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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates

6680-UR-124

FINAL DECISION

This is the Final Decision on the application of Wisconsin Power and Light Company (applicant) for approval to adjust Wisconsin retail electric and natural gas base rates for 2024 test year and electric base rates for 2025 test year, and for approval of the applicant's 2024 Fuel Cost Plan. Final overall rate changes[1] for the test year ending December 31, 2024 are authorized consisting of a $49,425,000 rate increase over currently authorized rates for retail electric operations, or 3.76 percent, and a $12,756,000 rate increase over currently authorized rates for natural gas operations, or 5.09 percent, based on a 9.80 percent return on equity (ROE). Final overall rate changes for the test year ending December 31, 2025 are authorized consisting of a $109,108,000 rate increase over currently authorized rates for retail electric operations, or 8.27 percent, and a $12,127,000 rate increase over currently authorized rates for natural gas operations, or a 4.77 percent[2], based on a 9.80 percent ROE.

Introduction

On April 28, 2023, the applicant filed an application requesting approval to adjust Wisconsin retail electric and natural gas base rates. (PSC REF#: 466481.)

[1] Changes reflected in the Final Decision reflect changes in the revenue requirement and any difference from rates shown in the appendices is due to rounding.
[2] The applicant originally requested that the natural gas revenue requirement and rate increase from 2024 be continued into 2025 with no change between 2024 and 2025. However, the Commission ultimately authorized natural gas rates as proposed by Commission staff which results in a slight decrease in natural gas revenue requirement and rates in 2025 as compared to 2024. Natural gas rates in 2025 are therefore an increase over current 2023 rates, but will be a decrease over 2024 rates.

On May 18, 2023, the Commission issued a Notice of Proceeding. (PSC REF#: 468588.) 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: 350 Wisconsin; Blacks For Political and Social Action of Dane County (BPSA); Citizens Utility Board of Wisconsin (CUB); Clean Wisconsin; Dane County; RENEW Wisconsin (RENEW); Vote Solar and Sierra Club (together, VS/SC); Solar Energy Industries Association (SEIA); Walmart Inc. (Walmart); Wisconsin Industrial Energy Group (WIEG) and Wisconsin Local Government Climate Coalition (WLGCC) (together with applicant, parties). (PSC REF#: 472010.)

On July 5, 2023, a Scheduling Order was issued establishing the issues, schedule and other facilitation matters for this proceeding pursuant to Wis. Admin. Code § PSC 2.04(4). (PSC REF#: 472010.)[3] The issues for hearing were identified as follows:

A. Should the Commission grant in whole or in part the applicant's request for electric and natural gas utility rate increases, and if so, under what terms and conditions?

   1. What is the applicant's revenue requirement for electric and natural gas service?
   2. What is the cost of service as related to each customer class?
   3. What is the appropriate rate design, including service rules, for each customer class?

On August 14, 2023, the Commission issued a Notice of Hearing. (PSC REF#: 475175.) Pursuant to due notice, on September 13, 2023, a public hearing was held in person and virtually for members of the general public. (PSC REF#: 481529.) The Commission's public hearing process involved the opportunity for members of the public to submit written comments through

[3] On July 15, 2023, CUB filed a motion for interlocutory review of the Scheduling Order. (PSC REF#: 472922.) Pursuant to Wis. Admin. Code § PSC 2.27(3), the motion was denied. Commission staff subsequently filed a motion to modify the schedule, changing the time of day when certain filings would be due to minimize conflicts with hearings in other pending rate cases. (PSC REF#: 476341.)

the Commission' web site or at the public hearing, or testify at the public hearing. The Commission received comments from 556 members of the public. (PSC REF#: 482308.)

A party hearing was also held virtually on September 27, 2023, to receive testimony and technical information from the parties to the proceeding.[4] (PSC REF#: 481530.)

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

The Commission considered this matter at its open meeting of November 9, 2023, and December 20, 2023.

Findings of Fact

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

2. Currently authorized rates for the applicant's Wisconsin retail electric utility operations will produce total tariff operating revenues of $1,314,597,000 and $1,320,050,000 for the 2024 and 2025 test years, respectively. This results in a retail net operating income of $369,298,000 and $354,996,000, respectively, which is insufficient.

3. For the applicant's retail electric utility operations, the estimated rate of return on average net investment rate base of $5,379,270,000 and $5,774,141,000 at current rates for the 2024 and 2025 test years, is 6.87 percent and 6.15 percent, respectively, which is insufficient.

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

[4] On September 11, 2023, the applicant requested that there be an in-person option for the party hearing session. (PSC REF#: 478371.) The Administrative Law Judge denied the request due to the late timing of the request. (PSC REF#: 478999.)

7.53 percent and 7.54 percent in the 2024 and 2025 test years is $49,425,000 and $109,108,000, respectively.

5. The applicant's filed electric operating income statement and net investment rate base for the 2024 and 2025 test years, as adjusted for Commission decisions, are reasonable.

6. Currently authorized rates for the applicant's Wisconsin retail natural gas utility operations will produce total tariff operating revenues of $250,681,000 and $254,293,000 for the 2024 and 2025 test years, respectively. This results in a retail net operating income of $28,731,000 and $30,687,000, respectively, which is insufficient.

7. For the applicant's retail natural gas utility operations, the estimated rate of return on average net investment rate base of $514,407,000 and $532,232,000 at current rates for the 2024 and 2025 test years, is 5.59 percent and 5.77 percent, respectively, which is insufficient.

8. A reasonable increase to the applicant's retail natural gas operating revenues to produce a rate of return on the applicant's average net investment rate base of 7.39 percent and 7.42 percent in the 2024 and 2025 test years is $12,756,000 and $12,127,000, respectively.

9. The applicant's filed natural gas operating income statement and net investment rate base for the 2024 and 2025 test years, as adjusted for Commission decisions, are reasonable.

10. A reasonable 2024 test year monitored fuel cost is $204,635,441 on a Wisconsin retail basis. A reasonable 2024 Fuel Cost Plan level for total company monitored fuel costs is $243,037,852. The fuel cost plan year monitored fuel cost divided by the authorized level of native requirements of 13,701,880 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $17.74.

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

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

13. It is reasonable to accept Commission staff's adjustment to remove the dispatch adders for the Riverside and West Riverside units.

14. It is reasonable to accept Commission staff's adjustment to remove the impact of the proposed sale of West Riverside Option 2 from monitored fuel costs.

15. It is reasonable to update dispatch adders for coal generators based on the most recent estimate of coal availability at the time of the final production fuel cost model run.

16. It is reasonable that the update to dispatch adders in the fuel cost model include a targeted end-of-year coal inventory of between 45- and 60-days supply at each coal unit.

17. It is reasonable to update fuel costs to reflect the New York Mercantile Exchange (NYMEX) commodity futures settlement prices for natural gas, oil, and electricity as of October 17, 2023 index values, Argus spot coal prices as of October 13, 2023, and new fuel-related contracts.

18. The fuel cost data in Appendix F shall be used to monitor the applicant's 2024 fuel costs.

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

20. It is reasonable that the applicant file for a 2025 Fuel Cost Plan in 2024 in accordance with Wis. Admin. Code ch. PSC 116.

21. It is reasonable for the applicant to accept Commission staff's electric sales forecast adjustment for the 2024 and 2025 test years.

22. It is reasonable for the applicant to amortize the applicant's remaining COVID-19 regulatory asset balance over two years (2024 and 2025).

23. It is reasonable for the applicant to discontinue escrow accounting treatment for credit card convenience fees and to require the applicant to undertake a final true-up of these costs in the applicant's next rate proceeding.

24. It is reasonable for the applicant to discontinue escrow accounting treatment for late payment fees and to require the applicant to undertake a final true-up of these costs in the applicant's next rate proceeding.

25. It is reasonable for the applicant to discontinue the solar project revenue requirement deferral after 2023, and to require the applicant to undertake a final true-up of these costs in the applicant's next rate proceeding.

26. It is reasonable for the applicant to defer any impacts of the Infrastructure Investment Jobs Act of 2021 (IIJA) and the Inflation Reduction Act (IRA), when the impacts are incurred or received, with carrying costs at the applicant's short-term debt rate, to a future rate proceeding.

27. It is not reasonable for the applicant to escrow any impacts of the Production Tax Credits (PTCs) associated with existing wind generation.

28. It is reasonable for the applicant to recover 50 percent of the association dues paid to Edison Electric Institute (EEI) and Wisconsin Utilities Association (WUA).

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

30. It is not reasonable to accept Commission staff's Operations and Maintenance (O&M) adjustments for the 2024 and 2025 test years for the Forward and Kossuth wind farms.

31. It is reasonable for the applicant to exclude all short-term incentive plan compensation costs in the 2024 and 2025 test years revenue requirement.

32. It is reasonable to require the applicant to provide incentive compensation information in future rate case proceedings only when rate recovery is sought in such proceedings.

33. It is reasonable that the wage percentage increase for non-represented employees be held to 2.5 percent for 2024 and 2.2 percent for 2025.

34. It is reasonable to include a reduction of 34 full-time equivalents (FTE) for 2024 and 2025.

35. It is reasonable to accept Commission staff's adjustments for plant and construction work in progress (CWIP) for 2024 and 2025 using budget-to-actual analysis.

36. It is not reasonable for the applicant to include the impacts of the proposed West Riverside Option 2 sale in revenue requirement in this proceeding.

37. It is not reasonable for the applicant to defer the revenue requirement impacts associated with proposed West Riverside Option 2 sale at this time.

38. It is reasonable to include the impacts of the Edgewater battery energy storage system (BESS) project in the applicant's electric operations revenue requirement in this proceeding.

39. It is not reasonable to include the impacts of the proposed Sheboygan Falls Energy Facility natural gas turbine project in the applicant's revenue requirement in this proceeding.

40. It is not reasonable for the applicant to defer the revenue requirement impacts associated with the proposed Sheboygan Falls Energy Facility natural gas turbine project at this time.

41. It is not reasonable to include the impacts of the proposed Neenah Energy Facility natural gas turbine project in in the applicant's revenue requirement in this proceeding.

42. It is not reasonable for the applicant to defer the revenue requirement impacts associated with the proposed Neenah Energy Facility natural gas turbine project at this time.

43. It is reasonable for the applicant to continue deferral accounting treatment for the difference in estimated and actual revenue requirement for any changes to the proposed June 2025 retirement of Edgewater Unit 5, with carrying costs at the applicant's pretax weighted cost of capital.

44. It is reasonable for the applicant to continue deferral accounting treatment for the differences in estimated and actual revenue requirement for any changes to the proposed June 2026 retirement of Columbia Units 1 and 2.

45. It is not reasonable to establish deferral or escrow accounting treatment at this time for Sheboygan Falls Lease costs associated with docket 6680-CE-186.

46. It is not reasonable to establish deferral or escrow accounting treatment at this time for CoOp Capacity Credits impacted by decisions and project costs from other proceedings.

47. It is not reasonable to establish deferral or escrow accounting treatment at this time for future Midcontinent Independent System Operator, Inc. (MISO) and bilateral capacity purchase costs.

48. It is reasonable to defer the impact of changes to a wholesale power supply contract identified in Rebuttal-WPL-Michek-c-45.

49. It is not reasonable to incorporate in revenue requirement or authorize escrow accounting treatment for estimated 2024 and 2025 underground locating cost increases.

50. It is reasonable to remove all of the costs of the applicant's proposed E-Readiness program from revenue requirement for both 2024 and 2025 test years.

51. It is reasonable for the applicant to return to customers already collected and unspent funds approved for the E-Charge and SmartCharge E-Perks programs.

52. It is reasonable for the applicant to amortize all other deferrals or escrows not contested by any party, over a two-year period (2024-2025), as identified in Appendix G.

53. It is reasonable to approve the applicant's proposed 2024 and 2025 conservation budgets with Commission staff's proposed adjustments, with the exception of allowing the applicant to include the Pensions & Benefits Reduction from Loaded Labor line item in the budgets.

54. It is reasonable for the applicant to record annual farm rewiring escrow expenses of $2,0776,940 for 2024 retail electric operations, and $2,158,917 for 2025 retail electric operations.

55. It is reasonable for the applicant to record transmission escrow expenses of approximately $188,431,179 for 2024, and $199,042,892 for 2025.

56. It is reasonable for the applicant to accrue a return on 50 percent of CWIP, except where the applicant requests to apply 100 percent allowance for funds used during construction (AFUDC) to new construction projects requiring a Certificate of Authority (CA) or a Certificate of Public Convenience and Necessity (CPCN).

57. It is reasonable for the applicant to continue to apply AFUDC to 100 percent of the solar projects in dockets 6680-CE-182 and 6680-CE-183.

58. It is reasonable to remove from revenue requirement the cost overruns associated with the solar projects authorized in docket 6680-CE-182 above the authorized construction cost estimate of $862 million and the cost overruns associated with the solar projects authorized in docket 6680-CE-183 above the authorized construction cost estimate of $660 million as identified in Ex.-WPL-Michek-4c.

59. It is reasonable to reflect in the revenue requirement the Commission staff adjustments not contested by any party and not listed separately as contested for Commission decision.

60. It is reasonable for the applicant to amortize and include in 2024 and 2025 regulatory asset and regulatory liability amortizations as identified in Appendix G.

61. A reasonable return on equity (ROE) for 2024 and 2025 is 9.80 percent.

62. It is reasonable to set the applicant's cost of short-term borrowing to 4.20 percent for 2024 and 3.70 percent for 2025 test years.

63. It is reasonable to set the applicant's cost of long-term borrowing to 4.36 percent for 2024 and 4.41 percent for 2025 test years.

64. It is reasonable to set the target level for the applicant's average common equity measured on a financial capital structure basis as 52.50 percent for the 2024 and 2025 test years.

65. It is reasonable for the applicant to maintain a regulatory capital structure for the 2024 test year consisting of 53.87 percent common equity, 44.41 percent long-term debt, and 1.72 percent short-term debt; and for the 2025 test year consisting of 53.70 percent common equity, 43.78 percent long-term debt, and 2.52 percent short-term debt.

66. It is reasonable to set AFUDC rates for 2024 and 2025 at 7.35 percent and 7.39 percent, respectively.

67. It is reasonable that the applicant's dividend restrictions be based on the financial capital structure in this proceeding. It is also reasonable to direct the applicant not to pay dividends, including any pass-through of subsidiary dividends, in excess of the forecasted levels in 2024 or 2025 if its actual average common equity ratio, on a financial basis, is or will fall below the test-year level of 52.50 percent for 2024 or 2025.

68. It is reasonable for the applicant to submit a 10-year financial forecast in its next rate proceeding.

69. It is reasonable for the applicant to have $222,582,000 in off-balance sheet obligations for 2024 and $220,450,000 in off-balance sheet obligations for 2025.

70. It is reasonable for the applicant to submit, in its next rate application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

71. It is reasonable to impose an Earnings Sharing Mechanism (ESM) for the 2024 and 2025 test years that is based on the following criteria: the applicant shall retain all earnings less than or equal to 15 basis points above authorized ROE, the applicant shall return to customers an amount equal to 50.00 percent of earnings between 15 and 75 basis points above authorized ROE, and the applicant shall return to customers an amount equal to 100 percent of earnings equal to or in excess of 75 basis points above the authorized ROE.

72. It is reasonable to authorize the applicant to continue recovery of the Edgewater Unit 5 in test years 2024 and 2025 using the levelization methodology and related accounting entries previously approved in docket 6680-UR-123 and as presented in this proceeding and recovery of remaining life net book value of Edgewater Unit 5 at a premised 9.80 percent ROE, adjusted to an effective ROE of 9.20 percent as a result of levelized cost recovery treatment.

73. It is reasonable for the applicant to submit additional analysis in its next rate proceeding regarding alternative recovery methodologies for Edgewater 5, including but not limited to an analysis of the impacts of levelization of the remaining net book value resulting from adjustments to the Edgewater ROE, additional cost sharing mechanisms, and securitization of the full remaining environmental controls. The applicant shall report back on any Department of Energy (DOE) funding opportunities to mitigate costs relating to Edgewater 5. At the time of retirement of Edgewater 5, the applicant shall submit the life net book value and shall defer the incremental differences between levelization at the current net book value and the life net book value.

74. It is reasonable to consider the results of multiple electric cost-of-service study (COSS) models, along with other factors, such as bill impacts, for 2024 and 2025 revenue allocation and rate design.

75. It is reasonable for the Commission to open a separate investigation into electric cost allocation and rate design principles.

76. It is reasonable to accept the comprehensive electric rate design proposed by Commission staff in Ex.-PSC-Meulemans-1, as adjusted for final revenue requirement, for the 2024 test year.

77. It is reasonable to accept the comprehensive electric rate design proposed by Commission staff in Ex.-PSC-Meulemans-2, as adjusted for final revenue requirement, for the 2025 test year.

78. It is reasonable to accept the flat fuel surcharge rate proposed by Commission staff from January 1, 2024 through December 31, 2025.

79. It is not reasonable to accept the applicant's proposal to approve the PgS-2 Power Partnership V2 tariff nor any of the component parts of proposed V2 tariff (using expired bill credits, establishing of a regulatory asset associated with a System Asset Value Credit (SAVC), or deferring the SAVC).

80. It is not reasonable to authorize the changes to the PgS-3 tariff, as proposed by the applicant.

81. It is reasonable to conduct additional investigation of net-metering in docket 5-EI-157.

82. It is not reasonable to authorize the applicant's request to create the Energy Care Credit (ECC) program, nor to require the applicant to adopt a Percentage of Income Plan or geo-targeted, low-income usage-reduction pilot program as proposed by BPSA.

83. It is not reasonable to authorize the applicant's request to make its Arrearage Management Program (AMP) permanent, but it is reasonable to authorize that the AMP continue as pilot program and to require that the applicant request authorization from the Commission for modifications to the AMP pilot as proposed by BPSA and discussed in this Final Decision.

84. It is reasonable to require the applicant to work with interested stakeholders to develop alternative programs and options to address customer affordability and energy burden, and for the Commission to open a docket to investigate the applicant's development of such programs by no later than April 1, 2024.

85. It is reasonable to direct the applicant to file a TE docket no later than December 31, 2024 to modify its community solar tariff to expand access for low-income customers to its community solar program consistent with the modifications proposed by BPSA and discussed in this Final Decision.

86. It is not reasonable to approve the Optimal Rate Switch – Opt Out program as proposed by the applicant in Ex.-PSC-Data Request Response-TCM-3.

87. It is reasonable to require the applicant to submit additional evidence and documentation to demonstrate that its activities are in compliance with Wis. Admin. Code § PSC 113.0406(4).

88. It is reasonable to approve updates to the applicant's extension rules language and amperage thresholds to align with modern applicant practices and to increase the threshold under which a refund or additional bill will be issued to customers upon completion of their service extension. It is also reasonable to require the applicant to work with Commission staff to finalize the return trip charge in the tariff and to delegate the final revision of the return trip charge to the administrator of the Division of Energy Regulation and Analysis once the Commission receives cost and rate information.

89. It is reasonable to authorize the uncontested tariff modifications as described in the record for the Ms-3 Streetlighting, Cp-INT Large Interruptible Tariff, Community Solar, Ms-1 Large Interruptible Streetlighting, Cp-1, Cg-2 TOD, and Duplicate Facilities Maintenance tariffs.

90. It is reasonable to consider the results of multiple natural gas COSS models, along with other factors, such as bill impacts, for 2024 and 2025 revenue allocation and rate design.

91. It is reasonable to accept the comprehensive natural gas rate design proposed by Commission staff in Ex.-PSC-Meulemans-3, as adjusted for final revenue requirement, for the 2024 and 2025 test years.

92. It is reasonable to authorize the uncontested tariff modifications as described in the record for the Nonrefundable Service Lateral Charges, Main Extensions to Developments, and Excess Construction Costs sections and the Reapportionment Option.

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

Conclusions of Law

1. The Commission has jurisdiction under Wis. Stat. § § 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.22, 196.37, 196.374, 196.395, 196.40, and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter this Final Decision authorizing the applicant to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B, C, D and E, and the fuel costs treatment set forth in Appendix F that are just and reasonable.

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

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

Opinion

Applicant and its Business

The applicant is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. Its territory extends across the southern portion of the state from Grant County in the southwest, to Walworth County in the east, and extends generally northward through the central part of the state to Wood County and Menominee County. The applicant provides service to approximately 491,000 retail electric customers and 200,000 natural gas customers. Among the cities it serves with electricity are Beaver Dam, Beloit, Fond du Lac, Janesville, Monroe, Portage, and Sheboygan. Cities that it provides with natural gas utility service include Beaver Dam, Beloit, Fond du Lac, Janesville, Portage, Ripon, and Stoughton. The applicant also sells electricity at wholesale rates to several utilities and cooperatives for resale. The Federal Regulatory Energy Commission (FERC) regulates wholesale sales and rates. The applicant's wholesale rates, therefore, are not affected by this Final Decision.

The applicant is a wholly-owned subsidiary of Alliant Energy Corporation, a holding company based in Madison, Wisconsin.

The Application

The applicant filed for approval of a 2024 Fuel Cost Plan pursuant to Wis. Admin. Code § PSC 116.03 an increase to electric and natural gas rates as described in the Revenue Requirement section below, and several new or modified tariff programs.

Intervenor and Public Participation

Stakeholder groups representing a broad variety of interests intervened, requested discovery, and provided testimony in this proceeding. Members of the public provided testimony and submitted more than 500 written comments, most of which were related to affordability of the applicant's service and to the applicant's proposal to modify its net metering programs tariffs. The robust technical record and public participation benefitted the Commission's review and decision-making in this proceeding.

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.

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,[5] assigns no burden of proof to any party with respect to any determination that the Commission must make. While other sections of ch. 196 require certain determinations to be made only upon "clear and convincing evidence" or "a preponderance of the evidence,"[6] Wis. Stat. § 196.37 does not specify a standard of proof the Commission must find. Arguments assigning a burden of proof standard to the applicant in the present docket are based on a misunderstanding of the task the Commission is required to undertake when making determinations regarding the setting of just and reasonable rates.

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

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

later challenged in court, the Commission's factual findings "must be upheld on review if there is any credible and substantial evidence in the record upon which reasonable persons could rely to make the same findings." *Currie v. State Dep't of Indus., Labor & Human relations, Equal Rights Div.*, 210 Wis. 2d 380, 386-87, 565 N.W.2d 253 (Ct. App. 1997).

The substantial evidence test "is not weighing the evidence to determine whether a burden of proof test is met. Such tests are not applicable to administrative decisions." *Wisconsin Ass'n of Mfrs. & Commerce, Inc. v. Pub. Serv. Comm'n*, 94 Wis. 2d 314, 321, 287 N.W.2d 844 (Ct. App. 1979). This test requires only that there be enough evidence for a finding to be reasonable. *Kitten v. State of Wis. Dept. of Workforce Dev.*, 2002 WI 54, ¶5, 252 Wis. 2d 561, 644 N.W.2d 649 ("Because this is a review of an administrative hearing, we will uphold the hearing examiner's findings of fact as long as they are supported by substantial evidence in the record. Wis. Stat. § 227.57(6)."). See *Wisconsin Ass'n of Mfrs. & Commerce*, 94 Wis. 2d at 322 ("When the issues basically involve a dispute over conflicting testimony and a reasonable [person] could be convinced by either side, it is within the administrative agency's province to weigh it and accept that which it finds more credible.") (citations omitted). Therefore, although administrative proceedings do observe the common-law rule that the "moving party" has the burden of proof, this rule is complied with by determining whether the applicant provided substantial evidence to support each of the Commission's determinations.

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

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

Revenue Requirement

The applicant filed for separate 2024 and 2025 test years. The applicant concluded its current electric and natural gas rates were insufficient and proposed a base rate increase in 2024 and 2025. For Wisconsin retail electric rates for the 2024 test year, the applicant requested an 8.4 percent increase above 2023 authorized rates, and an incremental increase of approximately 5.4 percent for the 2025 test year. For natural gas rates for the 2024 test year, the applicant requested a 6.3 percent increase above 2023 authorized rates, and for the 2025 test year the applicant proposed to maintain the 2024 retail natural gas rates.

Commission staff reviewed 2024 and 2025 test year filing information for both electric and natural gas operations. Based on its review, Commission staff determined that for 2024 retail electric operations, the applicant would require an increase above currently authorized 2023 retail electric rates of 5.65 percent, and an incremental increase of approximately 4.64 percent for the 2025 test year. For 2024 retail natural gas rates, Commission staff determined the applicant would require an increase above currently authorized 2023 retail natural gas rates of 5.44 percent. For 2025 retail natural gas rates, Commission staff determined an incremental decrease of 0.09 percent to the 2024 test year retail natural gas rates would be needed to prevent the applicant from over earning in 2025.

The applicant claimed the main drivers impacting the electric revenue requirement for the 2024 and 2025 test years include investments made on behalf of electric customers consistent with WPL's Clean Energy Blueprint and to provide safe, reliable, and efficient utility service; the expiration of material regulatory liability credits at the end of 2023; and proposed changes to the applicant's capital structure and costs of capital. The natural gas revenue requirement drivers include increased rate base; changes in regulatory asset and liability amortizations; and the impacts of proposed changes in the applicant's capital structure and costs of capital.

Income Statement

The applicant, other parties, and Commission staff presented testimony and exhibits at the hearing concerning revenue requirement estimates for the applicant's 2024 and 2025 electric and natural gas utility operations. Significant issues pertaining to the income statement are addressed separately below.

Fuel Costs

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

The Fuel Cost Plan filed as part of the applicant's April 28, 2023 application requested approval to adjust Wisconsin retail electric and natural gas base rates (PSC REF#: 466481) reflected a preliminary fuel cost estimate for the 2024 fuel plan year of $19.39 per MWh, which is a 28.6 percent decrease from the 2023 Fuel Cost Plan approved by the Commission in docket 6680-ER-103. (PSC REF#: 454719.) Commission staff conducted an audit of the applicant's fuel costs and Commission staff's adjustments consisted of updates for more recent information, corrections to modeling inputs and errors, updates to non-modeled generation profiles and fixed costs, and adjustments to remove the impact of proposals not yet approved by the Commission.

The Commission finds that a reasonable estimate of the applicant's 2024 test year fuel costs is $204,635,441 on a Wisconsin retail basis. The Commission finds that a reasonable estimate of the applicant's 2024 Fuel Cost Plan total company monitored fuel costs is $243,037,852. The test year monitored fuel costs divided by the test-year estimate of native energy requirements of 13,701,880 MWh results in an average net monitored fuel cost of $17.74 per MWh, which is a 34.7 percent decrease from the 2023 Fuel Cost Plan approved by the

Commission in docket 6680-ER-103. Appendix F shows the monthly fuel costs to be used for monitoring purposes. It is reasonable to monitor the applicant's fuel costs using a plus or minus 2.0 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

The applicant shall file for its 2025 Fuel Cost Plan in 2024 in accordance with Wis. Admin. Code ch. PSC 116.

Uncontested Fuel Adjustments

Commission staff and the applicant proposed various adjustments to the applicant's filed 2024 fuel costs that were not contested by any party. These adjustments included: (1) an increase of approximately $8.7 million reflecting updates to Locational Marginal Pricing (LMP) basis values, congestion hedging, and distribution of losses; (2) an increase of approximately $11.1 million reflecting updates to load forecast, solar profiles, capacity sales, and MISO expense; (3) a decrease of approximately $16.2 million reflecting updated market prices as of June 15, 2023, contracts, variable operation and maintenance (VOM), and chemical costs; (4) a decrease of approximately $4.8 million reflecting the removal of dispatch adders for the Sheboygan Falls, Neenah, and South Fond du lac units; (5) a decrease of approximately $7.6 million reflecting a correction to gas pipeline charges; (6) a decrease of approximately $5.2 million reflecting corrections to fuel surcharges and Edgewater rail rates, and (7) an increase of approximately $5.2 million reflecting the applicant's proposed update to the maintenance outage schedule.

The Commission finds it is reasonable to accept all of the above uncontested fuel adjustments.

NYMEX and Other Updates

Consistent with past Commission practice, Commission staff proposed a final update to the applicant's 2024 fuel costs to reflect updates to commodities (coal, natural gas, diesel, and electricity) prices and contracts. Natural gas, diesel, and electricity prices were based on NYMEX futures as of October 17, 2023. Spot coal prices were updated using the Argus publication dated October 13, 2023. This information was included in the delayed exhibit filed by Commission staff. (PSC REF#: 483585.) These adjustments were not contested by any party. These adjustments decreased the applicant's 2024 fuel costs by approximately $13.1 million. The Commission finds it reasonable to accept these uncontested final adjustments to reflect updated commodities pricing.

Coal Dispatch Adders

Commission staff proposed an additional update to the dispatch adders for the applicant's coal units to be included in the fuel cost model run at the time of the final update, based on the most recent estimate of coal availability at the time. This update to coal dispatch adders was not contested by any party. The update to coal dispatch adders increased the applicant's 2024 fuel costs by approximately $12.0 million. The Commission finds it reasonable to accept this adjustment for coal dispatch adders.

Commissioner Huebner dissents.

Commission staff additionally proposed that the update to dispatch adders in the fuel cost model include a targeted end of year coal inventory of between 45- and 60-days supply at each coal unit. This update to end of year inventory levels was not contested by any party. The Commission finds it reasonable to accept Commission staff's proposed end of year level of coal inventory.

Outage Rate for West Riverside

The outage rate used in the modeling of the West Riverside units has been a contested issue in several previous fuel cost plans. Commission staff has generally proposed adjustments based on the Equivalent Forced Outage Rate (EFOR) used in the CPCN for West Riverside, while the applicant has proposed using higher outage rates based on expected and actual operational difficulties during the early years of operation of the West Riverside units.

For the 2021 Fuel Cost Plan, the Commission found it reasonable to use the higher 10.00 percent EFOR proposed by the applicant. (PSC REF#: 402140.) For the 2022 Fuel Cost Plan, Commission staff proposed using a 7.50 percent EFOR, which was a compromise between the 10.00 percent EFOR proposed by the applicant and the lower CPCN rate. The Commission, while recognizing ongoing operational challenges at West Riverside, but also that the targeted EFOR should not be delayed indefinitely, found it reasonable to accept Commission staff's proposed 7.50 percent EFOR as a step toward achieving the target rate. (PSC REF#: 427760.)

While West Riverside has continued to experience operational challenges, improvement is expected by the 2024 test year. Consistent with the trend of previous Commission decisions and the expectation for West Riverside to continue moving toward normal operations as recent issues become resolved, Commission staff proposed modeling West Riverside using the EFOR from the CPCN for the 2024 Fuel Cost Plan. The applicant instead proposed modeling West Riverside using a different Equivalent Unplanned Outage Rate (EUOR), which takes into account both forced and maintenance outages. The applicant's proposed EUOR rate was based on the actual 2022 West Riverside EUOR, adjusted to remove outages for issues experienced in 2022 that were expected to be resolved for 2024.

The Commission finds it reasonable to accept Commission staff's proposed adjustment to the West Riverside outage rate and use the EFOR from the CPCN for the West Riverside units in the modeling of 2024 fuel costs. This adjustment decreased the applicant's 2024 fuel costs by approximately $5.9 million.

Chairperson Valcq dissents.

Dispatch adders for Riverside and West Riverside

Commission staff proposed an adjustment to remove dispatch adders for Riverside and West Riverside from the filed modeling of 2024 fuel costs. The applicant proposed the dispatch adders to align the capacity factor produced in the model to the 5-year historical average capacity factors for the Riverside and West Riverside units. The applicant noted that without dispatch adders, the capacity factors were higher than the 5-year historical average. Commission staff objected to the use of dispatch adders to target historical capacity factors on the basis that the purpose of modeling is to simulate the particular conditions expected in the modeled year, that each year is unique, and that the conditions affecting capacity factor such as market prices for fuel and energy, operational issues, and others, vary from year to year and are not necessarily the same as the historical average. Commission staff noted that modeled capacity factors without dispatch adders, while higher than the 5-year historical average, were still within the 5-year historical range and not anomalous.

The Commission finds it reasonable to accept Commission staff's adjustment to remove the dispatch adders for the Riverside and West Riverside units in the modeling of 2024 fuel costs. This adjustment decreased the applicant's 2024 fuel costs by approximately $3.2 million.

West Riverside Option 2

The applicant proposed to include in 2024 fuel costs the impact of the proposed second sale of partial ownership in West Riverside of 100 MW to Wisconsin Electric Power Company and 25 MW to Madison Gas and Electric Company. The Commission has authorized an initial sale of partial ownership in West Riverside of the same size and to the same parties. (PSC REF#: 461711 and PSC REF#: 455194.) The applicant anticipates the second sale of partial ownership in West Riverside will be approved as well.

Consistent with past Commission practice which does not assume future approvals or denials, Commission staff excluded the impact of the proposed second sale of partial ownership in West Riverside as this proposed Option 2 has not been authorized by the Commission. The Commission finds it reasonable to accept Commission staff's adjustment to remove the impact of the proposed sale of West Riverside Option 2 in the modeling of 2024 fuel costs. This adjustment decreased the applicant's 2024 fuel costs by approximately $9.3 million.

