919	$	584,394.63	$	707,755.06	$	123,360.43	21.11%	37,919	$	5,225,441.78	$	5,885,548.87	$	660,107.09	12.63%
10,333,333	37,919	$	602,267.96	$	730,808.39	$	128,540.43	21.34%	37,919	$	5,462,858.60	$	6,153,532.35	$	690,673.75	12.64%
10,800,000	37,919	$	620,141.29	$	753,861.72	$	133,720.43	21.56%	37,919	$	5,700,275.42	$	6,421,515.83	$	721,240.41	12.65%
11,266,666	37,919	$	638,014.62	$	776,915.05	$	138,900.43	21.77%	37,919	$	5,937,692.24	$	6,689,499.31	$	751,807.07	12.66%
11,733,333	37,919	$	655,887.95	$	799,968.38	$	144,080.43	21.97%	37,919	$	6,175,109.06	$	6,957,482.79	$	782,373.73	12.67%
12,199,999	37,919	$	673,761.28	$	823,021.71	$	149,260.43	22.15%	37,919	$	6,412,525.88	$	7,225,466.28	$	812,940.40	12.68%
12,666,666	37,919	$	691,634.61	$	846,075.04	$	154,440.43	22.33%	37,919	$	6,649,942.70	$	7,493,449.76	$	843,507.06	12.68%
13,133,333	37,919	$	709,507.94	$	869,128.37	$	159,620.43	22.50%	37,919	$	6,887,359.52	$	7,761,433.24	$	874,073.72	12.69%
13,599,999	37,919	$	727,381.27	$	892,181.70	$	164,800.43	22.66%	37,919	$	7,124,776.34	$	8,029,416.72	$	904,640.38	12.70%
14,066,666	37,919	$	745,254.61	$	915,235.03	$	169,980.42	22.81%	37,919	$	7,362,193.16	$	8,297,400.20	$	935,207.04	12.70%
14,533,332	37,919	$	763,127.94	$	938,288.36	$	175,160.42	22.95%	37,919	$	7,599,609.98	$	8,565,383.68	$	965,773.70	12.71%
14,999,999	37,919	$	781,001.27	$	961,341.69	$	180,340.42	23.09%	37,919	$	7,837,026.80	$	8,833,367.17	$	996,340.37	12.71%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	53.60%	53.60%	Winter Qty %	53.60%	53.60%
Summer QTY %	46.40%	46.40%	Summer QTY %	46.40%	46.40%

Gas Cost Rates:			Firm		Interruptible
Base Average Commodity Cost:		$	0.3717	$	0.3717
Base Average Peak Demand Cost:		$	0.1014	$	-
Base Average Annual Demand Cost:		$	0.0081	$	0.0081
Base Average Balancing Cost:		$	-	$	-
Base Average Surcharge Cost:		$	-	$	-
	Totals:	$	0.4812	$	0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 15,000,000 & Over Fg-8 & Tf-8

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.	$ 43,556.67	$ 43,556.67	$ -		$/Mo. Fixed or (	$ 43,495.83	$ 43,495.83	$ -	
	$/Day Fixed or equiv.	$ 1,432.00	$ 1,432.00	$ -		$/Day Fixed or (	$ 1,430.00	$ 1,430.00	$ -	
	Demand Charge	$ 0.0021	$ 0.0032	$ 0.0011		Demand Charg	$ 0.0021	$ 0.0032	$ 0.0011	
	$/Therm-Winter	$ 0.0160	$ 0.0264	$ 0.0104		$/Therm-Winter	$ 0.4321	$ 0.4969	$ 0.0648	
	$/Therm-Summer	$ 0.0160	$ 0.0264	$ 0.0104		$/Therm-Summ	$ 0.4321	$ 0.4969	$ 0.0648	

Usage in Therms	Class Maximum Demand	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Class laximum Demar	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
15,000,000	37,919	$ 791,744.91	$ 962,969.39	$ 171,224.48	21.63%	37,919	$ 6,907,421.96	$ 7,875,886.84	$ 968,464.88	14.02%
15,466,667	37,919	$ 799,211.58	$ 975,289.39	$ 176,077.81	22.03%	37,919	$ 7,105,176.82	$ 8,103,298.06	$ 998,121.24	14.05%
15,933,333	37,919	$ 806,678.24	$ 987,609.39	$ 180,931.15	22.43%	37,919	$ 7,302,931.68	$ 8,330,709.29	$ 1,027,777.61	14.07%
16,400,000	37,919	$ 814,144.91	$ 999,929.39	$ 185,784.48	22.82%	37,919	$ 7,500,686.54	$ 8,558,120.51	$ 1,057,433.97	14.10%
16,866,666	37,919	$ 821,611.58	$ 1,012,249.38	$ 190,637.80	23.20%	37,919	$ 7,698,441.39	$ 8,785,531.73	$ 1,087,090.34	14.12%
17,333,333	37,919	$ 829,078.24	$ 1,024,569.38	$ 195,491.14	23.58%	37,919	$ 7,896,196.25	$ 9,012,942.95	$ 1,116,746.70	14.14%
17,800,000	37,919	$ 836,544.91	$ 1,036,889.38	$ 200,344.47	23.95%	37,919	$ 8,093,951.11	$ 9,240,354.17	$ 1,146,403.06	14.16%
18,266,666	37,919	$ 844,011.57	$ 1,049,209.38	$ 205,197.81	24.31%	37,919	$ 8,291,705.97	$ 9,467,765.39	$ 1,176,059.42	14.18%
18,733,333	37,919	$ 851,478.24	$ 1,061,529.38	$ 210,051.14	24.67%	37,919	$ 8,489,460.83	$ 9,695,176.61	$ 1,205,715.78	14.20%
19,199,999	37,919	$ 858,944.90	$ 1,073,849.38	$ 214,904.48	25.02%	37,919	$ 8,687,215.68	$ 9,922,587.84	$ 1,235,372.16	14.22%
19,666,666	37,919	$ 866,411.57	$ 1,086,169.37	$ 219,757.80	25.36%	37,919	$ 8,884,970.54	$ 10,149,999.06	$ 1,265,028.52	14.24%
20,133,333	37,919	$ 873,878.24	$ 1,098,489.37	$ 224,611.13	25.70%	37,919	$ 9,082,725.40	$ 10,377,410.28	$ 1,294,684.88	14.25%
20,599,999	37,919	$ 881,344.90	$ 1,110,809.37	$ 229,464.47	26.04%	37,919	$ 9,280,480.26	$ 10,604,821.50	$ 1,324,341.24	14.27%
21,066,666	37,919	$ 888,811.57	$ 1,123,129.37	$ 234,317.80	26.36%	37,919	$ 9,478,235.11	$ 10,832,232.72	$ 1,353,997.61	14.29%
21,533,332	37,919	$ 896,278.23	$ 1,135,449.37	$ 239,171.14	26.68%	37,919	$ 9,675,989.97	$ 11,059,643.94	$ 1,383,653.97	14.30%
21,999,999	37,919	$ 903,744.90	$ 1,147,769.37	$ 244,024.47	27.00%	37,919	$ 9,873,744.83	$ 11,287,055.16	$ 1,413,310.33	14.31%

	Old	New		Old	New
Winter Qty %	57.08%	57.08%	Winter Qty %	50.00%	50.00%
Summer QTY %	42.92%	42.92%	Summer QTY °	48.07%	48.07%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt. Comm. Ind. 100000 to 499999 Ig-4

Usage in Therms		Transportation Service: Old Annual Rate	Transportation Service: New Annual Rate	Transportation Service: Increase (Decrease)	Transportation Service: Percent of Change		Sales Service: Old Annual Rate	Sales Service: New Annual Rate	Sales Service: Increase (Decrease)	Sales Service: Percent of Change
	$/Mo. Fixed or equiv.	N/A	N/A	N/A		$/Mo. Fixed or equiv.	$ 334.58	$ 334.58	$ -	
	$/Day Fixed or equiv.	N/A	N/A	N/A		$/Day Fixed or equiv.	$ 11.00	$ 11.00	$ -	
	$/Therm-Winter	N/A	N/A	N/A		$/Therm-Winter	$ 0.5111	$ 0.5308	$ 0.0197	
	$/Therm-Summer	N/A	N/A	N/A		$/Therm-Summer	$ 0.5111	$ 0.5308	$ 0.0197	

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
100,000		N/A	N/A	N/A	N/A		$ 55,125.00	$ 57,095.00	$ 1,970.00	3.57%
123,529		N/A	N/A	N/A	N/A		$ 67,150.85	$ 69,584.38	$ 2,433.53	3.62%
147,059		N/A	N/A	N/A	N/A		$ 79,176.70	$ 82,073.76	$ 2,897.06	3.66%
170,588		N/A	N/A	N/A	N/A		$ 91,202.56	$ 94,563.14	$ 3,360.58	3.68%
194,117		N/A	N/A	N/A	N/A		$ 103,228.41	$ 107,052.52	$ 3,824.11	3.70%
217,647		N/A	N/A	N/A	N/A		$ 115,254.26	$ 119,541.90	$ 4,287.64	3.72%
241,176		N/A	N/A	N/A	N/A		$ 127,280.11	$ 132,031.28	$ 4,751.17	3.73%
264,705		N/A	N/A	N/A	N/A		$ 139,305.97	$ 144,520.66	$ 5,214.69	3.74%
288,235		N/A	N/A	N/A	N/A		$ 151,331.82	$ 157,010.04	$ 5,678.22	3.75%
311,764		N/A	N/A	N/A	N/A		$ 163,357.67	$ 169,499.42	$ 6,141.75	3.76%
335,294		N/A	N/A	N/A	N/A		$ 175,383.52	$ 181,988.81	$ 6,605.29	3.77%
358,823		N/A	N/A	N/A	N/A		$ 187,409.38	$ 194,478.19	$ 7,068.81	3.77%
382,352		N/A	N/A	N/A	N/A		$ 199,435.23	$ 206,967.57	$ 7,532.34	3.78%
405,882		N/A	N/A	N/A	N/A		$ 211,461.08	$ 219,456.95	$ 7,995.87	3.78%
429,411		N/A	N/A	N/A	N/A		$ 223,486.93	$ 231,946.33	$ 8,459.40	3.79%
452,940		N/A	N/A	N/A	N/A		$ 235,512.78	$ 244,435.71	$ 8,922.93	3.79%
476,470		N/A	N/A	N/A	N/A		$ 247,538.64	$ 256,925.09	$ 9,386.45	3.79%
	Winter Qty %	N/A	N/A			Winter Qty %	62.07%	62.07%		
	Summer QTY %	N/A	N/A			Summer QTY %	37.93%	37.93%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

0

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt Comm. Ind. 500000 to 999999 Ig-5

	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.	N/A	N/A	N/A		$/Mo. Fixed or equiv.	$ 1,064.58	$ 1,064.58	$ -	
	$/Day Fixed or equiv.	N/A	N/A	N/A		$/Day Fixed or equiv.	$ 35.00	$ 35.00	$ -	
	$/Therm-Winter	N/A	N/A	N/A		$/Therm-Winter	$ 0.5030	$ 0.5075	$ 0.0045	
	$/Therm-Summer	N/A	N/A	N/A		$/Therm-Summer	$ 0.5030	$ 0.5075	$ 0.0045	

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
500,000		N/A	N/A	N/A	N/A		$ 264,275.00	$ 266,525.00	$ 2,250.00	0.85%
529,412		N/A	N/A	N/A	N/A		$ 279,069.09	$ 281,451.44	$ 2,382.35	0.85%
558,823		N/A	N/A	N/A	N/A		$ 293,863.18	$ 296,377.88	$ 2,514.70	0.86%
588,235		N/A	N/A	N/A	N/A		$ 308,657.26	$ 311,304.32	$ 2,647.06	0.86%
617,647		N/A	N/A	N/A	N/A		$ 323,451.35	$ 326,230.76	$ 2,779.41	0.86%
647,059		N/A	N/A	N/A	N/A		$ 338,245.44	$ 341,157.20	$ 2,911.76	0.86%
676,470		N/A	N/A	N/A	N/A		$ 353,039.53	$ 356,083.64	$ 3,044.11	0.86%
705,882		N/A	N/A	N/A	N/A		$ 367,833.62	$ 371,010.09	$ 3,176.47	0.86%
735,294		N/A	N/A	N/A	N/A		$ 382,627.70	$ 385,936.53	$ 3,308.83	0.86%
764,705		N/A	N/A	N/A	N/A		$ 397,421.79	$ 400,862.97	$ 3,441.18	0.87%
794,117		N/A	N/A	N/A	N/A		$ 412,215.88	$ 415,789.41	$ 3,573.53	0.87%
823,529		N/A	N/A	N/A	N/A		$ 427,009.97	$ 430,715.85	$ 3,705.88	0.87%
852,940		N/A	N/A	N/A	N/A		$ 441,804.06	$ 445,642.29	$ 3,838.23	0.87%
882,352		N/A	N/A	N/A	N/A		$ 456,598.14	$ 460,568.73	$ 3,970.59	0.87%
911,764		N/A	N/A	N/A	N/A		$ 471,392.23	$ 475,495.17	$ 4,102.94	0.87%
941,176		N/A	N/A	N/A	N/A		$ 486,186.32	$ 490,421.61	$ 4,235.29	0.87%
970,587		N/A	N/A	N/A	N/A		$ 500,980.41	$ 505,348.05	$ 4,367.64	0.87%
	Winter Qty %	N/A	N/A			Winter Qty %	62.07%	62.07%		
	Summer QTY %	N/A	N/A			Summer QTY %	37.93%	37.93%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

0

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Power Generation

Pg-2 and Pt-2

	Transportation Service: Old Annual Bill	Transportation Service: New Annual Bill	Transportation Service: Increase (Decrease)	Transportation Service: Percent of Change		Sales Service: Old Annual Bill	Sales Service: New Annual Bill	Sales Service: Increase (Decrease)	Sales Service: Percent of Change
$/Mo. Fixed or equiv.	$ 27,375.00	$ 27,496.67	$ 121.67		$/Mo. Fixed or equ	$ 27,314.17	$ 27,435.83	$ 121.66	
$/Day Fixed or equiv.	$ 900.00	$ 904.00	$ 4.00		$/Day Fixed or equ	$ 898.00	$ 902.00	$ 4.00	
Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0107	$ 0.0101	$ (0.0006)		$/Therm-Winter	$ 0.4186	$ 0.4294	$ 0.0108	
$/Therm-Summer	$ 0.0107	$ 0.0101	$ (0.0006)		$/Therm-Summer	$ 0.4186	$ 0.4294	$ 0.0108	

Usage in Therms	Transportation: Old Annual Bill	Transportation: New Annual Bill	Transportation: Increase (Decrease)	Transportation: Percent of Change	Sales: Old Annual Bill	Sales: New Annual Bill	Sales: Increase (Decrease)	Sales: Percent of Change
90,000	$ 328,500.00	$ 329,960.00	$ 1,460.00	0.44%	$ 327,770.04	$ 329,230.04	$ 1,460.00	0.45%
177,600	$ 328,500.00	$ 329,960.00	$ 1,460.00	0.44%	$ 327,770.07	$ 329,230.08	$ 1,460.01	0.45%
265,200	$ 328,500.00	$ 329,960.00	$ 1,460.00	0.44%	$ 327,770.11	$ 329,230.11	$ 1,460.00	0.45%
352,800	$ 328,500.00	$ 329,960.00	$ 1,460.00	0.44%	$ 327,770.15	$ 329,230.15	$ 1,460.00	0.45%
440,400	$ 328,500.00	$ 329,960.00	$ 1,460.00	0.44%	$ 327,770.18	$ 329,230.19	$ 1,460.01	0.45%
528,000	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.22	$ 329,230.23	$ 1,460.01	0.45%
615,600	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.26	$ 329,230.26	$ 1,460.00	0.45%
703,200	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.29	$ 329,230.30	$ 1,460.01	0.45%
790,800	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.33	$ 329,230.34	$ 1,460.01	0.45%
878,400	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.37	$ 329,230.38	$ 1,460.01	0.45%
966,000	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.40	$ 329,230.41	$ 1,460.01	0.45%
1,053,600	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.44	$ 329,230.45	$ 1,460.01	0.45%
1,141,200	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.48	$ 329,230.49	$ 1,460.01	0.45%
1,228,800	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.51	$ 329,230.53	$ 1,460.02	0.45%
1,316,400	$ 328,500.01	$ 329,960.01	$ 1,460.00	0.44%	$ 327,770.55	$ 329,230.57	$ 1,460.02	0.45%
1,404,000	$ 328,500.02	$ 329,960.01	$ 1,459.99	0.44%	$ 327,770.59	$ 329,230.60	$ 1,460.01	0.45%
1,491,600	$ 328,500.02	$ 329,960.02	$ 1,460.00	0.44%	$ 327,770.62	$ 329,230.64	$ 1,460.02	0.45%

	Transportation: Old	Transportation: New		Sales: Old	Sales: New
Winter Qty %	0.00%	0.00%	Winter Qty %	0.00%	0.00%
Summer QTY %	0.00%	0.00%	Summer QTY %	0.00%	0.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Power Generation

Pg-6 and Pt-6

Transportation Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 54,567.50	$ 54,658.75	$ 91.25	
$/Day Fixed or equ	$ 1,794.00	$ 1,797.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0285	$ 0.0281	$ (0.0004)	
$/Therm-Summer	$ 0.0285	$ 0.0281	$ (0.0004)	

Sales Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equ	$ 54,506.67	$ 54,597.92	$ 91.25	
$/Day Fixed or equ	$ 1,792.00	$ 1,795.00	$ 3.00	
Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.4364	$ 0.4474	$ 0.0110	
$/Therm-Summer	$ 0.4364	$ 0.4474	$ 0.0110	

Usage in Therms	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
100,000	$ 654,810.00	$ 655,905.00	$ 1,095.00	0.17%	$ 654,080.04	$ 655,175.04	$ 1,095.00	0.17%
200,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.09	$ 655,175.09	$ 1,095.00	0.17%
300,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.13	$ 655,175.13	$ 1,095.00	0.17%
400,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.17	$ 655,175.18	$ 1,095.01	0.17%
500,000	$ 654,810.01	$ 655,905.01	$ 1,095.00	0.17%	$ 654,080.22	$ 655,175.22	$ 1,095.00	0.17%
600,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.26	$ 655,175.27	$ 1,095.01	0.17%
700,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.31	$ 655,175.31	$ 1,095.00	0.17%
800,000	$ 654,810.02	$ 655,905.02	$ 1,095.00	0.17%	$ 654,080.35	$ 655,175.36	$ 1,095.01	0.17%
900,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.39	$ 655,175.40	$ 1,095.01	0.17%
1,000,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.44	$ 655,175.45	$ 1,095.01	0.17%
1,100,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.48	$ 655,175.49	$ 1,095.01	0.17%
1,200,000	$ 654,810.03	$ 655,905.03	$ 1,095.00	0.17%	$ 654,080.52	$ 655,175.54	$ 1,095.02	0.17%
1,300,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.57	$ 655,175.58	$ 1,095.01	0.17%
1,400,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.61	$ 655,175.63	$ 1,095.02	0.17%
1,500,000	$ 654,810.04	$ 655,905.04	$ 1,095.00	0.17%	$ 654,080.65	$ 655,175.67	$ 1,095.02	0.17%
1,600,000	$ 654,810.05	$ 655,905.04	$ 1,094.99	0.17%	$ 654,080.70	$ 655,175.72	$ 1,095.02	0.17%
1,700,000	$ 654,810.05	$ 655,905.05	$ 1,095.00	0.17%	$ 654,080.74	$ 655,175.76	$ 1,095.02	0.17%

	Transportation Old	Transportation New	Sales Old	Sales New
Winter Qty %	0.00%	0.00%	0.00%	0.00%
Summer QTY %	0.00%	0.00%	0.00%	0.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Power Generation

Pg-8 and Pt-8

	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 equ	$ 20,713.75	$ 20,865.83	$ 152.08		$/Mo. Fixed or equ	$ 20,652.92	$ 20,805.00	$ 152.08	
$/Day Fixed or equ	$ 681.00	$ 686.00	$ 5.00		$/Day Fixed or equ	$ 679.00	$ 684.00	$ 5.00	
Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
$/Therm-Winter	$ 0.0276	$ 0.0271	$ (0.0005)		$/Therm-Winter	$ 0.4355	$ 0.4464	$ 0.0109	
$/Therm-Summer	$ 0.0276	$ 0.0271	$ (0.0005)		$/Therm-Summer	$ 0.4355	$ 0.4464	$ 0.0109	

Usage in Therms	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
100,000	$ 251,325.00	$ 253,100.00	$ 1,775.00	0.71%	$ 291,385.04	$ 294,300.04	$ 2,915.00	1.00%
512,000	$ 262,696.21	$ 264,265.21	$ 1,569.00	0.60%	$ 470,811.22	$ 478,217.03	$ 7,405.81	1.57%
924,000	$ 274,067.43	$ 275,430.43	$ 1,363.00	0.50%	$ 650,237.40	$ 662,134.01	$ 11,896.61	1.83%
1,336,000	$ 285,438.64	$ 286,595.64	$ 1,157.00	0.41%	$ 829,663.58	$ 846,051.00	$ 16,387.42	1.98%
1,748,000	$ 296,809.85	$ 297,760.85	$ 951.00	0.32%	$ 1,009,089.76	$ 1,029,967.98	$ 20,878.22	2.07%
2,160,000	$ 308,181.06	$ 308,926.06	$ 745.00	0.24%	$ 1,188,515.94	$ 1,213,884.96	$ 25,369.02	2.13%
2,572,000	$ 319,552.27	$ 320,091.27	$ 539.00	0.17%	$ 1,367,942.12	$ 1,397,801.95	$ 29,859.83	2.18%
2,984,000	$ 330,923.48	$ 331,256.48	$ 333.00	0.10%	$ 1,547,368.30	$ 1,581,718.93	$ 34,350.63	2.22%
3,396,000	$ 342,294.69	$ 342,421.69	$ 127.00	0.04%	$ 1,726,794.48	$ 1,765,635.92	$ 38,841.44	2.25%
3,808,000	$ 353,665.91	$ 353,586.90	$ (79.01)	-0.02%	$ 1,906,220.66	$ 1,949,552.90	$ 43,332.24	2.27%
4,220,000	$ 365,037.12	$ 364,752.11	$ (285.01)	-0.08%	$ 2,085,646.84	$ 2,133,469.88	$ 47,823.04	2.29%
4,632,000	$ 376,408.33	$ 375,917.33	$ (491.00)	-0.13%	$ 2,265,073.02	$ 2,317,386.87	$ 52,313.85	2.31%
5,044,000	$ 387,779.54	$ 387,082.54	$ (697.00)	-0.18%	$ 2,444,499.20	$ 2,501,303.85	$ 56,804.65	2.32%
5,456,000	$ 399,150.75	$ 398,247.75	$ (903.00)	-0.23%	$ 2,623,925.38	$ 2,685,220.84	$ 61,295.46	2.34%
5,868,000	$ 410,521.96	$ 409,412.96	$ (1,109.00)	-0.27%	$ 2,803,351.56	$ 2,869,137.82	$ 65,786.26	2.35%
6,280,000	$ 421,893.17	$ 420,578.17	$ (1,315.00)	-0.31%	$ 2,982,777.73	$ 3,053,054.80	$ 70,277.07	2.36%
6,692,000	$ 433,264.38	$ 431,743.38	$ (1,521.00)	-0.35%	$ 3,162,203.91	$ 3,236,971.79	$ 74,767.88	2.36%

Winter Qty %	32.22%	32.22%	Winter Qty %	32.22%	32.22%
Summer QTY %	67.78%	67.78%	Summer QTY %	67.78%	67.78%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Power Generation

Pg-9 and Pt-9

	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 equ	$ 7,701.50	$ 7,701.50	$ -		$ 7,640.67	$ 7,640.67	$ -	
$/Day Fixed or equ	$ 253.20	$ 253.20	$ -		$ 251.20	$ 251.20	$ -	
Demand Charge	$ 0.0150	$ 0.0150	$ -		$ 0.0150	$ 0.0150	$ -	
$/Therm-Winter	$ 0.0023	$ 0.0015	$ (0.0008)		$ 0.4102	$ 0.4220	$ 0.0118	
$/Therm-Summer	$ 0.0023	$ 0.0015	$ (0.0008)		$ 0.4102	$ 0.4220	$ 0.0118	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
100,000	-	$ 92,648.00	$ 92,568.00	$ (80.00)	-0.09%	$ 132,708.00	$ 133,888.00	$ 1,180.00	0.89%
512,000	-	$ 93,595.60	$ 93,186.00	$ (409.60)	-0.44%	$ 301,710.40	$ 307,752.00	$ 6,041.60	2.00%
924,000	-	$ 94,543.20	$ 93,804.00	$ (739.20)	-0.78%	$ 470,712.80	$ 481,616.00	$ 10,903.20	2.32%
1,336,000	-	$ 95,490.80	$ 94,422.00	$ (1,068.80)	-1.12%	$ 639,715.20	$ 655,480.00	$ 15,764.80	2.46%
1,748,000	-	$ 96,438.40	$ 95,040.00	$ (1,398.40)	-1.45%	$ 808,717.60	$ 829,344.00	$ 20,626.40	2.55%
2,160,000	-	$ 97,386.00	$ 95,658.00	$ (1,728.00)	-1.77%	$ 977,720.00	$ 1,003,208.00	$ 25,488.00	2.61%
2,572,000	-	$ 98,333.60	$ 96,276.00	$ (2,057.60)	-2.09%	$ 1,146,722.40	$ 1,177,072.00	$ 30,349.60	2.65%
2,984,000	-	$ 99,281.20	$ 96,894.00	$ (2,387.20)	-2.40%	$ 1,315,724.80	$ 1,350,936.00	$ 35,211.20	2.68%
3,396,000	-	$ 100,228.80	$ 97,512.00	$ (2,716.80)	-2.71%	$ 1,484,727.20	$ 1,524,800.00	$ 40,072.80	2.70%
3,808,000	-	$ 101,176.40	$ 98,130.00	$ (3,046.40)	-3.01%	$ 1,653,729.60	$ 1,698,664.00	$ 44,934.40	2.72%
4,220,000	-	$ 102,124.00	$ 98,748.00	$ (3,376.00)	-3.31%	$ 1,822,732.00	$ 1,872,528.00	$ 49,796.00	2.73%
4,632,000	-	$ 103,071.60	$ 99,366.00	$ (3,705.60)	-3.60%	$ 1,991,734.40	$ 2,046,392.00	$ 54,657.60	2.74%
5,044,000	-	$ 104,019.20	$ 99,984.00	$ (4,035.20)	-3.88%	$ 2,160,736.80	$ 2,220,256.00	$ 59,519.20	2.75%
5,456,000	-	$ 104,966.80	$ 100,602.00	$ (4,364.80)	-4.16%	$ 2,329,739.20	$ 2,394,120.00	$ 64,380.80	2.76%
5,868,000	-	$ 105,914.40	$ 101,220.00	$ (4,694.40)	-4.43%	$ 2,498,741.60	$ 2,567,984.00	$ 69,242.40	2.77%
6,280,000	-	$ 106,862.00	$ 101,838.00	$ (5,024.00)	-4.70%	$ 2,667,744.00	$ 2,741,848.00	$ 74,104.00	2.78%
6,692,000	-	$ 107,809.60	$ 102,456.00	$ (5,353.60)	-4.97%	$ 2,836,746.40	$ 2,915,712.00	$ 78,965.60	2.78%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	63.16%	63.16%	Winter Qty %	63.16%	63.16%
Summer QTY %	36.84%	36.84%	Summer QTY %	36.84%	36.84%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Electric Power Company
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Power Generation