Electric and Natural Gas Sales Adjustments

Commission staff adjusted the electric sales residential rate class by increasing the sales forecast by 1,419,957 kilowatt hours (kWh) and 23,577,153 kWh for the 2024 and 2025 test years, respectively. This increase in kWh resulted in an increase of $348,000 and $3.7 million to the sales revenue forecast for the 2024 and 2025 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 compound annual growth rate of 0.93 percent to forecast the 2024 and 2025 test year total. The remaining portion of the sales adjustment were changes in electric wholesale driven primarily by changes to the fuel costs. The applicant disagreed with Commission's staff's residential growth adjustment and argued that the increase may not be indicative of future growth through 2025.

The Commission is not persuaded by the applicant's arguments. Commission staff's methodology not only looked at historical averages, but it also adjusted sales for linear growth rates or compound annual growth rates. Based on the evidence in the record, the Commission finds it reasonable to accept Commission staff's electric sales adjustment for the 2024 and 2025 test years.[7]

COVID-19

The March 24, 2020 Order in docket 5-AF-105 authorized deferral of expenditures incurred by utilities resulting from compliance with Emergency Order #11, Orders by the Commission in docket 5-UI-120, and as otherwise required to ensure the provision of safe, reliability and affordable access to utility services during the declared public health emergency for COVID-19. The December 22, 2021 Order in docket 5-AF-105 ended the deferral as of December 31, 2021, and directed utilities seeking recovery of the deferred regulatory asset to file a rate application within a one-to-two-year period from the effective date of that Order.

The applicant requested to amortize the deferred COVID-19 regulatory asset authorized in docket 5-AF-105 over the two-year period of 2024 through 2025. In dockets 6690-UR-127 and 5-UR-110 for Wisconsin Public Service Corporation (WPSC), Wisconsin Electric Power Company (WEPCO), Wisconsin Gas (WG), the Commission required those utilities to write-off the entirety of the utilities' COVID-19 deferrals over two years as this was included in the settlement discussions.

[7] As discussed later in this Final Decision and pursuant to the Commission's Final Decision in docket 6680-FR-2022, these authorized sales forecasts will be used to re-calculate the fuel surcharge rate for the remaining collection period (January 1, 2024 through December 31, 2025).

The costs incurred by the applicant were in response to a Commission directive to ensure customers had access to utility services during the pandemic. As such, the costs incurred by the applicant produced a customer benefit for which the utility should be entitled to recovery. In docket 6680-UR-123 (reopener), the Commission authorized the applicant to amortize the COVID-19 regulatory asset over a three-year period (2023-2025). The Commission's Final Decision on Reopening in that docket required a final true-up of the regulatory asset in the applicant's next rate case. In this proceeding, the amounts proposed for recovery reflect the true-up and finalization of amortization of the final deferred costs of $392,034 for electric and $41,981 for natural gas for both 2024 and 2025 test years. The Commission finds it reasonable for the applicant to amortize the applicant's remaining COVID-19 regulatory asset balance over a two-year period (2024 and 2025). The Commission's decision is consistent with its decision in docket 6680-UR-123. While the Commission required write-offs in dockets 5-UR-110 and 6690-UR-127, that determination was based upon the unique facts in those cases, which included an agreement among the parties for such write-offs. Such circumstances are not present here.

Credit Card Convenience Fees

The applicant proposed to discontinue escrow accounting treatment for credit card convenience fees indicating the program has been in place for a few years, the program costs or revenue have generally stabilized, and the level of variability is relatively immaterial in comparison to other escrow mechanisms. For these reasons, the Commission finds it reasonable for the applicant to discontinue escrow accounting treatment for credit card convenience fees. The applicant is required to undertake a final true-up of these costs in the applicant's next rate proceeding.

Commissioner Huebner dissents.

Late Payment Fees

The applicant proposed to discontinue escrow accounting treatment for late payment fees indicating the program has been in place for a few years, the program costs or revenue have generally stabilized, and the level of variability is relatively immaterial in comparison to other escrow mechanisms. For these reasons, the Commission finds it reasonable for the applicant to discontinue escrow accounting treatment for late payment fees. The applicant is required to undertake a final true-up of these costs in the applicant's next rate proceeding.

Commissioner Huebner dissents.

Solar Project Revenue Requirement Deferral

In docket 6680-UR-123, the Commission found it reasonable to include in the applicant's retail revenue requirement recovery for capital investments made regarding the solar projects in dockets 6680-CE-182 and 6680-CE-183. Further, the Commission found it reasonable to require the applicant to defer the differential between the actual revenue requirements and the estimated revenue requirements reflected in the 2022 and 2023 test years. The applicant proposed to discontinue the solar project revenue requirement deferral after 2023 as the applicant expects the projects to be completed in 2023 or early 2024.

In light of the anticipated timing of project completion, the Commission finds it reasonable for the applicant to discontinue the solar project revenue requirement deferral after 2023. The applicant is required to undertake a final true-up of these costs in the applicant's next rate proceeding.

Solar Projects Cost Overruns

In dockets 6680-CE-182 (CA I) and 6680-CE-183 (CA II), the Commission authorized the applicant to acquire, construct, own and operate a total of 12 solar projects (collectively Solar

Projects).[8] In CA I, the applicant originally proposed to own and operate the six solar facilities at issue in that docket through a tax equity partnership, but subsequently determined that traditional utility ownership under the IRA would produce significant revenue requirement savings in the longer term relative to tax equity financing.

The Commission's Final Decisions in dockets 6680-CE-182 and 6680-CE-183 imposed "cost caps" that required the applicant (1) notify the Commission if the amount the applicant sought to include in rate base net of the tax equity investor's minimum contribution exceeds $585 million in CA I and $449 million in CA II, and (2) seek Commission approval for recovery of any costs that exceed these amounts.

The applicant sought to include in revenue requirement for test years 2024 and 2025 the Solar Projects approved by the Commission in CA I and CA II that are or will be in service in 2022, 2023 and 2024. The proposed revenue requirement also included the impacts of owning the Solar Projects rather than ownership through tax equity partnerships that were assumed in the applicant's last rate case in addition to both actual and an estimate of future cost overruns. (Ex.-Application-IDR 90 (confidential), Direct-WPL-Michek-cr-4, 18, 26.), Ex.-WPL-Michek-4c summarizes these costs.

In direct testimony, the applicant's witness Tim Kreft described the progress of the construction of the Solar Projects and discussed generally the cost overruns and the reasons for them. Ex.-WPL-Kreft-2r and 3r are the notifications submitted to the Commission regarding the

[8] CA I included the following six solar projects: the North Rock project (50 MW in Rock County), the Grant County project (200 MW in Grant County), the Crawfish River project (75 MW in Jefferson County), the Onion River project (150 MW in Sheboygan County), the Richland County project (now known as Bear Creek) (50 MW in Richland County), and the Wood County project (150 MW in Wood County). CA II included the following additional six solar projects: the Albany project (50 MW in Green and Rock Counties), the Beaver Dam project (50 MW in Dodge County), the Cassville project (50 MW in Grant County), the Paddock project (65 MW in Rock County), the Springfield project (100 MW in Dodge County), and the Wautoma project (99 MW in Waushara County).

cost overruns for the CA I and CA II projects, respectively. In direct testimony, CUB's witness Corey Singletary identified the recovery of the projected final costs of the Solar Projects as an issue, responded to the applicant's testimony on the topic, and questioned whether it is reasonable for customers to bear these costs. (Direct-CUB-Singletary-r-43-45.)

The applicant and CUB assumed that since the ownership structure has changed, the appropriate cap is now $862 million (CA I) and $660 million (CA II). As recognized by the Commission's Final Decisions in dockets 6680-CE-182 and 6680-CE-183, these sums were the construction cost estimates for the Solar Projects at the time of the Commission's authorization. The applicant has identified cost overruns in excess of these cost estimates of approximately 7 to 10 percent higher for CA I, and 10 to 14 percent higher for CA II. (Direct-WPL-Kreft-cr-10-12).

Given the anticipated timing of completion of the Solar Projects, which are anticipated to be in service before the end of 2024, the Commission concludes that it is reasonable to include in the revenue requirement the costs up to the estimated construction costs of $862 million (CA I) and $660 million (CA II). As to the cost overruns above these authorized construction cost estimates, the Commission concludes that it is reasonable to exclude such costs from revenue requirement, at this time. The Commission prefers to review the reasonableness of the cost overruns and whether to allow recovery of some or all of such costs once the final total costs are known.

In addition to being premature to make a determination as to the recovery of the cost overruns, the record developed in this proceeding is insufficient to make such a determination. The only evidence explaining, at a very high level, the reasons for the increased costs is witness Kreft's direct testimony and exhibits, but the rationale is not tied back to specific costs in IDR-90 or Ex.-WPL-Michek-4c. The applicant may submit a separate deferral request if it wishes to seek recovery of these and any other cost overruns for the Solar Projects above the authorized construction cost estimates identified in the Final Decisions in docket 6680-CE-182 and 6680-CE-183. Once final cost overruns are identified, a more robust analysis of these costs can occur in a future rate proceeding.

Inflation Reduction Act (IRA) and Infrastructure Investment Act (IIJA)

On August 16, 2022, the IRA of 2022 was signed into law, and on November 15, 2021, the IIJA of 2021, also known as the Bipartisan Infrastructure Law, was signed into law. At this time, it is unknown if there will be any potential impacts resulting from these Acts. Therefore, the Commission finds it reasonable that the applicant defer any impacts of the IRA and IIJA, when impacts are incurred or received, with carrying costs at the short-term debt rate of 4.20 percent in 2024 and 3.70 percent in 2025, to a future rate proceeding. Deferral accounting treatment ensures both the applicant and its customers remain whole as this deferral captures any cost increases or savings that might arise from the IRA or IIJA.

Production Tax Credit (PTC) Associated with Existing Wind Generation

The applicant requested escrow accounting treatment for the PTCs and investment tax credits (ITCs) that were created or modified as part of the IRA. The applicant also requested escrow accounting treatment for PTCs associated with existing wind generation that are still eligible for PTCs, such as the Kossuth Wind Farm. The escrow accounting treatment for PTCs is to address various risks, including (among others) the cost of transferring ITCs and the timing of such transfers. The Commission finds that it is not reasonable to authorize the applicant to escrow any impacts of the PTCs associated with existing wind generation. Such uncertainty and risk associated with the use or transferability of PTCs and ITCs are inherent with the use of such tools and is a risk that the applicant should bear as a normal cost of doing business.

Industry Association Dues

The Commission allows the recovery of association dues, to the extent that the activities of an association provide a benefit to customers. Certain industry associations have programs and activities, such as lobbying and advertising, that generally do not provide a benefit to customers. To the extent that the amount of dues that provide a benefit to customers could not be determined with precision, Commission staff applied a recovery percentage to each association's dues that is intended to generally reflect the portion of activities that could be considered to provide a benefit to ratepayers.

In this proceeding, Commission staff decreased electric O&M expenses approximately $185,000 in both 2024 and 2025, and decreased natural gas O&M by $560 in both 2024 and 2025. These amounts corresponded to dues paid for lobbying and other association activities that do not provide a specific customer benefit. In determining a reasonable percentage of dues recoverable, Commission staff reviewed each entity's website as well as the organization's most recent Form 990 nonprofit tax filings and found the historical 50 percent recovery percentage for dues paid by the applicant to EEI and WUA remained reasonable.

VS/SC recommended disallowing all dues paid to industry associations, arguing that the applicant failed to satisfy its burden to prove that any portion of the associate dues resulted in a customer benefit. CUB supported the principle behind the adjustment as customers should not be required to pay for disallowed expenses, but suggested it would be useful to understand which ratios are used and how those ratios were determined to ensure that the end result in the revenue requirement reflects policy intent. CUB further suggested that the Commission may wish to direct a review of the adjustment procedure.

The Commission finds the adjustments made by Commission staff are reasonable and that it is reasonable for the applicant to recover 50 percent of the association dues paid to EEI and WUA. The Commission is not persuaded by VS/SC's arguments. Commission staff's audit of these expenditures was reasonable, specific to each entity's activities and most recent tax filings, and consistent with past practice. While VS/SC claimed that customers received no benefit from any of the expenditures, it presented no supporting evidence. The Commission has historically recognized the fact that activities of many different trade associations do provide benefits to customers.

That said, the Commission does find that future records could benefit from a more granular presentation and identification of the specific customer benefits associated with all of the association dues for which the applicant seeks recovery. While a generic investigation into the matter is not necessary to achieve this end, the Commission finds it reasonable that the applicant provide specific data in its initial data request responses in its next rate proceeding, demonstrating the specific customer benefits associated with any payment of association dues for which it intends to seek recovery in that proceeding.

Operations and Maintenance (O&M) Adjustments to Wind Farms

Commission staff adjusted electric O&M expenses for the Forward and Kossuth wind farms based on an inflated three-year average of non-labor O&M expense over a 3-year average of historical megawatt-hours. The applicant contested Commission staff's adjustments. For the Forward Wind Farm, the applicant noted that its filed O&M forecast relied upon the annual budgets prepared by the operator and that the majority of the O&M budget are based upon fixed service contracts that include annual cost escalators. For the Kossuth Wind Farm, the applicant stated that its filed O&M forecast reflected higher expenses due in part to the expiration of a parts warranty in 2022 which will place increased financial responsibility on the applicant.

While Commission staff's methodology is reasonable, based upon the specific facts presented by the applicant, the Commission does not find it reasonable to accept Commission staff's Forward and Kossuth O&M adjustments for the 2024 and 2025 test years.

Short-term Incentive Plan (STIP) Compensation

The applicant sought Commission approval to include STIP compensation in the 2024 and 2025 test years revenue requirements. The Commission has historically excluded all incentive compensation that is dependent on financial drivers. The weighing of the metrics in the STIP is 70 percent financial and 30 percent operational. If the applicant's financial goals are not met, the plan can still compensate employees for the remaining 30 percent associated with the operational goals, as long as the operational goals are met. The Commission finds it reasonable to continue to exclude the STIP costs in the revenue requirement consistent with historic practice and because the record in this proceeding was insufficient to demonstrate that the 30 percent of STIP tied to operational metrics provides a customer benefit.

CUB witness Corey Singletary recommended the Commission consider requiring the applicant to provide information regarding any employee performance incentive compensation programs in place during future rate proceedings, regardless of whether rate recovery is sought. The Commission finds that the applicant is required to provide incentive compensation information in future rate proceedings only when rate recovery is sought for incentive compensation in such proceedings.

Wage percentage increase for non-represented employees

The applicant requested a 3.0 percent wage increase for non-represented employees. The inflation rate at the time of filing was 2.5 percent for 2024 and 2.2 percent for 2025. It has been long standing Commission practice that the inflation rate is established at the date the application is filed and once set, is not updated for revenue requirement purposes. Therefore, the Commission finds it reasonable and consistent with past practice to use a 2.5 percent and 2.2 percent inflation rate for the wage increase for 2024 and 2025, respectively.

Full Time Equivalency (FTE) Adjustment

Commission staff reduced the filed 2024 and 2025 regular FTEs to reflect actual May 2023 levels and the average vacancy rates over 2022 and 2023, which resulted in a reduction of 34 FTEs for 2024 and 2025.

The applicant argued that it is starting to see the labor pool increase with increased numbers of applicants for open positions. The applicant stated both the applicant's and Alliant Energy Corporate Services' headcounts have increased throughout 2023 compared to year-end 2022, and that the test year forecasts of labor are based upon projections of the labor needed to provide safe utility service while recognizing that a vacancy level will always exist. (Rebuttal-WPL-Michek-cr-9.) The Commission finds that Commission staff's methodology, which used actual headcounts as of May 2023 and the average vacancy rates over 2022 and 2023, is more reliable than the forecasts based upon the projections of labor needed. Therefore, the Commission accepts staff's adjustment to regular FTEs.

Plant and Construction Work in Progress (CWIP)

In determining a reasonable forecast for plant and CWIP, Commission staff began by updating the 2022 balance to reflect year-end actuals for plant in service, CWIP, and accumulated depreciation, rather than the estimated 2022 year-end balances used by the applicant. Next, after isolating discrete projects from the analysis, Commission staff applied historic budget-to-actual percentages to the remaining 2023, 2024, and 2025 electric and natural gas expenditures and plant additions, and applied a three-year average to the actuals for the electric and natural gas retirements. The analysis reflected that based on a three-year average budget-to-actual basis, the applicant has historically forecasted higher construction expenditures than what it has actually incurred, forecasted a faster entry of plant in service than what has actually occurred, and forecasted retirements at a much lower amount than what has actually occurred.

The applicant argued that Commission staff's proposed adjustments related to plant additions relative to construction expenditures for functional plant categories only where the budget-to-actual analysis showed results lower than 100 percent of forecast, and that Commission staff ignored functional categories that showed results greater than 100 percent of forecast. As such, the applicant contended that the analysis is unbalanced and biased to only produce adjustments to lower the filed amounts.

The Commission is not persuaded by the applicant's argument and based on information in the record, the Commission finds it reasonable to accept Commission staff's adjustments for plant and CWIP. The Commission does not find the facts and circumstances presented justify deviating from this past practice.

Capital Investment Revenue Requirement Impacts

The applicant proposed including various capital investment in the applicant's 2024 and 2025 test year revenue requirements, including the proposed capital investments relating to: the Edgewater BESS project as identified in docket 6680-CE-184, the Neenah Energy Facility natural gas turbine project as identified in docket 6680-CE-185, the Sheboygan Falls Energy Facility natural gas turbine project as identified in docket 6680-CE-186, and the West Riverside Option 2 sale as identified in docket 5-BS-273. At the time of audit completion, the Commission had not yet issued authorization for these projects and sale. Therefore, Commission staff removed the projects and sale from the applicant's electric operations revenue requirement.

Based upon past Commission practice, which does not assume future approvals or denials, the Commission finds it reasonable to not include the impacts of the Neenah Energy Facility natural gas turbine project, the Sheboygan Falls Energy Facility natural gas turbine project, and the West Riverside Option 2 sale in the applicant's electric operations, since these projects have not been authorized by the Commission. Further, the Commission finds that the applicant's request for deferral accounting treatment for these proposed projects and sale are premature, and therefore concludes that it is not reasonable to authorize deferral accounting treatment for the potential revenue requirement impacts of Neenah Energy Facility, Sheboygan Falls Energy Facility and the West Riverside Option 2 sale, at this time.

As the Commission has, in the time period following audit completion and prior to the Commission decision in this proceeding, authorized in docket 6680-CE-184 the applicant's Edgewater BESS project, the Commission finds it reasonable to include the impacts of Edgewater BESS in the applicant's electric operations revenue requirement.

Edgewater Unit 5 Retirement Deferral Accounting Treatment

Edgewater Unit 5 is an approximately 400 MW coal-fired electric generating facility located in Edgewater, Wisconsin. The applicant was originally planning to retire Edgewater Unit 5 by the end of 2022; however, the applicant has updated the retirement date to June 2025, and has requested to continue deferral accounting treatment.

In docket 6680-UR-123, the Commission required the applicant to defer any differences in estimated and actual revenue requirements associated with retiring the Edgewater Unit 5 resulting from the change in the unit's retirement date. Given the updated retirement date, the Commission finds that it is reasonable to authorize the applicant to continue deferral accounting treatment if the planned timing of the retirement changes from the updated retirement date. It is reasonable for the deferral accounting to continue with carrying costs at the applicant's pretax weighted cost of capital.

Columbia Units 1 and 2 Accounting Treatment

In docket 6680-UR-123, the Commission required the applicant to defer the revenue requirement impacts of any differences in estimated and actual O&M costs at the Columbia Generating Station. The applicant requested continued deferral accounting treatment if the planned timing of the retirement of Columbia Units 1 and 2 changes from the assumptions used in the applicant's filing of Columbia Units 1 and 2 retiring in June 2026. The Commission finds that the proposed accounting treatment for the retirement of Columbia Units 1 and 2 is reasonable.

Purchased Capacity Costs

The applicant proposed to establish escrow accounting treatment for purchased capacity costs, including Sheboygan Falls Lease costs and CoOp Capacity Credit costs.

For the Sheboygan Falls Lease costs and CoOp Capacity Credit costs, the applicant indicated that these costs were out of the applicant's control. Specifically, the applicant noted that the Sheboygan Falls Lease costs were contingent upon decisions to be made in docket 6680-CE-186, and upon the actual timing and final costs of the project proposed in docket 6680-CE-186. Similarly, CoOp Capacity Credit costs would also be impacted by decisions made in other proceedings, and timing and final costs of projects from other proceedings. Commission staff did not oppose the principle of making the applicant whole for specific costs that may be impacted by decisions and projects from other proceedings. However, Commission staff proposed that if any such costs should be authorized, they be given deferral treatment rather than escrow treatment.

Prior Commission Orders relating to a utility's request for deferral of costs have adopted and applied the Commission staff accounting policy team's Statement of Position 94-01 (SOP 94-01),[9] and set forth the criteria for evaluating the reasonableness of the use of deferral accounting method. The criteria may be considered individually or together with other criteria. They are as follows:

1. The amount is outside the control of the utility;
2. The expenditure is unusual (e.g., non-typical, non-customary) and infrequently recurring (e.g., does not occur every two to five years);
3. The immediate recognition of the expenditure causes the utility serious financial harm or significantly distorts the current year's income; or
4. The immediate recognition of the expenditure causes significant ratepayer impact.

The Commission does not find the Sheboygan Falls Lease costs and CoOp Capacity Credit costs meet the criteria warranting a deferral. Further, the Commission finds it premature to authorize escrow or deferral treatment for Sheboygan Falls Lease costs and CoOp Capacity

[9] *See, e.g.,* Order, *Application of Northern States Power Company-Wisconsin, for Deferred Accounting Treatment for Pension Settlement Accounting Expense*, docket 4220-AF-100 (Wis. PSC Dec. 13, 2017) (PSC REF#: 334830); Order, *Northwestern Wisconsin Electric Company Request for Deferral*, docket 4280-AF-100 (Wis. PSC Feb. 8, 2018) (PSC REF#: 337504); Interim Order, *in re Wisconsin Power and Light Company*, docket 6680-UR-109, 1994 WL 747576 (Wis. PSC Dec. 8, 1994), Final Decision, *Joint Application of Wisconsin Public Service Corporation, Wisconsin Power and Light Company, and Madison Gas and Electric Company for Approval to Purchase the Forward Wind Energy Center from Forward Energy, LLC*, docket 5-BS-226 (Wis. PSC Mar. 20, 2018) (PSC REF#: 339856).

Credit costs associated with projects from other proceedings that have not been authorized at this time.

MISO Market and Bilateral Capacity Purchases

The applicant requested escrow accounting treatment for capacity purchase costs associated with MISO market and bilateral capacity purchases. While no MISO or bilateral capacity purchases were expected to be needed in the 2024 or 2025 test years, the applicant requested an escrow for these capacity purchase costs due to various uncertainties outside the applicant’s control, particularly capacity market price volatility and uncertainty with regard to changes in MISO’s capacity accreditation rules. The applicant’s position was that an escrow for capacity purchases would be a corollary to the treatment of capacity sales under the fuel rules.

Commission staff objected to the request for escrow of MISO market and bilateral capacity purchases. Commission staff noted that an escrow is not a corollary to the fuel rules, as fuel costs are subject to a full reconciliation and prudence review, and because the typical 2.0 percent tolerance bandwidth under the fuel rules shares risk between customers and the applicant. Commission staff noted that with an escrow, all risk is borne by the applicant’s customers. Commission staff also noted that escrow is typically only used for expenses outside a utility’s control, but that the applicant could control capacity purchase costs by managing and maintaining sufficient capacity to avoid the need to purchase capacity. Commission staff argued that the transfer of all capacity-related risk to customers is inappropriate given the applicant’s ability, and responsibility, to maintain sufficient capacity, which mitigates capacity market risk. Commission staff also expressed concerns that a capacity escrow would lessen the incentive for the applicant to maintain sufficient capacity, and of the impact that might have on future reliability.

Commission staff also noted it may be premature to establish an escrow for costs for capacity purchases not anticipated to occur during the test years based on concerns over uncertainty in the future, and that if unforeseen expenses are incurred, the applicant had the ability to request a deferral as part of a future proceeding.

The Commission accepts Commission staff's position regarding MISO market and bilateral capacity purchases, and finds it premature to establish escrow or deferral accounting for costs that may not be incurred. While the MISO changes may be beyond the applicant's control, how the applicant may choose to respond to such changes is not. The Commission is concerned that granting the applicant's request at this time may provide a disincentive for it to make the best choices when managing capacity needs in light of such changes. For these reasons, the Commission finds it reasonable to not establish deferral or escrow accounting treatment for MISO market and bilateral capacity purchases at this time.

Wholesale Power Supply Contract Accounting Treatment

The applicant requested deferral accounting treatment for changes to a wholesale power supply contract as identified in applicant witness Mr. Michek's rebuttal testimony. (Rebuttal-WPL-Michek-c-45.) The Commission finds it reasonable to defer changes to a wholesale power supply contract based on the uncertainty disclosed.

Underground Locating Costs

The applicant indicated it estimated that the combined electric and natural gas utility costs of underground locates will increase to approximately $14 million per year in 2024 and 2025. This is an increase in costs over the amounts included in the applicant's application of approximately $5.6 million and $5.3 million for the 2024 and 2025 test years, respectively. The electric utility share of these costs increases, approximately 53 percent, would be allocated entirely to the retail jurisdiction. The applicant requested the Commission consider including these cost estimates in this rate proceeding or authorize escrow accounting treatment.

Given the late notification regarding the change, Commission staff did not have an opportunity to review or fully vet the information and cannot corroborate the dollar amount impact. In light of the timing of the request, the Commission finds it is not reasonable for the applicant to incorporate in revenue requirement the increased costs of underground locates in this rate proceeding or to authorize escrow accounting treatment for the increase of the underground locates.

E-Readiness Program

The applicant included $1.0 million in O&M expenses in the revenue requirement for both the 2024 and 2025 test years for an E-Readiness program. The applicant indicated that the included amounts are not specific to the previously proposed pilot programs; however, the applicant is preparing and planning for an increased transition to electric vehicles and other electrification efforts will continue and the proposed budget reflected in this proceeding is intended to support those efforts. The applicant has not provided any specific details on its proposed E-Readiness program and has not indicated that the program is providing a specific service offered to customers. The Commission finds it is reasonable to remove the costs of the applicant's proposed E-Readiness program from revenue requirement for both 2024 and 2025 test years as these costs are not associated with any specific authorized program.

E-Charge and SmartCharge E-Perks Programs

In docket 6680-UR-123, and "in consideration of the entire Settlement Agreement and record in [that] proceeding, the Commission found it reasonable to approve the E-Charge and

SmartCharge E-Perks pilot programs."[10] In light of the record for this proceeding, it appears that the applicant unilaterally cancelled the pilot programs. Since the applicant did not provide, or even offer, the service under those approved programs, the Commission finds that it is reasonable for the applicant to return the funds, already charged under the programs, back to the applicant's customers. The costs included in the revenue requirement relating to the E-Charge pilot program and SmartCharge E-Perks pilot program were $972,823 for the 2022 test year and $760,733 for the 2023 test year.

In the record for this proceeding, and in particular at the hearing, questions were raised as to whether a Commission determination to refund costs relating to the programs would constitute unlawful retroactive ratemaking.[11] (PSC REF#: 481530 at 102-106.) Through its witness, the applicant confirmed that it never offered the service under those programs. *Id*. In its Initial Brief, through various generalizations about retroactive ratemaking, however, applicant restated concerns with the possibility of the Commission ordering refunds in this case. (PSC REF#: 481459 at 19-21.) The Commission is not persuaded by these generalizations, and the law is settled with regards to the facts in this case. There is no retroactive ratemaking when the Commission orders a refund for reasons other than its determination that rates for *services already provided* were not reasonable. *CenturyTel of the Midwest-Kendall, Inc. v. PSC*, 2002 WI App 236, 257 Wis. 2d 837, 653 N.W.2d 130. There are no approved rates for a service that is not offered, i.e., no service. Further, the Commission's authority to order refunds is well established. *GTE North Inc. v. PSC*, 176 Wis. 2d 559, 500 N.W.2d 284 (1993). If the Commission lacked the authority to order refunds, utilities would be allowed to impose charges

[10] Final Decision, Signed and Served 12/22/2021, docket 6680-UR-123, at 64. (PSC REF#: 427760)

[11] The Commission may not fix rates to be applied retroactively. Wis. Stat. § 196.37(1), *Algoma, Eagle River, New Holstein, Stratford, Sturgeon Bay & Two Rivers v. PSC*, 91 Wis. 2d 252, 283 N.W.2d 261 (Ct. App. 1978).

without consequence, inevitably resulting in harm to customers in the form of rates that are too high. *See*, *Wisconsin Bell, Inc. v. Public Service Commission*, 2004 WI App 8, 269 Wis. 2d 409, 675 N.W.2d 242, 02-3163 at ¶ 53.

In its consideration of potential refunds in this case, the question for the Commission is not whether it approved the applicant's plan to offer the programs and accordingly charge customers, but whether the applicant then lawfully charged its customers under the programs. Here, the applicant did not.[12] Stated another way, the charges approved in revenue requirement were conditioned[13] on the applicant offering and providing the services under the program to its customers. Beyond the specific concept of retroactive ratemaking, it is almost axiomatic; because the applicant did not offer and provide its services to its customers, it had no right to charge them for the services and thus must refund them. In this case, and using the words of the Wisconsin Court of Appeals, "a refund does not make or re-make 'rates.' The refund simply corrects an unlawful charge." *Id*. at ¶ 50.

Amortization Periods for all other Deferrals and Escrows

The applicant sought Commission approval for continued deferral and escrow accounting treatment of several deferrals over a 2-year period, 2024 through 2025 which were not contested by any party and not listed separately as contested for a Commission decision. Therefore, consistent with past Commission practice, the Commission finds it reasonable for the applicant to continue deferral and escrow accounting treatment over the 2-year period, 2024 through 2025, as identified in Appendix G.

[12] Although unnecessary for the Commission to reach its determination in this case, apparently the applicant never submitted a final tariff of the proposed programs for the Commission's approval. *See*, PSC REF#: 479276. Typical refund analysis under *GTE North Inc. v. PSC* and other cases includes consideration of the 'filed rate doctrine' which prescribes that unapproved or unfiled tariffs are unlawful tariffs.

[13] *See*, PSC REF#: 461873. Commission staff questioned the applicant whether it had the authority to unilaterally decide "to not execute the two pilot programs." *Id*.

Conservation

The applicant proposed a total 2024 conservation budget of $21,025,611 with $16,544,456 allocated to electric operations and $4,481,155 allocated to natural gas operations. Of the $16,544,456 for electric operations, $13,623,203 was for the applicant's required Focus on Energy contribution, $1,997,503 was for the Customer Service Conservation (CSC) activities, and $923,750 was for voluntary programs. Of the $4,481,155 allocated for natural gas operations, $2,214,730 was for the applicant's required Focus contribution, $1,424,675 was for CSC activities, and $841,750 was for voluntary programs.

The applicant proposed a total 2025 conservation budget of $21,980,555, with $17,099,998 allocated to electric operations and $4,880,557 allocated to natural gas operations. Of the $17,099,998 for electric operations, $14,184,527 was for the applicant's required Focus contribution, $1,899,471 was for CSC activities, and $1,016,000 was for voluntary programs. Of the $4,880,557 allocated for natural gas operations, $2,616,560 was for the applicant's Focus contribution, $1,391,997 was for CSC activities, and $872,000 was for voluntary programs.

From both the 2024 and 2025 conservation budgets, Commission staff recommended removing three budget line items for the Public Benefits Low Income Weatherization, the Smart Hours DR program, and the Pensions & Benefits Reduction from Loaded Labor. The applicant did not contest removal from the conservation budgets of the Low Income Weatherization and the Smart Hours DR program. The applicant proposed keeping the budget item for Pension & Benefits Reduction from Loaded Labor to avoid double recovery.

BPSA argued that the applicant's CSC activities and budget were insufficient and recommended that the applicant be directed to adopt a community-based geo-targeted energy efficiency program. While additional energy efficiency programs and expanded voluntary programs are worthy of further consideration, Wis. Stat. § 196.374(2)(a)3. prohibits the Commission from requiring the applicant to fund energy efficiency and renewable energy programs that are in addition to Focus on Energy. Additionally, Wis. Admin. Code § PSC 137.08(2) requires a request to administer a voluntary program come from the applicant.

As result, the Commission finds it reasonable to include the applicant's proposed 2024 and 2025 CSC activities and 2024 and 2025 conservation budgets with Commission staff's proposed budget adjustments, with the exception of allowing the applicant to include the Pensions & Benefits Reduction from Loaded Labor line item in the budgets.

Transmission Escrow

The applicant proposed maintaining escrow accounting treatment of the applicant's transmission costs through the test years 2024 and 2025. The Commission finds that continued escrow treatment for transmission costs through 2024 and 2025 is reasonable. The retail company transmission escrow expense to be included in the applicant's electric revenue requirement shall be approximately $188,431,179 for 2024 and $199,042,892 for 2025.

Conservation and Farm Rewiring Escrow

The Commission approved the applicant's proposed 2024 and 2025 conservation budgets with Commission staff's proposed adjustments, with the exception of allowing the applicant to include the Pensions & Benefits Reduction from Loaded Labor line item in the budgets. The application proposed maintaining escrow accounting treatment of the applicant's conservation costs through the test years 2024 and 2025. The Commission finds that continued escrow treatment for conservation and farm rewiring costs through 2024 and 2025 is reasonable. Estimated annual conservation expenditures for 2024 electric operations are $15.6 million plus the overspent amount of $1.1 million, for a total amortization amount of $16.7 million. For 2024 natural gas operations, the estimated annual conservation expenditures are $3.6 million less the underspent amount of $200,000, for a total amortization amount of $3.4 million. Estimated annual conservation expenditures for 2025 electric operations are $16.1 million plus the overspent amount of $548,000 for a total amortization amount of $16.6 million. For 2025 natural gas operations, the estimated annual conservation expenditures are $4.0 million less the underspent amount of $629,000 for a total amortization amount of $3.4 million.

The applicant proposed maintaining escrow accounting treatment of the applicant's farm rewiring costs through the test years 2024 and 2025. The farm rewiring escrow budget expenditures to be included in the applicant's revenue requirement shall be $2,076,940 for 2024 and $2,158,917 for 2025.

Allowance for Funds Used during Construction

The applicant requested to accrue a return on 50 percent of CWIP, except where the applicant requests to apply 100 percent AFUDC to new construction projects requiring a CA or CPCN. Additionally, the applicant requested to continue applying 100 percent AFUDC to the solar projects in dockets 6680-CE-182 and 6680-CE-183. This treatment on the solar projects was first approved in the Final Decisions in dockets 6680-AF-100 and 6680-AF-102. (PSC REF#: 402305, PSC REF#: 419437.)

The Commission finds it reasonable to authorize the applicant to accrue a return on 50 percent of CWIP, except where the applicant requests to apply 100 percent AFUDC to new construction projects requiring a CA or CPCN through the 2024 and 2025 test years. It is also reasonable for the applicant to continue to apply AFUDC to 100 percent of the Solar Projects in dockets 6680-CE-182 and 6680-CE-183.

Uncontested Audit Adjustments

There were a number of other Commission staff adjustments proposed to the applicant's filed electric and natural gas revenue requirement 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, all other issues agreed upon to arrive at the filed operating income statements are reasonable. Accordingly, per the Commission's decision, the estimated electric and natural gas operating income statements at present rates for the test years were updated, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2024 Test Year	**Total Co. Electric (000's)**	**Electric WI Jur. (000's)**	**Gas (000's)**
Operating Revenues			
Revenue From Sales	$1,469,796	$1,314,597	
Natural Gas Sales Revenue (Includes Gas Cost)			$250,681
Interruptible Credits		(1,146)	
Market Energy Sales	255,055	214,757	
Other Operating Revenues	9,926	9,194	567
Total Operating Revenues	$1,734,777	$1,537,402	$251,248
Operating Expenses			
Fuel and Purchased Power	$511,461	$430,760	
Purchased Gas			$139,078
Operation and Maintenance Expenses	239,164	218,918	39,781
Transmission Expenses	193,595	177,573	
Normal Depreciation	322,742	289,518	23,471
Regulatory Asset Amortizations	(17)	(588)	8,329
Taxes Other Than Income Taxes	54,519	51,073	3,640
Federal Income Taxes	(38,280)	(28,238)	2,507
State Income Taxes	16,351	15,454	863
Deferred Tax Expense	14,302	13,634	4,848
Total Operating Expenses	$1,313,837	$1,168,104	$222,517
Net Operating Income	$420,940	$369,298	$28,731

2025 Test Year	**Total Co. Electric (000's)**	**Electric WI Jur. (000's)**	**Gas (000's)**
Operating Revenues			
Revenue From Sales	$1,482,075	$1,320,050	
Natural Gas Sales Revenue (Includes Gas Cost)			$254,293
Interruptible Credits		(1,153)	
Market Energy Sales	271,838	228,914	
Other Operating Revenues	10,776	9,965	576
Total Operating Revenues	$1,764,689	$1,557,776	$254,869
Operating Expenses			
Fuel and Purchased Power	$531,302	$447,523	
Purchased Gas			$142,795
Operation and Maintenance Expenses	234,831	215,443	40,697
Transmission Expenses	203,598	186,934	
Normal Depreciation	338,624	303,628	24,223
Regulatory Asset Amortizations	48,630	46,999	4,729
Taxes Other Than Income Taxes	57,740	54,179	3,708
Federal Income Taxes	(107,977)	(91,886)	2,328
State Income Taxes	(329)	(470)	797
Deferred Tax Expense	45,581	40,430	4,905
Total Operating Expenses	$1,352,000	$1,202,780	$224,182
Net Operating Income	$412,689	$354,996	$30,687

Average Net Investment Rate Base

In addition to the findings regarding the specific items discussed in this Final Decision, all other issues agreed upon to arrive at the filed electric and natural gas average net investment rate bases are reasonable. Accordingly, per Commission decision, the estimated electric and natural gas average net investment rate bases for the 2024 and 2025 test years were updated, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2024 Test Year	Total Co. Electric (000's)	Electric WI Jur. (000's)	Gas (000's)
Utility Plant in Service	$9,542,273	$8,626,001	$867,985
Accumulated Depreciation	(2,644,820)	(2,386,158)	(311,576)
Net Plant in Service	$6,897,453	$6,239,843	556,409
Fuel Inventory	50,873	42,836	
Materials and Supplies Inventory	43,947	39,415	14,215
Investments in Associated Company	190	160	
Gas in Storage			15,563
Net Retired Plant	5,882	4,996	
Deferred Taxes	(976,480)	(907,505)	(116,193)
Customer Advances	(40,475)	(40,475)	(1,023)
Western Wisconsin – Gas			45,436
Average Net Investment Rate Base	$5,981,390	$5,379,270	$514,407

2025 Test Year	Total Co. Electric (000's)	Electric WI Jur. (000's)	Gas (000's)
Utility Plant in Service	$9,856,299	$8,916,718	$906,406
Accumulated Depreciation	(2,680,136)	(2,423,091)	(326,267)
Net Plant in Service	$7,176,163	$6,493,627	580,139
Fuel Inventory	54,005	45,478	
Materials and Supplies Inventory	44,596	40,002	14,425
Investments in Associated Company	190	160	
Gas in Storage			16,964
Net Retired Plant	(34,983)	(29,719)	
Retired Plant – Levelized Recovery	289,425	245,873	
Deferred Taxes	(1,056,098)	(976,872)	(121,100)
Customer Advances	(44,407)	(44,407)	(934)
Western Wisconsin – Gas			42,738
Average Net Investment Rate Base	$6,428,891	$5,774,142	$532,232

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

Line	2024				2025			
	Amount ('000)	Capital Ratio	Component Cost	Weighted Cost Rate	Amount ('000)	Capital Ratio	Component Cost	Weighted Cost Rate
Regulatory Capital Structure								
Common Stock Equity	$4,008,709	53.87%	9.80%	5.28%	$4,345,045	53.70%	9.80%	5.27%
Preferred Stock	$0				$0			
Long Term Debt	$3,304,449	44.41%	4.36%	1.94%	$3,542,231	43.78%	4.41%	1.93%
Short Term Debt	$128,050	1.72%	4.20%	0.07%	$204,025	2.52%	3.70%	0.09%
Total Capitalization	$7,441,208	100.00%		7.29%	$8,091,301	100.00%		7.29%

Assessing the reasonableness of the applicant's capital structure depends upon three important principles. First, capital structure decisions must be based on the applicant's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for the applicant and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of the applicant should be similar to typical electric utility dividend practices as long as the applicant 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 applicant must have flexibility to finance both foreseen and unforeseen capital requirements. In previous dockets, the Commission recognized the need to protect customers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices.

The Commission's determination of an appropriate capital structure and cost of capital are interrelated, and in making such determinations the Commission must strike an appropriate balance between the needs of the applicant and those of its customers. The applicant, like other Wisconsin investor-owned utilities (IOUs), is making significant, capital-intensive investments to transition its generation fleet and to maintain a reliable infrastructure for customers. The financial integrity of the utility is an important factor in this transition so that it can attract the capital it needs. To date, the strong financial health of this applicant has resulted in its ability to make these significant investments. While these investments are necessary, the Commission must also balance the utility's financial health with the needs of its customers and the utility's obligation to serve customers at just and reasonable rates. The application in this proceeding included a request for a significant rate increase.[14] As discussed later in this Final Decision, affordability is a significant concern for the applicant's customers.

The Commission has broad discretion and authority to ensure that rates are just and reasonable. In the exercise of this authority, the Commission must establish a capital structure and cost of capital that strike an appropriate balance and is not bound to any single regulatory formula. The Commission is permitted to make pragmatic adjustments called for by particular circumstances, and to consider fundamental ratemaking principles such as gradualism. The Commission must make these decisions based upon the totality of the record before it.

Capital Structure - Common Equity Ratio

In this proceeding, the applicant filed the financial capital structure requesting an increased common equity ratio of 55.00 percent, which represents an increase of 250 basis points

[14] The applicant requested an 8.4 percent increase for Wisconsin retail electric rates in 2024, and then an incremental increase of approximately 5.4 percent for 2025. The applicant requested a 6.3 percent increase in natural gas rates for 2024, and to maintain the requested 2024 retail natural gas rates into 2025.

over the approved financial capital structure in docket 6680-UR-123 of 52.50 percent. In conjunction with its determination on ROE as discussed below, the Commission finds that a 52.50 percent common equity ratio, measured on a financial basis, is reasonable. The 52.50 percent common equity ratio represents a continuation of the 52.50 percent common equity ratio authorized in the prior referenced docket. Increases in borrowing costs over the last two years, and a large renewable energy capital plan have placed upward pressure on the applicant's service rates while simultaneously decreasing the applicant's credit outlook. Maintaining a financial common equity ratio of 52.50 percent saves the applicant's customers approximately $11.77 million in 2024 and $11.79 million in 2025 compared to the equity layer increase proposed in the application. The Commission finds CUB's perspective on capital structure in this proceeding compelling, noting that it provides relief to the upward rate pressure on the applicant's customers in this case. The Commission did not explicitly change the applicant's total capitalization while denying the applicant's increased equity layer request. At the same time, the Commission acknowledges that the appropriate capital structure for the applicant would be dependent on the Commission's determinations on other interrelated issues. That leaves the potential that the Commission's decision on debt cost rates (discussed below) would reduce anticipated customer cost savings from the equity determination in this proceeding by approximately $1 to $2 million per year. The Commission notes, while this result is implied by the Commission's determinations and supported by the record, none of the parties, nor Commission staff, presented it in the proceeding.

The Commission encourages the applicant to search for efficiencies and cost savings in the applicant's current business processes or to seek funding through other government programs or tax advantaged partnerships to offset future costs. In consideration of the entirety of the record, the Commission finds it reasonable to maintain the applicant's common equity ratio at 52.50 percent on a financial basis for the 2024 and 2025 test years. This yields a reasonable WACC of 7.29 percent and generates an economic cost of capital of 9.26 percent for both test years. The pre-tax interest coverage ratio is 4.61 in 2024 and 4.57 in 2025.

Cost of Capital - Return on Equity

A principal factor used to determine the appropriate ROE is the anticipated return investors will require. Authorized returns 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 reasonable expectations. Unreasonably high returns would be unfair to utility consumers who ultimately pay for those returns in order to receive electricity and natural gas. In reaching its determination as to the appropriate ROE, the Commission must balance the needs of investors with the needs of customers, with due considerations to economic and financial conditions, along with public policy considerations. As noted above, the Commission's determination on ROE in this proceeding takes into account the Commission's determination on capital structure, as well as its decision on an Earning Sharing Mechanism (ESM), described below.

The applicant requested that it be authorized to maintain the 10.00 percent ROE authorized in the applicant's most recent rate case proceeding. CUB, joined by a number of other parties, argued that the ROE should be reduced to 9.30 percent. Walmart argued that the applicant's current ROE is too high in light of the average authorized ROEs for other vertically integrated electric utilities and that the utility already enjoys reduced risk by being authorized by the Commission to use future test years. Commission staff's analysis averaging the results of five different ROE models identified a range of 8.56 to 9.66 percent.

The Commission concludes, in light of the interrelated determinations made in this proceeding, that a 9.80 percent ROE for the 2024 and 2025 test years, which is a 20-basis point decrease from the 10.00 percent ROE authorization in the applicant's most recent rate case in docket 6680-UR-123, is reasonable. The authorized ROE falls within the range of ROEs most recently authorized by the Commission for other Wisconsin utilities, and financial models and related data made available within this proceeding. While the authorized ROE is above the range for the average of the models considered by Commission staff and is higher than the ROE advocated by CUB and others, this change takes into account the Commission's decision to not change the applicant's capital structure as requested by the applicant as discussed above, and is consistent with the principles of gradualism. This determination is also made in conjunction with the Commission's decision, discussed below, to impose an ESM. Therefore, for these reasons and based upon the evidence in the record, the Commission finds that reducing the applicant's ROE at 9.80 percent is reasonable.

Commissioner Huebner dissents and would have further reduced the applicant's ROE to 9.7 percent.

Cost of Capital - Debt Cost Rates

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

The applicant's filing in this proceeding forecasted a short-term debt cost rate of 4.20 percent on $128,130,000 in 2024 and a cost rate of 3.70 percent on $204,025,000 in 2025. In surrebuttal testimony, citing rising interest rates, applicant witness Neil Michek (Surrebuttal-WPL-Michek-r-8), requested an updated forecast for the 2024 and 2025 short-term debt rates of approximately 5.65 percent for 2024 and 4.95 percent for 2025. The Commission is not convinced that it is reasonable or appropriate to update the rates late in the process. Such an update is inconsistent with past Commission practice. Therefore, the Commission finds it reasonable to set the cost rate of issuing short-term debt at 4.20 percent and 3.70 percent for 2024 and 2025, respectively.

The applicant's filing in this proceeding forecasted a long-term debt cost rate of 4.36 percent in 2024 and a cost rate of 4.41 percent in 2025. No party contested the long-term debt cost rate forecasts, and the applicant did not provide alternative forecasts based upon potential additional long-term borrowing. The Commission concurs with the applicant's uncontested long-term debt cost rates for the 2024 and 2025 test years in this proceeding. Therefore, the Commission sets the cost rate of issuing long-term debt at 4.36 percent and 4.41 percent for 2024 and 2025, respectively.

As discussed in the Common Equity Ratio section of this Final Decision, the Commission did not address total capitalization for the applicant while making its determinations tied to the applicant's common equity ratio, ROE, and debt cost rates in the test years. In keeping total capitalization at the value forecasted by the applicant, with the common equity ratio determined by the Commission, the resulting computation would redistribute the applicant's common equity back into its capital structure as debt. This increased debt load may require the applicant to issue additional long-term debt securities during the test years at similarly forecasted rates. Had it been considered by the parties or Commission staff earlier in this proceeding, and by using calculations that were used throughout the record in this proceeding, the resulting recalculation would potentially add approximately $1 to $2 million back to the revenue requirement for each of the test years. While compared with the capital structure components that the Commission affirmatively determined, the Commission views this dollar amount as insubstantial for purposes of this proceeding. Specifically, it is less substantial when compared to the Commission's determination on forecasted long-term debt rates and common equity ratio, both of which were issues for which a specific Commission determination was requested and provided. As none of the parties, nor Commission staff, presented alternatives in consequence of the Commission's potential determinations in the individual, interrelated components of the applicant's capital structure, in particular the potential change to revenue requirement, the Commission must here acknowledge the outcome likely implied by its determinations. In its determination on forecasted long-term debt rates, the Commission declines to recalculate the revenue requirement for each of the test years.[15] Therefore, any deficiency carries through and is reasonable in consequence of the Commission's determinations in this rate proceeding.

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

[15] Any forecast in a rate proceeding is based on the information available at this time and will differ from actuals except for where a reconciliation mechanism has been required or authorized.

balance the interests of the utility, its investors, and its customers. The applicant and other IOUs have voluntarily offered to have such mechanisms in place. After having an ESM in place for several years, the applicant indicated in this proceeding that it would not consent to the imposition of an ESM unless it received its requested ROE and capital structure. The applicant argued that imposition of an ESM would result in an asymmetrical risk profile, where the applicant's upside earnings potential is capped but it would be expected to absorb virtually unlimited downside potential.

The Commission finds this argument unpersuasive. In setting just and reasonable rates, the Commission does not need the applicant's consent and has the authority to impose this mechanism to protect customers. The Commission's authorized capital structure and imposition of an ROE at the higher end of the range provide sufficient safeguards. Further, there are other mechanisms available to the applicant and mechanisms currently in place to minimize downside potential in the event of extraordinary circumstances beyond the applicant's control.

Therefore, in addition to setting an ROE of 9.80 percent, the Commission imposes an ESM. Under the ESM, the applicant shall retain all earnings less than or equal to 15 basis points above authorized ROE, the applicant shall return to customers an amount equal to 50.00 percent of earnings between 15 and 75 basis points above authorized ROE, and the applicant shall 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 OBO in calculating the applicant's financial capital structure.[16] 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 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 applicant's financial capital structure. This information is most readily available from the applicant 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.

[16] 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.

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 the test years, the Commission finds it reasonable to impute $222,582,000 for OBOs for 2024 and $220,450,000 for 2025.

Dividend Restriction

The applicant's common equity ratio, as discussed previously above, will remain at 52.50 percent, as measured on a financial basis. In its Final Decision in docket 6680-UR-123, the Commission directed the applicant not to pay dividends, including any pass-through of subsidiary dividends, in excess of this forecasted level, if its actual average common equity ratio, on a financial basis, is or will fall below the financial equity ratio upon which the revenue requirement was calculated. In this proceeding, the Commission finds it reasonable to direct the applicant not to pay dividends, including any pass-through of subsidiary dividends, in excess of the forecasted levels in 2024 or 2025 if its actual average common equity ratio, on a financial basis, is or will fall below the test-year level of 52.50 percent for 2024 or 2025.

Accounting Treatment for Retirement of Edgewater Unit 5

Edgewater Unit 5 was initially commissioned in 1985 and the applicant has invested in several pollution control projects over the last decade to ensure the unit could continue to serve customers reliably and affordably. The applicant has since conducted a collaborative planning analysis that has resulted in the applicant's Clean Energy Blueprint resource plan. As a result of that analysis, the applicant was originally planning to retire the Edgewater Unit 5 by the end of 2022; however, the applicant updated the retirement date to June 2025.

In docket 6680-UR-123 and pursuant to an agreement reached by the settling parties to that docket, the Commission accepted the plan agreed to by the applicant and those parties addressing the applicant's recovery of Edgewater Unit 5's remaining net book value (NBV) after retirement. Pursuant to that plan, after retirement the applicant will transfer the remaining NBV from the applicable utility plant in-service and accumulated depreciation accounts to Account 182.2 (Unrecovered Plant and Regulatory Study Costs), and include the transferred balance in the calculation of net investment rate base. Additionally, the applicant would record the amortization of the remaining NBV and costs of removal in Account 407 (Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs), and include that amortization expense in revenue requirement. The applicant would also segregate the remaining NBV transferred to Account 182.2 into separate projects to address recovery of the unit's original installed cost (Life NBV) and costs of removal. The applicant would recover the Life NBV of Edgewater Unit 5 through June 2045 on a levelized cost recovery basis at a premised 9.80 percent ROE, which resulted in an effective ROE of 9.20 percent due to the specific levelized cost recovery structure.

While the Commission authorized this recovery mechanism in docket 6680-UR-123, as a condition of that approval, the Commission required the applicant to file an analysis of alternatives regarding the recovery of the remaining useful life of Edgewater Unit 5 and other generating units proposed to be decommissioned prior to the end of the facility's useful life in its 2024 test year rate filing.

In this proceeding, the applicant requested continuation of the recovery mechanism previously approved in docket 6680-UR-123. The Edgewater Unit 5 retains approximately $472.7 million of undepreciated net book value beginning with its retirement in 2025. Under the recovery paradigm established in docket 6680-UR-123, the applicant would transfer the remaining net book value from the applicable utility plant in service and accumulated depreciation accounts to account 182.2 Unrecovered Plant and Regulatory Study Costs (Unrecovered Plant). In addition, the applicant proposed to include the balance transferred to Unrecovered Plant in NIRB, to include the continued amortization of the remaining net book value and the remaining costs of removal in account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (Retired Plant Amortization) and to include that amortization expense in revenue requirement. The applicant would levelize recovery of any remaining book value of Edgewater Unit 5 at a return on equity of 9.20 percent (modified to 9.10 percent if the applicant's test year proposed capital structure and updated cost of capital were approved).

The applicant also modeled two different cost recovery scenarios for the remaining net book value of the plant over 20 years (traditional v. levelized recovery). Additionally, the applicant modeled four different scenarios for the cost recovery of $100 million portion of this total utilizing securitization, levelized, extended, or traditional cost recovery mechanisms.

CUB argued that the record evidence in the current proceeding showed lower cost alternatives to the proposed continuation of the levelization approach previously agreed to, and advocated that the Commission reduce the rate of return on Edgewater Unit 5 recovery or make any other adjustment the Commission deemed just and reasonable to reflect the fact that there are recovery alternatives that produce lower costs to customers but which have not be pursued by the applicant. WIEG supported continuation of the levelization approach with modifications including directing applicant and intervenors to work together to utilize securitization, including possible sharing of cost savings realized through securitization. Clean Wisconsin noted federal funding opportunities made available by the Department of Energy through the Energy Infrastructure Reinvestment program that Clean Wisconsin suggests could be leveraged by the applicant to refinance some portion of the remaining book value.

The applicant declined to support alternatives and maintained that continuation of its proffered approach was in the best interest of customers. The Commission is disappointed in the applicant's engagement on this issue and its refusal to pursue other alternatives or variations on the levelization approach originally authorized. With Edgewater Unit 5 not retiring until at least 2025, there is still time for further analysis and the Commission strongly encourages the applicant to take advantage of that time and conduct a more robust analysis of future recovery alternatives. To that end, the applicant shall submit additional analysis in its next rate proceeding of alternatives regarding recovery of the remaining useful life of the Edgewater Unit 5, including without limitation an analysis of the impacts on levelization of the remaining net book value resulting from an adjustment to the ROE for Edgewater 5, additional cost sharing methodologies, and securitization of the full remaining value of environmental controls. In addition, the applicant shall report back to the Commission on any Department of Energy funding opportunities that may mitigate costs associated with the retirement of Edgewater 5. At the time of retirement of Edgewater 5, the applicant shall calculate and report to the Commission the final Actual Life NBV of Edgewater 5, and shall defer the incremental difference between levelization at the Remaining NBV and levelization at the Life NBV.

In the interim and based upon the record before it, the Commission authorizes continued recovery of the Edgewater Unit 5 using levelization methodology and recovery of the remaining Life NBV of Edgewater Unit 5 at a premised 9.80 percent ROE, which computes to an effective ROE of 9.20 percent due to the applicant's specific levelized cost recovery structure. This levelized cost-recovery mechanism benefits the applicant's customers by allowing an ROE (an effective 9.20 percent) for Edgewater Unit 5's Life NBV that is lower than the 9.80 percent ROE that will apply to the applicant's remaining rate base. Relative to traditional cost recovery, the levelized cost recovery shows an incremental reduction in 2025 revenue requirements and through the first nine years of the recovery period, however levelized recovery adds $59 million to the nominal life cycle revenue requirement recovery costs.

Required Return on Rate Base

The applicant's WACC of 7.29 percent in the 2024 and 2025 test years must be translated into a rate of return (ROR) that can be applied to the average NIRB and used to compute the overall return requirement in dollars. Wisconsin IOUs have utilized the RATIO in ratemaking to adjust the WACC in order to provide a return on net working capital. In the application, the applicant used a RATIO of 99.10 percent in 2024 to adjust its requested WACC of 7.29 percent to 7.52 percent for total company electric, 7.53 percent for Wisconsin retail electric and 7.39 percent for natural gas. In 2025, the applicant used a RATIO of 98.67 percent to adjust its requested WACC of 7.29 percent to 7.53 percent for total company electric, 7.54 percent for Wisconsin retail electric and 7.42 percent for natural gas. The RATIO adjustment and the adjustments identified below reflect all appropriate adjustments in the application for use in translating the composite cost of capital into a return requirement applicable to the average NIRB.

Accordingly, the Commission finds the ROR on average electric and natural gas NIRBs, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

2024 Test Year	**Total Co. Electric**	**Electric WI Jur.**	**Gas**
Weighted Cost of Capital	7.29%	7.29%	7.29%
Ratio of Average NIRB Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	99.10%	99.10%	99.10%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average NIRB	7.35%	7.35%	7.35%
Average CWIP Balance Allowed Current Return (000's)	$100,711	$97,434	$2,689
Average NIRB (000's)	$5,981,390	$5,379,270	$514,407
Adjustment to Adjusted Cost of Capital to Provide a Current Return on CWIP	0.12%	0.13%	0.04%
Adjustment to Return Requirement to Provide Short-term Debt Return on Regulatory Assets and ADIT Proration	0.05%	0.05%	0.00%
Required Rate of Return on NIRB	7.52%	7.53%	7.39%

2025 Test Year	**Total Co. Electric**	**Electric WI Jur.**	**Gas**
Weighted Cost of Capital	7.29%	7.29%	7.29%
Ratio of Average NIRB Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	98.67%	98.67%	98.67%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average NIRB	7.38%	7.38%	7.38%
Average CWIP Balance Allowed Current Return (000's)	$115,010	111,460	$3,017
Average NIRB (000's)	$6,428,891	$5,774,142	$532,230
Adjustment to Adjusted Cost of Capital to Provide a Current Return on CWIP	0.13%	0.14%	0.04%
Adjustment to Return Requirement to Provide Short-term Debt Return on Regulatory Assets and ADIT Proration	0.02%	0.02%	0.00%
Required Rate of Return on NIRB	7.53%	7.54%	7.42%
Rate of Return on NIRB – Edgewater Unit 5	7.06%	7.06%	0.00%

Electric Cost of Service, Revenue Allocation and Rates

2024 and 2025 Electric Cost of Service

The applicant, intervenors, and Commission staff testified regarding electric cost of service and the appropriate allocation methods for the allocation of plant and expenses that make up the applicant's revenue requirement for test years 2024 and 2025. The applicant proposed a COSS model that used the applicant-preferred assumptions for COSS. At the request of Commission staff, the applicant prepared a range of COSS models for Commission consideration. These models covered a variety of different allocations including a Standard method, 3CP method, Energy 10 Percent method, Energy 40 Percent method and a Locational method. The applicant prepared the COSS models to reflect Commission staff's audit adjusted revenue requirement.

The testimony in this proceeding covered the various COSS models and discussed the philosophical underpinnings of those models in detail. CUB did not submit its own COSS but indicated that it supported the 40 percent Energy and Locational COSS as the range of reasonable COSS models for purposes of revenue allocation and rate design. WIEG and Walmart testified that the 3CP COSS model represented their 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 in the record for the purposes of determining the final allocation of revenue requirement.

COSS Investigation

CUB and WIEG provided testimony regarding what should and should not be considered in cost allocation and the amount of weight the Commission should give various COSS models in determining revenue allocation and rate design. CUB proposed the Commission open an investigation into COSS models and how they are used to determine revenue allocation and rate design.

In light of the discussion of COSS models by parties in this case, and the ongoing evolution of production plants, the Commission finds it reasonable to open a separate, generic investigation into electric cost allocation and rate design principles. The Commission directs the investigation shall consider, but not be limited to, the types of production plants (e.g., base, peaker, etc.), renewable generation (e.g., wind, solar, etc.), and the average and excess method of allocating plant costs.

Electric Revenue Allocation - 2024 Test Year

The applicant, CUB, WIEG, RENEW, Walmart, and Commission staff provided testimony on electric revenue allocation for test year 2024. The applicant, WIEG, and Commission staff each provided a revenue allocation proposal. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement. It recovers approximately $110.84 million, which translates to an increase of 8.4 percent over current retail electric tariff revenues. WIEG and Commission staff offered alternative revenue allocations reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff proposed an alternative electric revenue allocation for the 2024 test year that recovers approximately $74.29 million, or 5.65 percent, above the applicant's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2024 test year at a 5.7 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 the applicant and Commission staff.

Consistent with the determinations the Commission has made in previous rate proceedings and the above determination regarding cost of service, the Commission finds that it is useful to 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 initially proposed by Commission staff, as adjusted for the final revenue requirement, and as proposed in Ex.-PSC-Meulemans-1 and shown in Appendix B. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Electric Revenue Allocation – 2025 Test Year

The applicant, CUB, WIEG, RENEW, Walmart, and Commission staff provided testimony on electric revenue allocation. The applicant's revenue allocation was based on the applicant's originally filed test-year revenue requirement. It recovers approximately $181.89 million, an increase of 13.8 percent over current 2023 electric revenues. Commission staff and WIEG offered alternative revenue allocations reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff proposed an alternative electric revenue allocation for the 2025 test year that recovers approximately $135.85 million, or 10.29 percent, above the applicant's Wisconsin retail revenue at present rates. WIEG proposed an electric revenue allocation for the 2025 test year that proposed to give the residential class a 6.13 percent increase, and an equal allocation to all other 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 consider the results of a number of different COSS in addition to other factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the electric revenue allocation initially proposed by Commission staff, as adjusted for the final revenue requirement, and as proposed in Ex.-PSC-Meulemans-2 and shown in Appendix C. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Electric Customer Rates and Tariff Changes

Overall Rate Design

The applicant and Commission staff provided comprehensive electric rate design proposals that include rates for all customer classes. The comprehensive rate designs proposed by the applicant and Commission staff share some similarities, but Commission staff's proposed rate design offers a more gradual approach to increasing demand charges for several customer classes. 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 demand charge increases 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.

Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed by Commission staff in Ex.-PSC-Meulemans-1 for test year 2024 and Ex.-PSC-Meulemans-2 for test year 2025, adjusted for final revenue requirement. The authorized rates appear in Appendices B and C. The Commission directs the applicant to file final form tariff sheet consistent with those rates.

Fuel Surcharge Rate

In the applicant's 2022 fuel reconciliation plan authorized in docket 6680-FR-2022[17], the Commission found it reasonable to reevaluate the surcharge collection rate in the applicant's rate case, altering the collection surcharge rate for 2024 and 2025 as necessary to ensure full recovery of the 2022 fuel cost deferral balance spread out over the accepted sales forecast. Commission staff's analysis showed that the applicant will start the calendar year with $104,333,009 remaining to be collected for the fuel cost deferred account. Commission staff proposed a flat fuel surcharge rate for January 2024 through December 2025 of $0.004667 per kWh in Direct-PSC-Meulemans-r:19-20. The Commission finds a flat surcharge that would recover the remaining fuel cost deferred account, as calculated by Commission staff, is reasonable and consistent with its decision in docket 6680-FR-2022 and the requirements of Wis. Admin. Code ch. PSC 116.

Parallel Generation – Net Metering Tariff Structure

The applicant, CUB, WIEG, SEIA, Dane County, RENEW, 350 Wisconsin, VS/SC, Clean Wisconsin, and Commission staff provided testimony on various tariff structures for parallel generation customers. In its application, the applicant proposed to make several modifications to how it serves parallel generation customers with a system size under 75 kW.

The applicant initially proposed to transition customers enrolled on the existing PgS-3 customers to the proposed PgS-2 Power Partnership tariff. The applicant had initially proposed

[17] Final Decision, signed and served August 25, 2023, Docket 6680-FR-2022 (PSC REF#: 476532)

to give currently enrolled customers an option to remain enrolled on this tariff until January 1, 2028 and to close the tariff to new customers as of January 1, 2024. In response to the concerns of various parties and members of the public, the applicant updated the proposal to allow customers currently enrolled on the PgS-3 tariff until January 1, 2033 and to close the tariff to new customers as of December 31, 2025.

The applicant had also proposed to offer the PgS-2 Power Partnership V2 tariff, which would serve as a replacement for the applicant's existing net metering parallel generation tariff, PgS-3. At a high level, the applicant stated that the intention of the Power Partnership tariff is to make all customers indifferent to the source of their energy, be that utility-owned or customer-sited generation. The proposed Power Partnership V2 tariff contained many novel approaches to parallel generation amongst Wisconsin utilities, including:

- Hourly netting of a customer's electric usage and exports to the grid for customers with a system size up to 75 kW;
- Providing distribution system upgrades for the purpose of interconnecting new facilities at no cost to the customer;
- Mandatory enrollment for the customer on their appropriate time-of-use based rate;
- The System Asset Value Credit; and
- A monthly credit limit where a customer's monthly bill cannot be reduced below $10 or $15 per month, depending on system size, but excess credits can be carried over monthly for up to 12 months.