Pg-11 and Pt-11

	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 equ	$ 12,834.92	$ 12,987.92	$ 153.00		$/Mo. Fixed or equ	$ 12,774.09	$ 12,927.08	$ 152.99	
$/Day Fixed or equ	$ 421.97	$ 427.00	$ 5.03		$/Day Fixed or equ	$ 419.97	$ 425.00	$ 5.03	
Demand Charge	$ -	$ -	$ -		Demand Charge	$ -	$ -	$ -	
$/Therm-Winter	$ 0.0011	$ 0.0015	$ 0.0004		$/Therm-Winter	$ 0.4090	$ 0.4208	$ 0.0118	
$/Therm-Summer	$ 0.0011	$ 0.0015	$ 0.0004		$/Therm-Summer	$ 0.4090	$ 0.4208	$ 0.0118	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
100,000	-	$ 154,129.05	$ 156,005.00	$ 1,875.95	1.22%	$ 194,189.05	$ 197,205.00	$ 3,015.95	1.55%
512,000	-	$ 154,582.25	$ 156,623.00	$ 2,040.75	1.32%	$ 362,697.05	$ 370,574.60	$ 7,877.55	2.17%
924,000	-	$ 155,035.45	$ 157,241.00	$ 2,205.55	1.42%	$ 531,205.05	$ 543,944.20	$ 12,739.15	2.40%
1,336,000	-	$ 155,488.65	$ 157,859.00	$ 2,370.35	1.52%	$ 699,713.05	$ 717,313.80	$ 17,600.75	2.52%
1,748,000	-	$ 155,941.85	$ 158,477.00	$ 2,535.15	1.63%	$ 868,221.05	$ 890,683.40	$ 22,462.35	2.59%
2,160,000	-	$ 156,395.05	$ 159,095.00	$ 2,699.95	1.73%	$ 1,036,729.05	$ 1,064,053.00	$ 27,323.95	2.64%
2,572,000	-	$ 156,848.25	$ 159,713.00	$ 2,864.75	1.83%	$ 1,205,237.05	$ 1,237,422.60	$ 32,185.55	2.67%
2,984,000	-	$ 157,301.45	$ 160,331.00	$ 3,029.55	1.93%	$ 1,373,745.05	$ 1,410,792.20	$ 37,047.15	2.70%
3,396,000	-	$ 157,754.65	$ 160,949.00	$ 3,194.35	2.02%	$ 1,542,253.05	$ 1,584,161.80	$ 41,908.75	2.72%
3,808,000	-	$ 158,207.85	$ 161,567.00	$ 3,359.15	2.12%	$ 1,710,761.05	$ 1,757,531.40	$ 46,770.35	2.73%
4,220,000	-	$ 158,661.05	$ 162,185.00	$ 3,523.95	2.22%	$ 1,879,269.05	$ 1,930,901.00	$ 51,631.95	2.75%
4,632,000	-	$ 159,114.25	$ 162,803.00	$ 3,688.75	2.32%	$ 2,047,777.05	$ 2,104,270.60	$ 56,493.55	2.76%
5,044,000	-	$ 159,567.45	$ 163,421.00	$ 3,853.55	2.41%	$ 2,216,285.05	$ 2,277,640.20	$ 61,355.15	2.77%
5,456,000	-	$ 160,020.65	$ 164,039.00	$ 4,018.35	2.51%	$ 2,384,793.05	$ 2,451,009.80	$ 66,216.75	2.78%
5,868,000	-	$ 160,473.85	$ 164,657.00	$ 4,183.15	2.61%	$ 2,553,301.05	$ 2,624,379.40	$ 71,078.35	2.78%
6,280,000	-	$ 160,927.05	$ 165,275.00	$ 4,347.95	2.70%	$ 2,721,809.05	$ 2,797,749.00	$ 75,939.95	2.79%
6,692,000	-	$ 161,380.25	$ 165,893.00	$ 4,512.75	2.80%	$ 2,890,317.05	$ 2,971,118.60	$ 80,801.55	2.80%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	63.16%	63.16%	Winter Qty %	63.16%	63.16%
Summer QTY %	36.84%	36.84%	Summer QTY %	36.84%	36.84%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3717	$ 0.3717
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0081	$ 0.0081
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3798	$ 0.3798

Transportation Administrative Charge: $ 2.00

Wisconsin Gas LLC
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 Revenue % Change
Residential Rg-1	596,394	513,502,545	$ 504,928,783	$ 235,497,140	$ 269,431,643	$ 517,355,544	$ 235,497,140	$ 281,858,404	$ 12,426,761	2.46%
Firm Comm. Ind. 0 to 3,999 Fg-1	41,854	62,241,846	$ 56,772,140	$ 29,155,800	$ 27,616,340	$ 59,635,267	$ 29,155,800	$ 30,479,467	$ 2,863,127	5.04%
Firm Comm. Ind. 4,000 to 39,999 Fg-2	14,861	168,594,649	$ 122,950,865	$ 76,815,332	$ 46,135,533	$ 134,179,268	$ 76,815,332	$ 57,363,936	$ 11,228,403	9.13%
Firm Comm. Ind. 40,000 to 99,999 Fg-3	672	42,013,448	$ 28,230,268	$ 18,892,765	$ 9,337,503	$ 30,448,576	$ 18,892,765	$ 11,555,811	$ 2,218,308	7.86%
Firm Comm. Ind. 100,000 to 499,999 Fg-4	165	29,760,005	$ 18,029,692	$ 12,811,116	$ 5,218,576	$ 19,345,081	$ 12,811,116	$ 6,533,965	$ 1,315,389	7.30%
Firm Comm. Ind. 500,000 to 999,999 Fg-5	8	6,247,169	$ 3,464,843	$ 2,570,661	$ 894,182	$ 3,746,589	$ 2,570,661	$ 1,175,928	$ 281,746	8.13%
Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6	3	3,782,999	$ 1,942,050	$ 1,484,340	$ 457,710	$ 2,108,031	$ 1,484,340	$ 623,691	$ 165,981	8.55%
Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Comm. Ind. 15,000,000 and Over Fg-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	192	1,545,338	$ 994,323	$ 557,339	$ 436,984	$ 1,041,451	$ 557,339	$ 484,112	$ 47,128	5.11%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	1,216,412	$ 720,962	$ 433,646	$ 287,316	$ 758,064	$ 433,646	$ 324,418	$ 37,102	5.11%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	1,053,469	$ 560,012	$ 369,334	$ 190,678	$ 592,142	$ 369,334	$ 222,808	$ 32,130	5.11%
Interrupt. Comm. Ind. 50000 to 99999 Ig-3	2	120,773	$ 69,098	$ 42,363	$ 26,735	$ 71,258	$ 42,363	$ 28,895	$ 2,160	3.13%
Interrupt. Comm. Ind. 100000 to 499999 Ig-4	15	2,968,875	$ 1,526,606	$ 1,020,230	$ 506,376	$ 1,554,218	$ 1,020,230	$ 533,988	$ 27,612	1.81%
Interrupt Comm. Ind. 500000 to 999999 Ig-5	1	745,399	$ 365,218	$ 259,347	$ 105,871	$ 372,820	$ 259,347	$ 113,473	$ 7,602	2.08%
Interrupt Comm. Ind. 1,000,000 to 7.999,999 Ig-6	3	4,756,858	$ 2,227,523	$ 1,621,287	$ 606,236	$ 2,273,011	$ 1,621,287	$ 651,724	$ 45,488	2.04%
Interrupt Comm. Ind. 8,000,000 to 14,999,999 Ig-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interrupt Comm. Ind. 15,000,000 and Over Ig-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NFPg-10 Power Generation Nominated Firm	-	67,150,189	$ 29,918,798	$ 27,998,302	$ 1,920,496	$ 33,021,136	$ 27,998,302	$ 5,022,834	$ 3,102,338	10.37%
Pg-10 Power Generation	1	-	$ 3,948,348	$ -	$ 3,948,348	$ 3,948,348	$ -	$ 3,948,348	$ -	0.00%
Class 800	1	4,728	$ 19,699	$ 1,520	$ 18,179	$ 19,817	$ 1,520	$ 18,297	$ 118	0.60%
NA -0	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA -1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA -2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA -3	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA -4	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 5	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 6	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 9	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 10	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 11	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 12	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 13	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NA- 14	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interdepartmental	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Total - Sales Customers - All	654,172	905,704,702	$ 776,669,228	$ 409,530,522	$ 367,138,706	$ 810,470,621	$ 409,530,522	$ 400,940,099	$ 33,801,393	4.35%

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

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 Revenue % Change
Residential Tr-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Comm. Ind. 0 to 3,999 Tf-1	17	53,482	$ 32,449	$ -	$ 32,449	$ 32,466	$ -	$ 32,466	$ 17	0.05%
Firm Comm. Ind. 4,000 to 39,999 Tf-2	492	12,954,357	$ 3,361,940	$ -	$ 3,361,940	$ 3,632,688	$ -	$ 3,632,688	$ 270,748	8.05%
Firm Comm. Ind. 40,000 to 99,999 Tf-3	485	30,079,733	$ 6,256,038	$ -	$ 6,256,038	$ 6,469,603	$ -	$ 6,469,603	$ 213,565	3.41%
Firm Comm. Ind. 100,000 to 499,999 Tf-4	428	89,094,141	$ 13,231,232	$ -	$ 13,231,232	$ 13,097,589	$ -	$ 13,097,589	$ (133,643)	-1.01%
Firm Comm. Ind. 500,000 to 999,999 Tf-5	85	62,974,351	$ 7,493,988	$ -	$ 7,493,988	$ 7,456,201	$ -	$ 7,456,201	$ (37,787)	-0.50%
Firm Comm. Ind. 1,000,000 to 7,999,999 Tf-6	87	186,244,665	$ 14,677,080	$ -	$ 14,677,080	$ 14,320,216	$ -	$ 14,320,216	$ (356,864)	-2.43%
Firm Comm. Ind. 8,000,000 to 14,999,999 Tf-7	2	20,679,265	$ 1,334,059	$ -	$ 1,334,059	$ 1,450,633	$ -	$ 1,450,633	$ 116,574	8.74%
Firm Comm. Ind. 15,000,000 and Over Tf-8	4	137,350,030	$ 4,886,794	$ -	$ 4,886,794	$ 5,420,327	$ -	$ 5,420,327	$ 533,533	10.92%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to . Comm. Ind. 50000 to 99999 Tf-3	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to . Comm. Ind. 100000 to 499999 Tf	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to Comm. Ind. 500000 to 999999 Tf	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to Comm. Ind. 1,000,000 to 7,999,999	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to Comm. Ind.8,000,000 to 14,999,999 Tf	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
From Interrupt to Comm. Ind.15,000,000 and over Tf-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NFPg-10 Power Generation Nominated Firm	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Pg-10 Power Generation	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 800	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 801	-	-	$ (49)	$ -	$ (49)	$ (48)	$ -	$ (48)	$ 1	-2.04%
Transportation Class 802	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 803	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 804	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 805	3	2,311,658	$ 239,865	$ -	$ 239,865	$ 238,947	$ -	$ 238,947	$ (918)	-0.38%
Transportation Class 806	11	25,778,396	$ 1,606,514	$ -	$ 1,606,514	$ 1,583,327	$ -	$ 1,583,327	$ (23,187)	-1.44%
Transportation Class 807	1	14,687,709	$ 719,126	$ -	$ 719,126	$ 788,373	$ -	$ 788,373	$ 69,247	9.63%
Transportation Class 808	2	44,982,655	$ 1,231,276	$ -	$ 1,231,276	$ 1,320,007	$ -	$ 1,320,007	$ 88,731	7.21%
Transportation Class 902	1	456,011,614	$ 1,245,096	$ -	$ 1,245,096	$ 1,245,096	$ -	$ 1,245,096	$ -	0.00%
Interdepartmental	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Total - Transportation Customers - All	1,618	1,083,202,056	$ 56,315,408	$ -	$ 56,315,408	$ 57,055,425	$ -	$ 57,055,425	$ 740,017	1.31%

Note1: Gas Costs are priced at Final base rates under both current Gas Revenues and Final 2023 Gas Revenues.

Wisconsin Gas LLC
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 Revenue % Change
Residential	596,394	513,502,545	$ 504,928,783	$ 235,497,140	$ 269,431,643	$ 517,355,544	$ 235,497,140	$ 281,858,404	$ 12,426,761	2.46%
Firm Comm. Ind. 0 to 3,999	41,871	62,295,328	$ 56,804,589	$ 29,155,800	$ 27,648,789	$ 59,667,733	$ 29,155,800	$ 30,511,933	$ 2,863,144	5.04%
Firm Comm. Ind. 4,000 to 39,999	15,353	181,549,006	$ 126,312,805	$ 76,815,332	$ 49,497,473	$ 137,811,956	$ 76,815,332	$ 60,996,624	$ 11,499,151	9.10%
Firm Comm. Ind. 40,000 to 99,999	1,157	72,093,181	$ 34,486,306	$ 18,892,765	$ 15,593,541	$ 36,918,179	$ 18,892,765	$ 18,025,414	$ 2,431,873	7.05%
Firm Comm. Ind. 100,000 to 499,999	593	118,854,146	$ 31,260,924	$ 12,811,116	$ 18,449,808	$ 32,442,670	$ 12,811,116	$ 19,631,554	$ 1,181,746	3.78%
Firm Comm. Ind. 500,000 to 999,999	93	69,221,520	$ 10,958,831	$ 2,570,661	$ 8,388,170	$ 11,202,790	$ 2,570,661	$ 8,632,129	$ 243,959	2.23%
Firm Comm. Ind. 1,000,000 to 7,999,999	90	190,027,664	$ 16,619,130	$ 1,484,340	$ 15,134,790	$ 16,428,247	$ 1,484,340	$ 14,943,907	$ (190,883)	-1.15%
Firm Comm. Ind. 8,000,000 to 14,999,999	2	20,679,265	$ 1,334,059	$ -	$ 1,334,059	$ 1,450,633	$ -	$ 1,450,633	$ 116,574	8.74%
Firm Comm. Ind. 15,000,000 & Over	4	137,350,030	$ 4,886,794	$ -	$ 4,886,794	$ 5,420,327	$ -	$ 5,420,327	$ 533,533	10.92%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	192	1,545,338	$ 994,323	$ 557,339	$ 436,984	$ 1,041,451	$ 557,339	$ 484,112	$ 47,128	5.11%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	1,216,412	$ 720,962	$ 433,646	$ 287,316	$ 758,064	$ 433,646	$ 324,418	$ 37,102	5.11%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	1,053,469	$ 560,012	$ 369,334	$ 190,678	$ 592,142	$ 369,334	$ 222,808	$ 32,130	5.11%
Interrupt. Comm. Ind. 50000 to 99999	2	120,773	$ 69,098	$ 42,363	$ 26,735	$ 71,258	$ 42,363	$ 28,895	$ 2,160	3.13%
Interrupt. Comm. Ind. 100000 to 499999	15	2,968,875	$ 1,526,606	$ 1,020,230	$ 506,376	$ 1,554,218	$ 1,020,230	$ 533,988	$ 27,612	1.81%
Interrupt Comm. Ind. 500000 to 999999	1	745,399	$ 365,218	$ 259,347	$ 105,871	$ 372,820	$ 259,347	$ 113,473	$ 7,602	2.08%
Interrupt Comm. Ind. 1,000,000 to 7.999,999	3	4,756,858	$ 2,227,523	$ 1,621,287	$ 606,236	$ 2,273,011	$ 1,621,287	$ 651,724	$ 45,488	2.04%
Interrupt Comm. Ind.8,000,000 to 14,999,999	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interrupt Comm. Ind.15,000,000 & Over	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NFPg-10 Power Generation Nominated Firm	-	67,150,189	$ 29,918,798	$ 27,998,302	$ 1,920,496	$ 33,021,136	$ 27,998,302	$ 5,022,834	$ 3,102,338	10.37%
Pg-10 Power Generation	1	-	$ 3,948,348	$ -	$ 3,948,348	$ 3,948,348	$ -	$ 3,948,348	$ -	0.00%
Class 800	1	4,728	$ 19,699	$ 1,520	$ 18,179	$ 19,817	$ 1,520	$ 18,297	$ 118	0.60%
Class 801	-	-	$ (49)	$ -	$ (49)	$ (48)	$ -	$ (48)	$ 1	-2.04%
Class 802	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 803	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 804	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 805	3	2,311,658	$ 239,865	$ -	$ 239,865	$ 238,947	$ -	$ 238,947	$ (918)	-0.38%
Class 806	11	25,778,396	$ 1,606,514	$ -	$ 1,606,514	$ 1,583,327	$ -	$ 1,583,327	$ (23,187)	-1.44%
Class 807	1	14,687,709	$ 719,126	$ -	$ 719,126	$ 788,373	$ -	$ 788,373	$ 69,247	9.63%
Class 808	2	44,982,655	$ 1,231,276	$ -	$ 1,231,276	$ 1,320,007	$ -	$ 1,320,007	$ 88,731	7.21%
Class 902	1	456,011,614	$ 1,245,096	$ -	$ 1,245,096	$ 1,245,096	$ -	$ 1,245,096	$ -	0.00%
Total - All Customers - All	655,790	1,988,906,758	$ 832,984,636	$ 409,530,522	$ 423,454,114	$ 867,526,046	$ 409,530,522	$ 457,995,524	$ 34,541,410	4.15%

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

Residential Service

Rates - Description	2025 Final Rates			2024 Current Rates			Final Change in Rates		
	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.3360	NA	$ 0.3360	$ 0.3578	NA	$ 0.3578	$ (0.0218)	NA	$ (0.0218)
Competitive Supply Margin	$ 0.0350	NA	$ -	$ 0.0242	NA	$ -	$ 0.0108	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.4090	NA	$ 0.3370	$ 0.3848	NA	$ 0.3585	$ 0.0242	NA	$ (0.0215)
Peak Demand	$ 0.1258	NA	$ -	$ 0.1258	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3397	NA	$ -	$ 0.3397	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	NA	$ -	$ 0.4796	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8886	NA	$ 0.3370	$ 0.8644	NA	$ 0.3585	$ 0.0242	NA	$ (0.0215)
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0082	NA	$ 0.0082	$ 0.0068	NA	$ 0.0068	$ 0.0014	NA	$ 0.0014

Commercial / Industrial Class 1 0 to 3,999 Therms Annually

Rates - Description	2025 Final Rates			2024 Current Rates			Final Change in Rates		
	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.3357	NA	$ 0.3357	$ 0.3357	NA	$ 0.3357	$ -	NA	$ -
Competitive Supply Margin	$ 0.0350	NA	$ -	$ 0.0242	NA	$ -	$ 0.0108	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.4087	NA	$ 0.3367	$ 0.3627	NA	$ 0.3364	$ 0.0460	NA	$ 0.0003
Peak Demand	$ 0.1258	NA	$ -	$ 0.1258	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3397	NA	$ -	$ 0.3397	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	NA	$ -	$ 0.4796	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8883	NA	$ 0.3367	$ 0.8423	NA	$ 0.3364	$ 0.0460	NA	$ 0.0003
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0124	NA	$ 0.0124	$ 0.0102	NA	$ 0.0102	$ 0.0022	NA	$ 0.0022

NA = Not Available NA = Not Available NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

Commercial / Industrial Class 2 4,000 to 39,999 Therms Annually

Rates - Description	2025 Final Rates			2024 Current Rates			Final Change in Rates		
	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 0.85	NA	$ 0.85	$ 0.85	NA	$ 0.85	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.2399	NA	$ 0.2399	$ 0.2193	NA	$ 0.2193	$ 0.0206	NA	$ 0.0206
Competitive Supply Margin	$ 0.0350	NA	$ -	$ 0.0242	NA	$ -	$ 0.0108	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.3129	NA	$ 0.2409	$ 0.2463	NA	$ 0.2200	$ 0.0666	NA	$ 0.0209
Peak Demand	$ 0.1258	NA	$ -	$ 0.1258	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3397	NA	$ -	$ 0.3397	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	NA	$ -	$ 0.4796	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.7925	NA	$ 0.2409	$ 0.7259	NA	$ 0.2200	$ 0.0666	NA	$ 0.0209
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0124	NA	$ 0.0124	$ 0.0102	NA	$ 0.0102	$ 0.0022	NA	$ 0.0022

NA = Not Available NA = Not Available NA = Not Available

Commercial / Industrial Class 3 40,000 to 99,999 Therms Annually

Rates - Description	2025 Final Rates			2024 Current Rates			Final Change in Rates		
	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1670	$ 0.1670	$ 0.1670	$ 0.1602	$ 0.1602	$ 0.1602	$ 0.0068	$ 0.0068	$ 0.0068
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.2400	$ 0.2030	$ 0.1680	$ 0.1872	$ 0.1851	$ 0.1609	$ 0.0528	$ 0.0179	$ 0.0071
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.7196	$ 0.5568	$ 0.1680	$ 0.6668	$ 0.5389	$ 0.1609	$ 0.0528	$ 0.0179	$ 0.0071
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0022	$ 0.0022	$ 0.0022

NA = Not Available NA = Not Available NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

Commercial / Industrial Class 4 100,000 to 499,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1162	$ 0.1162	$ 0.1162	$ 0.1180	$ 0.1180	$ 0.1180	$ (0.0018)	$ (0.0018)	$ (0.0018)
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1892	$ 0.1522	$ 0.1172	$ 0.1450	$ 0.1429	$ 0.1187	$ 0.0442	$ 0.0093	$ (0.0015)
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.6688	$ 0.5060	$ 0.1172	$ 0.6246	$ 0.4967	$ 0.1187	$ 0.0442	$ 0.0093	$ (0.0015)
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0022	$ 0.0022	$ 0.0022
	NA = Not Available			NA = Not Available			NA = Not Available		

Commercial / Industrial Class 5 500,000 to 999,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0942	$ 0.0942	$ 0.0942	$ 0.0951	$ 0.0951	$ 0.0951	$ (0.0009)	$ (0.0009)	$ (0.0009)
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1672	$ 0.1302	$ 0.0952	$ 0.1221	$ 0.1200	$ 0.0958	$ 0.0451	$ 0.0102	$ (0.0006)
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.6468	$ 0.4840	$ 0.0952	$ 0.6017	$ 0.4738	$ 0.0958	$ 0.0451	$ 0.0102	$ (0.0006)
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0022	$ 0.0022	$ 0.0022
	NA = Not Available			NA = Not Available			NA = Not Available		

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

Commercial / Industrial Class 6 1,000,000 to 7,999,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0057	$ 0.0057	$ 0.0057	$ 0.0055	$ 0.0055	$ 0.0055	$ 0.0002	$ 0.0002	$ 0.0002
Distribution Margin per therm	$ 0.0450	$ 0.0450	$ 0.0450	$ 0.0476	$ 0.0476	$ 0.0476	$ (0.0026)	$ (0.0026)	$ (0.0026)
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1180	$ 0.0810	$ 0.0460	$ 0.0746	$ 0.0725	$ 0.0483	$ 0.0434	$ 0.0085	$ (0.0023)
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.5976	$ 0.4348	$ 0.0460	$ 0.5542	$ 0.4263	$ 0.0483	$ 0.0434	$ 0.0085	$ (0.0023)
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -
	NA = Not Available			NA = Not Available			NA = Not Available		

Commercial / Industrial Class 7 8,000,000 Therms to 14,999,999 Therms Annually

	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation	Firm Sales	Interruptible Sales	Transportation
Daily Facitilties Charge	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0048	$ 0.0048	$ 0.0048	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0002	$ 0.0002	$ 0.0002
Distribution Margin per therm	$ 0.0427	$ 0.0427	$ 0.0427	$ 0.0378	$ 0.0378	$ 0.0378	$ 0.0049	$ 0.0049	$ 0.0049
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1157	$ 0.0787	$ 0.0437	$ 0.0648	$ 0.0627	$ 0.0385	$ 0.0509	$ 0.0160	$ 0.0052
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.5953	$ 0.4325	$ 0.0437	$ 0.5444	$ 0.4165	$ 0.0385	$ 0.0509	$ 0.0160	$ 0.0052
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -
	NA = Not Available			NA = Not Available			NA = Not Available		

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

Commercial / Industrial Class 8 15,000,000 Therms Annually & Over

Rates - Description	2025 Final Rates: Firm Sales	2025 Final Rates: Interruptible Sales	2025 Final Rates: Transportation	2024 Current Rates: Firm Sales	2024 Current Rates: Interruptible Sales	2024 Current Rates: Transportation	Final Change in Rates: Firm Sales	Final Change in Rates: Interruptible Sales	Final Change in Rates: Transportation
Daily Facitilties Charge	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0032	$ 0.0032	$ 0.0032	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0002	$ 0.0002	$ 0.0002
Distribution Margin per therm	$ 0.0192	$ 0.0192	$ 0.0192	$ 0.0159	$ 0.0159	$ 0.0159	$ 0.0033	$ 0.0033	$ 0.0033
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0922	$ 0.0552	$ 0.0202	$ 0.0429	$ 0.0408	$ 0.0166	$ 0.0493	$ 0.0144	$ 0.0036
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.5718	$ 0.4090	$ 0.0202	$ 0.5225	$ 0.3946	$ 0.0166	$ 0.0493	$ 0.0144	$ 0.0036
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