The System Asset Value Credit is a per-kWh credit proposed by the applicant that was set at a level to make the costs paid by consuming customers equivalent to the embedded capital cost rate for the marginal generator in the applicant's most recent resource plan. The System Asset Value Credit was designed to recognize that distributed generation is a part of the overall generation portfolio that the applicant uses to meet its customers' energy and demand needs.

The applicant proposed to establish a regulatory asset, with the applicant's authorized rate of return applied to it, for payments made out to customers under the System Asset Value Credit. The applicant stated this treatment of the System Asset Value Credit would allow the applicant to receive compensation for the additional value provided to distributed generation customers who use the system to conduct energy transactions (consuming and generating).

The applicant also proposed that the rate of return applied to this regulatory asset have conditional adders be established such that for every 5 percent that total interconnected systems exceed the applicant's forecast, the adder would increase by an amount equivalent to the effect of a 0.5 percent increase in the applicant's authorized return on equity.

The applicant also proposed that the System Asset Value Credits be accounted for as purchased power expense, and to defer the System Asset Value Credits incurred and include the costs in a future proceeding as a component of fuel costs. As part of the applicant's proposal to defer System Asset Value Credits costs, the applicant proposed carrying costs be based on the applicant's short-term debt rate.

The applicant, CUB, WIEG, SEIA, Dane County, RENEW, 350 Wisconsin, VS /SC, Clean Wisconsin, and Commission staff all provided testimony on these aspects of the applicant's proposal. Additionally, CUB provided testimony that payments made out under the PgS-2 Power Partnership V2 tariff should include avoided transmission costs. Lastly, several parties suggested that the Commission reject the proposed modifications and further investigate the appropriate tariff structure for parallel generation customers, citing several concerns around the applicant's proposal to place an end date on traditional net metering.

350 Wisconsin, Clean Wisconsin, Dane County, Vote Solar, Sierra Club, and WLGCC did not support the approval of the proposed Power Partnership V2, with several of these parties stating that the applicant's proposal is unreasonable and unnecessary. RENEW and SEIA expressed support for the program, stating that it offered a reasonable transition away from traditional net metering. CUB expressed support for the program, if the Commission ordered that the program include payments offered for avoided transmission costs.

While the Commission appreciates the efforts of the applicant to build consensus and for proposing several novel concepts, the Commission does not approve the applicant's proposal to close to new customers its PgS-3 tariff, and does not approve the applicant's request to offer the Power Partnership V2 tariff. The applicant's proposals did not provide adequate justification for some of the key aspects. In particular, the Commission did not find there to be adequate justification for authorizing a rate of return to the applicant for payments made out to parallel generation customers. The Commission did not find there to be sufficient evidence to set a closing date on net metering. Further, the complexity and novelty of many of the concepts simply require more analysis.

As noted above, several parties called on the Commission to further investigate the appropriate tariff structure for parallel generation customers, suggesting the Commission could continue docket 5 EI-157 Investigation of Parallel Generation Purchase Rates and:

- Determine an appropriate cost-of-service analysis that incorporates parallel generation classes;

- Collect more cost-of-service data from a broader set of parallel generation facilities;
- Establish a working group to identify methods for adjusting compensation formulas;
- Determine an appropriate per-kWh incentive for parallel-generation customers;
- Evaluate adoption rates;
- Conduct a Cost-Benefit Analysis study; and/or
- Conduct a Value of Solar study.

The Commission agrees that further analysis is required. Additional investigation of net metering shall proceed in docket 5 EI-157. The Commission notes that docket 5 EI-157 is a generic docket and that any party or utility may participate.

Affordability of Utility Service

Broad stakeholder groups raised concerns related to utility service affordability and emphasized during the course of this proceeding that affordability must remain a top priority.

CUB provided analysis supporting a decreased ROE of 9.3 percent in order to ease energy burden for customers while continuing to provide the utility with financial viability, in addition to supporting an ESM and rates that recognize the differing economics among customer classes. CUB suggested the Commission order the applicant to collaboratively evaluate and plan for all of its affordability programs, including its existing arrearage management and voluntary efficiency programs, in order to work toward service affordability and reduce energy burden.

BPSA provided analysis to support its assertions that large portions of the applicant's customers experience significant high energy burdens, and that the Commission should direct the applicant to adopt comprehensive affordability solutions, including a Percentage of Income

Payment Plan, modifications to its arrearage management program (AMP), and a geo-targeted low-income usage reduction program. BPSA and 350 Wisconsin suggested the Commission reject or reduce the applicant's rate increase request.

Many other intervenors and public commenters raised similar issues and suggestions related to working toward service affordability.

Energy Care Credit (ECC)

The applicant requested authorization for a new program, the ECC program. The program is designed for eligible residential gas and electric customers that receive benefits through the Wisconsin Home Energy Assistance Program (WHEAP). Customers enrolled in the ECC would receive a credit of $6.67 each month and be informed of opportunities to participate in various energy efficiency programs.

The applicant, CUB, 350 Wisconsin, BPSA, RENEW, and Commission staff provided testimony on the applicant's proposed ECC program. CUB argued that if approved, the Commission should require the applicant to work with staff and stakeholders to develop an evaluation plan and associated metrics that assess the effectiveness of the ECC and of other programs that the applicant designed to reduce energy burdens, including the AMP and the Voluntary Energy Efficiency Program. In response to the applicant's ECC proposal, BPSA suggested alternative proposals, including: modifications to the applicant's existing AMP, a Percentage of Income Plan (PIP), a geo-targeted, low-income usage-reduction pilot program, and modifications to the applicant's Community Solar programs to expand access to low-income customers.

The applicant argued the ECC Program would benefit non-participating customers by reducing collection costs, such as fewer non-pay notices, calls, disconnections, and write offs.

The applicant did not conduct a formal cost-benefit analysis for the program; however, the applicant envisioned that the evaluation and metrics plan would be developed in conjunction with Commission staff would include such an analysis.

The Commission notes that the applicant did not provide adequate cost-based justification for the program or metrics for gauging the program's success. Further, the Commission does not think it is reasonable to conclude that a $6.67 per month credit would materially reduce energy burden or impact how customers decide to consume energy or pay bills. Given the limited analysis offered by the applicant in support of its proposed ECC program, the Commission finds that it is not reasonable to authorize the creation of the ECC as proposed, and, as discussed below, directs the applicant to work with interested stakeholders to develop other offerings to address affordability and energy burden.

Arrearage Management Program

The applicant requested to make its current AMP pilot a permanent program, citing that AMP enrollment has increased on time payments by 39 percent, reduced arrears for enrollees by an average of 40 percent, and avoided the costs of disconnection. BPSA suggested modifying the applicant's AMP regarding expanded eligibility, extending AMP offering to customers whose service is disconnected, lowering the program's arrears threshold, and applying AMP payments as on-time payments. The applicant agreed it may be reasonable to extend the AMP offering to customers whose service is disconnected, when still connected to WHEAP approval.

It is clear that applicant's AMP pilot has been successful by increasing on time payments, reducing arrears and avoiding costs of disconnection – all of which benefit all of the applicant's customers not just those enrolled in the AMP. The Commission applauds the applicant's successful implementation of the pilot program thus far. However, given that affordability challenges persist, more can and should be done. To build off the initial success of the AMP pilot, the Commission concludes that it is reasonable to maintain the pilot status of the program and to direct the applicant to request approval to make modifications to the AMP pilot. Specifically, the applicant shall propose modifications to the AMP pilot to expand eligibility, extend the AMP offering to customers whose service is disconnected, lower the program's arrears threshold, and apply AMP payments as on-time

Other Affordability Programs

BPSA proposed that the Commission require the applicant to adopt the following three programs:

- Percentage of Income Plan to deliver affordable bills to customers at or below 200 percent of the Federal Poverty Level (FPL);
- A geo-targeted, low-income usage-reduction pilot program, with separate program components directed toward electricity and natural gas customers, that also targets customers who exhibit identified payment difficulties; and
- Expand access of low-income customers to applicant's Community Solar Program.

While additional affordability programs merit further study, the Commission declines to approve either a PIP or geo-targeted, low-income usage-reduction pilot program at this time. These and other programs require further analysis and collaborative development with the utility and stakeholders.

BPSA asserted that the applicant's Community Solar Gardens program fails to fully accomplish the applicant's objective of making "solar simple and accessible to everyone." BPSA recommended two components be added to the applicant's community solar program.

First, BPSA proposed that the applicant dedicate five percent of the total kW capacity to support first-time home buyers assisted through the State Department of Energy, Housing and Community Resources. Second, BPSA proposed that the applicant carve out a percentage of community solar blocks which is equal to the total percentage of the applicant's customers with income at or below 200 percent of the federal poverty line. As BPSA observed, there is precedent for such carve outs as the applicant set aside 171 blocks (5 percent of the blocks) from the Fond du Lac Community Solar program for distribution to 12 customers through Habitat for Humanity.

The Commission agrees that the applicant can do more to make its community solar program more accessible. Therefore, the Commission finds that it is reasonable to direct the applicant to file a TE docket, by no later than December 31, 2024, to propose modifications to its tariff regarding the expansion of access of low-income customers to its community solar program by dedicating five percent of the total kW capacity to support first-time home buyers assisted through the Division of Energy, Housing and Community Resources, and by carving out a percentage of community solar blocks which is equal to the total percentage of applicant's customers with income at or below 200 percent of the federal poverty line.

Affordability and Energy Burden Investigation

The Commission acknowledges that affordability is a serious issue in this rate case and highlights how customer affordability is not only a residential-customer issue; rather, customers of all classes are facing energy costs that are becoming increasingly burdensome. Therefore, the Commission finds it reasonable to direct the applicant to work with interested stakeholders to develop alternative programs and options to address customer affordability and energy burden, and that a docket shall be opened by the Commission to investigate the applicant's development of such programs no later than April 1, 2024.

Optimal Rate Switch – Opt Out Program

In a response to a Commission staff's data request, the applicant proposed to offer the Optimal Rate Switch – Opt Out program. This proposed tariff would allow that for each calendar year, the applicant may select for inclusion into this program up to 10,000 customers who are currently enrolled under the Rg-1, Rg-5, Rd-1, Gs-1, Gs-3, and Gd-1 rate schedules, where analysis predicts that those customers could incur lower bills under a different rate schedule, and automatically switch customers to the optimal rate should the customer choose not to opt out. In particular, the applicant proposed to switch customers "from the Rg-1 rate by data mining hourly data from customers who receive WHEAP benefits." (PSC REF#: 480892 at 17.) Further, the applicant would guarantee the participating customer lowest rate by potentially refunding the customer the difference between the charges under the differing rates (for the first year). (*Id*. at 18.)

At the party hearing, Commission staff questioned the applicant's witnesses as to its proposed selection criteria and whether the proposal overall complied with Wisconsin law. (PSC REF#: 481530 at 214-222, 235-238.) In particular, the witnesses could not describe how the applicant would select between otherwise qualifying customers and why it was using 10,000 customers for the proposal. Further, Commission staff questioned whether the applicant was complying with Wis. Admin. Code § PSC 113.0406(4)(e)[18] by not ensuring *all customers* are

[18] Subsection (a) states, "[e]ach bill for service shall be computed at the proper filed rate, which shall be the rate selected by the utility unless the customer selects a rate under par. (e)." Paragraph (e) states:

> When a customer is eligible to take service under more than one rate schedule, the utility shall inform the customer at the times specified in par. (f) of the option to select a rate, of the options and service classifications for which the customer may be eligible and the conditions necessary to qualify and of the firm service rate option that would have resulted in the lowest rate based on the previous 12 months'

assisted in "selecting the lowest rate consistent with the customer's anticipated usage and needs." *Id*.

Generally, Wisconsin law prohibits the Commission from approving discriminatory rates for "like contemporaneous service." Wis. Stat. § 196.01(1)(a). Along with the Wis. Stat. § 196.03(1) requirement that a public utility charges be "reasonable and just," the prohibition of discriminatory rates has been part of Wisconsin public utility law since its seminal legislation. Wisconsin Stat. § 196.60(1)(a) explains the concept under the title "Discrimination prohibited," providing as follows:

> [N]o public utility . . . may charge, demand, collect or receive from any person more or less compensation for any service rendered . . . than it charges, demands, collects or receives from any other person for a like contemporaneous service.

In this case, the Commission could not determine whether or not this program would be discriminatory and finds, at a minimum, the proposal raises concerns about the applicant's current compliance with Wis. Admin. Code § PSC 113.0406(4)(e).

In comments submitted on this issue, the applicant suggested that in the event the Commission approves a tariff, then different treatment between customer pursuant to the tariff is lawful. This is an oversimplification of the law and the Commission's role. In particular, the applicant cites to no authority in furtherance its proposal to refund the participating customers should a different rate have been better for them. And even amongst WHEAP eligible customers (let alone all customers in the class), participating customers would then get the guarantee that is not available to "any other person for a like contemporaneous service." Ultimately, the applicant

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service and on the metered customer usage information known to the utility. The information provided shall include a general explanation of electric service usage characteristics to assist the customer in selecting the lowest rate consistent with the customer's anticipated usage and needs. If the customer requests a change in rate classification, it shall be effective at the beginning of the current billing period if required billing information is available, but such change shall be effective no later than the beginning of the second billing period following the customer's request.

did not provide the Commission with sufficient evidence regarding the legality of the proposal. Thus, the Commission does not find it reasonable to approve the Optimal Rate Switch – Opt Out program as proposed by the applicant in Ex.-PSC-Data Request Response-TCM-3.2.

Compliance With Wis. Admin. Code § PSC 113.0406(4)(e)

As stated above, Commission staff identified an area of concern that the applicant may not be providing adequate notice to customers on the firm service rate that would have resulted in the lowest rate based on the previous 12-months service for whom the applicant has metered customer usage information. Because there was an overall lack of evidence in this proceeding surrounding the Optimal Rate Switch – Opt Out program as proposed by the applicant, the Commission finds it reasonable to require the applicant to submit additional evidence and documentation to demonstrate compliance with Wis. Admin. Code § PSC 113.0406(4)(e). Beyond analyzing program proposals in rate proceedings, the Commission is charged with ensuring compliance with Wisconsin statutes and administrative code. The evidence that was submitted raises concerns with the applicant's compliance.

Sections of the Extension Rules

The applicant proposed updates to sections of the applicant's extension rules. The first proposal updated language and amperage thresholds to align with modern applicant practices. The next proposal proposed to increase the threshold under which a refund or additional bill will be issued to customers upon completion of their service extension. The last proposal adds a charge for return trips if a customer claims a site is prepared for service and upon the applicant's crew's arrival, they determine that the site is not ready. The Commission finds it reasonable to approve updates language and amperage thresholds to align with modern applicant practices and to increase the threshold under which a refund or additional bill will be issued to customers upon completion of their service extension. It also finds that, once the Commission receives cost and rate information, it is reasonable to delegate approval of the final form revision tariff for the return trip charge to the Administrator of the Division of Energy Regulation and Analysis.

Uncontested Rate Design Proposals

The applicant proposed several modifications to other tariffs which were not opposed by any interested parties. These issues included:

- Ms-3 Streetlighting
- Cp-INT Large Interruptible Tariff
- Routine update to the solar production credit of the Community Solar tariff
- Increasing the program cap of the Community Solar tariff from 6 MW to 10 MW
- Ms-1 Large Interruptible Tariff Streetlighting
- Cp-1 tariff
- Cg-2 TOD tariff
- Duplicate Facilities Maintenance tariff

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.

Natural Gas Cost of Service, Revenue Allocation and Rates

Natural Gas Cost of Service

The applicant, CUB, and Commission staff provided testimony regarding natural gas cost-of-service methodology. The applicant prepared COSS results, COSS A and COSS B, using parameters established by Commission staff. The applicant supported the use of multiple

COSS models, recognizing a spectrum of allocation positions. Commission staff, BPSA, and CUB also supported the use of multiple COSS models, while Clean Wisconsin and Dane County took no position.

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 cost-of-service studies in the record for the purposes of class revenue requirement allocation for the 2024 and 2025 test years.

Natural Gas Revenue Allocation – 2024 Test Year

The applicant, CUB, and Commission staff provided testimony on the natural gas revenue allocation for the 2024 test year. Both the applicant and Commission staff provided comprehensive revenue allocation proposals. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff developed natural gas rates for the 2024 test year that recover approximately $13.65 million, or 12.23 percent, above the applicant'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 factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the natural gas revenue allocation initially proposed by Commission staff, as adjusted for the final revenue requirement and as shown in Ex.-PSC-Meulemans-3, as shown in Appendix D. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Natural Gas Revenue Allocation – 2025 Test Year

The applicant, CUB, and Commission staff provided testimony on the natural gas revenue allocation for the 2025 test year. Both the applicant and Commission staff provided comprehensive revenue allocation proposals. The applicant's revenue allocation was based on the applicant's originally filed test year revenue requirement. Commission staff offered an alternative revenue allocation reflecting Commission staff's adjustment to the applicant's test year revenue requirement. Commission staff also developed natural gas rates for the 2025 test year that recover approximately $13.61 million, or 12.20 percent, above the applicant'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 factors such as rate stability and customer bill impacts when making a determination on class revenue allocation in this case. Ultimately, the Commission finds it reasonable to approve the natural gas revenue allocation initially proposed by Commission staff, as adjusted for the final revenue requirement and as shown in Ex.-PSC-Meulemans-3, and shown in Appendix E. The Commission finds that this allocation facilitates a reasonable approach to rate design and results in a more equitable distribution among customer classes.

Rate Design

Overall Rate Design

The applicant and Commission staff provided comprehensive natural gas rate design proposals 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. The Commission finds that the rate design proposed by Commission staff Ex.-PSC-Meulemans-3, as modified by the Commission determinations in the above sections of this Final Decision, is reasonable.

Therefore, the Commission finds it reasonable to accept the comprehensive rate design proposed by Commission staff in Ex.-PSC-Meulemans-3 for the 2024 and 2025 test years, adjusted for final revenue requirement. The authorized rates appear in Appendices D and E.

Uncontested Rate Design Proposals

The applicant proposed several modifications to other tariffs, which were not opposed by any interested parties. These issues include:

- Updates to the Payment of Nonrefundable Service Lateral Charges section;
- Update to the Main Extensions to Developments section;
- Removing boring expenses from the Excess Construction Costs section; and
- Removing the Reapportionment Option as this is an outdated option and replaced by the Residential Extension model.

Commission staff found the aforementioned proposals reasonable and notes that no changes warranted concern (Direct-PSC-Meulemans-r). No other parties raised concerns about proposals. Therefore, the Commission finds it reasonable to authorize the uncontested natural gas rate design proposals.

Order

1. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2024, provided that the applicant file these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code §§ PSC 113.0406(1)(a) and 134.13(1)(b) by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

2. By January 1, 2025 the applicant shall revise its existing rates and tariff provisions for both electric and natural gas utility service for 2025, substituting the rate modifications and tariff provisions that expand the terms of services as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

3. The applicant may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B, C, D and E or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. The applicant shall prepare a bill message that properly identifies the rates authorized in this Final Decision. The applicant shall provide the message to customers no later

than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill message with the Commission before it provides the message to customers.

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

6. All 2024 fuel costs shall be monitored using a plus or minus 2.0 percent tolerance band pursuant to Wis. Admin. Code § PSC 116.06(3).

7. The electric fuel costs in Appendix F shall be used for monitoring the applicant's 2024 fuel costs pursuant to Wis. Admin. Code § PSC 116.06.

8. The applicant shall file for its 2025 Fuel Cost Plan in 2024 consistent with requirements of Wis. Admin. Code ch. PSC 116.

9. The applicant shall amortize the applicant's remaining COVID-19 regulatory balance over two years (2024 and 2025).

10. The applicant shall discontinue escrow accounting treatment for credit card convenience fees and the applicant shall undertake a final true-up of these costs in the applicant's next rate proceeding.

11. The applicant shall discontinue escrow accounting treatment for late payment fees and the applicant shall undertake a final true-up of these costs in the applicant's next rate proceeding.

12. The applicant shall discontinue the solar project revenue requirement deferral after 2023, and the applicant shall undertake a final true-up of these costs in the applicant's next rate proceeding.

13. The applicant shall defer any impacts of the IRA and the IIJA of 2021 when the impacts are incurred or received, with carrying costs at the applicant's short-term debt rate, to a future rate proceeding.

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

15. The applicant shall continue deferral accounting treatment for the retirement of Edgewater Unit 5 with carrying costs at the applicant's pretax weighted cost of capital..

16. The applicant shall continue deferral accounting treatment for the retirement of Columbia Units 1 and 2.

17. The applicant shall defer changes to a wholesale power supply contract identified in Rebuttal-WPL-Michek-c-45.

18. The applicant shall return the funds, already collected under the E-Charge and SmartCharge E-Perks programs, back to the applicant's customers, as they were charged for a service that was not provided.

19. The applicant shall continue deferral accounting over the 2-year period, 2024 through 2025, for all other deferrals and escrows not discussed as a separate issue, as identified in Appendix G

20. The applicant shall maintain escrow accounting treatment for the retail share of the applicant's transmission costs in Account 565 through the 2024 and 2025 test years.

21. The applicant shall maintain escrow accounting treatment for the costs of the applicant's conservation and farm rewiring programs through the 2024 and 2025 test years.

22. The applicant shall accrue a return on 50 percent of CWIP, except where the applicant requests to apply 100 percent AFUDC to new construction projects requiring a CA or CPCN.

23. The applicant shall continue to apply AFUDC to 100 percent of the solar projects in docket 6680-CE-182 and 6680-CE-183.

24. The applicant shall record transmission escrow consisting of forecasted transmission expenditures of $188,431,179 for 2024 and $199,042,892 for 2025.

25. The applicant shall record annual conservation escrow expense for retail electric operations of $16,700,999 and $16,608,749 in 2024 and 2025, respectively. The applicant shall record annual conservation escrow for Wisconsin natural gas operations of $3,385,645 and $3,355,395 in 2024 and 2025, respectively.

26. The applicant shall record an annual amount of $2,076,940 for 2024 and $2,158,917 for 2025, respectively, for farm rewiring expenses.

27. It is reasonable for the applicant to submit a 10-year financial forecast in its next rate case.

28. It is reasonable for the applicant to submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

29. Effective January 1, 2024, the applicant shall implement an ESM for 2024 and 2025 test years. 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, the applicant shall retain all earnings less than or equal to 15 basis points above authorized ROE, the applicant shall return to customers an amount equal to 50.00 percent of earnings between 15 and 75 basis

points above authorized ROE, and the applicant shall return to customers an amount equal to 100 percent of earnings equal to or in excess of 75 basis points above the authorized ROE.

30. The applicant may not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis to fall below the test-year authorized level of 52.50 percent in 2024 and 2025.

31. The applicant may continue recovery of the Edgewater Unit 5 for 2024 and 2025 test years using the levelization methodology and the related accounting entries initially authorized in docket 6680-UR-123 and as presented in this proceeding.

32. The applicant shall submit additional analysis in its next rate proceeding of alternatives regarding recovery of the remaining useful life of the Edgewater Unit 5, including without limitation an analysis of the impacts on levelization of the remaining net book value resulting from an adjustment to the ROE for Edgewater 5, additional cost sharing methodologies, and securitization of the full remaining value of environmental controls. In addition, the applicant shall report back to the Commission on any Department of Energy funding opportunities that may mitigate costs associated with the retirement of Edgewater 5.

33. At the time of retirement of Edgewater 5, the applicant shall calculate and report to the Commission the final Actual Life NBV of Edgewater 5, and shall defer the incremental difference between levelization at the Remaining NBV and levelization at the Life NBV.

34. The applicant shall apply the stipulated ROE for the remaining NBV of Edgewater Unit 5. The NBV shall reflect a premised 9.80 percent ROE adjusted to an effective ROE of 9.20 percent as a result of levelized cost recovery treatment.

35. The applicant shall file an application with the Commission requesting approval of modifications to the AMP pilot consistent with this Final Decision.

36. The applicant shall work with interested stakeholders to develop alternative programs and options to address customer affordability and energy burden, and a docket to investigate the applicant's development of such programs shall be opened by the Commission no later than April 1, 2024.

37. The applicant shall file a TE docket to modify its tariff regarding the expansion of access of low-income customers to its community solar program by no later than December 31, 2024.

38. The applicant shall submit additional evidence and documentation to demonstrate compliance with Wis. Admin. Code § PSC 113.0406(4)(e).

39. The applicant shall work with Commission staff on final extension rule tariff language to identify the specific return trip charge in the tariff.

40. This Final Decision takes effect on day after the date of service.

41. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 20th day of December, 2023.

By the Commission:

Cru Stubley
Secretary to the Commission

CS:JMR:arw:DL:01969244
See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
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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.[19] 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

[19] *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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Docket: 6680-UR-124 **Adjusted Present and Authorized Revenue Summary**
REVENUE SUMMARY TY2024

Rate Class by Rate Schedule	Rate Schedule	2024 kWh	2024 Revenue with Current Rates	2024 Revenue with Final Rates	2024 Change
Residential Service	**Rg-1**	3,263,574,728	$ 515,371,746	$ 551,898,259	7.09%
Residential Time of Use	**Rg-5**	88,413,651	$ 12,731,922	$ 13,622,505	6.99%
Residential Time of Use with demand	**Rd-1**	1,420,022	$ 181,375	$ 196,927	8.57%
Residential Time of Use w/ controlled water heatin	**Rw-5 (Gw-1)**	3,130,589	$ 448,043	$ 503,654	12.41%
RW-1 SEC 1-ph	**Rw-1**	1,044,931	$ 133,913	$ 145,245	8.46%
RW-3 SEC 1-ph	**Rw-3**	426,706	$ 51,058	$ 55,600	8.90%
LIHEAP Customer Discount Amount	**Rg-1,Rg-5,Rd-1**		$ -	$ -	
Residential Service Total		3,358,010,628	$ 528,918,056	$ 566,422,190	7.09%
General Service	**Gs-1**	1,207,977,938	$ 170,258,303	$ 172,245,275	1.17%
General Service Time of Use	**Gs-3**	178,855,273	$ 21,147,614	$ 21,818,788	3.17%
General Service Time of Use with demand	**Gd-1**	78,169,465	$ 8,691,156	$ 8,961,187	3.11%
General Service Non-metered	**Gs-4**	43,617	$ 10,535	$ 11,043	4.82%
General Service Total		1,465,046,292	$ 200,107,608	$ 203,036,293	1.46%
Commercial Service	**Cg-2TOD**	1,227,590,977	$ 134,054,164	$ 135,587,044	1.14%
Mid-size Commercial Service Total		1,227,590,977	$ 134,054,164	$ 135,587,044	1.14%
			$ 334,161,772		
Traffic Signals	**Mz-1**	1,754,513	$ 263,973	$ 281,773	6.74%
Civil Defense & Sirens	**Mz-2**	-	$ 3,632	$ 3,995	9.99%
Streetlighting Service	**Ms-1**	35,055,517	$ 6,800,766	$ 7,359,726	8.22%
Decorative Lighting	**Ms-2**	68,642	$ 8,445	$ 9,539	12.96%
Area Lighting	**Ms-3**	4,827,397	$ 2,281,206	$ 2,485,428	8.95%
Non-Standard Lighting Service	**NL-1**	45,967	$ 19,351	$ 20,084	3.79%
Lighting Service Total		41,752,036	$ 9,377,372	$ 10,160,545	8.35%
Industrial Service	**Cp-1**	3,724,873,670	$ 338,791,630	$ 343,315,783	1.34%
Industrial Service - Transmission	**Cp-2**	1,403,888,698	$ 103,378,154	$ 105,529,107	2.08%
Large Commercial and Industrial Service Total		5,128,762,368	$ 442,169,784	$ 448,844,890	1.51%
Total		11,221,162,301	$ 1,314,626,984	$ 1,364,050,963	3.76%

WISCONSIN POWER AND LIGHT COMPANY

Present and Proposed Revenue Detail TY2024

Rate Class and Rate Description		Number of Billing Units	Present Rates	Present Revenues	Proposed Rates	Proposed Revenues	Revenue Increase Amount	Percent
RESIDENTIAL SERVICE, Rg-1								
Daily Customer Charge:	Single-phase	149,810,960	0.493200	73,886,765	0.4932	73,886,765		12,484,247
	Three-phase	70,852	0.739800	52,416	0.7398	52,416		5,904
	Additional meter	1,364,157	0.100000	136,416	0.1650	225,086		113,680
	LIHEAP Discount	12,519,812	-	-	-	-		
Energy Charge (per kWh):								
	All kWh	3,263,574,728	0.130910	427,234,568	0.1464	477,787,340		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.001620)	-	(0.00162)	-		
Fuel Cost Surcharge:	Less 2nd nature	3,233,977,149	0.004355	14,083,970	-	-		
COMMUNITY SOLAR Subscriptions	30%	$ 15,998		15,998		15,998		
COMMUNITY SOLAR Solar kWh Productic	30%	615,375	(0.112690)	(69,347)	(0.112690)	(69,347)		
Total Rg-1	Total kWh	3,263,574,728		$ 515,340,786		$ 551,898,259	$36,557,472	7.09%
RESIDENTIAL SERVICE TIME-OF-USE, Rg-5								
Daily Customer Charge:	Single-phase	2,983,377	0.4932	1,471,401	0.4932	1,471,401		
	Three-phase	6,491	0.7398	4,802	0.7398	4,802		
	Additional Meter	9,970	0.1000	997	0.1650	1,645		
	LIHEAP Discount	249,747	-	-	-	-		
Energy Charge (per kWh):		0.33%						
TOU Schedule	High Rate	8,949,607	0.19600	1,754,123	0.25520	2,283,940		30.204%
	Regulator Rate	33,784,500	0.16300	5,506,873	0.18100	6,114,994		11.043%
	Low Rate	45,679,544	0.07900	3,608,684	0.08200	3,745,723		3.797%
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Credits		-	0.00162	-	(0.00162)	-		
Fuel Cost Surcharge:		88,413,651	0.004355	385,041	-	-		
Total Rg-5	Total kWh	88,413,651		$ 12,731,922		$ 13,622,505	$890,583	6.99%
RESIDENTIAL DEMAND SERVICE, Rd-1								
Daily Customer Charge:	Single-phase	65,132	0.3288	21,415	0.3288	21,415		
	Three-phase	-	0.7398	-	0.7398	-		
	Additional meter	-	0.1000	-	0.1650	-		
	LIHEAP Discount	5,441	-	-	-	-		
				-		-		
Customer Demand Charge (per kW)		621	-	-	-	-		
On-Peak Demand Charge (per kW)		621	4.80	2,982	4.80	2,982		
				-		-		
Energy Charge (per kWh):				-		-		
TOU Schedule	High Rate	128,671	0.17520	22,543	0.22441	28,875		28.088%
	Regulator Rate	575,762	0.13400	77,152	0.15555	89,560		16.082%
	Low Rate	712,653	0.07100	50,598	0.07500	53,449		5.634%
				-		-		
Energy Limiter	kWh at limiter	2,936	0.17000	499	0.22000	646		
				-		-		
ACT 141 Cost						-		
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00162)	-	(0.00162)	-		
Fuel Cost Surcharge:		1,420,022	0.004355	6,184	-	-		
Total Rd-1	Total kWh	1,420,022		$ 181,375		$ 196,927	$15,553	8.57%
Residental LIHEAP Discounted Rg-1, Rg-5, Rd-1				$ -		$ -		
CONTROLLED WATER HEATING 17 HR. SERVICE, Rw-1								
Daily Customer Charge		149,806	-	-	-	-		
Energy Charge (per kWh):	kWh	1,044,931	0.12380	129,362	0.13900	145,245		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00162)	-	-	-		
Fuel Cost Surcharge:		1,044,931	0.004355	4,551	-	-		
Total Rw-1	Total kWh	1,044,931		$ 133,913		$ 145,245	$11,332	8.46%

CONTROLLED WATER HEATING 11 HR. SERVICE, Rw-3

Daily Customer Charge		55,895	-	-	-	-		
Energy Charge (per kWh)	kWh	426,706	0.11530	49,199	0.13030	55,600		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00162)	-	-	-		
Fuel Cost Surcharge:		426,706	0.004355	1,858	-	-		
Total Rw-3	Total kWh	426,706		$ 51,058		$ 55,600	$4,542	8.90%

RESIDENTIAL SERVICE TIME-OF-USE with WATER HEATING, Rw-5

Daily Customer Charge			74,163	0.4932	36,577	0.4932	36,577		
Energy Charge (per kWh):									
	TOU Schedule	High Rate	380,367	0.18820	71,585	0.25520	97,070		
		Regulator Rate	1,459,481	0.15650	228,409	0.18100	264,166		
		Low Rate	1,290,742	0.07580	97,838	0.08200	105,841		
ACT 141 Cost									
ACT 141 Capped Contribution			-	-	-	-	-		
ACT 141 Capped Credits			-	(0.00162)	-	-	-		
Fuel Cost Surcharge:			3,130,589	0.004355	13,634	-	-		
	Total Rw-5	Total kWh	3,130,589		$ 448,043		$ 503,654	$55,611	12.41%

GENERAL SERVICE, Gs-1

Daily Customer Charge:	Single-phase	19,338,001	0.5589	10,808,009	0.5589	10,808,009		
	Three-phase	5,260,322	0.8384	4,410,254	0.8384	4,410,254		
Energy Charge (per kWh):								
	kWh	1,207,977,938	0.12400	149,789,264	0.13000	157,037,132		
Primary Voltage Discount								
	kWh	1,011,137	2.5%	(3,135)	2.5%	(3,286)		
ACT 141 Cost								
ACT 141 Capped Contribution		12,583,132	0.00097	12,167	0.00097	12,167		
ACT 141 Capped Credits		12,583,132	(0.00151)	(19,001)	(0.00151)	(19,001)		
Fuel Cost Surcharge:		1,207,977,938	0.004355	5,260,744	-	-		
Total Gs-1	Total kWh	1,207,977,938		$ 170,258,303		$ 172,245,275	$1,986,972	1.17%

GENERAL SERVICE TIME-OF-USE, Gs-3								
Daily Customer Charge:	Single-phase	1,050,453	0.5589	587,098	0.5589	587,098		
	Three-phase	591,165	0.8384	495,633	0.8384	495,633		
Energy Charge (per kWh):								
TOU Schedule	High Rate	19,691,991	0.17430	3,432,314	0.20230	3,983,690		16.064%
	Regulator Rate	71,817,383	0.13680	9,824,618	0.15080	10,830,061		10.234%
	Low Rate	87,345,899	0.06880	6,009,398	0.06790	5,930,787		-1.308%
Primary Energy Discounted:								
TOU Schedule	High Rate	87,412	2.5%	2,185	2.5%	(442)		
	Regulator Rate	331,214	2.5%	8,280	2.5%	(1,249)		
	Low Rate	366,910	2.5%	9,173	2.5%	(623)		
ACT 141 Cost								
ACT 141 Capped Contribution		10,474,077	0.00092	9,649	0.00092	9,649		
ACT 141 Credits		10,474,077	0.00151	(9,649)	(0.00151)	(15,816)		
Fuel Cost Surcharge:		178,855,273	0.004355	778,915	-	-		
Total Gs-3	Total kWh	178,855,273		$ 21,147,614		$ 21,818,788	$671,174	3.17%
GENERAL SERVICE DEMAND SERVICE, Gd-1								
Daily Customer Charge:	Single-phase	1,259,687	0.5589	704,039	0.5589	704,039		
	Three-phase	62,099	0.8384	52,064	0.8384	52,064		
Customer Demand Charge (per kW)		196,880	2.0000	393,761	2.4000	472,513		
On-Peak Demand Charge (per kW) 10 to 8 PM		141,224	8.2500	1,165,100	9.2500	1,306,325		
Energy Charge (per kWh):								
TOU Schedule	High Rate	7,772,053	0.1283	997,154	0.1740	1,352,337		35.620%
	Regulator Rate	32,497,252	0.0825	2,681,023	0.0870	2,827,261		5.455%
	Low Rate	37,846,598	0.0620	2,346,489	0.0590	2,232,949		-4.839%
Energy Limiter	kWh at limiter	53,562	0.1700	9,105	0.2200	11,784		
Primary Energy Discounted:								
Customer Demand Charge		-	$0.23	-	$0.23	-		
TOU Schedule	High Rate	7,039	2.50%	(23)	2.50%	(31)		
	Regulator Rate	29,432	2.50%	(61)	2.50%	(64)		
	Low Rate	34,277	2.50%	(53)	2.50%	(51)		
				-		-		
Limiter Primary Discounted	kWh at limiter	53,562	2.50%	(228)	2.50%	(295)		
ACT 141 Cost								
ACT 141 Capped Contribution		3,108	0.75923	2,360	0.75923	2,360		
ACT 141 Capped Credits		3,108	(0.00151)	(5)	(0.00151)	(5)		
Fuel Cost Surcharge:		78,169,465	0.004355	340,428	-	-		
Total Gd-1	Total kWh	78,169,465		$ 8,691,156		$ 8,961,187	$270,031	3.11%
GENERAL SERVICE NON-METERED, Gs-4								
Daily Customer Charge		13,140	0.4089	5,373	0.4089	5,373		
Energy Charge (per kWh)	kWh	43,617	0.11400	4,972	0.13000	5,670		
Fuel Cost Surcharge:		43,617	0.004355	190	-	-		
Total Gs-4	Total kWh	43,617		$ 10,535		$ 11,043	$508	4.82%
COMMERCIAL SERVICE -- Cg-2 TOD								
Daily Customer Charge:	Single-phase	47,317	0.9250	43,768	0.9250	43,768		
	Three-phase	1,106,265	1.1500	1,272,205	1.1500	1,272,205		
Firm Demand kW (All 10-10)		3,298,286	$11.95	39,414,518	$ 13.75	45,351,433		
Customer Demand Charge		4,849,949	$2.20	10,669,887	$ 2.60	12,609,867		
Energy Charge (per kWh):								
TOU Schedule	High Rate	136,096,445	0.08604	11,709,738	0.09420	12,820,285		9.484%
	Regulator Rate	565,140,443	0.06500	36,734,129	0.06420	36,282,016		-1.231%
	Low Rate	511,367,183	0.05190	26,539,957	0.04720	24,136,531		-9.056%
Energy Limiter	kWh at limiter	14,986,906	0.17000	2,547,774	0.22000	3,297,119		
Primary Energy Discounted:								
Firm Demand kW (All 10-10)		68,050	2.5%	(20,330)	2.5%	(23,392)		
Customer Demand Charge		117,303	$0.23	(26,980)	$ 0.23	(26,980)		
TOU Schedule	High Rate	2,692,246	2.5%	(5,791)	2.5%	(6,340)		
	Regulator Rate	11,088,243	2.5%	(18,018)	2.5%	(17,797)		
	Low Rate	10,044,700	2.5%	(13,033)	2.5%	(11,853)		
Limiter Primary Discounted	kWh at limiter	497,693	2.5%	(2,115)	2.5%	(2,115)		
ACT 141 Cost								
ACT 141 Capped Contribution		67,291,099	0.00092	61,989	0.00092	61,989		
ACT 141 Capped Credits		67,291,099	(0.00151)	(101,610)	(0.00151)	(101,610)		
Fuel Cost Surcharge:		1,227,590,977	0.004355	5,346,159	-	-		
COMMUNITY SOLAR Subscriptions	60%	$ 31,995		31,995		31,995		
COMMUNITY SOLAR Solar kWh Productic	60%	1,230,750	(0.105690)	(130,078)	(0.105690)	(130,078)		
Total Cg-2 TOD	Total kWh	1,227,590,977		$ 134,054,164		$ 135,587,044	$1,532,880	1.14%

INDUSTRIAL SERVICE, Cp-1 -- Secondary/Primary

		(0)						
Daily Customer Charge		369,015	6.2300	2,298,963	6.2300	2,298,963		
Firm Demand kW (All 10-10)		6,595,584	$14.02	92,470,090	$ 16.13	106,386,773		
Customer Demand Charge		10,317,606	$2.20	22,698,733	$ 2.60	26,825,775		
Cp-1C Stand-by Demand Charge		0	2.00	-	2.00	-		
Interruptible Demand Charges:								
Cp-1A. 1 Hr. Demand kW (All 10-10)		1,174,312	$9.66	11,343,855	$ 11.52	13,528,075		
Cp-2B. Inst. Demand kW (All 10-10)		529,403	$8.70	4,605,808	$ 10.50	5,558,734		
Energy Charge (per kWh):				-				
TOU Schedule	High Rate	374,089,114	$ 0.07323	27,394,546	0.07848	29,358,514		7.169%
	Regulator Rate	1,694,028,892	$ 0.05519	93,493,455	0.05372	91,003,232		-2.664%
	Low Rate	1,640,628,163	$ 0.04404	72,253,264	0.04370	71,695,451		-0.772%
Energy Limiter (per kWh):	kWh at limiter	16,127,501	$ 0.17000	2,741,675	0.22000	3,548,050		
Primary Voltage Discount:								
Customer Demand Charge		5,257,760	$0.23	(1,209,285)	$ 0.23	(1,209,285)		
Firm Demand kW (All 10-10)		2,677,620	2.5%	(938,506)	2.5%	(1,079,750)		
Cp-1A. 1 Hr. Demand kW (All 10-10)		973,569	2.5%	(235,117)	2.5%	(280,388)		
Cp-1B. Inst. Demand kW (All 10-10)		369,478	2.5%	(80,361)	2.5%	(96,988)		
TOU Schedule	High Rate	218,029,595	2.5%	(399,158)	2.5%	(427,774)		
	Regulator Rate	970,370,229	2.5%	(1,338,868)	2.5%	(1,303,207)		
	Low Rate	942,876,761	2.5%	(1,038,107)	2.5%	(1,030,093)		
Limiter Primary Discounted	kWh at limiter	3,260,798	2.5%	(13,858)	2.5%	(17,934)		
ECONOMIC DEVELOPMENT PROGRAM	$ Revenue Impa	-		-		-		
NEW LOAD MARKET PRICING RIDER	Above Baseline kWh	3,546,900		$ (138,051)		$ (138,051)		
ACT 141 Cost								
ACT 141 Capped Contribution		1,960,462,345	0.00084	1,652,819	0.00084	1,652,819		
ACT 141 Capped Credits		1,960,462,345	(0.00151)	(2,960,298)	(0.00151)	(2,960,298)		
Fuel Cost Surcharge:		3,721,326,770	0.004355	16,206,378	-	-		
COMMUNITY SOLAR Subscriptions	10%	$ 5,333		5,333		5,333		
COMMUNITY SOLAR Solar kWh Productic	10%	205,125	(0.105690)	(21,680)	(0.105690)	(2,168)		
Total Cp-1	Total kWh	3,724,873,670		$ 338,791,630		$ 343,315,783	$4,524,153	1.34%

INDUSTRIAL SERVICE, Cp-2 -- Transmission

Daily Customer Charge		7,665	35.0000	268,275	35.0000	268,275		
Firm Demand kW (All 10-10)		1,951,063	$13.25	25,851,589	$ 15.97	31,158,481		
Customer Demand Charge		2,998,342	$0.00	-	$ -	-		
Cp-2C Stand-by Demand Charge		180,000	2.00	360,000	2.00	360,000		
Cp-2C Stand-by Administration		365	6.00	2,190	6.00	2,190		
Interruptible Demand Charges:								
Cp-2A: 1 Hr. Demand kW (All 10-10)		378,422	$9.02	3,413,369	$ 11.50	4,351,856		
Cp-2B: Inst. Demand kW (All 10-10)		333,428	$8.10	2,700,763	$ 10.52	3,507,658		
Energy Charge (per kWh):								
TOU Schedule	High Rate	126,386,750	0.06993	8,838,225	0.07630	9,643,309		
	Regulator Rate	598,427,595	0.05275	31,567,056	0.05230	31,297,763		
	Low Rate	679,074,353	0.04213	28,609,402	0.04240	28,792,753		
Reactive Energy		-	0.001015	-	0.001015	-		
High Load Factor Energy Credit HLF		126,083,224	(0.0045)	(567,375)	(0.0045)	(567,375)		
HLF Credit + ERCO Rider		-	(0.0090)	-	(0.0090)	-		
ECONOMIC DEVELOPMENT PROGRAM	$ Revenue Impact			$ -		$ -		
NEW LOAD MARKET PRICING RIDER (N	Above Baseline kWh	-		$ -		$ -		
DAY AHEAD MARKET PRICING RIDER (D	Above Baseline kWh	113,311,816		$ (1,868,035)		$ (1,868,035)		
Fuel Cost Surcharge enbedded in Rev Im	Above Baseline k	113,311,816		-	-	-		
ACT 141 Cost								
ACT 141 Capped Contribution		1,403,888,698	0.00050	702,104	0.00050	702,104		
ACT 141 Capped Credits		1,403,888,698	(0.00151)	(2,119,872)	(0.00151)	(2,119,872)		
Fuel Cost Surcharge:	Less Above base	1,290,576,882	0.004355	5,620,462	-	-		
Total Cp-2	Total kWh	1,403,888,698		$ 103,378,154		$ 105,529,107	$2,150,953	2.08%
		1,028,373						

AREA LIGHTING SERVICE, Ms-3

line row Monthly Charges (current Tariff):	Fixtures	Fixtures * 12						
01a. 100 watt roadway type | Pole Option E	1,459	17,508	13.49	236,183	0	-		
01b. 100 watt roadway type | New Wood Pc	32	384	24.57	9,435	0	-		
01c. 100 watt roadway type | New Decorativ	198	2,376	27.86	66,195	0	-		
02a. 150 watt roadway type | Pole Option E	1,162	13,944	15.14	211,112	0	-		
02b. 150 watt roadway type | New Wood Pc	34	408	26.11	10,653	0	-		
02c. 150 watt roadway type | New Decorativ	215	2,580	29.39	75,826	0	-		
03a. 250 watt roadway type | Pole Option E	325	3,900	19.09	74,451	0	-		
03b. 250 watt roadway type | New Wood Pc	33	396	30.16	11,943	0	-		
03c. 250 watt roadway type | New Decorativ	121	1,452	32.57	47,292	0	-		
04a. 250 watt flood light | Pole Option Exist	1,115	13,380	20.73	277,367	0	-		
04b. 250 watt flood light | New Wood Pole v	55	660	31.92	21,067	0	-		
04c. 250 watt flood light | New Decorative F	167	2,004	34.76	69,659	0	-		
05a. 400 watt flood light | Pole Option Exist	2,010	24,120	22.81	550,177	0	-		
05b. 400 watt flood light | New Wood Pole v	156	1,872	34	63,648	0	-		
05c. 400 watt flood light | New Decorative F	233	2,796	37.18	103,955	0	-		
06a. 100 watt roadway type | Existing Wood	33	396	23.69	9,381	0	-		
06b. 100 watt roadway type | New Wood Pc	5	60	34.76	2,086	0	-		
07a. 150 watt roadway type | Existing Wood	35	420	24.57	10,319	0	-		
07b. 150 watt roadway type | New Wood Pc	4	48	35.97	1,727	0	-		
08a. 250 watt roadway type | Existing Wood	44	528	28.3	14,942	0	-		
08b. 250 watt roadway type | New Wood Pc	1	12	39.27	471	0	-		
09a. 250 watt flood light | Existing Wood Pc	39	468	29.72	13,909	0	-		
09b. 250 watt flood light | New Wood Pole v	4	48	40.91	1,964	0	-		
10a. 400 watt flood light | Existing Wood Pc	102	1,224	32.57	39,866	0	-		
10b. 400 watt flood light | New Wood Pole v	17	204	43.87	8,949	0	-		
11a. 70 watt Acorn Fixture* | pole paid upfr	42	504	26.11	13,159	0	-		
12b. 70 watt Acorn Fixture* | w/concrete po	119	1,428	28.95	41,341	0	-		
13b. 70 watt Acorn Fixture* | w/fiberglass p	34	408	28.95	11,812	0	-		
14a. 150 watt Acorn Fixture* | pole paid upf	47	564	29.39	16,576	0	-		
15b. 150 watt Acorn Fixture* | w/concrete p	24	288	44.31	12,761	0	-		
16b. 150 watt Acorn Fixture* | w/fiberglass	16	192	41.34	7,937	0	-		
20a. 70 watt Colonial Fixture* | Pole paid u	37	444	22.81	10,128	0	-		
21b. 70 watt Colonial Fixture* | w/concrete	60	720	24.24	17,453	0	-		
22b. 70 watt Colonial Fixture* | w/fiberglass	219	2,628	24.24	63,703	0	-		
23a. 150 watt Colonial Fixture* | Pole paid	13	156	24.57	3,833	0	-		
24b. 150 watt Colonial Fixture* | w/concrete	3	36	38.94	1,402	0	-		
25b. 150 watt Colonial Fixture* | w/fiberglas	27	324	35.53	11,512	0	-		
26a. 250 watt Down Light Fixture | Pole pai	32	384	27.86	10,698	0	-		
28b. 250 watt Down Light Fixture | w/fibergl	35	420	47.05	19,761	0	-		
30a. 400 watt Down Light Fixture | w/concre	27	324	29.39	9,522	0	-		
31b. 400 watt Down Light Fixture | w/fibergl	30	360	54.62	19,663	0	-		
33a. 250 watt Metal Halide Down Light Fixt	3	36	31.04	1,117	0	-		
34b. 250 watt Metal Halide Down Light Fixt	1	12	50.34	604	0	-		
35a. 400 watt Metal Halide Down Light Fixt	48	576	32.57	18,760	0	-		
37b. 400 watt Metal Halide Down Light Fixt	12	144	57.91	8,339	0	-		
				-	0	-		
Fixtures Separate from Poles			0	-	0	-		
Category A MS3	1,727	20,724	0	-	14.53	301,120		
Category B MS3	1,450	17,400	0	-	14.97	260,478		
Category C MS3	524	6,288	0	-	15.06	94,697		
Category D		-	0	-	0	-		
Category E	1,380	16,560	0	-	19.29	319,442		
Category F	2,518	30,216	0	-	19.48	588,608		
Category J	71	852	0	-	18.12	15,438		
Category K	117	1,404	0	-	18.31	25,707		
Category I	195	2,340	0	-	14.75	34,515		
Category M	87	1,044	0	-	15.19	15,858		
Category N	316	3,792	0	-	16.03	60,786		
Category O	43	516	0	-	16.21	8,364		
		-	0	-	0	-		
		-	0	-	0	-		
Poles		-	0	-	0	-		
Colonial Fiberglass	219	2,628	0	-	14.96	39,315		
Decorative	1,218	14,616	0	-	16.234	237,276		
Decorative Fiberglass	77	924	0	-	14.96	13,823		
Wood	341	4,092	0	-	8.33	34,086		
				-				
Energy Charges								
Annual kWh	kWh	4,827,397	0	-	0.0903	435,914		
Fuel Cost Surcharge:	2024 billed kWh	4,827,397	0.004355	-	-	-		
Fuel Cost Surcharge (per fixture-month):		101,136	0.480000	48,545		-		
Total Ms-3	Total kWh	4,827,397	$	2,281,206	$	2,485,428	$204,223	8.95%

STREET LIGHTING SERVICE, Ms-1		Billing	Present	Present	Proposed	Proposed	Increase	0
Annual Charges (per Unit):								
Fixture Category with Poles Separate								
Category A: 4,500-6,000 LED Lumens		16,424	40.50	665,172	$40.50	665,172		
Category B: 7,500-10,000 LED Lumens		17,118	42.70	730,939	$42.70	730,939		
Category C: 10,001-14,000 LED Lumens		3,920	43.00	168,560	$43.00	168,560		
Poles and Brackets								
Pole Wood		28,497	50.16	1,429,410	$50.16	1,429,410		
Pole Concrete		4,830	194.82	940,981	$194.82	940,981		
Pole Aluminum		876	169.32	148,324	$169.32	148,324		
Pole Fiberglass		30	179.52	5,386	$179.52	5,386		
Concrete Pole and Fixture Contribution (Closed)		1,755	41.51	72,850	$41.51	72,850		
Pole Contribution Option		485	67.20	32,592	$67.20	32,592		
Open		-	-	-	$0.00	-		
Energy Charge (per kWh):	kWh	35,055,517	0.07000	2,453,886	0.09030	3,165,513		
ACT 141 Cost								
ACT 141 Capped Contribution		17	-	-	-	-		
ACT 141 Capped Credits		17	(0.00151)	(0)	(0.00151)	(0)		
Fuel Cost Surcharge:		35,055,517	0.004355	152,667	-	-		
Total Ms-1	Total kWh	35,055,517		$ 6,800,766		$ 7,359,726	$558,960	8.22%

DECORATIVE LIGHTING SERVICE, Ms-2								
Monthly Charges (per Lamp):								
70 W Single		121	20.05	2,426	$20.05	2,426		
70 W Double		30	30.50	915	$30.50	915		
Energy Charge (per kWh):	kWh	68,642	0.07000	4,805	0.09030	6,198		
Fuel Cost Surcharge:		68,642	0.004355	299	-	-		
Total Ms-2	Total kWh	68,642		$ 8,445		$ 9,539	$1,094	12.96%

TRAFFIC SIGNAL SERVICE, Mz-1								
Daily Customer Charge		132,130	0.3200	42,282	0.3200	42,282		
Energy Charge (per kWh):	kWh	1,754,513	0.12200	214,051	0.13650	239,491		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00151)	-	(0.00151)	-		
Fuel Cost Surcharge:		1,754,513	0.004355	7,641	-	-		
Total Mz-1	Total kWh	1,754,513		$263,973		$281,773	$17,800	6.74%

CIVIL DEFENSE & FIRE SIRENS SERVICE, Mz-2								
Daily Customer Charge:	1-ph Sec.	14582	0.0470	685	0.0517	754		
	3-phase Sec.	16443	0.1792	2,947	0.1971	3,241		
	3 Ph +10 kW	0	0.0473	-	0.0520	-		
Fuel Cost Surcharge:		-	-	-	-	-		
Total Mz-2	Total kWh	-		$ 3,632		$ 3,995	$363	9.99%
NON-STANDARD LIGHTING SERVICE, NL-1								
Monthly Rate (applies to $ of investment)			1.80%	15,933	1.80%	15,933		
Energy Charge (per kWh):	kWh	45,967	0.07000	3,218	0.09030	4,151		
Fuel Cost Surcharge:		45,967	0.004355	200	-	-		
Total NL-1	Total kWh	45,967		$ 19,351		$ 20,084	$733	3.79%
SECOND NATURE PROGRAM, Sn-1 (rate Billing units and kWh volumes in Rg-1)								
Energy Charge (per kWh):								
	100% Level	13,456,577	0.01000	-	0.01000	-		
	50% Level	4,637,134	0.00500	-	0.00500	-		
	25% Level	6,387,162	0.00250	-	0.00250	-		
	Fixed Level	5,116,706	0.01000	-	0.01000	-		
Fuel Cost Surcharge:	100% Level	13,456,577	-	-	-	-		
Fuel Cost Surcharge:	50% Level	4,637,134	0.002178	10,097	-	-		
Fuel Cost Surcharge:	25% Level	6,387,162	0.003266	20,862	-	-		
Fuel Cost Surcharge:	Fixed Level	5,116,706	-	-	-	-		
Total Gs-1SN	Total kWh	29,597,579		$ 30,959		$ -	($30,959)	-100.00%
TOTAL	**Total kWh**	**11,221,162,301**		**1,314,626,984**		**1,364,050,963**	**49,423,979**	

WISCONSIN POWER AND LIGHT COMPANY

Appendix C: ELECTRIC RATES TY2024

Docket: 6680-UR-124

Adjusted Final Revenue

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
RESIDENTIAL SERVICE, Rg-1			Sheet 3.11
Daily Customer Charge:	Single-phase	$0.49320	$0.49320
	Three-phase	$0.73980	$0.73980
	Additional Meter	$0.10000	$0.16500
Energy Charge (per kWh):	All kwh	$0.13091	$0.14640
Fuel Adjustment (per kWh)		$0.004355	$0.000000
RESIDENTIAL TIME-OF-USE, Rg-5			Sheet 3.21
Daily Customer Charge:	Single-phase	$0.49320	$0.49320
	Three-phase	$0.73980	$0.73980
	Additional Meter	$0.10000	$0.16500
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.19600	$0.25520
	Regular Rate	$0.16300	$0.18100
	Low Rate	$0.07900	$0.08200
Fuel Adjustment (per kWh)		$0.004355	$0.000000
RESIDENTIAL DEMAND SERVICE, Rd-1			Sheet 3.31
Daily Customer Charge:	Single-phase	$0.32880	$0.32880
	Three-phase	$0.73980	$0.73980
	Additional meter	$0.10000	$0.16500
Customer Demand Charge (per kW)		$0.00000	$0.00000
On-Peak Demand Charge (per kW)		$4.80000	$4.80000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.17520	$0.22441
	Regular Rate	$0.13400	$0.15555
	Low Rate	$0.07100	$0.07500
Energy Limiter		$0.17000	$0.2200
Fuel Cost Surcharge		$0.004355	$0.000000
RESIDENTIAL SERVICE TIME-OF-USE with WATER HEATING, Rw-5 (Gw-1)			Sheet 4.70
Daily Customer Charge		$0.49320	$0.4932
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.18820	$0.25520
	Regular Rate	$0.15650	$0.18100
	Low Rate	$0.07580	$0.08200
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
GENERAL SERVICE, Gs-1			Sheet 4.01
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Energy Charge (per kWh):			
	All kwh	$0.12400	$0.13000
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment (per kWh)		$0.004355	$0.000000
GENERAL SERVICE TIME-OF-USE, Gs-3			Sheet 4.26
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.17430	$0.20230
	Regular Rate	$0.13680	$0.15080
	Low Rate	$0.06880	$0.06790
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment (per kWh)		$0.004355	$0.000000
GENERAL SERVICE DEMAND SERVICE, Gd-1			Sheet 4.33
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Customer Demand Charge (per kW)		$2.00000	$2.4000
On-Peak Demand Charge (per kW)		$8.25000	$9.2500
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.12830	$0.17400
	Regular Rate	$0.08250	$0.08700
	Low Rate	$0.06200	$0.05900
Energy Limiter		$0.17000	$0.22000
Customer Demand Discount (per kW)		$0.23000	$0.2300
Primary Voltage Discount		2.50%	2.50%
Fuel Cost Surcharge		$0.004355	$0.000000
GENERAL SERVICE NON-METERED, Gs-4			Sheet 4.80
Daily Customer Charge		$0.40890	$0.4089
Energy Charge (per kWh)		$0.11400	$0.13000
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
CONTROLLED WATER HEATING 17 HR. SERVICE, Rw-1			Sheet 4.40 & 4.70
Daily Customer Charge		$0.00000	$0.0000
Energy Charge (per kWh):			
	All kwh	$0.12380	$0.13900
Fuel Adjustment (per kWh)		$0.004355	$0.000000
CONTROLLED WATER HEATING 11 HR. SERVICE, Rw-3			Sheet 4.50
Daily Customer Charge		$0.00000	$0.0000
Energy Charge (per kWh)			
	All kwh	$0.11530	$0.13030
Fuel Adjustment (per kWh)		$0.004355	$0.000000
COMMERCIAL SERVICE -- Cg-2 TOD			Sheet 6.41
Daily Customer Charge:	Single-phase	$0.92500	$0.92500
	Three-phase	$1.15000	$1.15000
Firm Demand Charge (per kW)		$11.95000	$13.75000
Customer Demand Charge		$2.20000	$2.60000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.08604	$0.09420
	Regular Rate	$0.06500	$0.06420
	Low Rate	$0.05190	$0.04720
Energy Limiter		$0.17000	$0.22000
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.23000	$0.23000
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
INDUSTRIAL SERVICE, Cp-1 -- Secondary/Primary			Sheet 7.00 & 7.60
Daily Customer Charge		$6.23000	$6.23000
Firm Demand		$14.02000	$16.13000
Customer Demand Charge		$2.20000	$2.60000
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):		$9.66000	$11.52000
Instantaneous (12 hr):		$8.70000	$10.50000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.07323	$0.07848
	Regular Rate	$0.05519	$0.05372
	Low Rate	$0.04404	$0.04370
Energy Limiter (per kWh):		$0.17000	$0.22000
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.23000	$0.23000
Fuel Adjustment (per kWh)		$0.004355	$0.000000
INDUSTRIAL SERVICE, Cp-2 -- Transmission			Sheet 7.40 & 7.60
Daily Customer Charge		$35.00000	$35.00000
Firm Demand		$13.25000	$15.97000
Customer Demand Charge		$0.00000	$0.00000
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):		$9.02000	$11.50000
Instantaneous (12 hr):		$8.10000	$10.52000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.06993	$0.07630
	Regular Rate	$0.05275	$0.05230
	Low Rate	$0.04213	$0.04240
Reactive Energy		$0.00102	$0.00102
High Load Factor Energy Credit		-$0.00450	-$0.00450
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
STREET LIGHTING SERVICE, Ms-1		Annual	Sheet 8.01 & 8.03
Annual Charges (per Unit):			
Fixture Category with Poles Separate			
Category A: 4,500-6,000 LED Lumens		$40.50000	$40.50
Category B: 7,500-10,000 LED Lumens		$42.70000	$42.70
Category C: 10,001-14,000 LED Lumens		$43.00000	$43.00
Poles and Brackets			
Pole Wood		$50.16000	$50.16
Pole Concrete		$194.82000	$194.82
Pole Aluminum		$169.32000	$169.32
Pole Fiberglass		$179.52000	$179.52
Concrete Pole and Fixture Contribution (Closed)		$41.51000	$41.51
Pole Contribution Option		$67.20000	$67.20
Open		$0.00000	$0.00
Energy Charge (per kWh):	kWh	$0.07000	$0.09030
Credit Provision per fixture (per night of continued outage)			
Category A		$0.07775	$0.07775
Category B		$0.12404	$0.12404
Category C		$0.18932	$0.18932
Fuel Adjustment (per kWh)		$0.004355	$0.000000

DECORATIVE LIGHTING SERVICE, Ms-2			Sheet 8.10
Monthly Charges (per Lamp):			
70 W Single		$20.05000	$20.05
70 W Double		$30.50000	$30.50
Energy Charge (per kWh):	kwh	$0.07000	$0.09030
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION	PRESENT RATES	AUTHORIZED 2024 RATES
AREA LIGHTING SERVICE, Ms-3		Sheet 8.19 and 8.191
Monthly Charges (per Lamp):	Per Month	
01a. 100 watt roadway type | Pole Option Existing	$13.49000	$0.00000
01b. 100 watt roadway type | New Wood Pole w/ohd Service	$24.57000	$0.00000
01c. 100 watt roadway type | New Decorative Pole	$27.86000	$0.00000
02a. 150 watt roadway type | Pole Option Existing	$15.14000	$0.00000
02b. 150 watt roadway type | New Wood Pole w/ohd Service	$26.11000	$0.00000
02c. 150 watt roadway type | New Decorative Pole	$29.39000	$0.00000
03a. 250 watt roadway type | Pole Option Existing	$19.09000	$0.00000
03b. 250 watt roadway type | New Wood Pole w/ohd Service	$30.16000	$0.00000
03c. 250 watt roadway type | New Decorative Pole	$32.57000	$0.00000
04a. 250 watt flood light | Pole Option Existing	$20.73000	$0.00000
04b. 250 watt flood light | New Wood Pole w/ohd Service	$31.92000	$0.00000
04c. 250 watt flood light | New Decorative Pole	$34.76000	$0.00000
05a. 400 watt flood light | Pole Option Existing	$22.81000	$0.00000
05b. 400 watt flood light | New Wood Pole w/ohd Service	$34.00000	$0.00000
05c. 400 watt flood light | New Decorative Pole	$37.18000	$0.00000
06a. 100 watt roadway type | Existing Wood Pole w/ urd. Service	$23.69000	$0.00000
06b. 100 watt roadway type | New Wood Pole w/ urd. Service	$34.76000	$0.00000
07a. 150 watt roadway type | Existing Wood Pole w/ urd. Service	$24.57000	$0.00000
07b. 150 watt roadway type | New Wood Pole w/ urd. Service	$35.97000	$0.00000
08a. 250 watt roadway type | Existing Wood Pole w/ urd. Service	$28.30000	$0.00000
08b. 250 watt roadway type | New Wood Pole w/ urd. Service	$39.27000	$0.00000
09a. 250 watt flood light | Existing Wood Pole w/ urd. Service	$29.72000	$0.00000
09b. 250 watt flood light | New Wood Pole w/ urd. Service	$40.91000	$0.00000
10a. 400 watt flood light | Existing Wood Pole w/ urd. Service	$32.57000	$0.00000
10b. 400 watt flood light | New Wood Pole w/ urd. Service	$43.87000	$0.00000
11a. 70 watt Acorn Fixture* | pole paid upfront Pole Option Existing	$26.11000	$0.00000
12b. 70 watt Acorn Fixture* | w/concrete pole New Decorative Pole	$28.95000	$0.00000
13b. 70 watt Acorn Fixture* | w/fiberglass pole New Decorative Pole	$28.95000	$0.00000
14a. 150 watt Acorn Fixture* | pole paid upfront Pole Option Existing	$29.39000	$0.00000
15b. 150 watt Acorn Fixture* | w/concrete pole New Decorative Pole	$44.31000	$0.00000
16b. 150 watt Acorn Fixture* | w/fiberglass pole New Decorative Pole	$41.34000	$0.00000
20a. 70 watt Colonial Fixture* | Pole paid upfront-Pole Option Existing	$22.81000	$0.00000
21b. 70 watt Colonial Fixture* | w/concrete pole-New Decorative Pole	$24.24000	$0.00000
22b. 70 watt Colonial Fixture* | w/fiberglass pole-New Decorative Pole	$24.24000	$0.00000
23a. 150 watt Colonial Fixture* | Pole paid upfront-Pole Option Existing	$24.57000	$0.00000
24b. 150 watt Colonial Fixture* | w/concrete pole-New Decorative Pole	$38.94000	$0.00000
25b. 150 watt Colonial Fixture* | w/fiberglass pole-New Decorative Pole	$35.53000	$0.00000
26a. 250 watt Down Light Fixture | Pole paid upfront-Pole Option Existin	$27.86000	$0.00000
28b. 250 watt Down Light Fixture | w/fiberglass pole-New Decorative Pol	$47.05000	$0.00000
30a. 400 watt Down Light Fixture | w/concrete pole-New Decorative Pole	$29.39000	$0.00000
31b. 400 watt Down Light Fixture | w/fiberglass pole-New Decorative Pol	$54.62000	$0.00000
33a. 250 watt Metal Halide Down Light Fixture | w/concrete pole-New De	$31.04000	$0.00000
34b. 250 watt Metal Halide Down Light Fixture | w/fiberglass pole-New D	$50.34000	$0.00000
35a. 400 watt Metal Halide Down Light Fixture | Pole paid upfront-Pole C	$32.57000	$0.00000
37b. 400 watt Metal Halide Down Light Fixture | w/fiberglass pole-New D	$57.91000	$0.00000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
Fixtures Separate from Poles			
Category A MS3	Roadway	$0.00000	$14.53000
Category B MS3	Roadway	$0.00000	$14.97000
Category C MS3	Roadway	$0.00000	$15.06000
Category D	Roadway	$0.00000	$0.00000
Category E	Flood	$0.00000	$19.29000
Category F	Flood	$0.00000	$19.48000
Category J	Down	$0.00000	$18.12000
Category K	Down	$0.00000	$18.31000
Category I	Acorn	$0.00000	$14.75000
Category M	Acorn	$0.00000	$15.19000
Category N	Colonial	$0.00000	$16.03000
Category O	Colonial	$0.00000	$16.21000
Poles			
Colonial Fiberglass			$14.96000
Decorative			$16.23400
Decorative Fiberglass			$14.96000
Wood			$8.33000
Energy Charge (per kWh):	kWh	$0.00000	$0.09030
Fuel Adjustment (per kWh)		$0.004355	$0.000000
Fuel Adjustment (per fixture)		$0.480000	$0.0000