Agricultural Seasonal Use Sales Service Ag-1

Rates - Description	2025 Final Rates: Firm Sales Step 1	2025 Final Rates: Firm Sales Step 2	2025 Final Rates: Firm Sales Step 3	2024 Current Rates: Firm Sales Step 1	2024 Current Rates: Firm Sales Step 2	2024 Current Rates: Firm Sales Step 3	Final Change in Rates: Firm Sales Step 1	Final Change in Rates: Firm Sales Step 2	Final Change in Rates: Firm Sales Step 3
Daily Facitilties Charge	$ 0.50	$ -	$ -	$ 0.50	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.2176	$ 0.1937	$ 0.1385	$ 0.2331	$ 0.2092	$ 0.1540	$ (0.0155)	$ (0.0155)	$ (0.0155)
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ 0.0350	$ 0.0242	$ 0.0242	$ 0.0242	$ 0.0108	$ 0.0108	$ 0.0108
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ 0.0370	$ 0.0370	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0349	$ 0.0349	$ 0.0349
Other Margin									
Total All Margin Rates	$ 0.2906	$ 0.2667	$ 0.2115	$ 0.2601	$ 0.2362	$ 0.1810	$ 0.0305	$ 0.0305	$ 0.0305
Peak Demand	$ 0.1258	$ 0.1258	$ 0.1258	$ 0.1258	$ 0.1258	$ 0.1258	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ 0.3397	$ 0.3397	$ 0.3397	$ 0.3397	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.4796	$ 0.4796	$ 0.4796	$ 0.4796	$ 0.4796	$ -	$ -	$ -
Total Rate	$ 0.7702	$ 0.7463	$ 0.6911	$ 0.7397	$ 0.7158	$ 0.6606	$ 0.0305	$ 0.0305	$ 0.0305
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0124	$ 0.0124	$ 0.0124	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0022	$ 0.0022	$ 0.0022

NA = Not Available (2025 Final Rates) · NA = Not Available (2024 Current Rates) · NA = Not Available (Final Change in Rates)

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2025

	Power Generation Interruptible Sales Service								
	2025 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10
Daily Facitilties Charge		$ 10,235.00	$ 10,235.00		$ 10,235.00	$ 10,235.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ 0.0024	$ 0.0024	$ -	$ 0.0024	$ 0.0024	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0018	$ 0.0018	$ 0.0018	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0002	$ 0.0002	$ 0.0002
Competitive Supply Margin	$ 0.0350	$ 0.0350	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0108	$ 0.0108	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ -	$ 0.0007	$ 0.0007	$ -	$ 0.0003	$ 0.0003	$ -
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0748	$ 0.0378	$ 0.0018	$ 0.0286	$ 0.0265	$ 0.0016	$ 0.0462	$ 0.0113	$ 0.0002
Peak Demand	$ 0.1258	$ -	$ -	$ 0.1258	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3397	$ 0.3397	$ -	$ 0.3397	$ 0.3397	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.4796	$ 0.3538	$ -	$ 0.4796	$ 0.3538	$ -	$ -	$ -	$ -
Total Rate	$ 0.5544	$ 0.3916	$ 0.0018	$ 0.5082	$ 0.3803	$ 0.0016	$ 0.0462	$ 0.0113	$ 0.0002
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA
	NA = Not Available			NA = Not Available			NA = Not Available		

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

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Residential Rg-1

	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.	$ 70.87	$ 70.87	$ -		$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -	
	$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -		$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -	
	$/Therm-Winter	$ 0.3585	$ 0.3370	$ (0.0215)		$/Therm-Winter	$ 0.8644	$ 0.8886	$ 0.0242	
	$/Therm-Summer	$ 0.3585	$ 0.3370	$ (0.0215)		$/Therm-Summer	$ 0.7386	$ 0.7628	$ 0.0242	

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
375		$ 984.89	$ 976.83	$ (8.06)	-0.82%		$ 436.23	$ 445.30	$ 9.07	2.08%
475		$ 1,020.74	$ 1,010.53	$ (10.21)	-1.00%		$ 520.43	$ 531.93	$ 11.50	2.21%
575		$ 1,056.59	$ 1,044.23	$ (12.36)	-1.17%		$ 604.64	$ 618.56	$ 13.92	2.30%
675		$ 1,092.44	$ 1,077.93	$ (14.51)	-1.33%		$ 688.85	$ 705.18	$ 16.33	2.37%
775		$ 1,128.29	$ 1,111.63	$ (16.66)	-1.48%		$ 773.05	$ 791.81	$ 18.76	2.43%
861	584997	$ 1,159.12	$ 1,140.61	$ (18.51)	-1.60%		$ 845.47	$ 866.31	$ 20.84	2.46%
975		$ 1,199.99	$ 1,179.03	$ (20.96)	-1.75%		$ 941.47	$ 965.06	$ 23.59	2.51%
1,075		$ 1,235.84	$ 1,212.73	$ (23.11)	-1.87%		$ 1,025.68	$ 1,051.69	$ 26.01	2.54%
1,175		$ 1,271.69	$ 1,246.43	$ (25.26)	-1.99%		$ 1,109.88	$ 1,138.32	$ 28.44	2.56%
1,275		$ 1,307.54	$ 1,280.13	$ (27.41)	-2.10%		$ 1,194.09	$ 1,224.94	$ 30.85	2.58%
1,375		$ 1,343.39	$ 1,313.83	$ (29.56)	-2.20%		$ 1,278.30	$ 1,311.57	$ 33.27	2.60%
1,475		$ 1,379.24	$ 1,347.53	$ (31.71)	-2.30%		$ 1,362.50	$ 1,398.20	$ 35.70	2.62%
1,575		$ 1,415.09	$ 1,381.23	$ (33.86)	-2.39%		$ 1,446.71	$ 1,484.83	$ 38.12	2.63%
1,675		$ 1,450.94	$ 1,414.93	$ (36.01)	-2.48%		$ 1,530.92	$ 1,571.45	$ 40.53	2.65%
1,775		$ 1,486.79	$ 1,448.63	$ (38.16)	-2.57%		$ 1,615.13	$ 1,658.08	$ 42.95	2.66%
1,875		$ 1,522.64	$ 1,482.33	$ (40.31)	-2.65%		$ 1,699.33	$ 1,744.71	$ 45.38	2.67%
1,975		$ 1,558.49	$ 1,516.03	$ (42.46)	-2.72%		$ 1,783.54	$ 1,831.33	$ 47.79	2.68%
2,075		$ 1,594.34	$ 1,549.73	$ (44.61)	-2.80%		$ 1,867.75	$ 1,917.96	$ 50.21	2.69%

Winter Qty %	82.25%	82.25%	Winter Qty %	82.25%	82.25%
Summer QTY %	17.75%	17.75%	Summer QTY %	17.75%	17.75%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Ag. Seasonal Use Crop Drying Step 1 0 to 2,999 Ag-1

	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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7397	$ 0.7702	$ 0.0305	
						$/Therm-Winter Step 2	$ 0.7158	$ 0.7463	$ 0.0305	
						$/Therm-Winter Step 3	$ 0.6606	$ 0.6911	$ 0.0305	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6139	$ 0.6444	$ 0.0305	
						$/Therm-Summer Step 2	$ 0.5900	$ 0.6205	$ 0.0305	
						$/Therm-Summer Step 3	$ 0.5348	$ 0.5653	$ 0.0305	

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
250		NA	NA	NA	NA		$ 338	$ 345	$ 8	2.26%
420		NA	NA	NA	NA		$ 443	$ 456	$ 13	2.89%
590		NA	NA	NA	NA		$ 548	$ 566	$ 18	3.28%
760		NA	NA	NA	NA		$ 654	$ 677	$ 23	3.55%
930		NA	NA	NA	NA		$ 759	$ 788	$ 28	3.74%
1,100		NA	NA	NA	NA		$ 865	$ 898	$ 34	3.88%
1,270		NA	NA	NA	NA		$ 970	$ 1,009	$ 39	3.99%
1,440	59	NA	NA	NA	NA		$ 1,076	$ 1,119	$ 44	4.08%
1,610		NA	NA	NA	NA		$ 1,181	$ 1,230	$ 49	4.16%
1,780		NA	NA	NA	NA		$ 1,286	$ 1,341	$ 54	4.22%
1,950		NA	NA	NA	NA		$ 1,392	$ 1,451	$ 59	4.27%
2,120		NA	NA	NA	NA		$ 1,497	$ 1,562	$ 65	4.32%
2,290		NA	NA	NA	NA		$ 1,603	$ 1,673	$ 70	4.36%
2,460		NA	NA	NA	NA		$ 1,708	$ 1,783	$ 75	4.39%
2,630		NA	NA	NA	NA		$ 1,814	$ 1,894	$ 80	4.42%
2,800		NA	NA	NA	NA		$ 1,919	$ 2,004	$ 85	4.45%
2,999		NA	NA	NA	NA		$ 2,042	$ 2,134	$ 91	4.48%
	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:	$ 0.3397	$ 0.3397	$ 0.0305
Base Average Peak Demand Cost:	$ 0.1258	$ -	$ 0.0305
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141	$ 0.0305
Base Average Balancing Cost:	$ -	$ -	
Base Average Surcharge Cost:	$ -	$ -	
Totals:	$ 0.4796	$ 0.3538	

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Ag. Seasonal Use Crop Drying Step 2 3,000 to 9,999 Ag-1

	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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7397	$ 0.7702	$ 0.0305	
						$/Therm-Winter Step 2	$ 0.7158	$ 0.7463	$ 0.0305	
						$/Therm-Winter Step 3	$ 0.6606	$ 0.6911	$ 0.0305	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6139	$ 0.6444	$ 0.0305	
						$/Therm-Summer Step 2	$ 0.5900	$ 0.6205	$ 0.0305	
						$/Therm-Summer Step 3	$ 0.5348	$ 0.5653	$ 0.0305	

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
3,000		NA	NA	NA	NA		$ 2,026	$ 2,118	$ 92	4.52%
3,440		NA	NA	NA	NA		$ 2,296	$ 2,401	$ 105	4.57%
3,880		NA	NA	NA	NA		$ 2,567	$ 2,685	$ 118	4.61%
4,320		NA	NA	NA	NA		$ 2,837	$ 2,969	$ 132	4.64%
4,760	106	NA	NA	NA	NA		$ 3,108	$ 3,253	$ 145	4.67%
5,200		NA	NA	NA	NA		$ 3,378	$ 3,537	$ 159	4.70%
5,640		NA	NA	NA	NA		$ 3,648	$ 3,820	$ 172	4.71%
6,080		NA	NA	NA	NA		$ 3,919	$ 4,104	$ 185	4.73%
6,520		NA	NA	NA	NA		$ 4,189	$ 4,388	$ 199	4.75%
6,960		NA	NA	NA	NA		$ 4,460	$ 4,672	$ 212	4.76%
7,400		NA	NA	NA	NA		$ 4,730	$ 4,956	$ 226	4.77%
7,840		NA	NA	NA	NA		$ 5,000	$ 5,240	$ 239	4.78%
8,280		NA	NA	NA	NA		$ 5,271	$ 5,523	$ 253	4.79%
8,720		NA	NA	NA	NA		$ 5,541	$ 5,807	$ 266	4.80%
9,160		NA	NA	NA	NA		$ 5,812	$ 6,091	$ 279	4.81%
9,600		NA	NA	NA	NA		$ 6,082	$ 6,375	$ 293	4.81%
9,999		NA	NA	NA	NA		$ 6,327	$ 6,632	$ 305	4.82%
	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:	$ 0.3397	$ 0.3397	$ 0.0305
Base Average Peak Demand Cost:	$ 0.1258	$ -	$ 0.0305
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141	$ 0.0305
Base Average Balancing Cost:	$ -	$ -	
Base Average Surcharge Cost:	$ -	$ -	
Totals:	$ 0.4796	$ 0.3538	

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Ag. Seasonal Use Crop Drying Step 3 10,000 and over Ag-1

	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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7397	$ 0.7702	$ 0.0305	
						$/Therm-Winter Step 2	$ 0.7158	$ 0.7463	$ 0.0305	
						$/Therm-Winter Step 3	$ 0.6606	$ 0.6911	$ 0.0305	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6139	$ 0.6444	$ 0.0305	
						$/Therm-Summer Step 2	$ 0.5900	$ 0.6205	$ 0.0305	
						$/Therm-Summer Step 3	$ 0.5348	$ 0.5653	$ 0.0305	

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
10,000		NA	NA	NA	NA		$ 6,328	$ 6,633	$ 305	4.82%
15,620		NA	NA	NA	NA		$ 9,697	$ 10,173	$ 476	4.91%
21,240		NA	NA	NA	NA		$ 13,017	$ 13,665	$ 648	4.98%
26,860		NA	NA	NA	NA		$ 16,337	$ 17,156	$ 819	5.01%
32,480		NA	NA	NA	NA		$ 19,657	$ 20,647	$ 991	5.04%
38,100		NA	NA	NA	NA		$ 22,977	$ 24,139	$ 1,162	5.06%
43,720		NA	NA	NA	NA		$ 26,103	$ 27,437	$ 1,333	5.11%
49,340		NA	NA	NA	NA		$ 29,115	$ 30,619	$ 1,505	5.17%
54,960		NA	NA	NA	NA		$ 32,126	$ 33,802	$ 1,676	5.22%
60,580		NA	NA	NA	NA		$ 35,137	$ 36,985	$ 1,848	5.26%
66,200		NA	NA	NA	NA		$ 38,149	$ 40,168	$ 2,019	5.29%
71,820		NA	NA	NA	NA		$ 41,160	$ 43,350	$ 2,191	5.32%
77,440		NA	NA	NA	NA		$ 44,171	$ 46,533	$ 2,362	5.35%
83,060		NA	NA	NA	NA		$ 47,183	$ 49,716	$ 2,533	5.37%
88,680		NA	NA	NA	NA		$ 50,194	$ 52,899	$ 2,705	5.39%
94,300	19	NA	NA	NA	NA		$ 53,205	$ 56,081	$ 2,876	5.41%
99,999		NA	NA	NA	NA		$ 56,259	$ 59,309	$ 3,050	5.42%

	Transportation Old	Transportation New		Sales Old	Sales New
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:	$ 0.3397	$ 0.3397	$ 0.0305
Base Average Peak Demand Cost:	$ 0.1258	$ -	$ 0.0305
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141	$ 0.0305
Base Average Balancing Cost:	$ -	$ -	
Base Average Surcharge Cost:	$ -	$ -	
Totals:	$ 0.4796	$ 0.3538	

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 0 to 3,999 Fg-1 &
Firm Comm. Ind. 0 to 3,999 Tf-1

	Transportation Service				Sales Service		
	Old Annual Rate	New Annual Rate	Increase (Decrease)		Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -	$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -	$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -
Demand Charge	N/A	N/A	N/A	Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.3364	$ 0.3367	$ 0.0003	$/Therm-Winter	$ 0.8423	$ 0.8883	$ 0.0460
$/Therm-Summer	$ 0.3364	$ 0.3367	$ 0.0003	$/Therm-Summer	$ 0.7165	$ 0.7625	$ 0.0460

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		$ 929.50	$ 929.57	$ 0.07	0.01%		$ 314.56	$ 325.37	$ 10.81	3.44%
470		$ 1,008.56	$ 1,008.70	$ 0.14	0.01%		$ 508.67	$ 530.29	$ 21.62	4.25%
705		$ 1,087.61	$ 1,087.82	$ 0.21	0.02%		$ 702.78	$ 735.21	$ 32.43	4.61%
940		$ 1,166.67	$ 1,166.95	$ 0.28	0.02%		$ 896.89	$ 940.13	$ 43.24	4.82%
1,175		$ 1,245.72	$ 1,246.07	$ 0.35	0.03%		$ 1,091.00	$ 1,145.05	$ 54.05	4.95%
1,458		$ 1,340.92	$ 1,341.36	$ 0.44	0.03%	41,693	$ 1,324.75	$ 1,391.82	$ 67.07	5.06%
1,645		$ 1,403.83	$ 1,404.32	$ 0.49	0.03%		$ 1,479.21	$ 1,554.88	$ 75.67	5.12%
1,900	6	$ 1,489.61	$ 1,490.18	$ 0.57	0.04%		$ 1,689.84	$ 1,777.24	$ 87.40	5.17%
2,135		$ 1,568.66	$ 1,569.30	$ 0.64	0.04%		$ 1,883.95	$ 1,982.16	$ 98.21	5.21%
2,370		$ 1,647.72	$ 1,648.43	$ 0.71	0.04%		$ 2,078.06	$ 2,187.08	$ 109.02	5.25%
2,605		$ 1,726.77	$ 1,727.55	$ 0.78	0.05%		$ 2,272.17	$ 2,392.00	$ 119.83	5.27%
2,840		$ 1,805.83	$ 1,806.68	$ 0.85	0.05%		$ 2,466.28	$ 2,596.92	$ 130.64	5.30%
3,075		$ 1,884.88	$ 1,885.80	$ 0.92	0.05%		$ 2,660.39	$ 2,801.84	$ 141.45	5.32%
3,310		$ 1,963.93	$ 1,964.93	$ 1.00	0.05%		$ 2,854.50	$ 3,006.76	$ 152.26	5.33%
3,545		$ 2,042.99	$ 2,044.05	$ 1.06	0.05%		$ 3,048.61	$ 3,211.68	$ 163.07	5.35%
3,780		$ 2,122.04	$ 2,123.18	$ 1.14	0.05%		$ 3,242.72	$ 3,416.60	$ 173.88	5.36%
3,915		$ 2,167.46	$ 2,168.63	$ 1.17	0.05%		$ 3,354.23	$ 3,534.32	$ 180.09	5.37%

	Old	New		Old	New
Winter Qty %	77.82%	77.82%	Winter Qty %	87.04%	87.04%
Summer QTY %	22.18%	22.18%	Summer QTY %	12.96%	12.96%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 4,000 to 39,999 Fg-2 &
Firm Comm. Ind. 4,000 to 39,999 Tf-2

	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.	$ 86.69	$ 86.69	$ -		$/Mo. Fixed or equiv.	$ 25.85	$ 25.85	$ -	
	$/Day Fixed or equiv.	$ 2.85	$ 2.85	$ -		$/Day Fixed or equiv.	$ 0.85	$ 0.85	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.2200	$ 0.2409	$ 0.0209		$/Therm-Winter	$ 0.7259	$ 0.7925	$ 0.0666	
	$/Therm-Summer	$ 0.2200	$ 0.2409	$ 0.0209		$/Therm-Summer	$ 0.6001	$ 0.6667	$ 0.0666	

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
4,000		$ 1,920.25	$ 2,003.85	$ 83.60	4.35%		$ 3,114.02	$ 3,380.42	$ 266.40	8.55%
6,118		$ 2,386.21	$ 2,514.08	$ 127.87	5.36%		$ 4,598.61	$ 5,006.07	$ 407.46	8.86%
8,236		$ 2,852.17	$ 3,024.30	$ 172.13	6.04%		$ 6,083.20	$ 6,631.72	$ 548.52	9.02%
10,354		$ 3,318.13	$ 3,534.53	$ 216.40	6.52%		$ 7,567.80	$ 8,257.37	$ 689.57	9.11%
11,121		$ 3,486.87	$ 3,719.30	$ 232.43	6.67%	13952	$ 8,105.42	$ 8,846.08	$ 740.66	9.14%
14,590		$ 4,250.05	$ 4,554.98	$ 304.93	7.17%		$ 10,536.98	$ 11,508.68	$ 971.70	9.22%
16,708		$ 4,716.01	$ 5,065.21	$ 349.20	7.40%		$ 12,021.58	$ 13,134.33	$ 1,112.75	9.26%
18,826		$ 5,181.97	$ 5,575.43	$ 393.46	7.59%		$ 13,506.17	$ 14,759.98	$ 1,253.81	9.28%
20,944		$ 5,647.93	$ 6,085.66	$ 437.73	7.75%		$ 14,990.76	$ 16,385.63	$ 1,394.87	9.30%
23,062		$ 6,113.89	$ 6,595.89	$ 482.00	7.88%		$ 16,475.36	$ 18,011.29	$ 1,535.93	9.32%
25,180		$ 6,579.85	$ 7,106.11	$ 526.26	8.00%		$ 17,959.95	$ 19,636.94	$ 1,676.99	9.34%
27,298	382	$ 7,045.81	$ 7,616.34	$ 570.53	8.10%		$ 19,444.55	$ 21,262.59	$ 1,818.04	9.35%
29,416		$ 7,511.77	$ 8,126.56	$ 614.79	8.18%		$ 20,929.14	$ 22,888.24	$ 1,959.10	9.36%
31,534		$ 7,977.73	$ 8,636.79	$ 659.06	8.26%		$ 22,413.73	$ 24,513.90	$ 2,100.17	9.37%
33,652		$ 8,443.69	$ 9,147.02	$ 703.33	8.33%		$ 23,898.33	$ 26,139.55	$ 2,241.22	9.38%
35,770		$ 8,909.65	$ 9,657.24	$ 747.59	8.39%		$ 25,382.92	$ 27,765.20	$ 2,382.28	9.39%
37,888		$ 9,375.61	$ 10,167.47	$ 791.86	8.45%		$ 26,867.51	$ 29,390.85	$ 2,523.34	9.39%
	Winter Qty %	82.81%	82.81%			Winter Qty %	80.16%	80.16%		
	Summer QTY %	17.19%	17.19%			Summer QTY %	19.84%	19.84%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 40,000 to 99,999 Fg-3 &
Firm Comm. Ind. 40,000 to 99,999 Tf-3

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.	$ 243.33	$ 243.33	$ -		$/Mo. Fixed or equiv.	$ 182.50	$ 182.50	$ -	
	$/Day Fixed or equiv.	$ 8.00	$ 8.00	$ -		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1609	$ 0.1680	$ 0.0071		$/Therm-Winter	$ 0.6668	$ 0.7196	$ 0.0528	
	$/Therm-Summer	$ 0.1609	$ 0.1680	$ 0.0071		$/Therm-Summer	$ 0.5410	$ 0.5938	$ 0.0528	

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
40,000		$ 9,356.00	$ 9,640.00	$ 284.00	3.04%		$ 27,711.68	$ 29,823.68	$ 2,112.00	7.62%
43,529		$ 9,923.82	$ 10,232.87	$ 309.05	3.11%		$ 29,963.34	$ 32,261.67	$ 2,298.33	7.67%
47,058		$ 10,491.63	$ 10,825.74	$ 334.11	3.18%		$ 32,214.99	$ 34,699.65	$ 2,484.66	7.71%
50,587		$ 11,059.45	$ 11,418.62	$ 359.17	3.25%		$ 34,466.64	$ 37,137.63	$ 2,670.99	7.75%
54,116		$ 11,627.26	$ 12,011.49	$ 384.23	3.30%		$ 36,718.29	$ 39,575.61	$ 2,857.32	7.78%
57,645		$ 12,195.08	$ 12,604.36	$ 409.28	3.36%		$ 38,969.94	$ 42,013.59	$ 3,043.65	7.81%
61,236		$ 12,772.87	$ 13,207.65	$ 434.78	3.40%		$ 41,261.15	$ 44,494.41	$ 3,233.26	7.84%
63,512		$ 13,139.08	$ 13,590.02	$ 450.94	3.43%	646	$ 42,713.33	$ 46,066.76	$ 3,353.43	7.85%
68,232		$ 13,898.53	$ 14,382.98	$ 484.45	3.49%		$ 45,724.89	$ 49,327.54	$ 3,602.65	7.88%
71,761	389	$ 14,466.34	$ 14,975.85	$ 509.51	3.52%		$ 47,976.54	$ 51,765.52	$ 3,788.98	7.90%
75,290		$ 15,034.16	$ 15,568.72	$ 534.56	3.56%		$ 50,228.19	$ 54,203.50	$ 3,975.31	7.91%
78,819		$ 15,601.98	$ 16,161.59	$ 559.61	3.59%		$ 52,479.84	$ 56,641.49	$ 4,161.65	7.93%
82,348		$ 16,169.79	$ 16,754.46	$ 584.67	3.62%		$ 54,731.49	$ 59,079.47	$ 4,347.98	7.94%
85,877		$ 16,737.61	$ 17,347.34	$ 609.73	3.64%		$ 56,983.14	$ 61,517.45	$ 4,534.31	7.96%
89,406		$ 17,305.43	$ 17,940.21	$ 634.78	3.67%		$ 59,234.79	$ 63,955.43	$ 4,720.64	7.97%
92,935		$ 17,873.24	$ 18,533.08	$ 659.84	3.69%		$ 61,486.44	$ 66,393.41	$ 4,906.97	7.98%
96,464		$ 18,441.06	$ 19,125.95	$ 684.89	3.71%		$ 63,738.10	$ 68,831.39	$ 5,093.29	7.99%

	Old	New		Old	New
Winter Qty %	79.96%	79.96%	Winter Qty %	77.14%	77.14%
Summer QTY %	20.04%	20.04%	Summer QTY %	22.86%	22.86%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 100,000 to 499,999 Fg-4 &
Firm Comm. Ind. 100,000 to 499,999 Tf-4

	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.	$ 517.08	$ 517.08	$ -		$/Mo. Fixed or equiv.	$ 456.25	$ 456.25	$ -	
	$/Day Fixed or equiv.	$ 17.00	$ 17.00	$ -		$/Day Fixed or equiv.	$ 15.00	$ 15.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1187	$ 0.1172	$ (0.0015)		$/Therm-Winter	$ 0.6246	$ 0.6688	$ 0.0442	
	$/Therm-Summer	$ 0.1187	$ 0.1172	$ (0.0015)		$/Therm-Summer	$ 0.4988	$ 0.5430	$ 0.0442	