TRAFFIC SIGNAL SERVICE, Mz-1 Sheet 8.20

Daily Customer Charge		$0.32000	$0.3200
Energy Charge (per kWh):	kWh	$0.12200	$0.13650
Fuel Adjustment (per kWh)		$0.004355	$0.000000

CIVIL DEFENSE & FIRE SIRENS SERVICE, Mz-2 Sheet 8.30

Daily Customer Charge:	Single-phase Secor	$0.04700	$0.0517
	Three-phase Secor	$0.17920	$0.1971
	3 Ph Sec - Addtl. 1(	$0.04730	$0.0520

NON-STANDARD LIGHTING SERVICE, NL-1 Sheet 8.40

Monthly Rate (applies to $ of investment)		1.80%	1.80%
Energy Charge (per kWh):	kWh	$0.07000	$0.09030
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED 2024 RATES
SECOND NATURE PROGRAM, Sn-1			Sheet 4.05
Energy Charge (per kWh):	100% Participation	$0.01000	$0.010000
	50% Participation	$0.00500	$0.005000
	25% Participation	$0.00250	$0.002500

Act 141 Rates

Residential Rates: (per kWh)	$0.00171	0.00162
Non-Residential Rates (per kWh):	$0.00140	0.00151

Wisconsin Power and Light Company
Rate Impact Analysis

Avg/Month $ 7.35

3.08022

Residential Rg-1 2.95% **Proposed Change** **7.1%**

	Monthly Usage	Customer Charge	Energy Charge	Monthly Bill	Customer Charge	Energy Charge	Monthly Bill	% Change
	100	$ 15.00	$ 0.1353	$ 28.53	$ 15.00	$ 0.1464	$ 29.64	3.9%
	200	$ 15.00	$ 0.1353	$ 42.05	$ 15.00	$ 0.1464	$ 44.28	5.3%
	300	$ 15.00	$ 0.1353	$ 55.58	$ 15.00	$ 0.1464	$ 58.92	6.0%
	400	$ 15.00	$ 0.1353	$ 69.11	$ 15.00	$ 0.1464	$ 73.56	6.4%
	500	$ 15.00	$ 0.1353	$ 82.63	$ 15.00	$ 0.1464	$ 88.20	6.7%
	600	$ 15.00	$ 0.1353	$ 96.16	$ 15.00	$ 0.1464	$ 102.84	6.9%
Avg Cust	**660**	**$ 15.00**	**$ 0.1353**	**$ 104.28**	**$ 15.00**	**$ 0.1464**	**$ 111.63**	**7.0%**
	700	$ 15.00	$ 0.1353	$ 109.69	$ 15.00	$ 0.1464	$ 117.48	7.1%
	800	$ 15.00	$ 0.1353	$ 123.21	$ 15.00	$ 0.1464	$ 132.12	7.2%
	900	$ 15.00	$ 0.1353	$ 136.74	$ 15.00	$ 0.1464	$ 146.76	7.3%
	1000	$ 15.00	$ 0.1353	$ 150.27	$ 15.00	$ 0.1464	$ 161.40	7.4%
	1100	$ 15.00	$ 0.1353	$ 163.79	$ 15.00	$ 0.1464	$ 176.04	7.5%
	1200	$ 15.00	$ 0.1353	$ 177.32	$ 15.00	$ 0.1464	$ 190.68	7.5%
	1300	$ 15.00	$ 0.1353	$ 190.85	$ 15.00	$ 0.1464	$ 205.32	7.6%
	1400	$ 15.00	$ 0.1353	$ 204.37	$ 15.00	$ 0.1464	$ 219.96	7.6%
	1500	$ 15.00	$ 0.1353	$ 217.90	$ 15.00	$ 0.1464	$ 234.60	7.7%
	1600	$ 15.00	$ 0.1353	$ 231.43	$ 15.00	$ 0.1464	$ 249.24	7.7%
	1700	$ 15.00	$ 0.1353	$ 244.95	$ 15.00	$ 0.1464	$ 263.88	7.7%

Rg-1 12.2% 41.2% 46.6%

Rg-5 Current		Use % Profile 10.4%	39.8%	49.8%		**Proposed Rg-5**	Use % Profile 10.4%	39.8%	49.8%		
Monthly Usage	Customer Charge	High Energy	Reg Energy	Low Energy	Monthly Bill	Customer Charge	High Energy	Reg Energy	Low Energy	Monthly Bill	% Change
100	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 27.90	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 28.94	3.7%
200	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 40.79	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 42.88	5.1%
300	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 53.69	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 56.82	5.8%
400	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 66.58	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 70.76	6.3%
500	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 79.48	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 84.70	6.6%
600	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 92.37	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 98.64	6.8%
660	**$ 15.00**	**$ 0.20036**	**$ 0.16736**	**$ 0.08336**	**$ 100.11**	**$ 15.00**	**$ 0.2552**	**$ 0.1810**	**$ 0.0820**	**$ 107.01**	**6.9%**
700	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 105.27	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 112.58	7.0%
800	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 118.16	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 126.52	7.1%
900	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 131.06	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 140.46	7.2%
1000	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 143.95	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 154.40	7.3%
1100	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 156.84	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 168.34	7.3%
1200	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 169.74	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 182.28	7.4%
1300	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 182.63	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 196.22	7.4%
1400	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 195.53	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 210.16	7.5%
1500	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 208.42	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 224.10	7.5%
1600	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 221.32	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 238.04	7.6%
1700	$ 15.00	$ 0.20036	$ 0.16736	$ 0.08336	$ 234.21	$ 15.00	$ 0.2552	$ 0.1810	$ 0.0820	$ 251.98	7.6%

Rd-1	Load Factor 39.90%		Use % Profile 9.1%	40.6%	50.3%	Rd-1 Use Profile	
Customer Charge	Customer Demand	Billed Demand	High Energy	Reg Energy	Low Energy	Monthly Bill	Rd-1 Change from Rg-1
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 23.78	-19.8%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 37.56	-15.2%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 51.33	-12.9%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 65.11	-11.5%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 78.89	-10.6%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 92.67	-9.9%
$ 10.00	**$ -**	**$ 4.80**	**$ 0.2244**	**$ 0.1556**	**$ 0.0750**	**$ 100.93**	**-9.6%**
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 106.44	-9.4%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 120.22	-9.0%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 134.00	-8.7%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 147.78	-8.4%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 161.55	-8.2%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 175.33	-8.1%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 189.11	-7.9%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 202.89	-7.8%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 216.66	-7.6%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 230.44	-7.5%
$ 10.00	$ -	$ 4.80	$ 0.2244	$ 0.1556	$ 0.0750	$ 244.22	-7.5%

General Service Gs-1 **Proposed Change** **1.2%**

	Monthly Usage	Customer Charge	Energy Charge	Monthly Bill	Customer Charge	Energy Charge	Monthly Bill	% Change
	100	$ 17.00	$ 0.1284	$ 29.84	$ 17.00	$ 0.1300	$ 30.00	0.6%
	250	$ 17.00	$ 0.1284	$ 49.09	$ 17.00	$ 0.1300	$ 49.50	0.8%
	500	$ 17.00	$ 0.1284	$ 81.18	$ 17.00	$ 0.1300	$ 82.00	1.0%
	1000	$ 17.00	$ 0.1284	$ 145.35	$ 17.00	$ 0.1300	$ 147.00	1.1%
	1500	$ 17.00	$ 0.1284	$ 209.53	$ 17.00	$ 0.1300	$ 212.00	1.2%
Avg Cust	**1685**	**$ 17.00**	**$ 0.1284**	**$ 233.28**	**$ 17.00**	**$ 0.1300**	**$ 236.05**	**1.2%**
	2000	$ 17.00	$ 0.1284	$ 273.71	$ 17.00	$ 0.1300	$ 277.00	1.2%
	2500	$ 17.00	$ 0.1284	$ 337.89	$ 17.00	$ 0.1300	$ 342.00	1.2%
	3000	$ 17.00	$ 0.1284	$ 402.06	$ 17.00	$ 0.1300	$ 407.00	1.2%
	3500	$ 17.00	$ 0.1284	$ 466.24	$ 17.00	$ 0.1300	$ 472.00	1.2%
	4000	$ 17.00	$ 0.1284	$ 530.42	$ 17.00	$ 0.1300	$ 537.00	1.2%
	4500	$ 17.00	$ 0.1284	$ 594.60	$ 17.00	$ 0.1300	$ 602.00	1.2%
	5000	$ 17.00	$ 0.1284	$ 658.77	$ 17.00	$ 0.1300	$ 667.00	1.2%
	5500	$ 17.00	$ 0.1284	$ 722.95	$ 17.00	$ 0.1300	$ 732.00	1.3%
	6000	$ 17.00	$ 0.1284	$ 787.13	$ 17.00	$ 0.1300	$ 797.00	1.3%
	6500	$ 17.00	$ 0.1284	$ 851.31	$ 17.00	$ 0.1300	$ 862.00	1.3%
	7000	$ 17.00	$ 0.1284	$ 915.48	$ 17.00	$ 0.1300	$ 927.00	1.3%
	7500	$ 17.00	$ 0.1284	$ 979.66	$ 17.00	$ 0.1300	$ 992.00	1.3%

GS-3 Current		High Energy	Reg Energy	Low Energy		**GS-3 Proposed**	High Energy	Reg Energy	Low Energy		
Monthly Usage	Customer Charge	11.1%	42.2%	46.7%	Monthly Bill	Customer Charge	11.1%	42.2%	46.7%	Monthly Bill	% Change
100	$ 17.00	0.17866	0.14116	0.07316	$ 28.36	$ 17.00	0.20230	0.15080	0.06790	$ 28.78	1.5%
250	$ 17.00	0.17866	0.14116	0.07316	$ 45.39	$ 17.00	0.20230	0.15080	0.06790	$ 46.45	2.3%
500	$ 17.00	0.17866	0.14116	0.07316	$ 73.78	$ 17.00	0.20230	0.15080	0.06790	$ 75.90	2.9%
1000	$ 17.00	0.17866	0.14116	0.07316	$ 130.57	$ 17.00	0.20230	0.15080	0.06790	$ 134.81	3.3%
1500	$ 17.00	0.17866	0.14116	0.07316	$ 187.35	$ 17.00	0.20230	0.15080	0.06790	$ 193.71	3.4%
1685	**$ 17.00**	**0.17866**	**0.14116**	**0.07316**	**$ 208.36**	**$ 17.00**	**0.20230**	**0.15080**	**0.06790**	**$ 215.51**	**3.4%**
2000	$ 17.00	0.17866	0.14116	0.07316	$ 244.13	$ 17.00	0.20230	0.15080	0.06790	$ 252.62	3.5%
2500	$ 17.00	0.17866	0.14116	0.07316	$ 300.91	$ 17.00	0.20230	0.15080	0.06790	$ 311.52	3.5%
3000	$ 17.00	0.17866	0.14116	0.07316	$ 357.70	$ 17.00	0.20230	0.15080	0.06790	$ 370.43	3.6%
3500	$ 17.00	0.17866	0.14116	0.07316	$ 414.48	$ 17.00	0.20230	0.15080	0.06790	$ 429.33	3.6%
4000	$ 17.00	0.17866	0.14116	0.07316	$ 471.26	$ 17.00	0.20230	0.15080	0.06790	$ 488.24	3.6%
4500	$ 17.00	0.17866	0.14116	0.07316	$ 528.05	$ 17.00	0.20230	0.15080	0.06790	$ 547.14	3.6%
5000	$ 17.00	0.17866	0.14116	0.07316	$ 584.83	$ 17.00	0.20230	0.15080	0.06790	$ 606.05	3.6%
5500	$ 17.00	0.17866	0.14116	0.07316	$ 641.61	$ 17.00	0.20230	0.15080	0.06790	$ 664.95	3.6%
6000	$ 17.00	0.17866	0.14116	0.07316	$ 698.40	$ 17.00	0.20230	0.15080	0.06790	$ 723.86	3.6%
6500	$ 17.00	0.17866	0.14116	0.07316	$ 755.18	$ 17.00	0.20230	0.15080	0.06790	$ 782.76	3.7%
7000	$ 17.00	0.17866	0.14116	0.07316	$ 811.96	$ 17.00	0.20230	0.15080	0.06790	$ 841.67	3.7%
7500	$ 17.00	0.17866	0.14116	0.07316	$ 868.74	$ 17.00	0.20230	0.15080	0.06790	$ 900.57	3.7%

Gd-1 Load Factor

Gd-1	38.00%		High Energy	Reg Energy	Low Energy	Gd-1 use Profile	
Customer Charge	38.00%	Billed Demand	10.0%	41.6%	48.5%	Monthly Bill	Gd-1 Change from Gs-1
$ 17.00	$ 2.40	$ 9.25	0.1740	0.0870	0.0590	$ 29.41	-2.0%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 46.72	-5.6%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 76.43	-6.8%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 135.86	-7.6%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 195.29	-7.9%
$ 17.00	**$ 2.20**	**$ 8.00**	**0.1740**	**0.0870**	**0.0590**	**$ 217.28**	**-8.0%**
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 254.72	-8.0%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 314.15	-8.1%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 373.58	-8.2%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 433.01	-8.3%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 492.44	-8.3%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 551.87	-8.3%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 611.30	-8.4%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 670.73	-8.4%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 730.16	-8.4%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 789.59	-8.4%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 849.02	-8.4%
$ 17.00	$ 2.20	$ 8.00	0.1740	0.0870	0.0590	$ 908.45	-8.4%

REVENUE SUMMARY TY2025 **Authorized rate Revenue Summary**

Rate Class by Rate Schedule	Rate Schedule	2025 kWh	2025 Revenue with Current Rates	2025 Revenue with Final Rates	2025 Change from Current Rates	Change from Authorized 2024 Revenue
Residential Service	Rg-1	3,219,432,272	$ 508,443,269	$ 581,820,796	14.4%	
Residential Time of Use	Rg-5	155,083,971	$ 22,699,639	$ 26,004,566	14.6%	
Residential Time of Use with demar	Rd-1	7,532,688	$ 1,129,677	$ 1,292,357	14.4%	
Residential Time of Use w/ controlle	Rw-5 (Gw-1)	1,779,787	$ 253,598	$ 291,510	14.9%	
RW-1 SEC 1-ph	Rw-1	594,059	$ 76,132	$ 87,802	15.3%	
RW-3 SEC 1-ph	Rw-3	242,589	$ 29,027	$ 33,235	14.5%	
LIHEAP Customer Discount Amoun	Rg-1,Rg-5,Rd-1		$ -			
Residential Service Total		**3,384,665,366**	**$ 532,631,343**	**$ 609,530,266**	**14.4%**	**7.6%**
General Service	Gs-1	1,192,465,817	$ 168,322,810	$ 174,934,786	3.9%	
General Service Time of Use	Gs-3	183,092,010	$ 21,648,481	$ 23,907,090	10.4%	
General Service Time of Use with d	Gd-1	79,657,499	$ 8,859,275	$ 9,816,964	10.8%	
General Service Non-metered	Gs-4	43,617	$ 10,535	$ 11,654	10.6%	
General Service Total		**1,455,258,943**	**$ 198,841,102**	**$ 208,670,494**	**4.9%**	**2.8%**
Commercial Service	Cg-2TOD	1,234,924,040	$ 134,873,475	$ 137,516,759	2.0%	
Mid-size Commercial Service Total		**1,234,924,040**	**$ 134,873,475**	**$ 137,516,759**	**2.0%**	**1.4%**
Traffic Signals	Mz-1	1,754,513	$ 263,973	$ 297,739	12.8%	
Civil Defense & Sirens	Mz-2	-	$ 3,632	$ 3,995	10.0%	
Streetlighting Service	Ms-1	35,055,517	$ 6,800,766	$ 7,913,603	16.4%	
Decorative Lighting	Ms-2	68,642	$ 8,445	$ 10,624	25.8%	
Area Lighting	Ms-3	4,583,174	$ 2,301,165	$ 2,535,789	10.2%	
Non-Standard Lighting Service	NL-1	45,967	$ 19,351	$ 20,810	7.5%	
Lighting Service Total		**41,507,813**	**$ 9,397,332**	**$ 10,782,560**	**14.7%**	**6.1%**
Industrial Service	Cp-1	3,746,629,473	$ 341,306,782	$ 355,396,904	4.1%	
Industrial Service - Transmission	Cp-2	1,402,890,679	$ 103,001,887	$ 107,262,946	4.1%	
Large Commercial and Industrial Service Total		5,149,520,152	$ 444,308,668	$ 462,659,850	4.1%	3.1%
Total		**11,265,876,313**	**$ 1,320,051,919**	**$ 1,429,159,928**	**8.3%**	**4.8%**

WISCONSIN POWER AND LIGHT COMPANY

Present and Proposed Revenue Detail TY2025

Rate Class and Rate Description		Number of Billing Units	Present Rates	Present Revenues	Authorized Rates	Authorized Revenues	Revenue Increase Amount	Percent
RESIDENTIAL SERVICE, Rg-1								
Daily Customer Charge:	Single-phase	147,995,988	0.4932	72,991,621	0.4932	72,991,621		12,332,999
	Three-phase	69,774	0.7398	51,619	0.7398	51,619		5,814
	Additional mete	1,364,157	0.1000	136,416	0.1650	225,086		113,680
	LIHEAP Discount	12,222,789	-	-	-	-		
Energy Charge (per kWh):								
	All kWh	3,219,432,272	0.1309	421,455,879	0.1580	508,670,299		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00167)	-	(0.00167)	-		
Fuel Cost Surcharge:	Less 2nd nature	3,190,735,066	0.004355	13,895,651	-	-		
COMMUNITY SOLAR Subscriptions	30%	$ 31,995		31,995		31,995		
COMMUNITY SOLAR Solar kWh Productio	30%	1,329,525	(0.112690)	(149,824)	(0.112690)	(149,824)		
Total Rg-1	Total kWh	3,219,432,272		$ 508,413,356		$ 581,820,796	$73,407,439	14.44%
RESIDENTIAL SERVICE TIME-OF-USE, Rg-5								
Daily Customer Charge:	Single-phase	6,048,692	0.4932	2,983,215	0.4932	2,983,215		
	Three-phase	13,137	0.7398	9,718	0.7398	9,718		
	Additional Mete	9,970	0.1000	997	0.1650	1,645		
	LIHEAP Discount	500,402	-	-	-	-		
Energy Charge (per kWh):		0.16%						
TOU Schedule	High Rate	15,555,867	0.19600	3,048,950	0.26630	4,142,527		35.867%
	Regulator Rate	59,031,522	0.16300	9,622,138	0.19430	11,469,825		19.202%
	Low Rate	80,496,582	0.07900	6,359,230	0.09190	7,397,636		16.329%
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Credits		-	0.00167	-	(0.00167)	-		
Fuel Cost Surcharge:		155,083,971	0.004355	675,391	-	-		
Total Rg-5	Total kWh	155,083,971		$ 22,699,639		$ 26,004,566	$3,304,927	14.56%
RESIDENTIAL DEMAND SERVICE, Rd-1								
Daily Customer Charge:	Single-phase	627,601	0.3288	206,355	0.3288	206,355		
	Three-phase	-	0.7398	-	0.7398	-		
	Additional mete	-	0.1000	-	0.1650	-		
	LIHEAP Discount	51,808	-	-	-	-		
				-		-		
Customer Demand Charge (per kW)		18,879	-	-	-	-		
On-Peak Demand Charge (per kW)		18,879	4.80	90,617	4.90	92,505		
				-		-		
Energy Charge (per kWh):				-		-		
TOU Schedule	High Rate	682,554	0.17520	119,583	0.24870	169,751		41.952%
	Regulator Rate	3,054,203	0.13400	409,263	0.16870	515,244		25.896%
	Low Rate	3,780,356	0.07100	268,405	0.08070	305,075		13.662%
				-		-		
Energy Limiter	kWh at limiter	15,576	0.17000	2,648	0.22000	3,427		
				-		-		
ACT 141 Cost						-		
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00167)	-	(0.00167)	-		
Fuel Cost Surcharge:		7,532,688	0.004355	32,805	-	-		
Total Rd-1	Total kWh	7,532,688		$ 1,129,677		$ 1,292,357	$162,680	14.40%
Residental LIHEAP Discounted Rg-1, Rg-5, Rd-1				$ -		$ -		
CONTROLLED WATER HEATING 17 HR. SERVICE, Rw-1								
Daily Customer Charge		80,577	-	-	-	-		
Energy Charge (per kWh):	kWh	594,059	0.12380	73,544	0.14780	87,802		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00167)	-	-	-		
Fuel Cost Surcharge:		594,059	0.004355	2,587	-	-		
Total Rw-1	Total kWh	594,059		$ 76,132		$ 87,802	$11,670	15.33%

CONTROLLED WATER HEATING 11 HR. SERVICE, Rw-3

Daily Customer Charge		30,065	-	-	-	-		
Energy Charge (per kWh)	kWh	242,589	0.11530	27,970	0.13700	33,235		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00167)	-	-	-		
Fuel Cost Surcharge:		242,589	0.004355	1,056	-	-		
Total Rw-3	Total kWh	242,589		$ 29,027		$ 33,235	$4,208	14.50%

RESIDENTIAL SERVICE TIME-OF-USE with WATER HEATING, Rw-5

Daily Customer Charge		39,891	0.4932	19,674	0.4932	19,674		
Energy Charge (per kWh):								
TOU Schedule	High Rate	216,244	0.18820	40,697	0.26630	57,586		
	Regulator Rate	829,736	0.15650	129,854	0.18260	151,510		
	Low Rate	733,806	0.07580	55,622	0.08550	62,740		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00167)	-	-	-		
Fuel Cost Surcharge:		1,779,787	0.004355	7,751	-	-		
Total Rw-5	Total kWh	1,779,787		$ 253,598		$ 291,510	$37,912	14.95%

GENERAL SERVICE, Gs-1

Daily Customer Charge:	Single-phase	19,393,778	0.5589	10,839,183	0.5589	10,839,183		
	Three-phase	5,289,225	0.8384	4,434,486	0.8384	4,434,486		
Energy Charge (per kWh):								
	kWh	1,192,465,817	0.12400	147,865,761	0.13390	159,671,173		
Primary Voltage Discount								
	kWh	997,723	2.5%	(3,093)	2.5%	(3,340)		
ACT 141 Cost								
ACT 141 Capped Contribution		12,583,132	0.00099	12,410	0.00099	12,410		
ACT 141 Capped Credits		12,583,132	(0.00152)	(19,126)	(0.00152)	(19,126)		
Fuel Cost Surcharge:		1,192,465,817	0.004355	5,193,189	-	-		
Total Gs-1	Total kWh	1,192,465,817		$ 168,322,810		$ 174,934,786	$6,611,976	3.93%

GENERAL SERVICE TIME-OF-USE, Gs-3

Daily Customer Charge:	Single-phase	1,075,342	0.5589	601,008	0.5589	601,008		
	Three-phase	606,670	0.8384	508,632	0.8384	508,632		
Energy Charge (per kWh):								
TOU Schedule	High Rate	20,153,872	0.17430	3,512,820	0.23750	4,786,545		36.259%
	Regulator Rate	73,507,731	0.13680	10,055,858	0.15450	11,356,944		12.939%
	Low Rate	89,430,407	0.06880	6,152,812	0.07450	6,662,565		8.285%
Primary Energy Discounted:								
TOU Schedule	High Rate	88,960	2.5%	2,224	2.5%	(528)		
	Regulator Rate	337,077	2.5%	8,427	2.5%	(1,302)		
	Low Rate	373,404	2.5%	9,335	2.5%	(695)		
ACT 141 Cost								
ACT 141 Capped Contribution		10,474,077	0.00094	9,842	0.00094	9,842		
ACT 141 Credits		10,474,077	0.00152	(9,842)	(0.00152)	(15,921)		
Fuel Cost Surcharge:		183,092,010	0.004355	797,366	-	-		
Total Gs-3	Total kWh	183,092,010		$ 21,648,481		$ 23,907,090	$2,258,609	10.43%

GENERAL SERVICE DEMAND SERVICE, Gd-1

Daily Customer Charge:	Single-phase	1,281,191	0.5589	716,058	0.5589	716,058		
	Three-phase	63,226	0.8384	53,008	0.8384	53,008		
Customer Demand Charge (per kW)		201,108	2.0000	402,217	2.5000	502,771		
On-Peak Demand Charge (per kW) 10 to 8 PM		144,291	8.2500	1,190,400	9.0000	1,298,619		
Energy Charge (per kWh):								
TOU Schedule	High Rate	7,919,978	0.1283	1,016,133	0.1845	1,461,236		43.804%
	Regulator Rate	33,115,773	0.0825	2,732,051	0.0945	3,129,441		14.545%
	Low Rate	38,566,932	0.0620	2,391,150	0.0685	2,641,835		10.484%
Energy Limiter	kWh at limiter	54,816	0.1700	9,319	0.2200	12,059		
Primary Energy Discounted:								
Customer Demand Charge		-	$0.23	-	$0.23	-		
TOU Schedule	High Rate	7,144	2.50%	(23)	2.50%	(33)		
	Regulator Rate	29,870	2.50%	(62)	2.50%	(71)		
	Low Rate	34,786	2.50%	(54)	2.50%	(60)		
				-		-		
Limiter Primary Discounted	kWh at limiter	54,816	2.50%	(233)	2.50%	(301)		
ACT 141 Cost								
ACT 141 Capped Contribution		3,108	0.77442	2,407	0.77442	2,407		
ACT 141 Capped Credits		3,108	(0.00152)	(5)	(0.00152)	(5)		
Fuel Cost Surcharge:		79,657,499	0.004355	346,908	-	-		
Total Gd-1	Total kWh	79,657,499		$ 8,859,275		$ 9,816,964	$957,689	10.81%

GENERAL SERVICE NON-METERED, Gs-4

Daily Customer Charge		13,140	0.4089	5,373	0.4089	5,373		
Energy Charge (per kWh)	kWh	43,617	0.11400	4,972	0.14400	6,281		
Fuel Cost Surcharge:		43,617	0.004355	190	-	-		
Total Gs-4	Total kWh	43,617		$ 10,535		$ 11,654	$1,119	10.62%

COMMERCIAL SERVICE -- Cg-2 TOD

Daily Customer Charge:	Single-phase	47,725	0.9250	44,146	0.9250	44,146		
	Three-phase	1,115,804	1.1500	1,283,174	1.1500	1,283,174		
Firm Demand kW (All 10-10)		3,326,693	$11.95	39,753,976	$ 14.00	46,573,696		
Customer Demand Charge		4,891,765	$2.20	10,761,882	$ 2.95	14,430,705		
Energy Charge (per kWh):								
TOU Schedule	High Rate	136,869,103	0.08604	11,776,218	0.09300	12,728,827		8.089%
	Regulator Rate	568,590,634	0.06500	36,958,391	0.06300	35,821,210		-3.077%
	Low Rate	514,380,451	0.05190	26,696,345	0.04600	23,661,501		-11.368%
Energy Limiter	kWh at limiter	15,083,852	0.17000	2,564,255	0.22000	3,318,447		
Primary Energy Discounted:								
Firm Demand kW (All 10-10)		68,637	2.5%	(20,505)	2.5%	(24,023)		
Customer Demand Charge		118,314	$0.23	(27,212)	$ 0.23	(27,212)		
TOU Schedule	High Rate	2,708,329	2.5%	(5,826)	2.5%	(6,297)		
	Regulator Rate	11,154,479	2.5%	(18,126)	2.5%	(17,568)		
	Low Rate	10,104,702	2.5%	(13,111)	2.5%	(11,620)		
Limiter Primary Discounted	kWh at limiter	500,666	2.5%	(2,128)	2.5%	(2,128)		
ACT 141 Cost								
ACT 141 Capped Contribution		67,291,099	0.00094	63,229	0.00094	63,229		
ACT 141 Capped Credits		67,291,099	(0.00152)	(102,282)	(0.00152)	(102,282)		
Fuel Cost Surcharge:		1,234,924,040	0.004355	5,378,094	-	-		
COMMUNITY SOLAR Subscriptions	60%	$ 63,990		63,990		63,990		
COMMUNITY SOLAR Solar kWh Productio	60%	2,659,050	(0.105690)	(281,035)	(0.105690)	(281,035)		
Total Cg-2 TOD	Total kWh	1,234,924,040		$ 134,873,475		$ 137,516,759	$2,643,284	1.96%

INDUSTRIAL SERVICE, Cp-1 -- Secondary/Primary

		(0)						
Daily Customer Charge		372,574	6.2300	2,321,134	6.2300	2,321,134		
Firm Demand kW (All 10-10)		6,659,162	$14.02	93,361,446	$ 17.07	113,671,889		
Customer Demand Charge		10,417,108	$2.20	22,917,638	$ 2.95	30,730,469		
Cp-1C Stand-by Demand Charge		0	2.00	-	2.00	-		
Interruptible Demand Charges:								
Cp-1A. 1 Hr. Demand kW (All 10-10)		1,185,631	$9.66	11,453,192	$ 12.46	14,772,958		
Cp-2B. Inst. Demand kW (All 10-10)		534,506	$8.70	4,650,201	$ 11.44	6,114,747		
Energy Charge (per kWh):				-				
TOU Schedule	High Rate	376,124,293	$ 0.07323	27,543,582	0.07788	29,292,560		6.350%
	Regulator Rate	1,704,110,045	$ 0.05519	94,049,833	0.05325	90,743,860		-3.515%
	Low Rate	1,650,173,438	$ 0.04404	72,673,638	0.04310	71,122,475		-2.134%
Energy Limiter (per kWh):	kWh at limiter	16,221,697	$ 0.17000	2,757,688	0.22000	3,568,773		
Primary Voltage Discount:								
Customer Demand Charge		5,308,465	$0.23	(1,220,947)	$ 0.23	(1,220,947)		
Firm Demand kW (All 10-10)		2,703,431	2.5%	(947,552)	2.5%	(1,153,689)		
Cp-1A. 1 Hr. Demand kW (All 10-10)		982,953	2.5%	(237,383)	2.5%	(306,190)		
Cp-1B. Inst. Demand kW (All 10-10)		373,039	2.5%	(81,136)	2.5%	(106,689)		
TOU Schedule	High Rate	216,613,506	2.5%	(396,565)	2.5%	(421,746)		
	Regulator Rate	947,509,219	2.5%	(1,307,326)	2.5%	(1,261,372)		
	Low Rate	953,311,351	2.5%	(1,049,596)	2.5%	(1,027,193)		
Limiter Primary Discounted	kWh at limiter	3,279,843	2.5%	(13,939)	2.5%	(18,039)		
ECONOMIC DEVELOPMENT PROGRAM	$ Revenue Imp	-		-		-		
NEW LOAD MARKET PRICING RIDER	Above Baseline kWh	3,546,900		$ (138,051)		$ (138,051)		
ACT 141 Cost								
ACT 141 Capped Contribution		1,960,462,345	0.00086	1,685,876	0.00086	1,685,876		
ACT 141 Capped Credits		1,960,462,345	(0.00152)	(2,979,903)	(0.00152)	(2,979,903)		
Fuel Cost Surcharge:		3,743,082,573	0.004355	16,301,125	-	-		
COMMUNITY SOLAR Subscriptions	10%	$ 10,665		10,665		10,665		
COMMUNITY SOLAR Solar kWh Productio	10%	443,175	(0.105690)	(46,839)	(0.105690)	(4,684)		
Total Cp-1	Total kWh	3,746,629,473		$ 341,306,782		$ 355,396,904	$14,090,122	4.13%