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
100,000		$ 18,075.00	$ 17,925.00	$ (150.00)	-0.83%		$ 63,670.38	$ 68,090.38	$ 4,420.00	6.94%
123,529		$ 20,867.89	$ 20,682.60	$ (185.29)	-0.89%		$ 77,363.17	$ 82,823.15	$ 5,459.98	7.06%
158,630		$ 25,034.38	$ 24,796.44	$ (237.94)	-0.95%	151	$ 97,790.33	$ 104,801.78	$ 7,011.45	7.17%
177,075		$ 27,223.80	$ 26,958.19	$ (265.61)	-0.98%		$ 108,524.47	$ 116,351.18	$ 7,826.71	7.21%
194,116		$ 29,246.57	$ 28,955.40	$ (291.17)	-1.00%		$ 118,441.54	$ 127,021.47	$ 8,579.93	7.24%
217,645		$ 32,039.46	$ 31,712.99	$ (326.47)	-1.02%		$ 132,134.33	$ 141,754.24	$ 9,619.91	7.28%
241,174	382	$ 34,832.35	$ 34,470.59	$ (361.76)	-1.04%		$ 145,827.13	$ 156,487.02	$ 10,659.89	7.31%
264,703		$ 37,625.25	$ 37,228.19	$ (397.06)	-1.06%		$ 159,519.92	$ 171,219.79	$ 11,699.87	7.33%
288,232		$ 40,418.14	$ 39,985.79	$ (432.35)	-1.07%		$ 173,212.71	$ 185,952.56	$ 12,739.85	7.36%
311,761		$ 43,211.03	$ 42,743.39	$ (467.64)	-1.08%		$ 186,905.50	$ 200,685.33	$ 13,779.83	7.37%
335,290		$ 46,003.92	$ 45,500.99	$ (502.93)	-1.09%		$ 200,598.29	$ 215,418.11	$ 14,819.82	7.39%
358,819		$ 48,796.82	$ 48,258.59	$ (538.23)	-1.10%		$ 214,291.08	$ 230,150.88	$ 15,859.80	7.40%
382,348		$ 51,589.71	$ 51,016.19	$ (573.52)	-1.11%		$ 227,983.87	$ 244,883.65	$ 16,899.78	7.41%
405,877		$ 54,382.60	$ 53,773.78	$ (608.82)	-1.12%		$ 241,676.66	$ 259,616.43	$ 17,939.77	7.42%
429,406		$ 57,175.49	$ 56,531.38	$ (644.11)	-1.13%		$ 255,369.45	$ 274,349.20	$ 18,979.75	7.43%
452,935		$ 59,968.38	$ 59,288.98	$ (679.40)	-1.13%		$ 269,062.24	$ 289,081.97	$ 20,019.73	7.44%
476,464		$ 62,761.28	$ 62,046.58	$ (714.70)	-1.14%		$ 282,755.04	$ 303,814.74	$ 21,059.70	7.45%
	Winter Qty %	67.83%	67.83%			Winter Qty %	66.10%	66.10%		
	Summer QTY %	32.17%	32.17%			Summer QTY %	33.90%	33.90%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 500,000 to 999,999 Fg-5 &
Firm Comm. Ind. 500,000 to 999,999 Tf-5

	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.	$ 1,429.58	$ 1,429.58	$ -		$/Mo. Fixed or equiv.	$ 1,368.75	$ 1,368.75	$ -	
	$/Day Fixed or equiv.	$ 47.00	$ 47.00	$ -		$/Day Fixed or equiv.	$ 45.00	$ 45.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.0958	$ 0.0952	$ (0.0006)		$/Therm-Winter	$ 0.6017	$ 0.6468	$ 0.0451	
	$/Therm-Summer	$ 0.0958	$ 0.0952	$ (0.0006)		$/Therm-Summer	$ 0.4759	$ 0.5210	$ 0.0451	

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
500,000		$ 65,055.00	$ 64,755.00	$ (300.00)	-0.46%		$ 289,221.60	$ 311,771.60	$ 22,550.00	7.80%
529,412		$ 67,872.67	$ 67,555.02	$ (317.65)	-0.47%		$ 305,268.59	$ 329,145.07	$ 23,876.48	7.82%
558,824		$ 70,690.34	$ 70,355.04	$ (335.30)	-0.47%		$ 321,315.57	$ 346,518.54	$ 25,202.97	7.84%
588,236		$ 73,508.01	$ 73,155.07	$ (352.94)	-0.48%		$ 337,362.56	$ 363,892.01	$ 26,529.45	7.86%
617,648		$ 76,325.68	$ 75,955.09	$ (370.59)	-0.49%		$ 353,409.55	$ 381,265.47	$ 27,855.92	7.88%
661,674		$ 80,543.37	$ 80,146.36	$ (397.01)	-0.49%	9	$ 377,429.84	$ 407,271.33	$ 29,841.49	7.91%
676,472	85	$ 81,961.02	$ 81,555.13	$ (405.89)	-0.50%		$ 385,503.52	$ 416,012.41	$ 30,508.89	7.91%
705,884		$ 84,778.69	$ 84,355.16	$ (423.53)	-0.50%		$ 401,550.51	$ 433,385.88	$ 31,835.37	7.93%
735,296		$ 87,596.36	$ 87,155.18	$ (441.18)	-0.50%		$ 417,597.50	$ 450,759.35	$ 33,161.85	7.94%
757,365		$ 89,710.57	$ 89,256.15	$ (454.42)	-0.51%		$ 429,638.19	$ 463,795.36	$ 34,157.17	7.95%
794,120		$ 93,231.70	$ 92,755.22	$ (476.48)	-0.51%		$ 449,691.47	$ 485,506.28	$ 35,814.81	7.96%
823,532		$ 96,049.37	$ 95,555.25	$ (494.12)	-0.51%		$ 465,738.46	$ 502,879.75	$ 37,141.29	7.97%
852,944		$ 98,867.04	$ 98,355.27	$ (511.77)	-0.52%		$ 481,785.45	$ 520,253.22	$ 38,467.77	7.98%
882,356		$ 101,684.70	$ 101,155.29	$ (529.41)	-0.52%		$ 497,832.43	$ 537,626.69	$ 39,794.26	7.99%
911,768		$ 104,502.37	$ 103,955.31	$ (547.06)	-0.52%		$ 513,879.42	$ 555,000.16	$ 41,120.74	8.00%
941,180		$ 107,320.04	$ 106,755.34	$ (564.70)	-0.53%		$ 529,926.41	$ 572,373.63	$ 42,447.22	8.01%
970,592		$ 110,137.71	$ 109,555.36	$ (582.35)	-0.53%		$ 545,973.40	$ 589,747.09	$ 43,773.69	8.02%

	Old	New		Old	New
Winter Qty %	57.67%	57.67%	Winter Qty %	55.40%	55.40%
Summer QTY %	42.33%	42.33%	Summer QTY %	44.60%	44.60%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6 & Firm Comm. Ind. 1,000,000 to 7,999,999 Tf-6

	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.	$ 3,558.75	$ 3,558.75	$ -		$/Mo. Fixed or equiv.	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or equiv.	$ 117.00	$ 117.00	$ -		$/Day Fixed or equiv.	$ 115.00	$ 115.00	$ -	
	Demand Charge	$ 0.0055	$ 0.0057	$ 0.0002		Demand Charge	$ 0.0055	$ 0.0057	$ 0.0002	
	$/Therm-Winter	$ 0.0483	$ 0.0460	$ (0.0023)		$/Therm-Winter	$ 0.5542	$ 0.5976	$ 0.0434	
	$/Therm-Summer	$ 0.0483	$ 0.0460	$ (0.0023)		$/Therm-Summer	$ 0.4284	$ 0.4718	$ 0.0434	

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
1,000,000	11156	$ 113,400.67	$ 111,915.06	$ (1,485.61)	-1.31%	11156	$ 525,750.62	$ 569,152.85	$ 43,402.23	8.26%
1,370,671	11156	$ 131,304.08	$ 128,965.92	$ (2,338.16)	-1.78%	11156	$ 705,049.47	$ 764,538.82	$ 59,489.35	8.44%
1,823,530	11156	$ 153,177.17	$ 149,797.44	$ (3,379.73)	-2.21%	11156	$ 924,103.82	$ 1,003,247.26	$ 79,143.44	8.56%
2,235,295	11156	$ 173,065.42	$ 168,738.63	$ (4,326.79)	-2.50%	11156	$ 1,123,280.42	$ 1,220,294.46	$ 97,014.04	8.64%
2,647,060	11156	$ 192,953.67	$ 187,679.82	$ (5,273.85)	-2.73%	11156	$ 1,322,457.03	$ 1,437,341.66	$ 114,884.63	8.69%
3,058,825	11156	$ 212,841.92	$ 206,621.01	$ (6,220.91)	-2.92%	11156	$ 1,521,633.63	$ 1,654,388.87	$ 132,755.24	8.72%
3,470,590	11156	$ 232,730.17	$ 225,562.20	$ (7,167.97)	-3.08%	11156	$ 1,720,810.23	$ 1,871,436.07	$ 150,625.84	8.75%
3,882,355	11156	$ 252,618.42	$ 244,503.39	$ (8,115.03)	-3.21%	11156	$ 1,919,986.83	$ 2,088,483.27	$ 168,496.44	8.78%
4,294,120	11156	$ 272,506.67	$ 263,444.58	$ (9,062.09)	-3.33%	11156	$ 2,119,163.44	$ 2,305,530.48	$ 186,367.04	8.79%
4,705,885	11156	$ 292,394.92	$ 282,385.77	$ (10,009.15)	-3.42%	11156	$ 2,318,340.04	$ 2,522,577.68	$ 204,237.64	8.81%
5,117,650	11156	$ 312,283.17	$ 301,326.96	$ (10,956.21)	-3.51%	11156	$ 2,517,516.64	$ 2,739,624.88	$ 222,108.24	8.82%
5,529,415	11156	$ 332,171.41	$ 320,268.15	$ (11,903.26)	-3.58%	11156	$ 2,716,693.24	$ 2,956,672.09	$ 239,978.85	8.83%
6,000,000	11156	$ 354,900.67	$ 341,915.06	$ (12,985.61)	-3.66%	11156	$ 2,944,321.92	$ 3,204,724.15	$ 260,402.23	8.84%
6,352,945	11156	$ 371,947.91	$ 358,150.53	$ (13,797.38)	-3.71%	11156	$ 3,115,046.45	$ 3,390,766.49	$ 275,720.04	8.85%
6,764,710	11156	$ 391,836.16	$ 377,091.72	$ (14,744.44)	-3.76%	11156	$ 3,314,223.05	$ 3,607,813.69	$ 293,590.64	8.86%
7,176,475	11156	$ 411,724.41	$ 396,032.91	$ (15,691.50)	-3.81%	11156	$ 3,513,399.65	$ 3,824,860.90	$ 311,461.25	8.86%
7,588,240	11156	$ 431,612.66	$ 414,974.10	$ (16,638.56)	-3.85%	11156	$ 3,712,576.25	$ 4,041,908.10	$ 329,331.85	8.87%

Winter Qty %	55.62%	55.62%	Winter Qty %	43.97%	43.97%
Summer QTY %	44.38%	44.38%	Summer QTY %	56.03%	56.03%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7 & Firm Comm. Ind. 8,000,000 to 14,999,999 Tf-7

	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.	$ 13,748.33	$ 13,748.33	$ -		$/Mo. Fixed or equiv.	$ 13,687.50	$ 13,687.50	$ -	
	$/Day Fixed or equiv.	$ 452.00	$ 452.00	$ -		$/Day Fixed or equiv.	$ 450.00	$ 450.00	$ -	
	Demand Charge	$ 0.0046	$ 0.0048	$ 0.0002		Demand Charge	$ 0.0046	$ 0.0048	$ 0.0002	
	$/Therm-Winter	$ 0.0385	$ 0.0437	$ 0.0052		$/Therm-Winter	$ 0.5444	$ 0.5953	$ 0.0509	
	$/Therm-Summer	$ 0.0385	$ 0.0437	$ 0.0052		$/Therm-Summer	$ 0.4186	$ 0.4695	$ 0.0509	

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
8,000,000	61927	$ 576,955.43	$ 623,076.10	$ 46,120.67	7.99%	61927	$ 4,122,741.43	$ 4,534,462.10	$ 411,720.67	9.99%
8,437,500	61927	$ 593,799.18	$ 642,194.85	$ 48,395.67	8.15%	61927	$ 4,333,535.28	$ 4,767,524.70	$ 433,989.42	10.01%
8,875,000	61927	$ 610,642.93	$ 661,313.60	$ 50,670.67	8.30%	61927	$ 4,544,329.12	$ 5,000,587.29	$ 456,258.17	10.04%
9,312,500	61927	$ 627,486.68	$ 680,432.35	$ 52,945.67	8.44%	61927	$ 4,755,122.96	$ 5,233,649.89	$ 478,526.93	10.06%
9,750,000	61927	$ 644,330.43	$ 699,551.10	$ 55,220.67	8.57%	61927	$ 4,965,916.81	$ 5,466,712.48	$ 500,795.67	10.08%
10,187,500	61927	$ 661,174.18	$ 718,669.85	$ 57,495.67	8.70%	61927	$ 5,176,710.65	$ 5,699,775.07	$ 523,064.42	10.10%
10,625,000	61927	$ 678,017.93	$ 737,788.60	$ 59,770.67	8.82%	61927	$ 5,387,504.50	$ 5,932,837.67	$ 545,333.17	10.12%
11,062,500	61927	$ 694,861.68	$ 756,907.35	$ 62,045.67	8.93%	61927	$ 5,598,298.34	$ 6,165,900.26	$ 567,601.92	10.14%
11,500,000	61927	$ 711,705.43	$ 776,026.10	$ 64,320.67	9.04%	61927	$ 5,809,092.18	$ 6,398,962.85	$ 589,870.67	10.15%
11,937,500	61927	$ 728,549.18	$ 795,144.85	$ 66,595.67	9.14%	61927	$ 6,019,886.03	$ 6,632,025.45	$ 612,139.42	10.17%
12,375,000	61927	$ 745,392.93	$ 814,263.60	$ 68,870.67	9.24%	61927	$ 6,230,679.87	$ 6,865,088.04	$ 634,408.17	10.18%
12,812,500	61927	$ 762,236.68	$ 833,382.35	$ 71,145.67	9.33%	61927	$ 6,441,473.71	$ 7,098,150.64	$ 656,676.93	10.19%
13,250,000	61927	$ 779,080.43	$ 852,501.10	$ 73,420.67	9.42%	61927	$ 6,652,267.56	$ 7,331,213.23	$ 678,945.67	10.21%
13,687,500	61927	$ 795,924.18	$ 871,619.85	$ 75,695.67	9.51%	61927	$ 6,863,061.40	$ 7,564,275.82	$ 701,214.42	10.22%
14,125,000	61927	$ 812,767.93	$ 890,738.60	$ 77,970.67	9.59%	61927	$ 7,073,855.25	$ 7,797,338.42	$ 723,483.17	10.23%
14,562,500	61927	$ 829,611.68	$ 909,857.35	$ 80,245.67	9.67%	61927	$ 7,284,649.09	$ 8,030,401.01	$ 745,751.92	10.24%
14,900,000	61927	$ 842,605.43	$ 924,606.10	$ 82,000.67	9.73%	61927	$ 7,447,261.48	$ 8,210,192.15	$ 762,930.67	10.24%

	Old	New		Old	New
Winter Qty %	50.25%	50.25%	Winter Qty %	50.25%	50.25%
Summer QTY %	49.75%	49.75%	Summer QTY %	49.75%	49.75%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ 0.1258	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.4796	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Firm Comm. Ind. 15,000,000 and Over Fg-8 &
Firm Comm. Ind. 15,000,000 and Over Tf-8

	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.	$ 42,096.67	$ 42,096.67	$ -		$/Mo. Fixed or equiv.	$ 42,035.83	$ 42,035.83	$ -	
	$/Day Fixed or equiv.	$ 1,384.00	$ 1,384.00	$ -		$/Day Fixed or equiv.	$ 1,382.00	$ 1,382.00	$ -	
	Demand Charge	$ 0.0030	$ 0.0032	$ 0.0002		Demand Charge	$ 0.0030	$ 0.0032	$ 0.0002	
	$/Therm-Winter	$ 0.0166	$ 0.0202	$ 0.0036		$/Therm-Winter	$ 0.5225	$ 0.5718	$ 0.0493	
	$/Therm-Summer	$ 0.0166	$ 0.0202	$ 0.0036		$/Therm-Summer	$ 0.5225	$ 0.5718	$ 0.0493	

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	98606	$ 862,133.57	$ 923,331.81	$ 61,198.24	7.10%	98606	$ 8,449,903.57	$ 9,196,601.81	$ 746,698.24	8.84%
15,938,000	98606	$ 877,704.37	$ 942,279.41	$ 64,575.04	7.36%	98606	$ 8,940,008.57	$ 9,732,950.21	$ 792,941.64	8.87%
16,876,000	98606	$ 893,275.17	$ 961,227.01	$ 67,951.84	7.61%	98606	$ 9,430,113.57	$ 10,269,298.61	$ 839,185.04	8.90%
17,814,000	98606	$ 908,845.97	$ 980,174.61	$ 71,328.64	7.85%	98606	$ 9,920,218.57	$ 10,805,647.01	$ 885,428.44	8.93%
18,752,000	98606	$ 924,416.77	$ 999,122.21	$ 74,705.44	8.08%	98606	$ 10,410,323.57	$ 11,341,995.41	$ 931,671.84	8.95%
19,690,000	98606	$ 939,987.57	$ 1,018,069.81	$ 78,082.24	8.31%	98606	$ 10,900,428.57	$ 11,878,343.81	$ 977,915.24	8.97%
20,628,000	98606	$ 955,558.37	$ 1,037,017.41	$ 81,459.04	8.52%	98606	$ 11,390,533.57	$ 12,414,692.21	$ 1,024,158.64	8.99%
21,566,000	98606	$ 971,129.17	$ 1,055,965.01	$ 84,835.84	8.74%	98606	$ 11,880,638.57	$ 12,951,040.61	$ 1,070,402.04	9.01%
22,504,000	98606	$ 986,699.97	$ 1,074,912.61	$ 88,212.64	8.94%	98606	$ 12,370,743.57	$ 13,487,389.01	$ 1,116,645.44	9.03%
23,442,000	98606	$ 1,002,270.77	$ 1,093,860.21	$ 91,589.44	9.14%	98606	$ 12,860,848.57	$ 14,023,737.41	$ 1,162,888.84	9.04%
24,380,000	98606	$ 1,017,841.57	$ 1,112,807.81	$ 94,966.24	9.33%	98606	$ 13,350,953.57	$ 14,560,085.81	$ 1,209,132.24	9.06%
25,318,000	98606	$ 1,033,412.37	$ 1,131,755.41	$ 98,343.04	9.52%	98606	$ 13,841,058.57	$ 15,096,434.21	$ 1,255,375.64	9.07%
26,256,000	98606	$ 1,048,983.17	$ 1,150,703.01	$ 101,719.84	9.70%	98606	$ 14,331,163.57	$ 15,632,782.61	$ 1,301,619.04	9.08%
27,194,000	98606	$ 1,064,553.97	$ 1,169,650.61	$ 105,096.64	9.87%	98606	$ 14,821,268.57	$ 16,169,131.01	$ 1,347,862.44	9.09%
28,132,000	98606	$ 1,080,124.77	$ 1,188,598.21	$ 108,473.44	10.04%	98606	$ 15,311,373.57	$ 16,705,479.41	$ 1,394,105.84	9.11%
29,070,000	98606	$ 1,095,695.57	$ 1,207,545.81	$ 111,850.24	10.21%	98606	$ 15,801,478.57	$ 17,241,827.81	$ 1,440,349.24	9.12%
30,008,000	98606	$ 1,111,266.37	$ 1,226,493.41	$ 115,227.04	10.37%	98606	$ 16,291,583.57	$ 17,778,176.21	$ 1,486,592.64	9.12%
	Winter Qty %	54.86%	54.86%			Winter Qty %	63.26%	63.26%		
	Summer QTY %	45.14%	45.14%			Summer QTY %	36.74%	36.74%		

Gas Cost Rates:		Firm	Interruptible
Base Average Commodity Cost:		$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:		$ 0.1258	$ -
Base Average Annual Demand Cost:		$ 0.0141	$ 0.0141
Base Average Balancing Cost:		$ -	$ -
Base Average Surcharge Cost:		$ -	$ -
	Totals:	$ 0.4796	$ 0.3538
Transportation Administrative Charge:		$ 2.00	

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt. Comm. Ind. 50000 to 99999 Ig-3

		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.	$ 380.21	$ 182.50	$ (197.71)	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.5389	$ 0.5568	$ 0.0179	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.5389	$ 0.5568	$ 0.0179	

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 `
50,000		NA	NA	NA	NA		$ 29,135.00	$ 30,030.00	$ 895.00	3.07%
53,000		NA	NA	NA	NA		$ 30,751.70	$ 31,700.40	$ 948.70	3.09%
56,000		NA	NA	NA	NA		$ 32,368.40	$ 33,370.80	$ 1,002.40	3.10%
59,000		NA	NA	NA	NA		$ 33,985.10	$ 35,041.20	$ 1,056.10	3.11%
62,000		NA	NA	NA	NA		$ 35,601.80	$ 36,711.60	$ 1,109.80	3.12%
65,000		NA	NA	NA	NA		$ 37,218.50	$ 38,382.00	$ 1,163.50	3.13%
68,000		NA	NA	NA	NA	3	$ 38,835.20	$ 40,052.40	$ 1,217.20	3.13%
71,000		NA	NA	NA	NA		$ 40,451.90	$ 41,722.80	$ 1,270.90	3.14%
74,000		NA	NA	NA	NA		$ 42,068.60	$ 43,393.20	$ 1,324.60	3.15%
77,000		NA	NA	NA	NA		$ 43,685.30	$ 45,063.60	$ 1,378.30	3.16%
80,000		NA	NA	NA	NA		$ 45,302.00	$ 46,734.00	$ 1,432.00	3.16%
83,000		NA	NA	NA	NA		$ 46,918.70	$ 48,404.40	$ 1,485.70	3.17%
86,000		NA	NA	NA	NA		$ 48,535.40	$ 50,074.80	$ 1,539.40	3.17%
89,000		NA	NA	NA	NA		$ 50,152.10	$ 51,745.20	$ 1,593.10	3.18%
92,000		NA	NA	NA	NA		$ 51,768.80	$ 53,415.60	$ 1,646.80	3.18%
95,000		NA	NA	NA	NA		$ 53,385.50	$ 55,086.00	$ 1,700.50	3.19%
98,000		NA	NA	NA	NA		$ 55,002.20	$ 56,756.40	$ 1,754.20	3.19%
	Winter Qty %	NA	NA			Winter Qty %	66.10%	66.10%		
	Summer QTY %	NA	NA			Summer QTY %	33.90%	33.90%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3538	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt. Comm. Ind. 100000 to 499999 Ig-4

	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.	$ 456.25	$ 456.25	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 15.00	$ 15.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.4967	$ 0.5060	$ 0.0093	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.4967	$ 0.5060	$ 0.0093	

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
100,000		NA	NA	NA	NA		$ 55,145.00	$ 56,075.00	$ 930.00	1.69%
125,000		NA	NA	NA	NA		$ 67,562.50	$ 68,725.00	$ 1,162.50	1.72%
150,000		NA	NA	NA	NA		$ 79,980.00	$ 81,375.00	$ 1,395.00	1.74%
162,461		NA	NA	NA	NA	162	$ 86,169.38	$ 87,680.27	$ 1,510.89	1.75%
187,461		NA	NA	NA	NA		$ 98,586.88	$ 100,330.27	$ 1,743.39	1.77%
212,461		NA	NA	NA	NA		$ 111,004.38	$ 112,980.27	$ 1,975.89	1.78%
237,461		NA	NA	NA	NA		$ 123,421.88	$ 125,630.27	$ 2,208.39	1.79%
262,461		NA	NA	NA	NA		$ 135,839.38	$ 138,280.27	$ 2,440.89	1.80%
287,461		NA	NA	NA	NA		$ 148,256.88	$ 150,930.27	$ 2,673.39	1.80%
312,461		NA	NA	NA	NA		$ 160,674.38	$ 163,580.27	$ 2,905.89	1.81%
337,461		NA	NA	NA	NA		$ 173,091.88	$ 176,230.27	$ 3,138.39	1.81%
362,461		NA	NA	NA	NA		$ 185,509.38	$ 188,880.27	$ 3,370.89	1.82%
387,461		NA	NA	NA	NA		$ 197,926.88	$ 201,530.27	$ 3,603.39	1.82%
412,461		NA	NA	NA	NA		$ 210,344.38	$ 214,180.27	$ 3,835.89	1.82%
437,461		NA	NA	NA	NA		$ 222,761.88	$ 226,830.27	$ 4,068.39	1.83%
462,461		NA	NA	NA	NA		$ 235,179.38	$ 239,480.27	$ 4,300.89	1.83%
495,000		NA	NA	NA	NA		$ 251,341.50	$ 255,945.00	$ 4,603.50	1.83%
	Winter Qty %	NA	NA			Winter Qty %	55.40%	55.40%		
	Summer QTY %	NA	NA			Summer QTY %	44.60%	44.60%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3538	$ 0.3538
Transportation Administrative Charge:	$ 2.00	

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt Comm. Ind. 500000 to 999999 Ig-5

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.	$ 1,368.75	$ 1,368.75	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 45.00	$ 45.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ -	$ -	$ -	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.4738	$ 0.4840	$ 0.0102	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.4738	$ 0.4840	$ 0.0102	

Usage in Therms	Customer Demand Quantity	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
500,000		NA	NA	NA	NA	0	$ 253,325.00	$ 258,425.00	$ 5,100.00	2.01%
531,000		NA	NA	NA	NA	0	$ 268,012.80	$ 273,429.00	$ 5,416.20	2.02%
562,000		NA	NA	NA	NA	0	$ 282,700.60	$ 288,433.00	$ 5,732.40	2.03%
593,000		NA	NA	NA	NA	0	$ 297,388.40	$ 303,437.00	$ 6,048.60	2.03%
624,000		NA	NA	NA	NA	0	$ 312,076.20	$ 318,441.00	$ 6,364.80	2.04%
655,000		NA	NA	NA	NA	0	$ 326,764.00	$ 333,445.00	$ 6,681.00	2.04%
677,745		NA	NA	NA	NA	2	$ 337,540.58	$ 344,453.58	$ 6,913.00	2.05%
708,745		NA	NA	NA	NA	0	$ 352,228.38	$ 359,457.58	$ 7,229.20	2.05%
739,745		NA	NA	NA	NA	0	$ 366,916.18	$ 374,461.58	$ 7,545.40	2.06%
770,745		NA	NA	NA	NA	0	$ 381,603.98	$ 389,465.58	$ 7,861.60	2.06%
801,745		NA	NA	NA	NA	0	$ 396,291.78	$ 404,469.58	$ 8,177.80	2.06%
832,745		NA	NA	NA	NA	0	$ 410,979.58	$ 419,473.58	$ 8,494.00	2.07%
863,745		NA	NA	NA	NA	0	$ 425,667.38	$ 434,477.58	$ 8,810.20	2.07%
894,745		NA	NA	NA	NA	0	$ 440,355.18	$ 449,481.58	$ 9,126.40	2.07%
925,745		NA	NA	NA	NA	0	$ 455,042.98	$ 464,485.58	$ 9,442.60	2.08%
956,745		NA	NA	NA	NA	0	$ 469,730.78	$ 479,489.58	$ 9,758.80	2.08%
987,745		NA	NA	NA	NA	0	$ 484,418.58	$ 494,493.58	$ 10,075.00	2.08%

	Old	New		Old	New
Winter Qty %	NA	NA	Winter Qty %	43.97%	43.97%
Summer QTY %	NA	NA	Summer QTY %	56.03%	56.03%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3538	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2025

Interrupt Comm. Ind. 1,000,000 to 7.999,999 Ig-6

	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 equ	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equ	$ 115.00	$ 115.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ 0.0055	$ 0.0057	$ 0.0002	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.4263	$ 0.4348	$ 0.0085	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.4263	$ 0.4348	$ 0.0085	

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
1,000,000		NA	NA	NA	NA	12485	$ 493,338.64	$ 502,750.04	$ 9,411.40	1.91%
1,438,000		NA	NA	NA	NA	12485	$ 680,058.04	$ 693,192.44	$ 13,134.40	1.93%
1,758,307		NA	NA	NA	NA	12485	$ 816,604.91	$ 832,461.93	$ 15,857.02	1.94%
2,196,307		NA	NA	NA	NA	12485	$ 1,003,324.31	$ 1,022,904.33	$ 19,580.02	1.95%
2,634,307		NA	NA	NA	NA	12485	$ 1,190,043.71	$ 1,213,346.73	$ 23,303.02	1.96%
3,072,307		NA	NA	NA	NA	12485	$ 1,376,763.11	$ 1,403,789.13	$ 27,026.02	1.96%
3,510,307		NA	NA	NA	NA	12485	$ 1,563,482.51	$ 1,594,231.53	$ 30,749.02	1.97%
3,948,307		NA	NA	NA	NA	12485	$ 1,750,201.91	$ 1,784,673.93	$ 34,472.02	1.97%
4,386,307		NA	NA	NA	NA	12485	$ 1,936,921.31	$ 1,975,116.33	$ 38,195.02	1.97%
4,824,307		NA	NA	NA	NA	12485	$ 2,123,640.71	$ 2,165,558.73	$ 41,918.02	1.97%
5,262,307		NA	NA	NA	NA	12485	$ 2,310,360.11	$ 2,356,001.13	$ 45,641.02	1.98%
5,700,307		NA	NA	NA	NA	12485	$ 2,497,079.51	$ 2,546,443.53	$ 49,364.02	1.98%
6,000,000		NA	NA	NA	NA	12485	$ 2,624,838.64	$ 2,676,750.04	$ 51,911.40	1.98%
6,438,000		NA	NA	NA	NA	12485	$ 2,811,558.04	$ 2,867,192.44	$ 55,634.40	1.98%
6,876,000		NA	NA	NA	NA	12485	$ 2,998,277.44	$ 3,057,634.84	$ 59,357.40	1.98%
7,314,000		NA	NA	NA	NA	12485	$ 3,184,996.84	$ 3,248,077.24	$ 63,080.40	1.98%
7,502,000		NA	NA	NA	NA	12485	$ 3,265,141.24	$ 3,329,819.64	$ 64,678.40	1.98%
	Winter Qty %	NA	NA			Winter Qty %	50.25%	50.25%		
	Summer QTY %	NA	NA			Summer QTY %	49.75%	49.75%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3397	$ 0.3397
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3538	$ 0.3538

Transportation Administrative Charge: $ 2.00

Wisconsin Gas LLC
Change of Total Revenue Dollar Amounts between Current (PSCW Adjusted) 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 Revenue % Change
Residential Rg-1	597,023	512,539,474	$ 520,951,923	$ 251,815,108	$ 269,136,815	$ 547,808,999	$ 251,815,108	$ 295,993,891	$ 26,857,076	5.16%
Firm Comm. Ind. 0 to 3,999 Fg-1	42,041	62,742,952	$ 59,334,668	$ 31,513,958	$ 27,820,710	$ 63,889,807	$ 31,513,958	$ 32,375,849	$ 4,555,139	7.68%
Firm Comm. Ind. 4,000 to 39,999 Fg-2	14,928	170,087,222	$ 129,466,666	$ 82,942,804	$ 46,523,862	$ 143,719,976	$ 82,942,804	$ 60,777,172	$ 14,253,310	11.01%
Firm Comm. Ind. 40,000 to 99,999 Fg-3	676	42,400,207	$ 29,812,181	$ 20,395,347	$ 9,416,834	$ 32,491,874	$ 20,395,347	$ 12,096,527	$ 2,679,693	8.99%
Firm Comm. Ind. 100,000 to 499,999 Fg-4	166	30,070,855	$ 19,081,005	$ 13,814,639	$ 5,266,366	$ 20,614,617	$ 13,814,639	$ 6,799,978	$ 1,533,612	8.04%
Firm Comm. Ind. 500,000 to 999,999 Fg-5	8	6,319,996	$ 3,673,499	$ 2,770,427	$ 903,072	$ 4,021,732	$ 2,770,427	$ 1,251,305	$ 348,233	9.48%
Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6	3	3,782,999	$ 2,038,073	$ 1,580,363	$ 457,710	$ 2,233,701	$ 1,580,363	$ 653,338	$ 195,628	9.60%
Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Comm. Ind. 15,000,000 and Over Fg-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	192	1,545,338	$ 1,030,464	$ 593,480	$ 436,984	$ 1,046,069	$ 593,480	$ 452,589	$ 15,605	1.63%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	1,216,412	$ 749,694	$ 462,378	$ 287,316	$ 761,982	$ 462,378	$ 299,604	$ 12,288	1.63%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	1,053,469	$ 585,045	$ 394,367	$ 190,678	$ 595,685	$ 394,367	$ 201,318	$ 10,640	1.63%
Interrupt. Comm. Ind. 50000 to 99999 Ig-3	2	120,773	$ 73,211	$ 46,476	$ 26,735	$ 76,628	$ 46,476	$ 30,152	$ 3,417	4.67%
Interrupt. Comm. Ind. 100000 to 499999 Ig-4	15	2,968,875	$ 1,613,960	$ 1,107,584	$ 506,376	$ 1,661,760	$ 1,107,584	$ 554,176	$ 47,800	2.96%
Interrupt Comm. Ind. 500000 to 999999 Ig-5	1	745,399	$ 389,849	$ 283,978	$ 105,871	$ 404,906	$ 283,978	$ 120,928	$ 15,057	3.86%
Interrupt Comm. Ind. 1,000,000 to 7,999,999 Ig-6	3	4,756,858	$ 2,350,659	$ 1,740,858	$ 609,801	$ 2,434,826	$ 1,740,858	$ 693,968	$ 84,167	3.58%
Interrupt Comm. Ind. 8,000,000 to 14,999,999 Ig-7	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interrupt Comm. Ind. 15,000,000 and Over Ig-8	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NFPg-10 Power Generation Nominated Firm	-	69,405,021	$ 32,865,779	$ 30,880,794	$ 1,984,985	$ 36,106,993	$ 30,880,794	$ 5,226,199	$ 3,241,214	9.86%
Pg-10 Power Generation	1	-	$ 3,948,348	$ -	$ 3,948,348	$ 3,948,348	$ -	$ 3,948,348	$ -	0.00%
Class 800	1	4,866	$ 19,873	$ 1,669	$ 18,204	$ 20,186	$ 1,669	$ 18,517	$ 313	1.58%
Total - Sales Customers - All	655,060	909,760,716	$ 807,984,897	$ 440,344,230	$ 367,640,667	$ 861,838,089	$ 440,344,230	$ 421,493,859	$ 53,853,192	6.67%

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 Revenue % Change
Residential Tr-1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Firm Comm. Ind. 0 to 3,999 Tf-1	17	53,965	$ 32,609	$ -	$ 32,609	$ 34,034	$ -	$ 34,034	$ 1,425	4.37%
Firm Comm. Ind. 4,000 to 39,999 Tf-2	504	13,235,302	$ 3,436,057	$ -	$ 3,436,057	$ 3,933,704	$ -	$ 3,933,704	$ 497,647	14.48%
Firm Comm. Ind. 40,000 to 99,999 Tf-3	495	30,729,206	$ 6,390,713	$ -	$ 6,390,713	$ 6,913,107	$ -	$ 6,913,107	$ 522,394	8.17%
Firm Comm. Ind. 100,000 to 499,999 Tf-4	438	91,035,649	$ 13,523,741	$ -	$ 13,523,741	$ 13,960,710	$ -	$ 13,960,710	$ 436,969	3.23%
Firm Comm. Ind. 500,000 to 999,999 Tf-5	87	64,365,786	$ 7,661,592	$ -	$ 7,661,592	$ 8,234,452	$ -	$ 8,234,452	$ 572,860	7.48%
Firm Comm. Ind. 1,000,000 to 7,999,999 Tf-6	87	186,244,665	$ 14,677,080	$ -	$ 14,677,080	$ 15,678,300	$ -	$ 15,678,300	$ 1,001,220	6.82%
Firm Comm. Ind. 8,000,000 to 14,999,999 Tf-7	2	23,679,265	$ 1,473,859	$ -	$ 1,473,859	$ 1,602,659	$ -	$ 1,602,659	$ 128,800	8.74%
Firm Comm. Ind. 15,000,000 and Over Tf-8	4	137,350,030	$ 4,886,794	$ -	$ 4,886,794	$ 5,604,687	$ -	$ 5,604,687	$ 717,893	14.69%
Transportation Class 801	-	-	$ (49)	$ -	$ (49)	$ (52)	$ -	$ (52)	$ (3)	6.12%
Transportation Class 802	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 803	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 804	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Transportation Class 805	3	2,311,658	$ 239,865	$ -	$ 239,865	$ 257,435	$ -	$ 257,435	$ 17,570	7.32%
Transportation Class 806	11	25,778,396	$ 1,569,554	$ -	$ 1,569,554	$ 1,645,878	$ -	$ 1,645,878	$ 76,324	4.86%
Transportation Class 807	1	14,687,709	$ 721,915	$ -	$ 721,915	$ 788,501	$ -	$ 788,501	$ 66,586	9.22%
Transportation Class 808	2	44,982,655	$ 1,320,795	$ -	$ 1,320,795	$ 1,436,935	$ -	$ 1,436,935	$ 116,140	8.79%
Transportation Class 902	1	458,516,728	$ 1,247,601	$ -	$ 1,247,601	$ 1,247,601	$ -	$ 1,247,601	$ -	0.00%
FITS 1	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
FITS 2	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
FITS 3	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Total - Transportation Customers - All	1,653	1,092,971,014	$ 48,796,417	$ -	$ 57,182,126	$ 61,337,951	$ -	$ 61,337,951	$ 4,155,825	8.52%

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

Wisconsin Gas LLC
Change of Total Revenue Dollar Amounts between Current (PSCW Adjusted) 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 Revenue % Change
Residential	597,023	512,539,474	$ 520,951,923	$ 251,815,108	$ 269,136,815	$ 547,808,999	$ 251,815,108	$ 295,993,891	$ 26,857,076	5.16%
Firm Comm. Ind. 0 to 3,999	42,058	62,796,917	$ 59,367,277	$ 31,513,958	$ 27,853,319	$ 63,923,841	$ 31,513,958	$ 32,409,883	$ 4,556,564	7.68%
Firm Comm. Ind. 4,000 to 39,999	15,432	183,322,524	$ 132,902,723	$ 82,942,804	$ 49,959,919	$ 147,653,680	$ 82,942,804	$ 64,710,876	$ 14,750,957	11.10%
Firm Comm. Ind. 40,000 to 99,999	1,171	73,129,413	$ 36,202,894	$ 20,395,347	$ 15,807,547	$ 39,404,981	$ 20,395,347	$ 19,009,634	$ 3,202,087	8.84%
Firm Comm. Ind. 100,000 to 499,999	604	121,106,504	$ 32,604,746	$ 13,814,639	$ 18,790,107	$ 34,575,327	$ 13,814,639	$ 20,760,688	$ 1,970,581	6.04%
Firm Comm. Ind. 500,000 to 999,999	95	70,685,782	$ 11,335,091	$ 2,770,427	$ 8,564,664	$ 12,256,184	$ 2,770,427	$ 9,485,757	$ 921,093	8.13%
Firm Comm. Ind. 1,000,000 to 7,999,999	90	190,027,664	$ 16,715,153	$ 1,580,363	$ 15,134,790	$ 17,912,001	$ 1,580,363	$ 16,331,638	$ 1,196,848	7.16%
Firm Comm. Ind. 8,000,000 to 14,999,999	2	23,679,265	$ 1,473,859	$ -	$ 1,473,859	$ 1,602,659	$ -	$ 1,602,659	$ 128,800	8.74%
Firm Comm. Ind. 15,000,000 & Over	4	137,350,030	$ 4,886,794	$ -	$ 4,886,794	$ 5,604,687	$ -	$ 5,604,687	$ 717,893	14.69%
Ag. Seasnl Use Crop Drying Step 1 0 to 2,999 Ag-1	192	1,545,338	$ 1,030,464	$ 593,480	$ 436,984	$ 1,046,069	$ 593,480	$ 452,589	$ 15,605	1.63%
Ag. Seasnl Use Crop Drying Step 2 3000 to 9999 Ag-1	-	1,216,412	$ 749,694	$ 462,378	$ 287,316	$ 761,982	$ 462,378	$ 299,604	$ 12,288	1.63%
Ag. Seasnl Use Crop Drying Step 3 Over 9,999 Ag-1	-	1,053,469	$ 585,045	$ 394,367	$ 190,678	$ 595,685	$ 394,367	$ 201,318	$ 10,640	1.63%
Interrupt. Comm. Ind. 50000 to 99999	2	120,773	$ 73,211	$ 46,476	$ 26,735	$ 76,628	$ 46,476	$ 30,152	$ 3,417	4.67%
Interrupt. Comm. Ind. 100000 to 499999	15	2,968,875	$ 1,613,960	$ 1,107,584	$ 506,376	$ 1,661,760	$ 1,107,584	$ 554,176	$ 47,800	2.96%
Interrupt Comm. Ind. 500000 to 999999	1	745,399	$ 389,849	$ 283,978	$ 105,871	$ 404,906	$ 283,978	$ 120,928	$ 15,057	3.86%
Interrupt Comm. Ind. 1,000,000 to 7.999,999	3	4,756,858	$ 2,350,659	$ 1,740,858	$ 609,801	$ 2,434,826	$ 1,740,858	$ 693,968	$ 84,167	3.58%
Interrupt Comm. Ind.8,000,000 to 14,999,999	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Interrupt Comm. Ind.15,000,000 & Over	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
NFPg-10 Power Generation Nominated Firm	-	69,405,021	$ 32,865,779	$ 30,880,794	$ 1,984,985	$ 36,106,993	$ 30,880,794	$ 5,226,199	$ 3,241,214	9.86%
Pg-10 Power Generation	1	-	$ 3,948,348	$ -	$ 3,948,348	$ 3,948,348	$ -	$ 3,948,348	$ -	0.00%
Class 800	1	4,866	$ 19,873	$ 1,669	$ 18,204	$ 20,186	$ 1,669	$ 18,517	$ 313	1.58%
Class 801	-	-	$ (49)	$ -	$ (49)	$ (52)	$ -	$ (52)	$ (3)	6.12%
Class 802	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 803	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 804	-	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0.00%
Class 805	3	2,311,658	$ 239,865	$ -	$ 239,865	$ 257,435	$ -	$ 257,435	$ 17,570	7.32%
Class 806	11	25,778,396	$ 1,569,554	$ -	$ 1,569,554	$ 1,645,878	$ -	$ 1,645,878	$ 76,324	4.86%
Class 807	1	14,687,709	$ 721,915	$ -	$ 721,915	$ 788,501	$ -	$ 788,501	$ 66,586	9.22%
Class 808	2	44,982,655	$ 1,320,795	$ -	$ 1,320,795	$ 1,436,935	$ -	$ 1,436,935	$ 116,140	8.79%
Class 902	1	458,516,728	$ 1,247,601	$ -	$ 1,247,601	$ 1,247,601	$ -	$ 1,247,601	$ -	0.00%
Total - All Customers - All	656,712	2,002,731,730	$ 865,167,023	$ 440,344,230	$ 424,822,793	$ 923,176,040	$ 440,344,230	$ 482,831,810	$ 58,009,017	6.70%

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

Residential Service

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.3637	NA	$ 0.3637	$ 0.3578	NA	$ 0.3578	$ 0.0059	NA	$ 0.0059
Competitive Supply Margin	$ 0.0355	NA	$ -	$ 0.0242	NA	$ -	$ 0.0113	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.4372	NA	$ 0.3647	$ 0.3848	NA	$ 0.3585	$ 0.0524	NA	$ 0.0062
Peak Demand	$ 0.1252	NA	$ -	$ 0.1252	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3721	NA	$ -	$ 0.3721	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	NA	$ -	$ 0.5114	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.9486	NA	$ 0.3647	$ 0.8962	NA	$ 0.3585	$ 0.0524	NA	$ 0.0062
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0082	NA	$ 0.0082	$ 0.0068	NA	$ 0.0068	$ 0.0014	NA	$ 0.0014

Commercial / Industrial Class 1 0 to 3,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.33	NA	$ 0.33	$ 0.33	NA	$ 0.33	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.3618	NA	$ 0.3618	$ 0.3357	NA	$ 0.3357	$ 0.0261	NA	$ 0.0261
Competitive Supply Margin	$ 0.0355	NA	$ -	$ 0.0242	NA	$ -	$ 0.0113	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.4353	NA	$ 0.3628	$ 0.3627	NA	$ 0.3364	$ 0.0726	NA	$ 0.0264
Peak Demand	$ 0.1252	NA	$ -	$ 0.1252	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3721	NA	$ -	$ 0.3721	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	NA	$ -	$ 0.5114	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.9467	NA	$ 0.3628	$ 0.8741	NA	$ 0.3364	$ 0.0726	NA	$ 0.0264
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0122	NA	$ 0.0122	$ 0.0102	NA	$ 0.0102	$ 0.0020	NA	$ 0.0020

NA = Not Available　NA = Not Available　NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

Commercial / Industrial Class 2 4,000 to 39,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 0.85	NA	$ 0.85	$ 0.85	NA	$ 0.85	$ -	NA	$ -
Transportation Administrative	$ -	NA	$ 2.00	$ -	NA	$ 2.00	$ -	NA	$ -
Daily Demand Charge	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Distribution Margin per therm	$ 0.2566	NA	$ 0.2566	$ 0.2193	NA	$ 0.2193	$ 0.0373	NA	$ 0.0373
Competitive Supply Margin	$ 0.0355	NA	$ -	$ 0.0242	NA	$ -	$ 0.0113	NA	$ -
Daily Balancing Margin	$ 0.0010	NA	$ 0.0010	$ 0.0007	NA	$ 0.0007	$ 0.0003	NA	$ 0.0003
Peak Day Margin	$ 0.0370	NA	$ -	$ 0.0021	NA	$ -	$ 0.0349	NA	$ -
Other Margin									
Total All Margin Rates	$ 0.3301	NA	$ 0.2576	$ 0.2463	NA	$ 0.2200	$ 0.0838	NA	$ 0.0376
Peak Demand	$ 0.1252	NA	$ -	$ 0.1252	NA	$ -	$ -	NA	$ -
Annual Demand	$ 0.0141	NA	$ -	$ 0.0141	NA	$ -	$ -	NA	$ -
Commodity	$ 0.3721	NA	$ -	$ 0.3721	NA	$ -	$ -	NA	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	NA	$ -	$ 0.5114	NA	$ -	$ -	NA	$ -
Total Rate	$ 0.8415	NA	$ 0.2576	$ 0.7577	NA	$ 0.2200	$ 0.0838	NA	$ 0.0376
Lost and Unaccounted For Gas	$ -	NA	$ -	$ -	NA	$ -	$ -	NA	$ -
Act 141 Surcharge Rate	$ 0.0122	NA	$ 0.0122	$ 0.0102	NA	$ 0.0102	$ 0.0020	NA	$ 0.0020

NA = Not Available NA = Not Available NA = Not Available

Commercial / Industrial Class 3 40,000 to 99,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1769	$ 0.1769	$ 0.1769	$ 0.1602	$ 0.1602	$ 0.1602	$ 0.0167	$ 0.0167	$ 0.0167
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.2504	$ 0.2134	$ 0.1779	$ 0.1872	$ 0.1851	$ 0.1609	$ 0.0632	$ 0.0283	$ 0.0170
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.7618	$ 0.5996	$ 0.1779	$ 0.6986	$ 0.5713	$ 0.1609	$ 0.0632	$ 0.0283	$ 0.0170
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0020	$ 0.0020	$ 0.0020

NA = Not Available NA = Not Available NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

Commercial / Industrial Class 4 100,000 to 499,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ 15.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1225	$ 0.1225	$ 0.1225	$ 0.1180	$ 0.1180	$ 0.1180	$ 0.0045	$ 0.0045	$ 0.0045
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1960	$ 0.1590	$ 0.1235	$ 0.1450	$ 0.1429	$ 0.1187	$ 0.0510	$ 0.0161	$ 0.0048
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.7074	$ 0.5452	$ 0.1235	$ 0.6564	$ 0.5291	$ 0.1187	$ 0.0510	$ 0.0161	$ 0.0048
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0020	$ 0.0020	$ 0.0020

NA = Not Available NA = Not Available NA = Not Available

Commercial / Industrial Class 5 500,000 to 999,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1037	$ 0.1037	$ 0.1037	$ 0.0951	$ 0.0951	$ 0.0951	$ 0.0086	$ 0.0086	$ 0.0086
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1772	$ 0.1402	$ 0.1047	$ 0.1221	$ 0.1200	$ 0.0958	$ 0.0551	$ 0.0202	$ 0.0089
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.6886	$ 0.5264	$ 0.1047	$ 0.6335	$ 0.5062	$ 0.0958	$ 0.0551	$ 0.0202	$ 0.0089
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0020	$ 0.0020	$ 0.0020

NA = Not Available NA = Not Available NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

Commercial / Industrial Class 6 1,000,000 to 7,999,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0058	$ 0.0058	$ 0.0058	$ 0.0055	$ 0.0055	$ 0.0055	$ 0.0003	$ 0.0003	$ 0.0003
Distribution Margin per therm	$ 0.0521	$ 0.0521	$ 0.0521	$ 0.0476	$ 0.0476	$ 0.0476	$ 0.0045	$ 0.0045	$ 0.0045
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1256	$ 0.0886	$ 0.0531	$ 0.0746	$ 0.0725	$ 0.0483	$ 0.0510	$ 0.0161	$ 0.0048
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.6370	$ 0.4748	$ 0.0531	$ 0.5860	$ 0.4587	$ 0.0483	$ 0.0510	$ 0.0161	$ 0.0048
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

NA = Not Available NA = Not Available NA = Not Available

Commercial / Industrial Class 7 8,000,000 Therms to 14,999,999 Therms Annually

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ 450.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0049	$ 0.0049	$ 0.0049	$ 0.0046	$ 0.0046	$ 0.0046	$ 0.0003	$ 0.0003	$ 0.0003
Distribution Margin per therm	$ 0.0423	$ 0.0423	$ 0.0423	$ 0.0378	$ 0.0378	$ 0.0378	$ 0.0045	$ 0.0045	$ 0.0045
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.1158	$ 0.0788	$ 0.0433	$ 0.0648	$ 0.0627	$ 0.0385	$ 0.0510	$ 0.0161	$ 0.0048
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.6272	$ 0.4650	$ 0.0433	$ 0.5762	$ 0.4489	$ 0.0385	$ 0.0510	$ 0.0161	$ 0.0048
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

Commercial / Industrial Class 8 15,000,000 Therms Annually & Over

Rates - Description	2026 Final Rates Firm Sales	2026 Final Rates Interruptible Sales	2026 Final Rates Transportation	2024 Current Rates Firm Sales	2024 Current Rates Interruptible Sales	2024 Current Rates Transportation	Final Change in Rates Firm Sales	Final Change in Rates Interruptible Sales	Final Change in Rates Transportation
Daily Facitilties Charge	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ 1,382.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ 0.0033	$ 0.0033	$ 0.0033	$ 0.0030	$ 0.0030	$ 0.0030	$ 0.0003	$ 0.0003	$ 0.0003
Distribution Margin per therm	$ 0.0204	$ 0.0204	$ 0.0204	$ 0.0159	$ 0.0159	$ 0.0159	$ 0.0045	$ 0.0045	$ 0.0045
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0939	$ 0.0569	$ 0.0214	$ 0.0429	$ 0.0408	$ 0.0166	$ 0.0510	$ 0.0161	$ 0.0048
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.6053	$ 0.4431	$ 0.0214	$ 0.5543	$ 0.4270	$ 0.0166	$ 0.0510	$ 0.0161	$ 0.0048
Lost and Unaccounted For Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Act 141 Surcharge Rate	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ 0.0001	$ -	$ -	$ -