INDUSTRIAL SERVICE, Cp-2 -- Transmission

Daily Customer Charge		7,665	35.0000	268,275	35.0000	268,275		
Firm Demand kW (All 10-10)		1,926,395	$13.25	25,524,740	$ 16.90	32,556,083		
Customer Demand Charge		2,998,342	$0.00	-	$ -	-		
Cp-2C Stand-by Demand Charge		180,000	2.00	360,000	2.00	360,000		
Cp-2C Stand-by Administration		365	6.00	2,190	6.00	2,190		
Interruptible Demand Charges:								
Cp-2A: 1 Hr. Demand kW (All 10-10)		378,422	$9.02	3,413,369	$ 12.43	4,703,788		
Cp-2B: Inst. Demand kW (All 10-10)		333,428	$8.10	2,700,763	$ 11.45	3,817,746		
Energy Charge (per kWh):								
TOU Schedule	High Rate	126,365,159	0.06993	8,836,716	0.07610	9,616,389		
	Regulator Rate	598,056,082	0.05275	31,547,458	0.05210	31,158,722		
	Low Rate	678,469,438	0.04213	28,583,917	0.04220	28,631,410		
Reactive Energy		-	0.001015	-	0.001015	-		
High Load Factor Energy Credit HLF		126,083,224	(0.0045)	(567,375)	(0.0045)	(567,375)		
HLF Credit + ERCO Rider		-	(0.0090)	-	(0.0090)	-		
ECONOMIC DEVELOPMENT PROGRAM	$ Revenue Impact			$ -		$ -		
NEW LOAD MARKET PRICING RIDER (NI	Above Baseline kWh	-		$ -		$ -		
DAY AHEAD MARKET PRICING RIDER (D	Above Baseline kWh	113,311,816		$ (1,868,035)		$ (1,868,035)		
Fuel Cost Surcharge enbedded in Rev Im	Above Baseline	113,311,816		-	-	-		
ACT 141 Cost								
ACT 141 Capped Contribution		1,402,890,680	0.00051	716,146	0.00051	716,146		
ACT 141 Capped Credits		1,402,890,680	(0.00152)	(2,132,394)	(0.00152)	(2,132,394)		
Fuel Cost Surcharge:	Less Above bas	1,289,578,864	0.004355	5,616,116	-	-		
Total Cp-2	Total kWh	1,402,890,679		$ 103,001,887		$ 107,262,946	$4,261,059	4.14%
		1,027,711						

AREA LIGHTING SERVICE, Ms-3

line row Monthly Charges (current Tariff):	Fixtures	Fixtures * 12						
01a. 100 watt roadway type | Pole Option E	1,459	17,508	13.49	236,183	0	-		
01b. 100 watt roadway type | New Wood Pc	32	384	24.57	9,435	0	-		
01c. 100 watt roadway type | New Decorativ	198	2,376	27.86	66,195	0	-		
02a. 150 watt roadway type | Pole Option E	1,162	13,944	15.14	211,112	0	-		
02b. 150 watt roadway type | New Wood Pc	34	408	26.11	10,653	0	-		
02c. 150 watt roadway type | New Decorativ	215	2,580	29.39	75,826	0	-		
03a. 250 watt roadway type | Pole Option E	325	3,900	19.09	74,451	0	-		
03b. 250 watt roadway type | New Wood Pc	33	396	30.16	11,943	0	-		
03c. 250 watt roadway type | New Decorativ	121	1,452	32.57	47,292	0	-		
04a. 250 watt flood light | Pole Option Existi	1,115	13,380	20.73	277,367	0	-		
04b. 250 watt flood light | New Wood Pole w	55	660	31.92	21,067	0	-		
04c. 250 watt flood light | New Decorative P	167	2,004	34.76	69,659	0	-		
05a. 400 watt flood light | Pole Option Existi	2,010	24,120	22.81	550,177	0	-		
05b. 400 watt flood light | New Wood Pole w	156	1,872	34	63,648	0	-		
05c. 400 watt flood light | New Decorative P	233	2,796	37.18	103,955	0	-		
06a. 100 watt roadway type | Existing Wooc	33	396	23.69	9,381	0	-		
06b. 100 watt roadway type | New Wood Pc	5	60	34.76	2,086	0	-		
07a. 150 watt roadway type | Existing Wooc	35	420	24.57	10,319	0	-		
07b. 150 watt roadway type | New Wood Pc	4	48	35.97	1,727	0	-		
08a. 250 watt roadway type | Existing Wooc	44	528	28.3	14,942	0	-		
08b. 250 watt roadway type | New Wood Pc	1	12	39.27	471	0	-		
09a. 250 watt flood light | Existing Wood Po	39	468	29.72	13,909	0	-		
09b. 250 watt flood light | New Wood Pole w	4	48	40.91	1,964	0	-		
10a. 400 watt flood light | Existing Wood Po	102	1,224	32.57	39,866	0	-		
10b. 400 watt flood light | New Wood Pole w	17	204	43.87	8,949	0	-		
11a. 70 watt Acorn Fixture* | pole paid upfrc	42	504	26.11	13,159	0	-		
12b. 70 watt Acorn Fixture* | w/concrete pol	119	1,428	28.95	41,341	0	-		
13b. 70 watt Acorn Fixture* | w/fiberglass p	34	408	28.95	11,812	0	-		
14a. 150 watt Acorn Fixture* | pole paid upfi	47	564	29.39	16,576	0	-		
15b. 150 watt Acorn Fixture* | w/concrete p	24	288	44.31	12,761	0	-		
16b. 150 watt Acorn Fixture* | w/fiberglass p	16	192	41.34	7,937	0	-		
20a. 70 watt Colonial Fixture* | Pole paid up	37	444	22.81	10,128	0	-		
21b. 70 watt Colonial Fixture* | w/concrete p	60	720	24.24	17,453	0	-		
22b. 70 watt Colonial Fixture* | w/fiberglass	219	2,628	24.24	63,703	0	-		
23a. 150 watt Colonial Fixture* | Pole paid u	13	156	24.57	3,833	0	-		
24b. 150 watt Colonial Fixture* | w/concrete	3	36	38.94	1,402	0	-		
25b. 150 watt Colonial Fixture* | w/fiberglas	27	324	35.53	11,512	0	-		
26a. 250 watt Down Light Fixture | Pole paic	32	384	27.86	10,698	0	-		
28b. 250 watt Down Light Fixture | w/fibergl	35	420	47.05	19,761	0	-		
30a. 400 watt Down Light Fixture | w/concre	27	324	29.39	9,522	0	-		
31b. 400 watt Down Light Fixture | w/fibergl	30	360	54.62	19,663	0	-		
33a. 250 watt Metal Halide Down Light Fixtu	3	36	31.04	1,117	0	-		
34b. 250 watt Metal Halide Down Light Fixtu	1	12	50.34	604	0	-		
35a. 400 watt Metal Halide Down Light Fixtu	48	576	32.57	18,760	0	-		
37b. 400 watt Metal Halide Down Light Fixtu	12	144	57.91	8,339	0	-		
				-	0	-		
Fixtures Separate from Poles			0	-	0	-		
Category A MS3	1,727	20,724	0	-	14.53	301,120		
Category B MS3	1,450	17,400	0	-	14.97	260,478		
Category C MS3	524	6,288	0	-	15.06	94,697		
Category D		-	0	-	0	-		
Category E	1,380	16,560	0	-	19.29	319,442		
Category F	2,518	30,216	0	-	19.48	588,608		
Category J	71	852	0	-	18.12	15,438		
Category K	117	1,404	0	-	18.31	25,707		
Category I	195	2,340	0	-	14.75	34,515		
Category M	87	1,044	0	-	15.19	15,858		
Category N	316	3,792	0	-	16.03	60,786		
Category O	43	516	0	-	16.21	8,364		
		-	0	-	0	-		
		-	0	-	0	-		
Poles		-	0	-	0	-		
Colonial Fiberglass	$219.00	2,628	0	-	14.96	39,315		
Decorative	$1,218.00	14,616	0	-	16.234	237,276		
Decorative Fiberglass	$77.00	924	0	-	14.96	13,823		
Wood	$341.00	4,092	0	-	8.33	34,086		
				-				
Energy Charges								
Annual kWh	kWh	4,583,174	0	-	0.1061	486,275		
Fuel Cost Surcharge:	2024 billed kWh	4,583,174	0.004355	19,960	-	-		
Fuel Cost Surcharge (per fixture-month):		101,136	0.480000	48,545		-		
Total Ms-3	Total kWh	4,583,174	$	2,301,165	$	2,535,789	$234,624	10.20%

STREET LIGHTING SERVICE, Ms-1		Billing	Present	Present	Authorized	Authorized	Increase	0
Annual Charges (per Unit):								
Fixture Category with Poles Separate								
Category A: 4,500-6,000 LED Lumens		16,424	40.50	665,172	$40.50	665,172		
Category B: 7,500-10,000 LED Lumens		17,118	42.70	730,939	$42.70	730,939		
Category C: 10,001-14,000 LED Lumens		3,920	43.00	168,560	$43.00	168,560		
Poles and Brackets								
Pole Wood		28,497	50.16	1,429,410	$50.16	1,429,410		
Pole Concrete		4,830	194.82	940,981	$194.82	940,981		
Pole Aluminum		876	169.32	148,324	$169.32	148,324		
Pole Fiberglass		30	179.52	5,386	$179.52	5,386		
Concrete Pole and Fixture Contribution (Closed)		1,755	41.51	72,850	$41.51	72,850		
Pole Contribution Option		485	67.20	32,592	$67.20	32,592		
Open		-	-	-	$0.00	-		
Energy Charge (per kWh):	kWh	35,055,517	0.07000	2,453,886	0.10610	3,719,390		
ACT 141 Cost								
ACT 141 Capped Contribution		17	-	-	-	-		
ACT 141 Capped Credits		17	(0.00152)	(0)	(0.00152)	(0)		
Fuel Cost Surcharge:		35,055,517	0.004355	152,667	-	-		
Total Ms-1	Total kWh	35,055,517		$ 6,800,766		$ 7,913,603	$1,112,837	16.36%

DECORATIVE LIGHTING SERVICE, Ms-2								
Monthly Charges (per Lamp):								
70 W Single		121	20.05	2,426	$20.05	2,426		
70 W Double		30	30.50	915	$30.50	915		
Energy Charge (per kWh):	kWh	68,642	0.07000	4,805	0.10610	7,283		
Fuel Cost Surcharge:		68,642	0.004355	299	-	-		
Total Ms-2	Total kWh	68,642		$ 8,445		$ 10,624	$2,179	25.80%

TRAFFIC SIGNAL SERVICE, Mz-1								
Daily Customer Charge		132,130	0.3200	42,282	0.3200	42,282		
Energy Charge (per kWh):	kWh	1,754,513	0.12200	214,051	0.14560	255,457		
ACT 141 Cost								
ACT 141 Capped Contribution		-	-	-	-	-		
ACT 141 Capped Credits		-	(0.00152)	-	(0.00152)	-		
Fuel Cost Surcharge:		1,754,513	0.004355	7,641	-	-		
Total Mz-1	Total kWh	1,754,513		$263,973		$297,739	$33,766	12.79%

CIVIL DEFENSE & FIRE SIRENS SERVICE, Mz-2

Daily Customer Charge:	1-ph Sec.	14582	0.0470	685	0.0517	754		
	3-phase Sec.	16443	0.1792	2,947	0.1971	3,241		
	3 Ph +10 kW	0	0.0473	-	0.0520	-		
Fuel Cost Surcharge:		-	-	-	-	-		
Total Mz-2	Total kWh	-		$ 3,632		$ 3,995	$363	9.99%

NON-STANDARD LIGHTING SERVICE, NL-1

Monthly Rate (applies to $ of investment)			1.80%	15,933	1.80%	15,933		
Energy Charge (per kWh):	kWh	45,967	0.07000	3,218	0.10610	4,877		
Fuel Cost Surcharge:		45,967	0.004355	200	-	-		
Total NL-1	Total kWh	45,967		$ 19,351		$ 20,810	$1,459	7.54%

SECOND NATURE PROGRAM, Sn-1 (rate Billing units and kWh volumes in Rg-1)

Energy Charge (per kWh):								
	100% Level	13,144,056	0.01000	-	0.01000	-		
	50% Level	4,537,743	0.00500	-	0.00500	-		
	25% Level	6,133,118	0.00250	-	0.00250	-		
	Fixed Level	4,882,289	0.01000	-	0.01000	-		
Fuel Cost Surcharge:	100% Level	13,144,056	-	-	-	-		
Fuel Cost Surcharge:	50% Level	4,537,743	0.002178	9,881	-	-		
Fuel Cost Surcharge:	25% Level	6,133,118	0.003266	20,032	-	-		
Fuel Cost Surcharge:	Fixed Level	4,882,289	-	-	-	-		
Total Gs-1SN	Total kWh	28,697,206		$ 29,913		$ -	($29,913)	-100.00%

TOTAL	**Total kWh**	**11,265,876,313**		**1,320,051,919**		**1,429,159,928**	**109,108,009**	

WISCONSIN POWER AND LIGHT COMPANY

Appendix D: ELECTRIC RATES TY2025

Docket: 6680-UR-124

PSC 441 Adjusted Authorized ELECTRIC RATES

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES

RESIDENTIAL SERVICE, Rg-1 Sheet 3.11

Daily Customer Charge:	Single-phase	$0.49320	$0.49320
	Three-phase	$0.73980	$0.73980
	Additional Meter	$0.10000	$0.16500
Energy Charge (per kWh):	All kwh	$0.13091	$0.15800
Fuel Adjustment (per kWh)		$0.004355	$0.000000

RESIDENTIAL TIME-OF-USE, Rg-5 Sheet 3.21

Daily Customer Charge:	Single-phase	$0.49320	$0.49320
	Three-phase	$0.73980	$0.73980
	Additional Meter	$0.10000	$0.16500
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.19600	$0.26630
	Regular Rate	$0.16300	$0.19430
	Low Rate	$0.07900	$0.09190
Fuel Adjustment (per kWh)		$0.004355	$0.000000

RESIDENTIAL DEMAND SERVICE, Rd-1 Sheet 3.31

Daily Customer Charge:	Single-phase	$0.32880	$0.32880
	Three-phase	$0.73980	$0.73980
	Additional meter	$0.10000	$0.16500
Customer Demand Charge (per kW)		$0.00000	$0.00000
On-Peak Demand Charge (per kW)		$4.80000	$4.90000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.17520	$0.24870
	Regular Rate	$0.13400	$0.16870
	Low Rate	$0.07100	$0.08070
Energy Limiter		$0.17000	$0.2200
Fuel Cost Surcharge		$0.004355	$0.000000

RESIDENTIAL SERVICE TIME-OF-USE with WATER HEATING, Rw-5 (Gw-1) Sheet 4.70

Daily Customer Charge		$0.49320	$0.4932
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.18820	$0.26630
	Regular Rate	$0.15650	$0.18260
	Low Rate	$0.07580	$0.08550
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES
GENERAL SERVICE, Gs-1			Sheet 4.01
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Energy Charge (per kWh):			
	All kwh	$0.12400	$0.13390
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment (per kWh)		$0.004355	$0.000000

GENERAL SERVICE TIME-OF-USE, Gs-3			Sheet 4.26
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.17430	$0.23750
	Regular Rate	$0.13680	$0.15450
	Low Rate	$0.06880	$0.07450
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment (per kWh)		$0.004355	$0.000000

GENERAL SERVICE DEMAND SERVICE, Gd-1			Sheet 4.33
Daily Customer Charge:	Single-phase	$0.55890	$0.5589
	Three-phase	$0.83840	$0.8384
Customer Demand Charge (per kW)		$2.00000	$2.5000
On-Peak Demand Charge (per kW)		$8.25000	$9.0000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.12830	$0.18450
	Regular Rate	$0.08250	$0.09450
	Low Rate	$0.06200	$0.06850
Energy Limiter		$0.17000	$0.22000
Customer Demand Discount (per kW)		$0.23000	$0.2300
Primary Voltage Discount		2.50%	2.50%
Fuel Cost Surcharge		$0.004355	$0.000000

GENERAL SERVICE NON-METERED, Gs-4			Sheet 4.80
Daily Customer Charge		$0.40890	$0.4089
Energy Charge (per kWh)		$0.11400	$0.14400
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES
CONTROLLED WATER HEATING 17 HR. SERVICE, Rw-1			Sheet 4.40 & 4.70
Daily Customer Charge		$0.00000	$0.0000
Energy Charge (per kWh):			
	All kwh	$0.12380	$0.14780
Fuel Adjustment (per kWh)		$0.004355	$0.000000
CONTROLLED WATER HEATING 11 HR. SERVICE, Rw-3			Sheet 4.50
Daily Customer Charge		$0.00000	$0.0000
Energy Charge (per kWh)			
	All kwh	$0.11530	$0.13700
Fuel Adjustment (per kWh)		$0.004355	$0.000000
COMMERCIAL SERVICE -- Cg-2 TOD			Sheet 6.41
Daily Customer Charge:	Single-phase	$0.92500	$0.92500
	Three-phase	$1.15000	$1.15000
Firm Demand Charge (per kW)		$11.95000	$14.00000
Customer Demand Charge		$2.20000	$2.95000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.08604	$0.09300
	Regular Rate	$0.06500	$0.06300
	Low Rate	$0.05190	$0.04600
Energy Limiter		$0.17000	$0.22000
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.23000	$0.23000
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES
INDUSTRIAL SERVICE, Cp-1 -- Secondary/Primary			Sheet 7.00 & 7.60
Daily Customer Charge		$6.23000	$6.23000
Firm Demand		$14.02000	$17.07000
Customer Demand Charge		$2.20000	$2.95000
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):		$9.66000	$12.46000
Instantaneous (12 hr):		$8.70000	$11.44000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.07323	$0.07788
	Regular Rate	$0.05519	$0.05325
	Low Rate	$0.04404	$0.04310
Energy Limiter (per kWh):		$0.17000	$0.22000
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.23000	$0.23000
Fuel Adjustment (per kWh)		$0.004355	$0.000000
INDUSTRIAL SERVICE, Cp-2 -- Transmission			Sheet 7.40 & 7.60
Daily Customer Charge		$35.00000	$35.00000
Firm Demand		$13.25000	$16.90000
Customer Demand Charge		$0.00000	$0.00000
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):		$9.02000	$12.43000
Instantaneous (12 hr):		$8.10000	$11.45000
Energy Charge (per kWh):			
TOU Schedule:	High Rate	$0.06993	$0.07610
	Regular Rate	$0.05275	$0.05210
	Low Rate	$0.04213	$0.04220
Reactive Energy		$0.00102	$0.00102
High Load Factor Energy Credit		-$0.00450	-$0.00450
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES
STREET LIGHTING SERVICE, Ms-1		Annual	Sheet 8.01 & 8.03
Annual Charges (per Unit):			
Fixture Category with Poles Separate			
Category A: 4,500-6,000 LED Lumens		$40.50000	$40.50
Category B: 7,500-10,000 LED Lumens		$42.70000	$42.70
Category C: 10,001-14,000 LED Lumens		$43.00000	$43.00
Poles and Brackets			
Pole Wood		$50.16000	$50.16
Pole Concrete		$194.82000	$194.82
Pole Aluminum		$169.32000	$169.32
Pole Fiberglass		$179.52000	$179.52
Concrete Pole and Fixture Contribution (Closed)		$41.51000	$41.51
Pole Contribution Option		$67.20000	$67.20
Open		$0.00000	$0.00
Energy Charge (per kWh):	kWh	$0.07000	$0.10610
Credit Provision per fixture (per night of continued outage)			
Category A		$0.07775	$0.07775
Category B		$0.12404	$0.12404
Category C		$0.18932	$0.18932
Fuel Adjustment (per kWh)		$0.004355	$0.000000

DECORATIVE LIGHTING SERVICE, Ms-2			Sheet 8.10
Monthly Charges (per Lamp):			
70 W Single		$20.05000	$20.05
70 W Double		$30.50000	$30.50
Energy Charge (per kWh):	kwh	$0.07000	$0.10610
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION	PRESENT RATES	Authorized 2025 RATES
AREA LIGHTING SERVICE, Ms-3		Sheet 8.19 and 8.191
Monthly Charges (per Lamp):	Per Month	
01a. 100 watt roadway type | Pole Option Existing	$13.49000	$0.00000
01b. 100 watt roadway type | New Wood Pole w/ohd Service	$24.57000	$0.00000
01c. 100 watt roadway type | New Decorative Pole	$27.86000	$0.00000
02a. 150 watt roadway type | Pole Option Existing	$15.14000	$0.00000
02b. 150 watt roadway type | New Wood Pole w/ohd Service	$26.11000	$0.00000
02c. 150 watt roadway type | New Decorative Pole	$29.39000	$0.00000
03a. 250 watt roadway type | Pole Option Existing	$19.09000	$0.00000
03b. 250 watt roadway type | New Wood Pole w/ohd Service	$30.16000	$0.00000
03c. 250 watt roadway type | New Decorative Pole	$32.57000	$0.00000
04a. 250 watt flood light | Pole Option Existing	$20.73000	$0.00000
04b. 250 watt flood light | New Wood Pole w/ohd Service	$31.92000	$0.00000
04c. 250 watt flood light | New Decorative Pole	$34.76000	$0.00000
05a. 400 watt flood light | Pole Option Existing	$22.81000	$0.00000
05b. 400 watt flood light | New Wood Pole w/ohd Service	$34.00000	$0.00000
05c. 400 watt flood light | New Decorative Pole	$37.18000	$0.00000
06a. 100 watt roadway type | Existing Wood Pole w/ urd. Service	$23.69000	$0.00000
06b. 100 watt roadway type | New Wood Pole w/ urd. Service	$34.76000	$0.00000
07a. 150 watt roadway type | Existing Wood Pole w/ urd. Service	$24.57000	$0.00000
07b. 150 watt roadway type | New Wood Pole w/ urd. Service	$35.97000	$0.00000
08a. 250 watt roadway type | Existing Wood Pole w/ urd. Service	$28.30000	$0.00000
08b. 250 watt roadway type | New Wood Pole w/ urd. Service	$39.27000	$0.00000
09a. 250 watt flood light | Existing Wood Pole w/ urd. Service	$29.72000	$0.00000
09b. 250 watt flood light | New Wood Pole w/ urd. Service	$40.91000	$0.00000
10a. 400 watt flood light | Existing Wood Pole w/ urd. Service	$32.57000	$0.00000
10b. 400 watt flood light | New Wood Pole w/ urd. Service	$43.87000	$0.00000
11a. 70 watt Acorn Fixture* | pole paid upfront Pole Option Existing	$26.11000	$0.00000
12b. 70 watt Acorn Fixture* | w/concrete pole New Decorative Pole	$28.95000	$0.00000
13b. 70 watt Acorn Fixture* | w/fiberglass pole New Decorative Pole	$28.95000	$0.00000
14a. 150 watt Acorn Fixture* | pole paid upfront Pole Option Existing	$29.39000	$0.00000
15b. 150 watt Acorn Fixture* | w/concrete pole New Decorative Pole	$44.31000	$0.00000
16b. 150 watt Acorn Fixture* | w/fiberglass pole New Decorative Pole	$41.34000	$0.00000
20a. 70 watt Colonial Fixture* | Pole paid upfront-Pole Option Existing	$22.81000	$0.00000
21b. 70 watt Colonial Fixture* | w/concrete pole-New Decorative Pole	$24.24000	$0.00000
22b. 70 watt Colonial Fixture* | w/fiberglass pole-New Decorative Pole	$24.24000	$0.00000
23a. 150 watt Colonial Fixture* | Pole paid upfront-Pole Option Existing	$24.57000	$0.00000
24b. 150 watt Colonial Fixture* | w/concrete pole-New Decorative Pole	$38.94000	$0.00000
25b. 150 watt Colonial Fixture* | w/fiberglass pole-New Decorative Pole	$35.53000	$0.00000
26a. 250 watt Down Light Fixture | Pole paid upfront-Pole Option Existing	$27.86000	$0.00000
28b. 250 watt Down Light Fixture | w/fiberglass pole-New Decorative Pol	$47.05000	$0.00000
30a. 400 watt Down Light Fixture | w/concrete pole-New Decorative Pole	$29.39000	$0.00000
31b. 400 watt Down Light Fixture | w/fiberglass pole-New Decorative Pol	$54.62000	$0.00000
33a. 250 watt Metal Halide Down Light Fixture | w/concrete pole-New De	$31.04000	$0.00000
34b. 250 watt Metal Halide Down Light Fixture | w/fiberglass pole-New D	$50.34000	$0.00000
35a. 400 watt Metal Halide Down Light Fixture | Pole paid upfront-Pole O	$32.57000	$0.00000
37b. 400 watt Metal Halide Down Light Fixture | w/fiberglass pole-New D	$57.91000	$0.00000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES
Fixtures Separate from Poles			
Category A MS3	Roadway	$0.00000	$14.53000
Category B MS3	Roadway	$0.00000	$14.97000
Category C MS3	Roadway	$0.00000	$15.06000
Category D	Roadway	$0.00000	$0.00000
Category E	Flood	$0.00000	$19.29000
Category F	Flood	$0.00000	$19.48000
Category J	Down	$0.00000	$18.12000
Category K	Down	$0.00000	$18.31000
Category I	Acorn	$0.00000	$14.75000
Category M	Acorn	$0.00000	$15.19000
Category N	Colonial	$0.00000	$16.03000
Category O	Colonial	$0.00000	$16.21000
Poles			
Colonial Fiberglass			$14.96000
Decorative			$16.23400
Decorative Fiberglass			$14.96000
Wood			$8.33000
Energy Charge (per kWh):	kWh	$0.00000	$0.10610
Fuel Adjustment (per kWh)		$0.004355	$0.000000
Fuel Adjustment (per fixture)		$0.480000	$0.0000

TRAFFIC SIGNAL SERVICE, Mz-1 Sheet 8.20

Daily Customer Charge		$0.32000	$0.3200
Energy Charge (per kWh):	kWh	$0.12200	$0.14560
Fuel Adjustment (per kWh)		$0.004355	$0.000000

CIVIL DEFENSE & FIRE SIRENS SERVICE, Mz-2 Sheet 8.30

Daily Customer Charge:	Single-phase Secor	$0.04700	$0.0517
	Three-phase Secon	$0.17920	$0.1971
	3 Ph Sec - Addtl. 1(	$0.04730	$0.0520

NON-STANDARD LIGHTING SERVICE, NL-1 Sheet 8.40

Monthly Rate (applies to $ of investment)		1.80%	1.80%
Energy Charge (per kWh):	kWh	$0.07000	$0.10610
Fuel Adjustment (per kWh)		$0.004355	$0.000000

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	Authorized 2025 RATES

SECOND NATURE PROGRAM, Sn-1 — Sheet 4.05

Energy Charge (per kWh):	100% Participation	$0.01000	$0.010000
	50% Participation	$0.00500	$0.005000
	25% Participation	$0.00250	$0.002500

Act 141 Rates

Residential Rates: (per kWh)	$0.00171	0.00167
Non-Residential Rates (per kWh):	$0.00140	0.00152

Wisconsin Power and Light Company
Rate Impact Analysis 2025

Avg/Month $ 15.01

Residential Rg-1 — **Authorized Change** **14.4%**

	Monthly Usage	Customer Charge	Energy Charge	Monthly Bill	Customer Charge	Energy Charge	Monthly Bill	% Change
	100	$ 15.00	$0.1353	$ 28.53	$ 15.00	$ 0.1580	$ 30.80	8.0%
	200	$ 15.00	$0.1353	$ 42.05	$ 15.00	$ 0.1580	$ 46.60	10.8%
	300	$ 15.00	$0.1353	$ 55.58	$ 15.00	$ 0.1580	$ 62.40	12.3%
	400	$ 15.00	$0.1353	$ 69.11	$ 15.00	$ 0.1580	$ 78.20	13.2%
	500	$ 15.00	$0.1353	$ 82.63	$ 15.00	$ 0.1580	$ 94.00	13.8%
	600	$ 15.00	$0.1353	$ 96.16	$ 15.00	$ 0.1580	$ 109.80	14.2%
Avg C	**660**	**$ 15.00**	**$0.1353**	**$ 104.28**	**$ 15.00**	**$ 0.1580**	**$ 119.28**	**14.4%**
	700	$ 15.00	$0.1353	$ 109.69	$ 15.00	$ 0.1580	$ 125.60	14.5%
	800	$ 15.00	$0.1353	$ 123.21	$ 15.00	$ 0.1580	$ 141.40	14.8%
	900	$ 15.00	$0.1353	$ 136.74	$ 15.00	$ 0.1580	$ 157.20	15.0%
	1000	$ 15.00	$0.1353	$ 150.27	$ 15.00	$ 0.1580	$ 173.00	15.1%
	1100	$ 15.00	$0.1353	$ 163.79	$ 15.00	$ 0.1580	$ 188.80	15.3%
	1200	$ 15.00	$0.1353	$ 177.32	$ 15.00	$ 0.1580	$ 204.60	15.4%
	1300	$ 15.00	$0.1353	$ 190.85	$ 15.00	$ 0.1580	$ 220.40	15.5%
	1400	$ 15.00	$0.1353	$ 204.37	$ 15.00	$ 0.1580	$ 236.20	15.6%
	1500	$ 15.00	$0.1353	$ 217.90	$ 15.00	$ 0.1580	$ 252.00	15.7%
	1600	$ 15.00	$0.1353	$ 231.43	$ 15.00	$ 0.1580	$ 267.80	15.7%
	1700	$ 15.00	$0.1353	$ 244.95	$ 15.00	$ 0.1580	$ 283.60	15.8%

Rg-5 Current — Use % Profile: 10.4% / 39.8% / 49.8%; Rg-1: 12.2% / 41.2% / 46.6%

Rg-5 Authorized — Use % Profile: 10.4% / 39.8% / 49.8%

Monthly Usage	Customer Charge	High Energy (10.4%)	Reg Energy (39.8%)	Low Energy (49.8%)	Monthly Bill	Authorized Customer Charge	High Energy (10.4%)	Reg Energy (39.8%)	Low Energy (49.8%)	Monthly Bill	% Change
100	$ 15.00	$0.20036	$0.16736	$0.08336	$ 27.90	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 30.08	7.8%
200	$ 15.00	$0.20036	$0.16736	$0.08336	$ 40.79	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 45.16	10.7%
300	$ 15.00	$0.20036	$0.16736	$0.08336	$ 53.69	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 60.24	12.2%
400	$ 15.00	$0.20036	$0.16736	$0.08336	$ 66.58	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 75.31	13.1%
500	$ 15.00	$0.20036	$0.16736	$0.08336	$ 79.48	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 90.39	13.7%
600	$ 15.00	$0.20036	$0.16736	$0.08336	$ 92.37	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 105.47	14.2%
660	**$ 15.00**	**$0.20036**	**$0.16736**	**$0.08336**	**$ 100.11**	**$ 15.00**	**$ 0.2663**	**$ 0.1943**	**$ 0.0919**	**$ 114.52**	**14.4%**
700	$ 15.00	$0.20036	$0.16736	$0.08336	$ 105.27	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 120.55	14.5%
800	$ 15.00	$0.20036	$0.16736	$0.08336	$ 118.16	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 135.63	14.8%
900	$ 15.00	$0.20036	$0.16736	$0.08336	$ 131.06	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 150.70	15.0%
1000	$ 15.00	$0.20036	$0.16736	$0.08336	$ 143.95	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 165.78	15.2%
1100	$ 15.00	$0.20036	$0.16736	$0.08336	$ 156.84	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 180.86	15.3%
1200	$ 15.00	$0.20036	$0.16736	$0.08336	$ 169.74	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 195.94	15.4%
1300	$ 15.00	$0.20036	$0.16736	$0.08336	$ 182.63	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 211.01	15.5%
1400	$ 15.00	$0.20036	$0.16736	$0.08336	$ 195.53	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 226.09	15.6%
1500	$ 15.00	$0.20036	$0.16736	$0.08336	$ 208.42	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 241.17	15.7%
1600	$ 15.00	$0.20036	$0.16736	$0.08336	$ 221.32	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 256.25	15.8%
1700	$ 15.00	$0.20036	$0.16736	$0.08336	$ 234.21	$ 15.00	$ 0.2663	$ 0.1943	$ 0.0919	$ 271.33	15.8%