Agricultural Seasonal Use Sales Service Ag-1

Rates - Description	2026 Final Rates Firm Sales Step 1	2026 Final Rates Firm Sales Step 2	2026 Final Rates Firm Sales Step 3	2024 Current Rates Firm Sales Step 1	2024 Current Rates Firm Sales Step 2	2024 Current Rates Firm Sales Step 3	Final Change in Rates Firm Sales Step 1	Final Change in Rates Firm Sales Step 2	Final Change in Rates Firm Sales Step 3
Daily Facitilties Charge	$ 0.50	$ -	$ -	$ 0.50	$ -	$ -	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Daily Demand Charge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Margin per therm	$ 0.1967	$ 0.1728	$ 0.1176	$ 0.2331	$ 0.2092	$ 0.1540	$ (0.0364)	$ (0.0364)	$ (0.0364)
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ 0.0355	$ 0.0242	$ 0.0242	$ 0.0242	$ 0.0113	$ 0.0113	$ 0.0113
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ 0.0010	$ 0.0007	$ 0.0007	$ 0.0007	$ 0.0003	$ 0.0003	$ 0.0003
Peak Day Margin	$ 0.0370	$ 0.0370	$ 0.0370	$ 0.0021	$ 0.0021	$ 0.0021	$ 0.0349	$ 0.0349	$ 0.0349
Other Margin									
Total All Margin Rates	$ 0.2702	$ 0.2463	$ 0.1911	$ 0.2601	$ 0.2362	$ 0.1810	$ 0.0101	$ 0.0101	$ 0.0101
Peak Demand	$ 0.1252	$ 0.1252	$ 0.1252	$ 0.1252	$ 0.1252	$ 0.1252	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ 0.0141	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ 0.3721	$ 0.3721	$ 0.3721	$ 0.3721	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.5114	$ 0.5114	$ 0.5114	$ 0.5114	$ 0.5114	$ -	$ -	$ -
Total Rate	$ 0.7816	$ 0.7577	$ 0.7025	$ 0.7715	$ 0.7476	$ 0.6924	$ 0.0101	$ 0.0101	$ 0.0101
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	$ 0.0122	$ 0.0122	$ 0.0122	$ 0.0102	$ 0.0102	$ 0.0102	$ 0.0020	$ 0.0020	$ 0.0020

NA = Not Available
NA = Not Available
NA = Not Available

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

Wisconsin Gas LLC
Final and Current Rates
for the test year ended December 31, 2026

	Power Generation Interruptible Sales Service								
	2026 Final Rates			2024 Current Rates			Final Change in Rates		
Rates - Description	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10	Nominated Firm Power Generation NFPg-10	Power Generation Interruptible Sales Pg-10	Transportation Pg-10
Daily Facitilties Charge		$ 10,235.00	$ 10,235.00		$ 10,235.00	$ 10,235.00	$ -	$ -	$ -
Transportation Administrative	$ -	$ -	$ 2.00	$ -	$ -	$ 2.00	$ -	$ -	$ -
Daily Demand Charge	$ -	$ 0.0024	$ 0.0024	$ -	$ 0.0024	$ 0.0024	$ -	$ -	$ -
Distribution Margin per therm	$ 0.0018	$ 0.0018	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0016	$ 0.0002	$ 0.0002	$ -
Competitive Supply Margin	$ 0.0355	$ 0.0355	$ -	$ 0.0242	$ 0.0242	$ -	$ 0.0113	$ 0.0113	$ -
Daily Balancing Margin	$ 0.0010	$ 0.0010	$ -	$ 0.0007	$ 0.0007	$ -	$ 0.0003	$ 0.0003	$ -
Peak Day Margin	$ 0.0370	$ -	$ -	$ 0.0021	$ -	$ -	$ 0.0349	$ -	$ -
Other Margin									
Total All Margin Rates	$ 0.0753	$ 0.0383	$ 0.0016	$ 0.0286	$ 0.0265	$ 0.0016	$ 0.0467	$ 0.0118	$ -
Peak Demand	$ 0.1252	$ -	$ -	$ 0.1252	$ -	$ -	$ -	$ -	$ -
Annual Demand	$ 0.0141	$ 0.0141	$ -	$ 0.0141	$ 0.0141	$ -	$ -	$ -	$ -
Commodity	$ 0.3721	$ 0.3721	$ -	$ 0.3721	$ 0.3721	$ -	$ -	$ -	$ -
Total Natural Gas Rate Per Therm	$ 0.5114	$ 0.3862	$ -	$ 0.5114	$ 0.3862	$ -	$ -	$ -	$ -
Total Rate	$ 0.5867	$ 0.4245	$ 0.0016	$ 0.5400	$ 0.4127	$ 0.0016	$ 0.0467	$ 0.0118	$ -
Lost and Unaccounted For Gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Act 141 Surcharge Rate	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not Available (for each of the three rate groups)

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

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Residential Rg-1

Transportation Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -	
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -	
$/Therm-Winter	$ 0.3585	$ 0.3647	$ 0.0062	
$/Therm-Summer	$ 0.3585	$ 0.3647	$ 0.0062	

Sales Service

	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -	
$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -	
$/Therm-Winter	$ 0.8962	$ 0.9486	$ 0.0524	
$/Therm-Summer	$ 0.7710	$ 0.8234	$ 0.0524	

Usage in Therms	# of Customers & Class Average Use	Transportation Old Annual Bill	Transportation New Annual Bill	Transportation Increase (Decrease)	Transportation Percent of Change	# of Customers & Class Average Use	Sales Old Annual Bill	Sales New Annual Bill	Sales Increase (Decrease)	Sales Percent of Change
375		$ 984.89	$ 987.21	$ 2.32	0.24%		$ 448.24	$ 467.89	$ 19.65	4.38%
475		$ 1,020.74	$ 1,023.68	$ 2.94	0.29%		$ 535.65	$ 560.54	$ 24.89	4.65%
575		$ 1,056.59	$ 1,060.15	$ 3.56	0.34%		$ 623.07	$ 653.20	$ 30.13	4.84%
675		$ 1,092.44	$ 1,096.62	$ 4.18	0.38%		$ 710.48	$ 745.85	$ 35.37	4.98%
775		$ 1,128.29	$ 1,133.09	$ 4.80	0.43%		$ 797.89	$ 838.50	$ 40.61	5.09%
861	597023	$ 1,159.12	$ 1,164.46	$ 5.34	0.46%		$ 873.06	$ 918.18	$ 45.12	5.18%
975		$ 1,199.99	$ 1,206.03	$ 6.04	0.50%		$ 972.71	$ 1,023.80	$ 51.09	5.25%
1,075		$ 1,235.84	$ 1,242.50	$ 6.66	0.54%		$ 1,060.12	$ 1,116.45	$ 56.33	5.31%
1,175		$ 1,271.69	$ 1,278.97	$ 7.28	0.57%		$ 1,147.53	$ 1,209.10	$ 61.57	5.37%
1,275		$ 1,307.54	$ 1,315.44	$ 7.90	0.60%		$ 1,234.95	$ 1,301.76	$ 66.81	5.41%
1,375		$ 1,343.39	$ 1,351.91	$ 8.52	0.63%		$ 1,322.36	$ 1,394.41	$ 72.05	5.45%
1,475		$ 1,379.24	$ 1,388.38	$ 9.14	0.66%		$ 1,409.77	$ 1,487.06	$ 77.29	5.48%
1,575		$ 1,415.09	$ 1,424.85	$ 9.76	0.69%		$ 1,497.18	$ 1,579.71	$ 82.53	5.51%
1,675		$ 1,450.94	$ 1,461.32	$ 10.38	0.72%		$ 1,584.59	$ 1,672.36	$ 87.77	5.54%
1,775		$ 1,486.79	$ 1,497.79	$ 11.00	0.74%		$ 1,672.00	$ 1,765.01	$ 93.01	5.56%
1,875		$ 1,522.64	$ 1,534.26	$ 11.62	0.76%		$ 1,759.42	$ 1,857.67	$ 98.25	5.58%
1,975		$ 1,558.49	$ 1,570.73	$ 12.24	0.79%		$ 1,846.83	$ 1,950.32	$ 103.49	5.60%
2,075		$ 1,594.34	$ 1,607.20	$ 12.86	0.81%		$ 1,934.24	$ 2,042.97	$ 108.73	5.62%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	82.36%	82.36%	Winter Qty %	82.36%	82.36%
Summer QTY %	17.64%	17.64%	Summer QTY %	17.64%	17.64%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Ag. Seasonal Use Crop Drying Step 1 0 to 2,999 Ag-1

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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equ	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7715	$ 0.7816	$ 0.0101	
						$/Therm-Winter Step 2	$ 0.7476	$ 0.7577	$ 0.0101	
						$/Therm-Winter Step 3	$ 0.6924	$ 0.7025	$ 0.0101	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6463	$ 0.6564	$ 0.0101	
						$/Therm-Summer Step 2	$ 0.6224	$ 0.6325	$ 0.0101	
						$/Therm-Summer Step 3	$ 0.5672	$ 0.5773	$ 0.0101	

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
250		NA	NA	NA	NA		$ 346	$ 348	$ 3	0.73%
420		NA	NA	NA	NA		$ 457	$ 461	$ 4	0.93%
590		NA	NA	NA	NA		$ 568	$ 573	$ 6	1.05%
760		NA	NA	NA	NA		$ 678	$ 686	$ 8	1.13%
930		NA	NA	NA	NA		$ 789	$ 799	$ 9	1.19%
1,100		NA	NA	NA	NA		$ 900	$ 911	$ 11	1.23%
1,270		NA	NA	NA	NA		$ 1,011	$ 1,024	$ 13	1.27%
1,440	59	NA	NA	NA	NA		$ 1,122	$ 1,137	$ 15	1.30%
1,610		NA	NA	NA	NA		$ 1,233	$ 1,249	$ 16	1.32%
1,780		NA	NA	NA	NA		$ 1,344	$ 1,362	$ 18	1.34%
1,950		NA	NA	NA	NA		$ 1,455	$ 1,475	$ 20	1.35%
2,120		NA	NA	NA	NA		$ 1,566	$ 1,587	$ 21	1.37%
2,290		NA	NA	NA	NA		$ 1,677	$ 1,700	$ 23	1.38%
2,460		NA	NA	NA	NA		$ 1,788	$ 1,813	$ 25	1.39%
2,630		NA	NA	NA	NA		$ 1,899	$ 1,925	$ 27	1.40%
2,800		NA	NA	NA	NA		$ 2,010	$ 2,038	$ 28	1.41%
2,999		NA	NA	NA	NA		$ 2,140	$ 2,170	$ 30	1.42%
	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:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Ag. Seasonal Use Crop Drying Step 2 3,000 to 9,999 Ag-1

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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7715	$ 0.7816	$ 0.0101	
						$/Therm-Winter Step 2	$ 0.7476	$ 0.7577	$ 0.0101	
						$/Therm-Winter Step 3	$ 0.6924	$ 0.7025	$ 0.0101	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6463	$ 0.6564	$ 0.0101	
						$/Therm-Summer Step 2	$ 0.6224	$ 0.6325	$ 0.0101	
						$/Therm-Summer Step 3	$ 0.5672	$ 0.5773	$ 0.0101	

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
3,000		NA	NA	NA	NA		$ 2,123	$ 2,154	$ 30	1.43%
3,440		NA	NA	NA	NA		$ 2,408	$ 2,443	$ 35	1.44%
3,880		NA	NA	NA	NA		$ 2,693	$ 2,732	$ 39	1.46%
4,320		NA	NA	NA	NA		$ 2,977	$ 3,021	$ 44	1.47%
4,760	106	NA	NA	NA	NA		$ 3,262	$ 3,310	$ 48	1.47%
5,200		NA	NA	NA	NA		$ 3,547	$ 3,599	$ 53	1.48%
5,640		NA	NA	NA	NA		$ 3,831	$ 3,888	$ 57	1.49%
6,080		NA	NA	NA	NA		$ 4,116	$ 4,177	$ 61	1.49%
6,520		NA	NA	NA	NA		$ 4,400	$ 4,466	$ 66	1.50%
6,960		NA	NA	NA	NA		$ 4,685	$ 4,755	$ 70	1.50%
7,400		NA	NA	NA	NA		$ 4,970	$ 5,044	$ 75	1.50%
7,840		NA	NA	NA	NA		$ 5,254	$ 5,334	$ 79	1.51%
8,280		NA	NA	NA	NA		$ 5,539	$ 5,623	$ 84	1.51%
8,720		NA	NA	NA	NA		$ 5,824	$ 5,912	$ 88	1.51%
9,160		NA	NA	NA	NA		$ 6,108	$ 6,201	$ 93	1.51%
9,600		NA	NA	NA	NA		$ 6,393	$ 6,490	$ 97	1.52%
9,999		NA	NA	NA	NA		$ 6,651	$ 6,752	$ 101	1.52%
	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:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Ag. Seasonal Use Crop Drying Step 3 10,000 and over Ag-1

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.	$ 15.21	$ 15.21	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or equiv.	$ 0.50	$ 0.50	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter Step 1	$ 0.7715	$ 0.7816	$ 0.0101	
						$/Therm-Winter Step 2	$ 0.7476	$ 0.7577	$ 0.0101	
						$/Therm-Winter Step 3	$ 0.6924	$ 0.7025	$ 0.0101	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer Step 1	$ 0.6463	$ 0.6564	$ 0.0101	
						$/Therm-Summer Step 2	$ 0.6224	$ 0.6325	$ 0.0101	
						$/Therm-Summer Step 3	$ 0.5672	$ 0.5773	$ 0.0101	

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
10,000		NA	NA	NA	NA		$ 6,652	$ 6,753	$ 101	1.52%
15,620		NA	NA	NA	NA		$ 10,203	$ 10,360	$ 158	1.55%
21,240		NA	NA	NA	NA		$ 13,705	$ 13,919	$ 215	1.57%
26,860		NA	NA	NA	NA		$ 17,207	$ 17,478	$ 271	1.58%
32,480		NA	NA	NA	NA		$ 20,709	$ 21,037	$ 328	1.58%
38,100		NA	NA	NA	NA		$ 24,211	$ 24,596	$ 385	1.59%
43,720		NA	NA	NA	NA		$ 27,520	$ 27,961	$ 442	1.60%
49,340		NA	NA	NA	NA		$ 30,713	$ 31,211	$ 498	1.62%
54,960		NA	NA	NA	NA		$ 33,906	$ 34,462	$ 555	1.64%
60,580		NA	NA	NA	NA		$ 37,100	$ 37,712	$ 612	1.65%
66,200		NA	NA	NA	NA		$ 40,293	$ 40,962	$ 669	1.66%
71,820		NA	NA	NA	NA		$ 43,487	$ 44,212	$ 725	1.67%
77,440		NA	NA	NA	NA		$ 46,680	$ 47,462	$ 782	1.68%
83,060		NA	NA	NA	NA		$ 49,873	$ 50,712	$ 839	1.68%
88,680		NA	NA	NA	NA		$ 53,067	$ 53,963	$ 896	1.69%
94,300	19	NA	NA	NA	NA		$ 56,260	$ 57,213	$ 952	1.69%
99,999		NA	NA	NA	NA		$ 59,499	$ 60,509	$ 1,010	1.70%
	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:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 0 to 3,999 Fg-1 &
Firm Comm. Ind. 0 to 3,999 Tf-1

Transportation Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 70.87	$ 70.87	$ -
$/Day Fixed or equiv.	$ 2.33	$ 2.33	$ -
Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.3364	$ 0.3628	$ 0.0264
$/Therm-Summer	$ 0.3364	$ 0.3628	$ 0.0264

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)
$/Mo. Fixed or equiv.	$ 10.04	$ 10.04	$ -
$/Day Fixed or equiv.	$ 0.33	$ 0.33	$ -
Demand Charge	N/A	N/A	N/A
$/Therm-Winter	$ 0.8741	$ 0.9467	$ 0.0726
$/Therm-Summer	$ 0.7489	$ 0.8215	$ 0.0726

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		$ 929.50	$ 935.71	$ 6.21	0.67%		$ 322.02	$ 339.08	$ 17.06	5.30%
470		$ 1,008.56	$ 1,020.97	$ 12.41	1.23%		$ 523.58	$ 557.70	$ 34.12	6.52%
705		$ 1,087.61	$ 1,106.22	$ 18.61	1.71%		$ 725.15	$ 776.33	$ 51.18	7.06%
940		$ 1,166.67	$ 1,191.48	$ 24.81	2.13%		$ 926.71	$ 994.95	$ 68.24	7.36%
1,175		$ 1,245.72	$ 1,276.74	$ 31.02	2.49%		$ 1,128.28	$ 1,213.58	$ 85.30	7.56%
1,457		$ 1,340.58	$ 1,379.05	$ 38.47	2.87%	41,693	$ 1,370.15	$ 1,475.93	$ 105.78	7.72%
1,645		$ 1,403.83	$ 1,447.26	$ 43.43	3.09%		$ 1,531.41	$ 1,650.83	$ 119.42	7.80%
1,900	6	$ 1,489.61	$ 1,539.77	$ 50.16	3.37%		$ 1,750.13	$ 1,888.07	$ 137.94	7.88%
2,135		$ 1,568.66	$ 1,625.03	$ 56.37	3.59%		$ 1,951.69	$ 2,106.69	$ 155.00	7.94%
2,370		$ 1,647.72	$ 1,710.29	$ 62.57	3.80%		$ 2,153.26	$ 2,325.32	$ 172.06	7.99%
2,605		$ 1,726.77	$ 1,795.54	$ 68.77	3.98%		$ 2,354.82	$ 2,543.94	$ 189.12	8.03%
2,840		$ 1,805.83	$ 1,880.80	$ 74.97	4.15%		$ 2,556.39	$ 2,762.57	$ 206.18	8.07%
3,075		$ 1,884.88	$ 1,966.06	$ 81.18	4.31%		$ 2,757.95	$ 2,981.20	$ 223.25	8.09%
3,310		$ 1,963.93	$ 2,051.32	$ 87.39	4.45%		$ 2,959.52	$ 3,199.82	$ 240.30	8.12%
3,545		$ 2,042.99	$ 2,136.58	$ 93.59	4.58%		$ 3,161.08	$ 3,418.45	$ 257.37	8.14%
3,780		$ 2,122.04	$ 2,221.83	$ 99.79	4.70%		$ 3,362.65	$ 3,637.07	$ 274.42	8.16%
3,915		$ 2,167.46	$ 2,270.81	$ 103.35	4.77%		$ 3,478.44	$ 3,762.67	$ 284.23	8.17%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	77.82%	77.82%	Winter Qty %	86.92%	86.92%
Summer QTY %	22.18%	22.18%	Summer QTY %	13.08%	13.08%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 4,000 to 39,999 Fg-2 &
Firm Comm. Ind. 4,000 to 39,999 Tf-2

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.	$ 86.69	$ 86.69	$ -		$/Mo. Fixed or equiv.	$ 25.85	$ 25.85	$ -	
	$/Day Fixed or equiv.	$ 2.85	$ 2.85	$ -		$/Day Fixed or equiv.	$ 0.85	$ 0.85	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.2200	$ 0.2576	$ 0.0376		$/Therm-Winter	$ 0.7577	$ 0.8415	$ 0.0838	
	$/Therm-Summer	$ 0.2200	$ 0.2576	$ 0.0376		$/Therm-Summer	$ 0.6325	$ 0.7163	$ 0.0838	

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
4,000		$ 1,920.25	$ 2,070.65	$ 150.40	7.83%		$ 3,240.89	$ 3,576.09	$ 335.20	10.34%
6,118		$ 2,386.21	$ 2,616.25	$ 230.04	9.64%		$ 4,792.66	$ 5,305.35	$ 512.69	10.70%
8,236		$ 2,852.17	$ 3,161.84	$ 309.67	10.86%		$ 6,344.44	$ 7,034.61	$ 690.17	10.88%
10,354		$ 3,318.13	$ 3,707.44	$ 389.31	11.73%		$ 7,896.21	$ 8,763.88	$ 867.67	10.99%
11,121		$ 3,486.87	$ 3,905.02	$ 418.15	11.99%	13952	$ 8,458.16	$ 9,390.10	$ 931.94	11.02%
14,590		$ 4,250.05	$ 4,798.63	$ 548.58	12.91%		$ 10,999.76	$ 12,222.40	$ 1,222.64	11.12%
16,708		$ 4,716.01	$ 5,344.23	$ 628.22	13.32%		$ 12,551.53	$ 13,951.66	$ 1,400.13	11.16%
18,826		$ 5,181.97	$ 5,889.83	$ 707.86	13.66%		$ 14,103.31	$ 15,680.93	$ 1,577.62	11.19%
20,944		$ 5,647.93	$ 6,435.42	$ 787.49	13.94%		$ 15,655.08	$ 17,410.19	$ 1,755.11	11.21%
23,062		$ 6,113.89	$ 6,981.02	$ 867.13	14.18%		$ 17,206.85	$ 19,139.45	$ 1,932.60	11.23%
25,180		$ 6,579.85	$ 7,526.62	$ 946.77	14.39%		$ 18,758.63	$ 20,868.71	$ 2,110.08	11.25%
27,298	382	$ 7,045.81	$ 8,072.21	$ 1,026.40	14.57%		$ 20,310.40	$ 22,597.98	$ 2,287.58	11.26%
29,416		$ 7,511.77	$ 8,617.81	$ 1,106.04	14.72%		$ 21,862.18	$ 24,327.24	$ 2,465.06	11.28%
31,534		$ 7,977.73	$ 9,163.41	$ 1,185.68	14.86%		$ 23,413.95	$ 26,056.50	$ 2,642.55	11.29%
33,652		$ 8,443.69	$ 9,709.01	$ 1,265.32	14.99%		$ 24,965.72	$ 27,785.76	$ 2,820.04	11.30%
35,770		$ 8,909.65	$ 10,254.60	$ 1,344.95	15.10%		$ 26,517.50	$ 29,515.02	$ 2,997.52	11.30%
37,888		$ 9,375.61	$ 10,800.20	$ 1,424.59	15.19%		$ 28,069.27	$ 31,244.29	$ 3,175.02	11.31%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	82.79%	82.79%	Winter Qty %	80.00%	80.00%
Summer QTY %	17.21%	17.21%	Summer QTY %	20.00%	20.00%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 40,000 to 99,999 Fg-3 &
Firm Comm. Ind. 40,000 to 99,999 Tf-3

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.	$ 243.33	$ 243.33	$ -		$/Mo. Fixed or equiv.	$ 182.50	$ 182.50	$ -	
	$/Day Fixed or equiv.	$ 8.00	$ 8.00	$ -		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1609	$ 0.1779	$ 0.0170		$/Therm-Winter	$ 0.6986	$ 0.7618	$ 0.0632	
	$/Therm-Summer	$ 0.1609	$ 0.1779	$ 0.0170		$/Therm-Summer	$ 0.5734	$ 0.6366	$ 0.0632	

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
40,000		$ 9,356.00	$ 10,036.00	$ 680.00	7.27%		$ 28,980.16	$ 31,508.16	$ 2,528.00	8.72%
43,529		$ 9,923.82	$ 10,663.81	$ 739.99	7.46%		$ 31,343.72	$ 34,094.75	$ 2,751.03	8.78%
47,058		$ 10,491.63	$ 11,291.62	$ 799.99	7.63%		$ 33,707.28	$ 36,681.35	$ 2,974.07	8.82%
50,587		$ 11,059.45	$ 11,919.43	$ 859.98	7.78%		$ 36,070.84	$ 39,267.94	$ 3,197.10	8.86%
54,116		$ 11,627.26	$ 12,547.24	$ 919.98	7.91%		$ 38,434.40	$ 41,854.53	$ 3,420.13	8.90%
57,645		$ 12,195.08	$ 13,175.05	$ 979.97	8.04%		$ 40,797.96	$ 44,441.13	$ 3,643.17	8.93%
61,270		$ 12,778.34	$ 13,819.93	$ 1,041.59	8.15%		$ 43,225.82	$ 47,098.09	$ 3,872.27	8.96%
63,512		$ 13,139.08	$ 14,218.78	$ 1,079.70	8.22%	646	$ 44,727.41	$ 48,741.37	$ 4,013.96	8.97%
68,232		$ 13,898.53	$ 15,058.47	$ 1,159.94	8.35%		$ 47,888.65	$ 52,200.91	$ 4,312.26	9.00%
71,761	389	$ 14,466.34	$ 15,686.28	$ 1,219.94	8.43%		$ 50,252.21	$ 54,787.51	$ 4,535.30	9.03%
75,290		$ 15,034.16	$ 16,314.09	$ 1,279.93	8.51%		$ 52,615.77	$ 57,374.10	$ 4,758.33	9.04%
78,819		$ 15,601.98	$ 16,941.90	$ 1,339.92	8.59%		$ 54,979.33	$ 59,960.70	$ 4,981.37	9.06%
82,348		$ 16,169.79	$ 17,569.71	$ 1,399.92	8.66%		$ 57,342.90	$ 62,547.29	$ 5,204.39	9.08%
85,877		$ 16,737.61	$ 18,197.52	$ 1,459.91	8.72%		$ 59,706.46	$ 65,133.88	$ 5,427.42	9.09%
89,406		$ 17,305.43	$ 18,825.33	$ 1,519.90	8.78%		$ 62,070.02	$ 67,720.48	$ 5,650.46	9.10%
92,935		$ 17,873.24	$ 19,453.14	$ 1,579.90	8.84%		$ 64,433.58	$ 70,307.07	$ 5,873.49	9.12%
96,464		$ 18,441.06	$ 20,080.95	$ 1,639.89	8.89%		$ 66,797.14	$ 72,893.67	$ 6,096.53	9.13%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	79.94%	79.94%	Winter Qty %	76.96%	76.96%
Summer QTY %	20.06%	20.06%	Summer QTY %	23.04%	23.04%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 100,000 to 499,999 Fg-4 &
Firm Comm. Ind. 100,000 to 499,999 Tf-4

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.	$ 517.08	$ 517.08	$ -		$/Mo. Fixed or equiv.	$ 456.25	$ 456.25	$ -	
	$/Day Fixed or equiv.	$ 17.00	$ 17.00	$ -		$/Day Fixed or equiv.	$ 15.00	$ 15.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.1187	$ 0.1235	$ 0.0048		$/Therm-Winter	$ 0.6564	$ 0.7074	$ 0.0510	
	$/Therm-Summer	$ 0.1187	$ 0.1235	$ 0.0048		$/Therm-Summer	$ 0.5312	$ 0.5822	$ 0.0510	

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
100,000		$ 18,075.00	$ 18,555.00	$ 480.00	2.66%		$ 66,841.92	$ 71,941.92	$ 5,100.00	7.63%
123,529		$ 20,867.89	$ 21,460.83	$ 592.94	2.84%		$ 81,280.95	$ 87,580.93	$ 6,299.98	7.75%
158,630		$ 25,034.38	$ 25,795.81	$ 761.43	3.04%	151	$ 102,821.35	$ 110,911.48	$ 8,090.13	7.87%
177,158		$ 27,233.65	$ 28,084.01	$ 850.36	3.12%		$ 114,191.42	$ 123,226.47	$ 9,035.05	7.91%
194,116		$ 29,246.57	$ 30,178.33	$ 931.76	3.19%		$ 124,598.02	$ 134,497.93	$ 9,899.91	7.95%
217,645		$ 32,039.46	$ 33,084.16	$ 1,044.70	3.26%		$ 139,037.04	$ 150,136.94	$ 11,099.90	7.98%
241,174	382	$ 34,832.35	$ 35,989.99	$ 1,157.64	3.32%		$ 153,476.07	$ 165,775.94	$ 12,299.87	8.01%
264,703		$ 37,625.25	$ 38,895.82	$ 1,270.57	3.38%		$ 167,915.09	$ 181,414.94	$ 13,499.85	8.04%
288,232		$ 40,418.14	$ 41,801.65	$ 1,383.51	3.42%		$ 182,354.11	$ 197,053.94	$ 14,699.83	8.06%
311,761		$ 43,211.03	$ 44,707.48	$ 1,496.45	3.46%		$ 196,793.14	$ 212,692.95	$ 15,899.81	8.08%
335,290		$ 46,003.92	$ 47,613.32	$ 1,609.40	3.50%		$ 211,232.16	$ 228,331.95	$ 17,099.79	8.10%
358,819		$ 48,796.82	$ 50,519.15	$ 1,722.33	3.53%		$ 225,671.18	$ 243,970.95	$ 18,299.77	8.11%
382,348		$ 51,589.71	$ 53,424.98	$ 1,835.27	3.56%		$ 240,110.21	$ 259,609.95	$ 19,499.74	8.12%
405,877		$ 54,382.60	$ 56,330.81	$ 1,948.21	3.58%		$ 254,549.23	$ 275,248.96	$ 20,699.73	8.13%
429,406		$ 57,175.49	$ 59,236.64	$ 2,061.15	3.60%		$ 268,988.25	$ 290,887.96	$ 21,899.71	8.14%
452,935		$ 59,968.38	$ 62,142.47	$ 2,174.09	3.63%		$ 283,427.28	$ 306,526.96	$ 23,099.68	8.15%
476,464		$ 62,761.28	$ 65,048.30	$ 2,287.02	3.64%		$ 297,866.30	$ 322,165.96	$ 24,299.66	8.16%

Winter Qty %	67.81%	67.81%	Winter Qty %	65.87%	65.87%
Summer QTY %	32.19%	32.19%	Summer QTY %	34.13%	34.13%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 500,000 to 999,999 Fg-5 &
Firm Comm. Ind. 500,000 to 999,999 Tf-5

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.	$ 1,429.58	$ 1,429.58	$ -		$/Mo. Fixed or equiv.	$ 1,368.75	$ 1,368.75	$ -	
	$/Day Fixed or equiv.	$ 47.00	$ 47.00	$ -		$/Day Fixed or equiv.	$ 45.00	$ 45.00	$ -	
	Demand Charge	N/A	N/A	N/A		Demand Charge	N/A	N/A	N/A	
	$/Therm-Winter	$ 0.0958	$ 0.1047	$ 0.0089		$/Therm-Winter	$ 0.6335	$ 0.6886	$ 0.0551	
	$/Therm-Summer	$ 0.0958	$ 0.1047	$ 0.0089		$/Therm-Summer	$ 0.5083	$ 0.5634	$ 0.0551	

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
500,000		$ 65,055.00	$ 69,505.00	$ 4,450.00	6.84%		$ 305,105.16	$ 332,655.16	$ 27,550.00	9.03%
529,412		$ 67,872.67	$ 72,584.44	$ 4,711.77	6.94%		$ 322,086.48	$ 351,257.08	$ 29,170.60	9.06%
558,824		$ 70,690.34	$ 75,663.87	$ 4,973.53	7.04%		$ 339,067.80	$ 369,859.01	$ 30,791.21	9.08%
588,236		$ 73,508.01	$ 78,743.31	$ 5,235.30	7.12%		$ 356,049.13	$ 388,460.93	$ 32,411.80	9.10%
617,648		$ 76,325.68	$ 81,822.75	$ 5,497.07	7.20%		$ 373,030.45	$ 407,062.85	$ 34,032.40	9.12%
661,674		$ 80,543.37	$ 86,432.27	$ 5,888.90	7.31%	9	$ 398,449.31	$ 434,907.55	$ 36,458.24	9.15%
676,472	85	$ 81,961.02	$ 87,981.62	$ 6,020.60	7.35%		$ 406,993.09	$ 444,266.70	$ 37,273.61	9.16%
705,884		$ 84,778.69	$ 91,061.05	$ 6,282.36	7.41%		$ 423,974.41	$ 462,868.62	$ 38,894.21	9.17%
735,296		$ 87,596.36	$ 94,140.49	$ 6,544.13	7.47%		$ 440,955.73	$ 481,470.54	$ 40,514.81	9.19%
760,956		$ 90,054.58	$ 96,827.09	$ 6,772.51	7.52%		$ 455,770.80	$ 497,699.48	$ 41,928.68	9.20%
794,120		$ 93,231.70	$ 100,299.36	$ 7,067.66	7.58%		$ 474,918.38	$ 518,674.39	$ 43,756.01	9.21%
823,532		$ 96,049.37	$ 103,378.80	$ 7,329.43	7.63%		$ 491,899.70	$ 537,276.31	$ 45,376.61	9.22%
852,944		$ 98,867.04	$ 106,458.24	$ 7,591.20	7.68%		$ 508,881.02	$ 555,878.24	$ 46,997.22	9.24%
882,356		$ 101,684.70	$ 109,537.67	$ 7,852.97	7.72%		$ 525,862.34	$ 574,480.16	$ 48,617.82	9.25%
911,768		$ 104,502.37	$ 112,617.11	$ 8,114.74	7.77%		$ 542,843.66	$ 593,082.08	$ 50,238.42	9.25%
941,180		$ 107,320.04	$ 115,696.55	$ 8,376.51	7.81%		$ 559,824.99	$ 611,684.00	$ 51,859.01	9.26%
970,592		$ 110,137.71	$ 118,775.98	$ 8,638.27	7.84%		$ 576,806.31	$ 630,285.93	$ 53,479.62	9.27%
	Winter Qty %	57.65%	57.65%			Winter Qty %	55.16%	55.16%		
	Summer QTY %	42.35%	42.35%			Summer QTY %	44.84%	44.84%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 1,000,000 to 7,999,999 Fg-6 &
Firm Comm. Ind. 1,000,000 to 7,999,999 Tf-6

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.	$ 3,558.75	$ 3,558.75	$ -		$/Mo. Fixed or equiv.	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or equiv.	$ 117.00	$ 117.00	$ -		$/Day Fixed or equiv.	$ 115.00	$ 115.00	$ -	
	Demand Charge	$ 0.0055	$ 0.0058	$ 0.0003		Demand Charge	$ 0.0055	$ 0.0058	$ 0.0003	
	$/Therm-Winter	$ 0.0483	$ 0.0531	$ 0.0048		$/Therm-Winter	$ 0.5860	$ 0.6370	$ 0.0510	
	$/Therm-Summer	$ 0.0483	$ 0.0531	$ 0.0048		$/Therm-Summer	$ 0.4608	$ 0.5118	$ 0.0510	

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
1,000,000	11156	$ 113,400.67	$ 119,422.25	$ 6,021.58	5.31%	11156	$ 557,886.80	$ 608,890.14	$ 51,003.34	9.14%
1,261,000	11156	$ 126,006.97	$ 133,281.35	$ 7,274.38	5.77%	11156	$ 692,523.76	$ 756,838.11	$ 64,314.35	9.29%
1,823,530	11156	$ 153,177.17	$ 163,151.70	$ 9,974.53	6.51%	11156	$ 982,705.11	$ 1,075,708.49	$ 93,003.38	9.46%
2,235,295	11156	$ 173,065.42	$ 185,016.42	$ 11,951.00	6.91%	11156	$ 1,195,114.27	$ 1,309,117.66	$ 114,003.39	9.54%
2,647,060	11156	$ 192,953.67	$ 206,881.14	$ 13,927.47	7.22%	11156	$ 1,407,523.42	$ 1,542,526.83	$ 135,003.41	9.59%
3,058,825	11156	$ 212,841.92	$ 228,745.86	$ 15,903.94	7.47%	11156	$ 1,619,932.58	$ 1,775,936.00	$ 156,003.42	9.63%
3,470,590	11156	$ 232,730.17	$ 250,610.58	$ 17,880.41	7.68%	11156	$ 1,832,341.74	$ 2,009,345.17	$ 177,003.43	9.66%
3,882,355	11156	$ 252,618.42	$ 272,475.30	$ 19,856.88	7.86%	11156	$ 2,044,750.89	$ 2,242,754.34	$ 198,003.45	9.68%
4,294,120	11156	$ 272,506.67	$ 294,340.02	$ 21,833.35	8.01%	11156	$ 2,257,160.05	$ 2,476,163.52	$ 219,003.47	9.70%
4,705,885	11156	$ 292,394.92	$ 316,204.75	$ 23,809.83	8.14%	11156	$ 2,469,569.21	$ 2,709,572.69	$ 240,003.48	9.72%
5,117,650	11156	$ 312,283.17	$ 338,069.47	$ 25,786.30	8.26%	11156	$ 2,681,978.36	$ 2,942,981.86	$ 261,003.50	9.73%
5,529,415	11156	$ 332,171.41	$ 359,934.19	$ 27,762.78	8.36%	11156	$ 2,894,387.52	$ 3,176,391.03	$ 282,003.51	9.74%
6,000,000	11156	$ 354,900.67	$ 384,922.25	$ 30,021.58	8.46%	11156	$ 3,137,139.00	$ 3,443,142.34	$ 306,003.34	9.75%
6,352,945	11156	$ 371,947.91	$ 403,663.63	$ 31,715.72	8.53%	11156	$ 3,319,205.83	$ 3,643,209.37	$ 324,003.54	9.76%
6,764,710	11156	$ 391,836.16	$ 425,528.35	$ 33,692.19	8.60%	11156	$ 3,531,614.99	$ 3,876,618.54	$ 345,003.55	9.77%
7,176,475	11156	$ 411,724.41	$ 447,393.07	$ 35,668.66	8.66%	11156	$ 3,744,024.14	$ 4,110,027.72	$ 366,003.58	9.78%
7,588,240	11156	$ 431,612.66	$ 469,257.80	$ 37,645.14	8.72%	11156	$ 3,956,433.30	$ 4,343,436.89	$ 387,003.59	9.78%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	55.62%	55.62%	Winter Qty %	43.97%	43.97%
Summer QTY %	44.38%	44.38%	Summer QTY %	56.03%	56.03%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 8,000,000 to 14,999,999 Fg-7 &
Firm Comm. Ind. 8,000,000 to 14,999,999 Tf-7

Transportation Service

Usage in Therms		Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
	$/Mo. Fixed or equiv.	$ 13,748.33	$ 13,748.33	$ -	
	$/Day Fixed or equiv.	$ 452.00	$ 452.00	$ -	
	Demand Charge	$ 0.0046	$ 0.0049	$ 0.0003	
	$/Therm-Winter	$ 0.0385	$ 0.0433	$ 0.0048	
	$/Therm-Summer	$ 0.0385	$ 0.0433	$ 0.0048	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
8,000,000	69162	$ 589,103.00	$ 635,076.24	$ 45,973.24	7.80%
8,437,500	69162	$ 605,946.75	$ 654,019.99	$ 48,073.24	7.93%
8,875,000	69162	$ 622,790.50	$ 672,963.74	$ 50,173.24	8.06%
9,312,500	69162	$ 639,634.25	$ 691,907.49	$ 52,273.24	8.17%
9,750,000	69162	$ 656,478.00	$ 710,851.24	$ 54,373.24	8.28%
10,187,500	69162	$ 673,321.75	$ 729,794.99	$ 56,473.24	8.39%
10,625,000	69162	$ 690,165.50	$ 748,738.74	$ 58,573.24	8.49%
11,062,500	69162	$ 707,009.25	$ 767,682.49	$ 60,673.24	8.58%
11,500,000	69162	$ 723,853.00	$ 786,626.24	$ 62,773.24	8.67%
11,937,500	69162	$ 740,696.75	$ 805,569.99	$ 64,873.24	8.76%
12,375,000	69162	$ 757,540.50	$ 824,513.74	$ 66,973.24	8.84%
12,812,500	69162	$ 774,384.25	$ 843,457.49	$ 69,073.24	8.92%
13,250,000	69162	$ 791,228.00	$ 862,401.24	$ 71,173.24	9.00%
13,687,500	69162	$ 808,071.75	$ 881,344.99	$ 73,273.24	9.07%
14,125,000	69162	$ 824,915.50	$ 900,288.74	$ 75,373.24	9.14%
14,562,500	69162	$ 841,759.25	$ 919,232.49	$ 77,473.24	9.20%
14,900,000	69162	$ 854,753.00	$ 933,846.24	$ 79,093.24	9.25%

	Old	New
Winter Qty %	50.22%	50.22%
Summer QTY %	49.78%	49.78%

Sales Service

	Old Annual Rate	New Annual Rate	Increase (Decrease)	Percent of Change
$/Mo. Fixed or equiv.	$ 13,687.50	$ 13,687.50	$ -	
$/Day Fixed or equiv.	$ 450.00	$ 450.00	$ -	
Demand Charge	$ 0.0046	$ 0.0049	$ 0.0003	
$/Therm-Winter	$ 0.5762	$ 0.6272	$ 0.0510	
$/Therm-Summer	$ 0.4510	$ 0.5020	$ 0.0510	

Usage in Therms	Demand Charge Quantity	Old Annual Bill	New Annual Bill	Increase (Decrease)	Percent of Change
8,000,000	69162	$ 4,391,376.52	$ 4,806,949.76	$ 415,573.24	9.46%
8,437,500	69162	$ 4,616,197.02	$ 5,054,082.76	$ 437,885.74	9.49%
8,875,000	69162	$ 4,841,017.53	$ 5,301,215.77	$ 460,198.24	9.51%
9,312,500	69162	$ 5,065,838.03	$ 5,548,348.77	$ 482,510.74	9.52%
9,750,000	69162	$ 5,290,658.54	$ 5,795,481.78	$ 504,823.24	9.54%
10,187,500	69162	$ 5,515,479.04	$ 6,042,614.78	$ 527,135.74	9.56%
10,625,000	69162	$ 5,740,299.55	$ 6,289,747.79	$ 549,448.24	9.57%
11,062,500	69162	$ 5,965,120.05	$ 6,536,880.79	$ 571,760.74	9.59%
11,500,000	69162	$ 6,189,940.56	$ 6,784,013.80	$ 594,073.24	9.60%
11,937,500	69162	$ 6,414,761.06	$ 7,031,146.80	$ 616,385.74	9.61%
12,375,000	69162	$ 6,639,581.57	$ 7,278,279.81	$ 638,698.24	9.62%
12,812,500	69162	$ 6,864,402.07	$ 7,525,412.81	$ 661,010.74	9.63%
13,250,000	69162	$ 7,089,222.58	$ 7,772,545.82	$ 683,323.24	9.64%
13,687,500	69162	$ 7,314,043.08	$ 8,019,678.82	$ 705,635.74	9.65%
14,125,000	69162	$ 7,538,863.59	$ 8,266,811.83	$ 727,948.24	9.66%
14,562,500	69162	$ 7,763,684.09	$ 8,513,944.83	$ 750,260.74	9.66%
14,900,000	69162	$ 7,937,117.05	$ 8,704,590.29	$ 767,473.24	9.67%

	Old	New
Winter Qty %	50.22%	50.22%
Summer QTY %	49.78%	49.78%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Firm Comm. Ind. 15,000,000 and Over Fg-8 &
Firm Comm. Ind. 15,000,000 and Over Tf-8

Transportation Service / Sales Service

Usage in Therms		Old Annual Rate (Transportation)	New Annual Rate (Transportation)	Increase (Decrease) (Transportation)	Percent of Change (Transportation)		Old Annual Rate (Sales)	New Annual Rate (Sales)	Increase (Decrease) (Sales)	Percent of Change (Sales)
	$/Mo. Fixed or equiv.	$ 42,096.67	$ 42,096.67	$ -		$/Mo. Fixed or equiv.	$ 42,035.83	$ 42,035.83	$ -	
	$/Day Fixed or equiv.	$ 1,384.00	$ 1,384.00	$ -		$/Day Fixed or equiv.	$ 1,382.00	$ 1,382.00	$ -	
	Demand Charge	$ 0.0030	$ 0.0033	$ 0.0003		Demand Charge	$ 0.0030	$ 0.0033	$ 0.0003	
	$/Therm-Winter	$ 0.0166	$ 0.0214	$ 0.0048		$/Therm-Winter	$ 0.5543	$ 0.6053	$ 0.0510	
	$/Therm-Summer	$ 0.0166	$ 0.0214	$ 0.0048		$/Therm-Summer	$ 0.5543	$ 0.6053	$ 0.0510	

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	98606	$ 862,133.57	$ 944,930.93	$ 82,797.36	9.60%	98606	$ 8,926,903.57	$ 9,702,700.93	$ 775,797.36	8.69%
15,938,000	98606	$ 877,704.37	$ 965,004.13	$ 87,299.76	9.95%	98606	$ 9,446,836.97	$ 10,270,472.33	$ 823,635.36	8.72%
16,876,000	98606	$ 893,275.17	$ 985,077.33	$ 91,802.16	10.28%	98606	$ 9,966,770.37	$ 10,838,243.73	$ 871,473.36	8.74%
17,814,000	98606	$ 908,845.97	$ 1,005,150.53	$ 96,304.56	10.60%	98606	$ 10,486,703.77	$ 11,406,015.13	$ 919,311.36	8.77%
18,752,000	98606	$ 924,416.77	$ 1,025,223.73	$ 100,806.96	10.90%	98606	$ 11,006,637.17	$ 11,973,786.53	$ 967,149.36	8.79%
19,690,000	98606	$ 939,987.57	$ 1,045,296.93	$ 105,309.36	11.20%	98606	$ 11,526,570.57	$ 12,541,557.93	$ 1,014,987.36	8.81%
20,628,000	98606	$ 955,558.37	$ 1,065,370.13	$ 109,811.76	11.49%	98606	$ 12,046,503.97	$ 13,109,329.33	$ 1,062,825.36	8.82%
21,566,000	98606	$ 971,129.17	$ 1,085,443.33	$ 114,314.16	11.77%	98606	$ 12,566,437.37	$ 13,677,100.73	$ 1,110,663.36	8.84%
22,504,000	98606	$ 986,699.97	$ 1,105,516.53	$ 118,816.56	12.04%	98606	$ 13,086,370.77	$ 14,244,872.13	$ 1,158,501.36	8.85%
23,442,000	98606	$ 1,002,270.77	$ 1,125,589.73	$ 123,318.96	12.30%	98606	$ 13,606,304.17	$ 14,812,643.53	$ 1,206,339.36	8.87%
24,380,000	98606	$ 1,017,841.57	$ 1,145,662.93	$ 127,821.36	12.56%	98606	$ 14,126,237.57	$ 15,380,414.93	$ 1,254,177.36	8.88%
25,318,000	98606	$ 1,033,412.37	$ 1,165,736.13	$ 132,323.76	12.80%	98606	$ 14,646,170.97	$ 15,948,186.33	$ 1,302,015.36	8.89%
26,256,000	98606	$ 1,048,983.17	$ 1,185,809.33	$ 136,826.16	13.04%	98606	$ 15,166,104.37	$ 16,515,957.73	$ 1,349,853.36	8.90%
27,194,000	98606	$ 1,064,553.97	$ 1,205,882.53	$ 141,328.56	13.28%	98606	$ 15,686,037.77	$ 17,083,729.13	$ 1,397,691.36	8.91%
28,132,000	98606	$ 1,080,124.77	$ 1,225,955.73	$ 145,830.96	13.50%	98606	$ 16,205,971.17	$ 17,651,500.53	$ 1,445,529.36	8.92%
29,070,000	98606	$ 1,095,695.57	$ 1,246,028.93	$ 150,333.36	13.72%	98606	$ 16,725,904.57	$ 18,219,271.93	$ 1,493,367.36	8.93%
30,008,000	98606	$ 1,111,266.37	$ 1,266,102.13	$ 154,835.76	13.93%	98606	$ 17,245,837.97	$ 18,787,043.33	$ 1,541,205.36	8.94%

	Old	New		Old	New
Winter Qty %	54.86%	54.86%	Winter Qty %	63.26%	63.26%
Summer QTY %	45.14%	45.14%	Summer QTY %	36.74%	36.74%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ 0.1252	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.5114	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt. Comm. Ind. 50000 to 99999 Ig-3

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.	$ 182.50	$ 182.50	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 6.00	$ 6.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.5713	$ 0.5996	$ 0.0283	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.5713	$ 0.5996	$ 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 `
50,000		NA	NA	NA	NA		$ 30,755.00	$ 32,170.00	$ 1,415.00	4.60%
53,000		NA	NA	NA	NA		$ 32,468.90	$ 33,968.80	$ 1,499.90	4.62%
56,000		NA	NA	NA	NA		$ 34,182.80	$ 35,767.60	$ 1,584.80	4.64%
59,000		NA	NA	NA	NA		$ 35,896.70	$ 37,566.40	$ 1,669.70	4.65%
60,387		NA	NA	NA	NA		$ 36,689.09	$ 38,398.05	$ 1,708.96	4.66%
65,000		NA	NA	NA	NA		$ 39,324.50	$ 41,164.00	$ 1,839.50	4.68%
68,000		NA	NA	NA	NA	3	$ 41,038.40	$ 42,962.80	$ 1,924.40	4.69%
71,000		NA	NA	NA	NA		$ 42,752.30	$ 44,761.60	$ 2,009.30	4.70%
74,000		NA	NA	NA	NA		$ 44,466.20	$ 46,560.40	$ 2,094.20	4.71%
77,000		NA	NA	NA	NA		$ 46,180.10	$ 48,359.20	$ 2,179.10	4.72%
80,000		NA	NA	NA	NA		$ 47,894.00	$ 50,158.00	$ 2,264.00	4.73%
83,000		NA	NA	NA	NA		$ 49,607.90	$ 51,956.80	$ 2,348.90	4.73%
86,000		NA	NA	NA	NA		$ 51,321.80	$ 53,755.60	$ 2,433.80	4.74%
89,000		NA	NA	NA	NA		$ 53,035.70	$ 55,554.40	$ 2,518.70	4.75%
92,000		NA	NA	NA	NA		$ 54,749.60	$ 57,353.20	$ 2,603.60	4.76%
95,000		NA	NA	NA	NA		$ 56,463.50	$ 59,152.00	$ 2,688.50	4.76%
98,000		NA	NA	NA	NA		$ 58,177.40	$ 60,950.80	$ 2,773.40	4.77%

	Transportation Old	Transportation New		Sales Old	Sales New
Winter Qty %	NA	NA	Winter Qty %	65.87%	65.87%
Summer QTY %	NA	NA	Summer QTY %	34.13%	34.13%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3862	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt. Comm. Ind. 100000 to 499999 Ig-4

		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.	$ 456.25	$ 456.25	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 15.00	$ 15.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	NA	NA	NA	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.5291	$ 0.5452	$ 0.0161	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.5291	$ 0.5452	$ 0.0161	

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
100,000		NA	NA	NA	NA		$ 58,385.00	$ 59,995.00	$ 1,610.00	2.76%
125,000		NA	NA	NA	NA		$ 71,612.50	$ 73,625.00	$ 2,012.50	2.81%
150,000		NA	NA	NA	NA		$ 84,840.00	$ 87,255.00	$ 2,415.00	2.85%
162,461		NA	NA	NA	NA	162	$ 91,433.12	$ 94,048.74	$ 2,615.62	2.86%
197,925		NA	NA	NA	NA		$ 110,197.12	$ 113,383.71	$ 3,186.59	2.89%
222,925		NA	NA	NA	NA		$ 123,424.62	$ 127,013.71	$ 3,589.09	2.91%
247,925		NA	NA	NA	NA		$ 136,652.12	$ 140,643.71	$ 3,991.59	2.92%
272,925		NA	NA	NA	NA		$ 149,879.62	$ 154,273.71	$ 4,394.09	2.93%
297,925		NA	NA	NA	NA		$ 163,107.12	$ 167,903.71	$ 4,796.59	2.94%
322,925		NA	NA	NA	NA		$ 176,334.62	$ 181,533.71	$ 5,199.09	2.95%
347,925		NA	NA	NA	NA		$ 189,562.12	$ 195,163.71	$ 5,601.59	2.96%
372,925		NA	NA	NA	NA		$ 202,789.62	$ 208,793.71	$ 6,004.09	2.96%
397,925		NA	NA	NA	NA		$ 216,017.12	$ 222,423.71	$ 6,406.59	2.97%
422,925		NA	NA	NA	NA		$ 229,244.62	$ 236,053.71	$ 6,809.09	2.97%
447,925		NA	NA	NA	NA		$ 242,472.12	$ 249,683.71	$ 7,211.59	2.97%
472,925		NA	NA	NA	NA		$ 255,699.62	$ 263,313.71	$ 7,614.09	2.98%
495,000		NA	NA	NA	NA		$ 267,379.50	$ 275,349.00	$ 7,969.50	2.98%
	Winter Qty %	NA	NA			Winter Qty %	55.16%	55.16%		
	Summer QTY %	NA	NA			Summer QTY %	44.84%	44.84%		

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3862	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt Comm. Ind. 500000 to 999999 Ig-5

		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.	$ 1,368.75	$ 1,368.75	$ -	
	$/Day Fixed or equiv.	NA	NA	NA		$/Day Fixed or equiv.	$ 45.00	$ 45.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ -	$ -	$ -	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.5062	$ 0.5264	$ 0.0202	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.5062	$ 0.5264	$ 0.0202	

Usage in Therms	Customer Demand Quantity	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
500,000		NA	NA	NA	NA	0	$ 269,525.00	$ 279,625.00	$ 10,100.00	3.75%
531,000		NA	NA	NA	NA	0	$ 285,217.20	$ 295,943.40	$ 10,726.20	3.76%
562,000		NA	NA	NA	NA	0	$ 300,909.40	$ 312,261.80	$ 11,352.40	3.77%
593,000		NA	NA	NA	NA	0	$ 316,601.60	$ 328,580.20	$ 11,978.60	3.78%
624,000		NA	NA	NA	NA	0	$ 332,293.80	$ 344,898.60	$ 12,604.80	3.79%
655,000		NA	NA	NA	NA	0	$ 347,986.00	$ 361,217.00	$ 13,231.00	3.80%
677,745		NA	NA	NA	NA	2	$ 359,499.52	$ 373,189.97	$ 13,690.45	3.81%
708,745		NA	NA	NA	NA	0	$ 375,191.72	$ 389,508.37	$ 14,316.65	3.82%
745,399		NA	NA	NA	NA	0	$ 393,745.97	$ 408,803.03	$ 15,057.06	3.82%
776,399		NA	NA	NA	NA	0	$ 409,438.17	$ 425,121.43	$ 15,683.26	3.83%
807,399		NA	NA	NA	NA	0	$ 425,130.37	$ 441,439.83	$ 16,309.46	3.84%
838,399		NA	NA	NA	NA	0	$ 440,822.57	$ 457,758.23	$ 16,935.66	3.84%
869,399		NA	NA	NA	NA	0	$ 456,514.77	$ 474,076.63	$ 17,561.86	3.85%
900,399		NA	NA	NA	NA	0	$ 472,206.97	$ 490,395.03	$ 18,188.06	3.85%
931,399		NA	NA	NA	NA	0	$ 487,899.17	$ 506,713.43	$ 18,814.26	3.86%
962,399		NA	NA	NA	NA	0	$ 503,591.37	$ 523,031.83	$ 19,440.46	3.86%
993,399		NA	NA	NA	NA	0	$ 519,283.57	$ 539,350.23	$ 20,066.66	3.86%

Winter Qty %	NA	NA	Winter Qty %	43.97%	43.97%
Summer QTY %	NA	NA	Summer QTY %	56.03%	56.03%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3862	$ 0.3862

Transportation Administrative Charge: $ 2.00

Wisconsin Gas, LLC
Gas Utility
Customer Level Comparison of Revenues at Present and Final Rates
Test Year: 2026

Interrupt Comm. Ind. 1,000,000 to 7.999,999 Ig-6

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 equ	$ 3,497.92	$ 3,497.92	$ -	
	$/Day Fixed or eq	NA	NA	NA		$/Day Fixed or eq	$ 115.00	$ 115.00	$ -	
	Demand Charge	NA	NA	NA		Demand Charge	$ 0.0055	$ 0.0058	$ 0.0003	
	$/Therm-Winter	NA	NA	NA		$/Therm-Winter	$ 0.4587	$ 0.4748	$ 0.0161	
	$/Therm-Summer	NA	NA	NA		$/Therm-Summer	$ 0.4587	$ 0.4748	$ 0.0161	

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
1,000,000		NA	NA	NA	NA	12485	$ 525,738.64	$ 543,205.75	$ 17,467.11	3.32%
1,585,619		NA	NA	NA	NA	12485	$ 794,362.07	$ 821,257.65	$ 26,895.58	3.39%
1,758,307		NA	NA	NA	NA	12485	$ 873,574.06	$ 903,249.91	$ 29,675.85	3.40%
2,196,307		NA	NA	NA	NA	12485	$ 1,074,484.66	$ 1,111,212.31	$ 36,727.65	3.42%
2,634,307		NA	NA	NA	NA	12485	$ 1,275,395.26	$ 1,319,174.71	$ 43,779.45	3.43%
3,072,307		NA	NA	NA	NA	12485	$ 1,476,305.86	$ 1,527,137.11	$ 50,831.25	3.44%
3,510,307		NA	NA	NA	NA	12485	$ 1,677,216.46	$ 1,735,099.51	$ 57,883.05	3.45%
3,948,307		NA	NA	NA	NA	12485	$ 1,878,127.06	$ 1,943,061.91	$ 64,934.85	3.46%
4,386,307		NA	NA	NA	NA	12485	$ 2,079,037.66	$ 2,151,024.31	$ 71,986.65	3.46%
4,824,307		NA	NA	NA	NA	12485	$ 2,279,948.26	$ 2,358,986.71	$ 79,038.45	3.47%
5,262,307		NA	NA	NA	NA	12485	$ 2,480,858.86	$ 2,566,949.11	$ 86,090.25	3.47%
5,700,307		NA	NA	NA	NA	12485	$ 2,681,769.46	$ 2,774,911.51	$ 93,142.05	3.47%
6,000,000		NA	NA	NA	NA	12485	$ 2,819,238.64	$ 2,917,205.75	$ 97,967.11	3.47%
6,438,000		NA	NA	NA	NA	12485	$ 3,020,149.24	$ 3,125,168.15	$ 105,018.91	3.48%
6,876,000		NA	NA	NA	NA	12485	$ 3,221,059.84	$ 3,333,130.55	$ 112,070.71	3.48%
7,314,000		NA	NA	NA	NA	12485	$ 3,421,970.44	$ 3,541,092.95	$ 119,122.51	3.48%
7,502,000		NA	NA	NA	NA	12485	$ 3,508,206.04	$ 3,630,355.35	$ 122,149.31	3.48%

	Transportation: Old	New		Sales: Old	New
Winter Qty %	NA	NA	Winter Qty %	50.22%	50.22%
Summer QTY %	NA	NA	Summer QTY %	49.78%	49.78%

Gas Cost Rates:	Firm	Interruptible
Base Average Commodity Cost:	$ 0.3721	$ 0.3721
Base Average Peak Demand Cost:	$ -	$ -
Base Average Annual Demand Cost:	$ 0.0141	$ 0.0141
Base Average Balancing Cost:	$ -	$ -
Base Average Surcharge Cost:	$ -	$ -
Totals:	$ 0.3862	$ 0.3862

Transportation Administrative Charge: $ 2.00

Steam Rate Design - Test Year 2025
Wisconsin Electric (District Steam Service)

				2025			
Rate Class	**Present Rates**	**Quantity**	**Revenues**	**Proposed Rates**	**Quantity**	**Revenues**	**Percent Change**
Downtown Milwaukee Steam - Ag1							
Facilities Charge ($/day)	$3.13	129,575	$405,570	$3.13	129,575	$405,570	0.00%
Customer Demand Charge ($/Mlb/day)	$0.93771	3,394,967	$3,183,494	$0.96115	3,394,967	$3,263,072	2.50%
Energy Charge ($/Mlb)	$14.63389	1,721,765	$25,196,124	$14.91444	1,721,765	$25,679,165	1.92%
Tax Surcharge ($/Mlb)	$0.00000	1,721,765	$0	$0.00000	1,721,765	$0	N/A
Fuel Adjustment ($/Mlb)	-$0.47268	1,721,765	-$813,852	$0.00000	1,721,765	$0	-100.00%
Total Ag1 Revenue			**$27,971,336**			**$29,347,807**	**4.92%**
Downtown Milwaukee Steam - Ag2							
Facilities Charge per day ($/day)	$3.13	0	$0	$3.13	0	$0	
Customer Demand Charge ($/Mlb/day)	$0.33454	0	$0	$0.34290	0	$0	
Energy Charge ($/Mlb)	$5.07023	0	$0	$5.16743	0	$0	
Condensate Return Water Quantity Credit ($/Mlb)	$0.17555	0	$0	$0.17892	0	$0	
Condensate Return Water Quality Credit ($/Mlb)	$0.40377	0	$0	$0.41151	0	$0	
Tax Surcharge ($/Mlb)	$0.00000	0	$0	$0.00000	0	$0	
Fuel Adjustment ($/Mlb)	$0.00000	0	$0	$0.00000	0	$0	
Total Ag2 Revenue			**$0**			**$0**	
Economic Development Rate - Ag3							
Facilities Charge per day ($/day)	$3.13	2,920	$9,140	$3.13	2,920	$9,140	0.00%
Customer Demand Charge ($/Mlb/day)	$0.93771	65,130	$61,073	$0.96115	65,130	$62,600	2.50%
Energy Charge ($/Mlb)							
Months 1 to 60	$8.13459	32,254	$262,375	$8.29054	32,254	$267,405	1.92%
Months 61 to 120	$10.45673	32,823	$343,224	$10.65720	32,823	$349,804	1.92%
Months 121 to 180	$12.53131	0	$0	$12.77155	0	$0	
Fuel Adjustment ($/Mlb)	-$0.47268	65,078	-$30,761	$0.00000	65,078	$0	-100.00%
Total Ag3 Revenue			**$645,051**			**$688,948**	**6.81%**
Non-Firm Service - Ag4							
Facilities Charge per day ($/day)	$3.13	1,095	$3,427	$3.13	1,095	$3,427	0.00%
Customer Demand Charge ($/Mlb/day)	$0.93771	106,535	$99,899	$0.96115	106,535	$102,396	2.50%
Energy Charge ($/Mlb)	$13.40723	41,877	$561,459	$13.68778	41,877	$573,208	2.09%
Tax Surcharge ($/Mlb)	$0.00000	41,877	$0	$0.00000	41,877	$0	N/A
Fuel Adjustment ($/Mlb)	-$0.47268	41,877	-$19,795	$0.00000	41,877	$0	-100.00%
Total Ag1 Revenue			**$644,990**			**$679,031**	**5.28%**

Revised Calculation of Fuel Cost in Base Energy Rate
Wisconsin Electric (District Steam Service)
For Test Year ending December 31, 2025

Valley Fuel Cost in Steam Base Rates

Total Valley Method	2025 Test Year
Total Valley Fuel Costs net of Fixed Gas Costs	$28,396,793
Heat Value of Fuel (MMBtu)	6,268,244
Valley Fuel Cost ($/MMBtu)	**$4.53026**
Conversion rate from MMBtu to Mlbs	1.04800
Valley Steam Fuel Cost ($/Mlb)	**$4.74771**
Current Valley Cost of Fuel in Base Steam Rates ($/MMBtu)	$ 5.75502
Test Year Valley Steam Fuel Cost Adjustment	$ (1.22476)

Valley Fuel Conversion Rate

Valley Steam Heat Value of Fuel (MMBtu)	1,917,020
Valley Steam Sales (Mlbs)	1,828,720
Revised Conversion rate from million Btu production to Mlb sales	**1.048**
Current rate from million Btu production to Mlbs sales	1.018
Adjustment to conversion rate for test year	0.030

Steam Embedd Credit Calculation - Test Year 2025

		Downtown Milwaukee
1	Distribution Plant	$97,929,295
2	Distribution Plant Depreciation Reserve	$52,610,074
3	Depreciated Cost	$45,319,222
4	Total Consumption Mlbs	1,828,720
5	Embedded Credit $/Mlb.	**$25**

Appendix I

Wisconsin Electric Power Company
Docket 5-UR-111
Monitored Fuel Costs for 2025

	Total Fuel Rules Cost	System Requirements	Monthly $/kWh	Cumulative $/kWh
January	$88,475,218	2,099,842	$ 42.13	$ 42.13
February	$75,768,859	1,843,703	$ 41.10	$ 41.65
March	$69,218,202	1,864,665	$ 37.12	$ 40.20
April	$61,036,053	1,773,278	$ 34.42	$ 38.84
May	$75,072,517	1,799,471	$ 41.72	$ 39.40
June	$86,969,395	2,052,481	$ 42.37	$ 39.93
July	$112,917,589	2,322,743	$ 48.61	$ 41.40
August	$107,783,373	2,201,957	$ 48.95	$ 42.44
September	$88,309,986	1,976,507	$ 44.68	$ 42.69
October	$63,981,643	1,790,832	$ 35.73	$ 42.05
November	$70,405,585	1,830,341	$ 38.47	$ 41.75
December	$90,898,326	2,012,886	$ 45.16	$ 42.04
Total	$ 990,836,747	23,568,705	$ 42.04	

Wisconsin Electric Power Company / Wisconsin Gas
Regulatory Asset and Liability 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 Electric Power Company										
Badger Hollow II Cost Overrun	WE Electric	407	182	**11,095**	**-**	**(383)**	**10,712**	**-**	**(383)**	**10,330**
Bluewater Operating Cost Escrow	WE Gas	824	254	**14,572**	**18,644**	**(22,764)**	**10,452**	**12,312**	**(22,764)**	**0**
Darien Solar Cost Overrun	WE Electric		182	**-**	**16,125**	**-**	**16,125**	**-**	**-**	**16,125**
DER and DRER Acquisition Costs	WE Electric		182	**1,461**	**1,265**	**(176)**	**2,550**	**1,320**	**(176)**	**3,694**
Earnings Sharing				**(6,488)**	**-**	**3,244**	**(3,244)**	**-**	**3,244**	**(0)**
Earnings Cap Elec	WE Electric	Various	254	(5,995)	-	2,998	(2,998)	-	2,998	(0)
Earnings Cap Gas	WE Electric	Various	254	(448)	-	224	(224)	-	224	(0)
Earnings Cap Steam	WE Electric	Various	254	(44)	-	22	(22)	-	22	(0)
Electric Transmission Costs	WE Electric	Various	182	**(24,258)**	**392,304**	**(368,046)**	**0**	**399,368**	**(399,368)**	**0**
Energy efficiency programs				**11,888**	**61,562**	**(68,944)**	**4,506**	**64,438**	**(68,944)**	**(0)**
Act 141 Electric Utility Payments	WE Electric	908	182	3,142	35,478	(38,057)	563	37,494	(38,057)	(0)
Act 141 Elec Large Cust Escrow	WE Electric	908	182	(3,909)	11,821	(9,866)	(1,955)	11,821	(9,866)	(0)
ConserEscrow PTF EnerProcure Elec	WE Electric	908	254	12,820	3,724	(10,190)	6,354	3,836	(10,190)	(0)
WE Agricultural Service Program	WE Electric	908	254	(1,070)	1,572	(1,061)	(558)	1,619	(1,061)	0
Energy Efficiency Gas Program	WE Gas	908	182	(1,099)	2,214	(1,698)	(583)	2,280	(1,698)	0
Act 141 Gas Utility Payments	WE Gas	908	182	708	5,998	(6,670)	37	6,633	(6,670)	0
Act 141 Gas Large Customer Escrow	WE Gas	908	182	1,296	755	(1,403)	648	755	(1,403)	0
Environmental Remediation Costs	WE Gas	735	182	**572**	**50**	**7**	**629**	**50**	**7**	**686**
Escrowed PTF - WI	WE Electric	Various	182	**(16,307)**	**426,968**	**(422,117)**	**(11,456)**	**433,574**	**(422,117)**	**(0)**
Income Tax Related				**(406,415)**	**(32,988)**	**76,266**	**(363,138)**	**28,000**	**20,315**	**(314,823)**
WE - Deferred Tax Expense (Pre-Tax) - TAX REPAIRS	WE Electric	Various	182	256,280	28,000	(5,695)	278,585	28,000	(6,255)	300,330
Inflation Reduction Act (includes Carry)	WE Electric	Various	182	(8,121)	-	4,061	(4,061)	-	4,061	(0)
WE - TR - Remeasure - Electric (P)	WE Electric	410/411	254	(553,069)	-	84,070	(469,000)	-	18,559	(450,440)
WE - TR - Remeasure - Electric (U) & (P)/(U) ARAM Escrow	WE Electric	410/411	254	(1,269)	-	634	(634)	-	634	(0)
WE - TR - Remeasure - Gas (P)	WE Gas	410/411	254	(75,886)	-	2,170	(73,716)	-	2,171	(71,545)
WE - TR - Remeasure - Gas (U) & (P)/(U) ARAM Escrow	WE Gas	410/411	254	(274)	-	137	(137)	-	137	0
WE - TR - Remeasure - Gas (U) non-ARAM	WE Gas	410/411	254	0	-	-	0	-	-	0
WE - TR - Remeasure - Steam (P)	WE Steam	410/411	254	(5,675)	-	146	(5,530)	-	138	(5,391)
WE - TR - Remeasure - Steam (U) & (P)/(U) ARAM Escrow	WE Steam	410/411	254	(98)	-	49	(49)	-	49	0
WE - TR - Remeasure Electric (U) P4 ARAM	WE Electric	410/411	254	(15,384)	-	1,049	(14,336)	-	1,049	(13,287)
WE - TR - Remeasure Electric (U) PIPP ARAM	WE Electric	410/411	254	(4,442)	-	370	(4,072)	-	370	(3,702)
WE - TR - Remeasure Electric (U) SSR ARAM	WE Electric	410/411	254	(15,042)	-	1,504	(13,538)	-	1,504	(12,033)
WE TR - Remeasure - Electric (P) OC 5&6	WE Electric	410/411	254	(9,310)	-	816	(8,495)	-	816	(7,679)
WE TR - Remeasure - Electric (P) OC 7&8	WE Electric	410/411	254	-	(60,988)	-	(60,988)	-	3,588	(57,401)
Electric Unprotected Remeasure True-up	WE Electric	456	254	(449)	-	449	-	-	-	-
Gas Unprotected Remeasure True-up	WE Gas	495	254	5,783	-	(5,783)	-	-	-	-
Steam Unprotected Remeasure True-up	WE Steam	467	254	1,559	-	(1,381)	178	-	(178)	0
DPMD-Electric	WE Electric	410/421	182	18,979	-	(6,326)	12,653	-	(6,326)	6,326
WE Tax Items Assets - Electric Tax & Int Assess Payments	WE Electric	408	182	239	-	(119)	119	-	(119)	0
WE Tax Items Liability - Electric Tax & Int Refunds Receipts	WE Electric	408	254	(224)	-	112	(112)	-	112	(0)
WE Tax Items Liability - Gas Tax & Int Refunds Receipts	WE Gas	408	254	74	-	(37)	37	-	(37)	(0)
WE Tax Items Liability - Steam Tax & Int Refunds Receipts	WE Steam	408	254	0	-	0	0	-	0	0
WE Tax Items Liability - Electric Tax/Interest Refunds Receipts Grossed Up	WE Electric	408	254	(84)	-	42	(42)	-	42	0
WE Tax Items Liability - Gas Tax/Interest Refunds Receipts Grossed Up	WE Gas	408	254	9	-	(5)	5	-	(5)	0
WE Tax Items Liability - Steam Tax/Interest Refunds Receipts Grossed Up	WE Steam	408	254	(8)	-	4	(4)	-	4	(0)
Other				**2,022**	**(3,742)**	**(1,301)**	**(3,021)**	**(8,050)**	**213**	**(10,858)**
Section 1603 Treasury Grant-FERC	WE Electric	410	254	(5,091)	-	-	(5,091)	-	-	(5,091)
MISO Sch 33 Black Start Revenue	WE Electric	456	254	6,156	(2,526)	(525)	3,105	(2,580)	(525)	0

Wisconsin Electric Power Company / Wisconsin Gas
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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
Act 24 CUB Funding - Electric	WE Electric	928	182	(8)	208	(204)	(4)	208	(204)	-
Act 24 CUB Funding - Gas	WE Gas	928	182	(3)	89	(88)	(1)	89	(88)	-
Electric Vehicle Pilot Rebate Payments	WE Electric	928	182	968	-	(484)	484	-	(484)	(0)
WE Pre-collected GRT	WE Electric	928	182	-	(1,514)	-	(1,514)	(5,767)	1,514	(5,767)
Paris Solar and BESS Cost Overrun	WE Electric		182	**-**	**126,450**	**-**	**126,450**	**-**	**-**	**126,450**
Paris Solar Incremental RR Deferral	WE Electric	407	182	**(35,808)**	**-**	**35,808**	**-**	**-**	**-**	**-**
Pension & OPEB Escrow	WE Common	Various	182	**29,614**	**-**	**(14,807)**	**14,807**	**-**	**(14,807)**	**-**
Pension Settlement Accounting	WE Common	926	182	**6,402**	**-**	**(1,380)**	**5,023**	**-**	**(1,380)**	**3,643**
Pipeline Contributions	WE Gas	407	182	**278**	-	**(11)**	**268**	-	**(11)**	**257**
Plant Retirements				**621,295**	**522,577**	**(45,440)**	**1,098,431**	**10,500**	**(92,313)**	**1,016,619**
WEPCO P4 Retirement	WE Electric	407	182	430,259	-	(26,285)	403,974	-	(26,285)	377,688
P4 AFUDC Equity deferral	WE Electric	409	182	15,597	-	(1,063)	14,534	-	(1,063)	13,470
WEPCO Presque Isle (PIPP) Plant Retirement	WE Electric	407	182	130,818	-	(9,726)	121,092	-	(9,726)	111,366
PIPP AFUDC Equity deferral	WE Electric	409	182	991	-	(83)	908	-	(83)	826
Byron Wind Plant Retirement	WE Electric	407	182	312	-	(57)	255	-	(57)	198
WE Oak Creek 5&6 COR NBV	WE Electric	407	182	(33,362)	2,502	(1,509)	(32,369)	2,500	(1,509)	(31,378)
WE Oak Creek 5&6 Life NBV	WE Electric	407	182	75,166	-	(6,584)	68,582	-	(6,584)	61,998
WE Unrecovered Plant Balance Oak Creek 5&6 (Tax Asset)	WE Electric	409	182	1,513	-	(132)	1,380	-	(132)	1,248
WE Oak Creek 7&8 COR NBV	WE Electric	407	182	-	(137,716)	-	(137,716)	8,000	(8,179)	(137,895)
WE Oak Creek 7&8 Life NBV	WE Electric	407	182	-	645,048	-	645,048	-	(37,944)	607,104
WE Unrecovered Plant Balance Oak Creek 7&8 (Tax Asset)	WE Electric	409	182	-	12,743	-	12,743	-	(750)	11,994
Reactive Power (Sch 2) Transmission O&M	WE Electric	565	182	**10,602**	**-**	**(5,301)**	**5,301**	**-**	**(5,301)**	**-**
Uncollectible Expense				**105,646**	**69,664**	**(65,237)**	**110,073**	**70,385**	**(180,458)**	**0**
Uncoll Exp Elec	WE Electric	904	254	86,104	58,429	(55,498)	89,035	59,084	(148,119)	0
Uncoll Exp Gas	WE Gas	904	254	19,542	11,234	(9,739)	21,038	11,301	(32,339)	(0)
West Riverside Energy Center Acquisition Costs	WE Electric	407	182	**1,748**	**-**	**(437)**	**1,311**	**-**	**(437)**	**874**
West Riverside Energy Center Revenue Requirement Deferral	WE Electric	407	182	**19,174**	**-**	**(4,794)**	**14,381**	**-**	**(4,794)**	**9,587**
Whitewater Acquisition Costs	WE Electric	407	182	**227**	**-**	**(17)**	**209**	**-**	**(17)**	**192**
Whitewater Gas Lateral	WE Electric	407	182	**2,089**	**-**	**(157)**	**1,933**	**-**	**(157)**	**1,776**
WI SSR Deferral				**125,071**	**-**	**(12,513)**	**112,559**	**-**	**(12,513)**	**100,046**
Total Wisconsin Electric Power Company				**474,480**	**1,598,879**	**(918,500)**	**1,154,859**	**1,011,898**	**(1,202,161)**	**964,596**

Wisconsin Electric Power Company / Wisconsin Gas
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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 Gas										
Bluewater Operating Cost Escrow	WG Gas	824	254	**15,845**	**21,164**	**(25,722)**	**11,287**	**14,435**	**(25,722)**	**0**
Earnings Sharing				**67**	**-**	**(33)**	**33**	**-**	**(33)**	**0**
Earnings Cap Gas	WG Gas	495	254	67	-	(33)	33	-	(33)	0
Energy Efficiency Programs				**(395)**	**12,409**	**(12,647)**	**(633)**	**13,279**	**(12,647)**	**(0)**
Act 141 Gas Large Customer Escrow	WG Gas	908	182	1,083	862	(1,403)	542	862	(1,403)	0
Act 141 Gas Utility Payments	WG Gas	908	182	0	8,712	(9,105)	(393)	9,497	(9,105)	(0)
Energy Efficiency Gas Program	WG Gas	908	182	(1,479)	2,835	(2,138)	(782)	2,920	(2,138)	(0)
Environmental Remediation Costs	WG Gas	735	182	**64,726**	**3,701**	**(14,244)**	**54,182**	**236**	**(14,244)**	**40,174**
Income Tax Related				**(172,868)**	**-**	**6,148**	**(166,720)**	**-**	**3,112**	**(163,608)**
WG - TR - Remeasure - Gas (P)	WG Gas	410/411	254	(168,458)	-	2,397	(166,061)	-	2,453	(163,608)
WG - TR - Remeasure - Gas (U) & (P)/(U) ARAM Escrow	WG Gas	410/411	254	(1,433)	-	716	(716)	-	716	0
Gas Unprotected Remeasure True-up	WG Gas	495	254	(3,091)	-	3,091	-	-	-	-
WG Tax Items Assets - Gas Tax & Int Assess Payments	WG Gas	408	182	114	-	(57)	57	-	(57)	0
Other - ACT 24 CUB Funding	WG Gas	928	182	**(8)**	**115**	**(111)**	**(4)**	**115**	**(111)**	**(0)**
Pension & OPEB Escrow	WG Gas	Various	182	**8,635**	**-**	**(4,317)**	**4,317**	**-**	**(4,317)**	**-**
Pension settlement accounting	WG Gas	926	182	**1,682**	-	**(314)**	**1,368**	-	**(314)**	**1,053**
Pipeline Contributions	WG Gas	407	182	**5,491**	**-**	**(215)**	**5,276**	**-**	**(215)**	**5,061**
Ixonia LNG Cost Overrun	WG Gas	407	182	**19,319**	**-**	**(493)**	**18,826**	**-**	**(493)**	**18,333**
Uncollectible Expense	WG Gas	904	254	**(19,252)**	**9,977**	**(371)**	**(9,645)**	**10,016**	**(371)**	**(0)**
Total Wisconsin Gas				**(76,760)**	**47,366**	**(52,320)**	**(81,713)**	**38,081**	**(55,355)**	**(98,987)**