Rd-1 — Load Factor 39.90%; Use % Profile: 9.1% / 40.6% / 50.3%; Rd-1 Use Profile

Monthly Usage	Customer Charge	Customer Demand	Billed Demand	High Energy	Reg Energy	Low Energy	Monthly Bill	Rd-1 Change from Rg-1
100	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 24.85	-19.3%
200	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 39.71	-14.8%
300	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 54.56	-12.6%
400	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 69.41	-11.2%
500	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 84.27	-10.4%
600	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 99.12	-9.7%
660	**$ 10.00**	**$ -**	**$ 4.90**	**$ 0.2487**	**$ 0.1687**	**$ 0.0807**	**$ 108.03**	**-9.4%**
700	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 113.97	-9.3%
800	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 128.83	-8.9%
900	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 143.68	-8.6%
1000	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 158.53	-8.4%
1100	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 173.39	-8.2%
1200	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 188.24	-8.0%
1300	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 203.09	-7.9%
1400	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 217.95	-7.7%
1500	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 232.80	-7.6%
1600	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 247.65	-7.5%
1700	$ 10.00	$ -	$ 4.90	$ 0.2487	$ 0.1687	$ 0.0807	$ 262.51	-7.4%

General Service Gs-1 — **Authorized Change** **3.9%**

	Monthly Usage	Customer Charge	Energy Charge	Monthly Bill	Customer Charge	Energy Charge	Monthly Bill	% Change
	100	$ 17.00	$0.1284	$ 29.84	$ 17.00	$ 0.1339	$ 30.39	1.9%
	250	$ 17.00	$0.1284	$ 49.09	$ 17.00	$ 0.1339	$ 50.47	2.8%
	500	$ 17.00	$0.1284	$ 81.18	$ 17.00	$ 0.1339	$ 83.95	3.4%
	1000	$ 17.00	$0.1284	$ 145.35	$ 17.00	$ 0.1339	$ 150.90	3.8%
	1500	$ 17.00	$0.1284	$ 209.53	$ 17.00	$ 0.1339	$ 217.85	4.0%
Avg C	**1685**	**$ 17.00**	**$0.1284**	**$ 233.28**	**$ 17.00**	**$ 0.1339**	**$ 242.62**	**4.0%**
	2000	$ 17.00	$0.1284	$ 273.71	$ 17.00	$ 0.1339	$ 284.80	4.1%
	2500	$ 17.00	$0.1284	$ 337.89	$ 17.00	$ 0.1339	$ 351.75	4.1%
	3000	$ 17.00	$0.1284	$ 402.06	$ 17.00	$ 0.1339	$ 418.70	4.1%
	3500	$ 17.00	$0.1284	$ 466.24	$ 17.00	$ 0.1339	$ 485.65	4.2%
	4000	$ 17.00	$0.1284	$ 530.42	$ 17.00	$ 0.1339	$ 552.60	4.2%
	4500	$ 17.00	$0.1284	$ 594.60	$ 17.00	$ 0.1339	$ 619.55	4.2%
	5000	$ 17.00	$0.1284	$ 658.77	$ 17.00	$ 0.1339	$ 686.50	4.2%
	5500	$ 17.00	$0.1284	$ 722.95	$ 17.00	$ 0.1339	$ 753.45	4.2%
	6000	$ 17.00	$0.1284	$ 787.13	$ 17.00	$ 0.1339	$ 820.40	4.2%
	6500	$ 17.00	$0.1284	$ 851.31	$ 17.00	$ 0.1339	$ 887.35	4.2%
	7000	$ 17.00	$0.1284	$ 915.48	$ 17.00	$ 0.1339	$ 954.30	4.2%
	7500	$ 17.00	$0.1284	$ 979.66	$ 17.00	$ 0.1339	$1,021.25	4.2%

GS-3 Current / **GS-3 Authorized**

Monthly Usage	Customer Charge	High Energy 11.6%	Reg Energy 45.7%	Low Energy 42.7%	Monthly Bill	Authorized Customer Charge	High Energy 11.6%	Reg Energy 45.7%	Low Energy 42.7%	Monthly Bill	% Change
100	$ 17.00	0.17866	0.14116	0.07316	$ 28.65	$ 17.00	0.23750	0.15450	0.07450	$ 30.00	4.7%
250	$ 17.00	0.17866	0.14116	0.07316	$ 46.12	$ 17.00	0.23750	0.15450	0.07450	$ 49.49	7.3%
500	$ 17.00	0.17866	0.14116	0.07316	$ 75.23	$ 17.00	0.23750	0.15450	0.07450	$ 81.98	9.0%
1000	$ 17.00	0.17866	0.14116	0.07316	$ 133.47	$ 17.00	0.23750	0.15450	0.07450	$ 146.97	10.1%
1500	$ 17.00	0.17866	0.14116	0.07316	$ 191.70	$ 17.00	0.23750	0.15450	0.07450	$ 211.95	10.6%
1685	**$ 17.00**	**0.17866**	**0.14116**	**0.07316**	**$ 213.25**	**$ 17.00**	**0.23750**	**0.15450**	**0.07450**	**$ 236.00**	**10.7%**
2000	$ 17.00	0.17866	0.14116	0.07316	$ 249.94	$ 17.00	0.23750	0.15450	0.07450	$ 276.94	10.8%
2500	$ 17.00	0.17866	0.14116	0.07316	$ 308.17	$ 17.00	0.23750	0.15450	0.07450	$ 341.92	11.0%
3000	$ 17.00	0.17866	0.14116	0.07316	$ 366.41	$ 17.00	0.23750	0.15450	0.07450	$ 406.90	11.1%
3500	$ 17.00	0.17866	0.14116	0.07316	$ 424.64	$ 17.00	0.23750	0.15450	0.07450	$ 471.89	11.1%
4000	$ 17.00	0.17866	0.14116	0.07316	$ 482.88	$ 17.00	0.23750	0.15450	0.07450	$ 536.87	11.2%
4500	$ 17.00	0.17866	0.14116	0.07316	$ 541.11	$ 17.00	0.23750	0.15450	0.07450	$ 601.86	11.2%
5000	$ 17.00	0.17866	0.14116	0.07316	$ 599.34	$ 17.00	0.23750	0.15450	0.07450	$ 666.84	11.3%
5500	$ 17.00	0.17866	0.14116	0.07316	$ 657.58	$ 17.00	0.23750	0.15450	0.07450	$ 731.82	11.3%
6000	$ 17.00	0.17866	0.14116	0.07316	$ 715.81	$ 17.00	0.23750	0.15450	0.07450	$ 796.81	11.3%
6500	$ 17.00	0.17866	0.14116	0.07316	$ 774.05	$ 17.00	0.23750	0.15450	0.07450	$ 861.79	11.3%
7000	$ 17.00	0.17866	0.14116	0.07316	$ 832.28	$ 17.00	0.23750	0.15450	0.07450	$ 926.78	11.4%
7500	$ 17.00	0.17866	0.14116	0.07316	$ 890.52	$ 17.00	0.23750	0.15450	0.07450	$ 991.76	11.4%

Gd-1 Load Factor

Gd-1 38.00% — Gd-1 use Profile

Monthly Usage	Customer Charge	38.00%	Billed Demand	High Energy 10.0%	Reg Energy 41.6%	Low Energy 48.5%	Monthly Bill	Gd-1 Change from Gs-1
100	$ 17.00	$ 2.50	$ 9.00	0.1845	0.0945	0.0685	$ 30.23	-0.5%
250	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 48.91	-3.1%
500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 80.81	-3.7%
1000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 144.63	-4.2%
1500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 208.44	-4.3%
1685	**$ 17.00**	**$ 2.20**	**$ 8.00**	**0.1845**	**0.0945**	**0.0685**	**$ 232.05**	**-4.4%**
2000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 272.26	-4.4%
2500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 336.07	-4.5%
3000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 399.88	-4.5%
3500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 463.70	-4.5%
4000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 527.51	-4.5%
4500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 591.33	-4.6%
5000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 655.14	-4.6%
5500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 718.95	-4.6%
6000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 782.77	-4.6%
6500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 846.58	-4.6%
7000	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 910.40	-4.6%
7500	$ 17.00	$ 2.20	$ 8.00	0.1845	0.0945	0.0685	$ 974.21	-4.6%

Account	Description	Total	RG-1	RG-5	Rd-1	GS-1	GS-3	Gd-1	GS-4	Rw-5 (Gw-1)	Rw-1	Rw-3	Cg-2TOD	Mz-1&2	Ms-1	Ms-2	Ms-3	NL-1	Cp-1	Cp-2
Present Revenue	Present	1,320,051,919	508,443,269	22,699,639	1,129,677	168,322,810	21,648,481	8,859,275	10,535	253,598	76,132	29,027	134,873,475	267,605	6,800,766	8,445	2,301,165	19,351	341,306,782	103,001,887
Proposed Revenue	Proposed	1,429,159,928	581,820,796	26,004,566	1,292,357	174,934,786	23,907,090	9,816,964	11,654	291,510	87,802	33,235	137,516,759	301,733	7,913,603	10,624	2,535,789	20,810	355,396,904	107,262,946
Difference		109,108,009	73,377,526	3,304,927	162,680	6,611,976	2,258,609	957,689	1,119	37,912	11,670	4,208	2,643,284	34,128	1,112,837	2,179	234,624	1,459	14,090,122	4,261,059
Percentage Difference		8.3%	14.43%	14.56%	14.4%	3.93%	10.4%	10.8%	10.6%	14.9%	15.3%	14.5%	1.96%	12.8%	16.4%	26%	10%	8%	4.13%	4.14%
	Rev Req	9																		
Present Functional		(109,108,000)																		
	Energy	1,024,955,508	435,263,614	19,705,709	832,705	153,049,141	20,538,841	6,497,592	5,162	233,924	76,132	29,027	83,078,014	221,691	2,606,553	5,104	68,505	3,418	232,007,826	70,732,550
	Demand	191,128,068	-	-	90,617	-	-	1,592,617	-	-	-	-	50,468,141	-	-	-	-	-	106,977,821	31,998,872
	Customer	103,968,343	73,179,655	2,993,930	206,355	15,273,669	1,109,640	769,066	5,373	19,674	-	-	1,327,320	45,914	4,194,213	3,341	2,232,660	15,933	2,321,134	270,465
	Total	1,320,051,919	508,443,269	22,699,639	1,129,677	168,322,810	21,648,481	8,859,275	10,535	253,598	76,132	29,027	134,873,475	267,605	6,800,766	8,445	2,301,165	19,351	341,306,782	103,001,887
	% Energy	78%	86%	87%	74%	91%	95%	73%	49%	92%	100%	100%	62%	83%	38%	60%	3%	18%	68%	69%
	% Demand	14%	0%	0%	8%	0%	0%	18%	0%	0%	0%	0%	37%	0%	0%	0%	0%	0%	31%	31%
	% Customer	8%	14%	13%	18%	9%	5%	9%	51%	8%	0%	0%	1%	17%	62%	40%	97%	82%	1%	0%
	Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Proposed Functional																				
	Energy	1,089,228,291	508,552,470	23,009,988	993,497	159,661,117	22,797,450	7,246,508	6,281	271,836	87,802	33,235	75,236,273	255,457	3,719,390	7,283	486,275	4,877	221,303,690	65,554,863
	Demand	236,056,758	-	-	92,505	-	-	1,801,389	-	-	-	-	60,953,166	-	-	-	-	-	131,772,079	41,437,617
88,670	Customer	103,874,879	73,268,326	2,994,578	206,355	15,273,669	1,109,640	769,066	5,373	19,674	-	-	1,327,320	46,276	4,194,213	3,341	2,049,514	15,933	2,321,134	270,465
	Total	1,429,159,928	581,820,796	26,004,566	1,292,357	174,934,786	23,907,090	9,816,964	11,654	291,510	87,802	33,235	137,516,759	301,733	7,913,603	10,624	2,535,789	20,810	355,396,904	107,262,946
	% Energy	76%	87%	88%	77%	91%	95%	74%	54%	93%	100%	100%	55%	85%	47%	69%	19%	23%	62%	61%
	% Demand	17%	0%	0%	7%	0%	0%	18%	0%	0%	0%	0%	44%	0%	0%	0%	0%	0%	37%	39%
	% Customer	7%	13%	12%	16%	9%	5%	8%	46%	7%	0%	0%	1%	15%	53%	31%	81%	77%	1%	0%
	Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Entry	10		15.00		10.00	17.00			12.44				34.98						189.50	1,065
Effective Rate:	0.3288		RG-1	RG-5	Rd-1	GS-1	GS-3	Gd-1	GS-4	Gw-1(Rw-5)	Rw-1	Rw-3	Cg-2TOD	Mz-1&2	Ms-1	Ms-2	Ms-3	NL-1	Cp-1	Cp-2
Customer Charge ($/day)			$ 0.49320	$ 0.49320	$ 0.32880	$ 0.55890	$ 0.55890	$ 0.55890	$ 0.40890	$ 0.49320	$ -	$ -	$ 0.92500	$ 0.32000					$ 6.2300	$ 35.0000
3-ph																			0.07819	0.07640
Energy	Summer ($/kWh)		$ 0.15800			$ 0.13390			$ 0.14400		$ 0.14780	$ 0.13700		0.145600					0.05356	0.05240
	Non-Summer ($/kWh)		$ 0.15800			$ 0.13390			$ 0.14400		$ 0.14780	$ 0.13700		$ 0.14560					0.04340	0.04240
Multi-peak Energy			% CP1			% CP1		% CP1				% CP1			LMP % CP1	LMP				
High Rate		$ 0.27	342%	$ 0.26630	$ 0.24870	305%	$ 0.23750	$ 0.18450	237%	$ 0.26630		119%	$ 0.09300	$ 0.08730	80%	0.062066	174%	0.07323	$ 0.07788	$ 0.07610
Regular Rate		$ 0.19	365%	$ 0.19430	$ 0.16870	290%	$ 0.15450	$ 0.09450	177%	$ 0.18260		118%	$ 0.06300	$ 0.05969	83%	0.044322	125%	0.05519	$ 0.05325	$ 0.05210
Low Rate		$ 0.09	213%	$ 0.09190	$ 0.08070	173%	$ 0.07450	$ 0.06850	159%	$ 0.08550		107%	$ 0.04600	$ 0.04832	83%	0.035574		0.04404	$ 0.04310	$ 0.04220
				$ 0.14837		Weight Avg $/kWh	$ 0.12456													
Multi-peak Firm Demand					$ 4.90000			$ 9.00000					$ 14.00						$ 17.07	$ 16.90
Multi-peak 1-HR Int Demand																			$ 12.46	$ 12.43
Multi-peak Inst Int Demand																			$ 11.44	$ 11.45
Customer Demand ($/kW)					$ -			$ 2.50000					$ 2.95						$ 2.95	$ -
							0.0045													
Other	Limiter				$ 0.22000			$ 0.22000					$ 0.22000						$ 0.22000	
	Primary Discount					2.50%	2.50%	2.50%					2.50%						2.50%	
	Primary Cust. Demand Discount							$ 0.23					$ 0.23						$ 0.23	
	3-phase metering		$ 0.73980	$ 0.73980	$ 0.73980	$ 0.83840	$ 0.83840	$ 0.83840					$ 1.1500							
	HLF Credit																			($0.0045)
	Reactive Power													% increase	Manual	% increase	Manual			$0.001015
Lighting	Fixture											Guide GS-3	on Light % TOU	1.1000	Rate List	1	Rate List	Rate List		
	Energy											Wt Avg =>	$ 0.1067		$ 0.10610	$ 0.1061	$ 0.1061	$ 0.1061		
			$ 0.37									High	5.6%							

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
SUMMARY OF PRESENT AND PROPOSED MARGIN RATES BY RATE CLASS
Forecasted Sales

	2024							
Description	**Monthly Customers**	**Billing Units**	**Present Rates**	**Present Revenues**	**Authorized Rates**	**Authorized Revenues**	**Change in Revenue**	**Percent Change**
GG-1 RESIDENTIAL SERVICE								
Daily Customer Charge	181,908	66,578,328	$ 0.4113	$ 27,383,666	$ 0.4113	$ 27,383,666	$ -	**0.0%**
Distribution Charge		138,383,416	$ 0.3012	$ 41,681,085	$ 0.3618	$ 50,067,120	$ 8,386,035	
Gas Supply Acquisition Charge		138,383,416	$ 0.0129	$ 1,785,146	$ 0.0155	$ 2,144,943	$ 359,797	
TOTAL GG-1 DISTRIBUTION REVENUES				**$ 70,849,897**		**$ 79,595,729**	$ 8,745,832	**12.3%**
Commodity		138,383,416	$ 0.4190	$ 57,982,651	$ 0.4190	$ 57,982,651	$ -	
Maximum Daily Demand		103,787,621	$ 0.1581	$ 16,408,823	$ 0.1581	$ 16,408,823	$ -	
Annual Demand		138,383,416	$ 0.0706	$ 9,769,869	$ 0.0706	$ 9,769,869	$ -	
TOTAL GG-1 GAS SUPPLY REVENUES				**$ 84,161,343**		**$ 84,161,343**	$ -	
TOTAL GG-1 DISTRIBUTION + GAS SUPPLY REVENUES				**$ 155,011,241**		**$ 163,757,073**	$ 8,745,832	**5.6%**
						$ 0.60818		
GC-1 SMALL COMMERCIAL & INDUSTRIAL SERVICE								
Daily Customer Charge	16,817	6,155,022	$ 0.4741	$ 2,918,096	$ 0.4741	$ 2,918,096	$ -	**0.0%**
Distribution Charge		25,246,333	$ 0.2592	$ 6,543,849	$ 0.3004	$ 7,583,998	$ 1,040,149	
Gas Supply Acquisition Charge		25,246,333	$ 0.0127	$ 320,628	$ 0.0152	$ 383,744	$ 63,116	
TOTAL GC-1 DISTRIBUTION REVENUES				**$ 9,782,574**		**$ 10,885,839**	$ 1,103,265	**11.3%**
Commodity		25,246,333	$ 0.4190	$ 10,578,213	$ 0.4190	$ 10,578,213	$ -	
Maximum Daily Demand		19,552,416	$ 0.1581	$ 3,091,237	$ 0.1581	$ 3,091,237	$ -	
Annual Demand		25,246,333	$ 0.0706	$ 1,782,391	$ 0.0706	$ 1,782,391	$ -	
TOTAL GC-1 GAS SUPPLY REVENUES				**$ 15,451,842**		**$ 15,451,842**	$ -	
TOTAL GC-1 DISTRIBUTION + GAS SUPPLY REVENUES				**$ 25,234,415**		**$ 26,337,680**	$ 1,103,265	**4.4%**
GC-2 COMMERCIAL & INDUSTRIAL SERVICE 5-20								
Daily Customer Charge	2,996	1,096,536	$ 1.8902	$ 2,072,672	$ 1.8902	$ 2,072,672	$ -	**0.0%**
Distribution Charge - Sales	2,978	28,509,655	$ 0.1363	$ 3,885,866	$ 0.1523	$ 4,342,020	$ 456,154	
Distribution Charge - Transport	18	252,587	$ 0.1363	$ 34,428	$ 0.1523	$ 38,469	$ 4,041	
Transport Administration		6,588	$ 2.2700	$ 14,955	$ 2.2700	$ 14,955	$ -	
Transport Remote Metering	1	366	$ 1.2400	$ 454	$ 1.2400	$ 454	$ -	
Gas Supply Acquisition Charge		28,509,655	$ 0.0127	$ 362,073	$ 0.0152	$ 433,347	$ 71,274	
TOTAL GC-2F DISTRIBUTION REVENUES				**$ 6,370,447**		**$ 6,901,917**	$ 531,470	**8.3%**
Commodity		28,509,655	$ 0.4190	$ 11,945,545	$ 0.4190	$ 11,945,545	$ -	
Maximum Daily Demand		20,513,578	$ 0.1581	$ 3,243,197	$ 0.1581	$ 3,243,197	$ -	
Annual Demand		28,509,655	$ 0.0706	$ 2,012,782	$ 0.0706	$ 2,012,782	$ -	
TOTAL GC-2F GAS SUPPLY REVENUES				**$ 17,201,524**		**$ 17,201,524**	$ -	
TOTAL GC-2F DISTRIBUTION + GAS SUPPLY REVENUES				**$ 23,571,971**		**$ 24,103,441**	$ 531,470	**2.3%**
GC-3F/I COMMERCIAL & INDUSTRIAL SERVICE 20-200								
Customer Charge	1,008	368,928	$ 3.0000	$ 1,106,784	$ 3.0000	$ 1,106,784	$ -	**0.0%**
Distribution Charge - Firm Supply	806	36,724,394	$ 0.1176	$ 4,318,789	$ 0.1307	$ 4,799,878	$ 481,090	
Distribution Charge - Interruptible Supply	14	1,603,651	$ 0.1176	$ 188,589	$ 0.1307	$ 209,597	$ 21,008	
Distribution Charge - Transport	188	15,138,566	$ 0.1176	$ 1,780,295	$ 0.1307	$ 1,978,611	$ 198,315	
Transport Administration	188	68,808	$ 2.2700	$ 156,194	$ 2.2700	$ 156,194	$ -	
Transport Remote Metering	6	2,196	$ 1.2400	$ 2,723	$ 1.2400	$ 2,723	$ -	
Gas Supply Acquisition Charge-Firm		36,724,394	$ 0.0118	$ 433,348	$ 0.0141	$ 517,814	$ 84,466	
Gas Supply Acquisition Charge-Interruptible		1,603,651	$ 0.0114	$ 18,282	$ 0.0137	$ 21,970	$ 3,688	
TOTAL GC-3F/I DISTRIBUTION REVENUES				**$ 8,005,004**		**$ 8,793,571**	$ 788,567	**9.9%**
Commodity		38,328,045	$ 0.4190	$ 16,059,451	$ 0.4190	$ 16,059,451	$ -	
Maximum Daily Demand		25,279,185	$ 0.1581	$ 3,996,639	$ 0.1581	$ 3,996,639	$ -	
Annual Demand		38,328,045	$ 0.0706	$ 2,705,960	$ 0.0706	$ 2,705,960	$ -	
TOTAL GC-3F/I GAS SUPPLY REVENUES				**$ 22,762,050**		**$ 22,762,050**	$ -	
TOTAL GC-3F/I DISTRIBUTION + GAS SUPPLY REVENUES				**$ 30,767,054**		**$ 31,555,621**	$ 788,567	**2.6%**
GC-4F/I COMMERCIAL & INDUSTRIAL 200-1300								
Customer Charge	138	50,508	$ 21.3500	$ 1,078,346	$ 21.3500	$ 1,078,346	$ -	**0.0%**
Distribution Charge - Firm Supply	37	16,204,385	$ 0.0782	$ 1,267,183	$ 0.0856	$ 1,387,095	$ 119,912	
Distribution Charge - Interruptible Supply	5	2,165,581	$ 0.0782	$ 169,348	$ 0.0856	$ 185,374	$ 16,025	
Distribution Charge - Transport	96	47,841,216	$ 0.0782	$ 3,741,183	$ 0.0856	$ 4,095,208	$ 354,025	
Transport Administration		35,136	$ 2.2700	$ 79,759	$ 2.2700	$ 79,759	$ -	
Transport Remote Metering	26	9,516	$ 1.2400	$ 11,800	$ 1.2400	$ 11,800	$ -	
Gas Supply Acquisition Charge- Firm		16,204,385	$ 0.0118	$ 191,212	$ 0.0141	$ 228,482	$ 37,270	
Gas Supply Acquisition Charge-Interruptible		2,165,581	$ 0.0114	$ 24,688	$ 0.0137	$ 29,668	$ 4,981	
TOTAL 4F/I DISTRIBUTION REVENUES				**$ 6,563,518**		**$ 7,095,732**	$ 532,214	**8.1%**
Commodity		18,369,966	$ 0.4190	$ 7,697,016	$ 0.4190	$ 7,697,016	$ -	
Maximum Daily Demand		8,668,241	$ 0.1581	$ 1,370,449	$ 0.1581	$ 1,370,449	$ -	
Annual Demand		18,369,966	$ 0.0706	$ 1,296,920	$ 0.0706	$ 1,296,920	$ -	
TOTAL 4F/I GAS SUPPLY REVENUES				**$ 10,364,384**		**$ 10,364,384**	$ -	
TOTAL 4F/I DISTRIBUTION + GAS SUPPLY REVENUES				**$ 16,927,902**		**$ 17,460,116**	$ 532,214	**3.1%**

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
SUMMARY OF PRESENT AND PROPOSED MARGIN RATES BY RATE CLASS
Forecasted Sales

	2024							
Description	Monthly Customers	Billing Units	Present Rates	Present Revenues	Authorized Rates	Authorized Revenues	Change in Revenue	Percent Change
GC-5F/I COMMERCIAL & INDUSTRIAL 1300-7500								
Customer Charge	23	8,418	$ 36.2500	$ 305,153	$ 36.2500	$ 305,153	$ -	**0.0%**
Distribution Charge - Firm Supply	-	0	$ 0.0547	$ -	$ 0.0686	$ -		
Distribution Charge - Transport	23	56,199,676	$ 0.0547	$ 3,074,122	$ 0.0676	$ 3,799,098	$ 724,976	
Transport Administration	23	8,418	$ 2.2700	$ 19,109	$ 2.2700	$ 19,109	$ -	
Transport Remote Metering	5	1,830	$ 1.2400	$ 2,269	$ 1.2400	$ 2,269	$ -	
Gas Supply Acquisition Charge Firm		-	$ 0.0118	$ -	$ 0.0141	$ -	$ -	
Gas Supply Acquisition Charge Interruptible		-	$ 0.0114	$ -	$ 0.0137	$ -	$ -	
TOTAL GC-5 DISTRIBUTION REVENUES				**$ 3,400,653**		**$ 4,125,629**	$ 724,976	**21.3%**
Commodity		-	$ 0.4190	$ -	$ 0.4190	$ -	$ -	
Maximum Daily Demand		-	$ 0.1581	$ -	$ 0.1581	$ -	$ -	
Annual Demand		-	$ 0.0706	$ -	$ 0.0706	$ -	$ -	
TOTAL 4F/I GAS SUPPLY REVENUES				**$ -**		**$ -**		
TOTAL 5F/I DISTRIBUTION + GAS SUPPLY REVENUES				**$ 3,400,653**		**$ 4,125,629**	$ 724,976	**21.3%**
GC-6F/I LARGE COMMERCIAL & INDUSTRIAL >7500								
Customer Charge	1	366	$ 41.8820	$ 15,329	$ 41.8820	$ 15,329	$ -	**0.0%**
Distribution Charge - Transport	1	24,304,207	$ 0.0404	$ 981,890	$ 0.0503	$ 1,222,502	$ 240,612	**24.5%**
Transport Administration	1	366	$ 2.2700	$ 831	$ 2.2700	$ 831	$ -	
Transport Remote Metering	1	366	$ 1.2400	$ 454	$ 1.2400	$ 454	$ -	
Gas Supply Acquisition Charge Firm		0	$ 0.0118	$ -	$ 0.0141	$ -	$ -	
Gas Supply Acquisition Charge Interruptible		0	$ 0.0114	$ -	$ 0.0137	$ -	$ -	
TOTAL 6F/I DISTRIBUTION + GAS SUPPLY REVENUES				**$ 998,503**		**$ 1,239,115**	$ 240,612	**24.1%**
GN-9 SMALL GENERATION > 200,000								
Customer Charge	4	1,464	$ 36.1598	$ 52,938	$ 36.1598	$ 52,938	$ -	
Distribution Charge - Transport	4	2,455,777	$ 0.1990	$ 488,700	$ 0.2150	$ 527,992	$ 39,292	
Transport Administration		1,464	$ 2.2700	$ 3,323	$ 2.2700	$ 3,323	$ -	
Transport Remote Metering		0	$ 1.2400	$ -	$ 1.2400			
TOTAL GN-9 GENERATION DISTRIBUTION REVENUES				**$ 544,961**		**$ 584,253**	$ 39,292	**7.2%**
S-1 SEASONAL SERVICE								
Customer Charge	262	95,892	$ 1.8902	$ 181,255	$ 1.8902	$ 181,255	$ -	**0.0%**
On-Season Distribution Charge		246,867	$ 0.1661	$ 41,005	$ 0.1781	$ 43,967	$ 2,962	
Block 1 Off-Season Dist. Chg.		535,108	$ 0.1661	$ 88,881	$ 0.1781	$ 95,303	$ 6,421	
Block 2 Off-Season Dist. Chg.		729,693	$ 0.1138	$ 83,039	$ 0.1210	$ 88,293	$ 5,254	
Block 3 Off-Season Dist. Chg.		3,599,819	$ 0.0954	$ 343,423	$ 0.1014	$ 365,022	$ 21,599	
Gas Supply Acquisition Charge		5,111,487	$ 0.0123	$ 62,871	$ 0.0148	$ 75,650	$ 12,779	
TOTAL S-1 DISTRIBUTION REVENUES				**$ 800,474**		**$ 849,489**	$ 49,015	**6.1%**
Commodity		5,111,487	$ 0.4190	$ 2,141,713	$ 0.4190	$ 2,141,713	$ -	
Annual Demand		5,111,487	$ 0.0706	$ 360,871	$ 0.0706	$ 360,871	$ -	
TOTAL S-1 GAS SUPPLY REVENUES				**$ 2,502,584**		**$ 2,502,584**	$ -	
TOTAL S-1 DISTRIBUTION + GAS SUPPLY REVENUES				**$ 3,303,058**		**$ 3,352,073**	$ 49,015	**1.5%**
CONTRACT RATE REVENUES [1]				$ 1,304,592		$ 1,304,592		
				$ -		$ -		
RIVERSIDE AND WEST RIVERSIDE		532,309,036		$ 2,982,684		$ 2,982,684		
TOTAL DISTRIBUTION REVENUES				**$ 111,603,308**		**$ 124,358,550**	**$ 12,755,242**	**11.4%**
				$ 107,316,032		**$ 120,071,274**		
GAS SUPPLY REVENUES				**$ 152,443,727**		**$ 152,443,727**	**$ -**	**0.0%**
TOTAL DISTRIB. REV. + GAS SUPPLY REV.				**$ 264,047,035**		**$ 276,802,277**	**$ 12,755,242**	**4.8%**
TOTAL THROUGHPUT		**400,140,931**					12,755,242	
TOTAL GAS SALES (therms)		**253,948,902**						

[1] Includes revenue from REC as regulated by FERC

WISCONSIN POWER AND LIGHT COMPANY
6680-UR-124
GAS RATES

Summary of Present and Proposed Rates

	Present Rates	2024 Authorized Rates	Billing Unit
Residential Service GG-1			
Customer Charge	$0.4113	$0.4113	per day
Distribution Charge	$0.3012	$0.3618	per therm
Gas Supply Acquisition Charge	$0.0129	$0.0155	per therm
Small Commercial & Industrial (<5,000 therms) GC-1			
Customer Charge	$0.4741	$0.4741	per day
Distribution Charge	$0.2592	$0.3004	per therm
Gas Supply Acquisition Charge - System Supply Service	$0.0127	$0.0152	per therm
Commercial & Industrial (5,000-20,000 therms) GC-2			
Customer Charge	$1.8902	$1.8902	per day
Distribution Charge	$0.1363	$0.1523	per therm
Gas Supply Acquisition Charge - System Supply Service	$0.0127	$0.0152	per therm
Commercial & Industrial (20,000-200,000 therms) GC-3			
Customer Charge	$3.0000	$3.0000	per day
Distribution Charge			
Firm	$0.1176	$0.1307	per therm
Interruptible	$0.1176	$0.1307	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Commercial & Industrial (200,000-1,300,000 therms) GC-4			
Customer Charge	$21.3500	$21.3500	per day
Distribution Charge			
Firm	$0.0782	$0.0856	per therm
Interruptible	$0.0782	$0.0856	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Commercial & Industrial (1,300,000-7,500,000 therms) GC-5			
Customer Charge	$36.2500	$36.2500	per day
Distribution Charge			
Firm	$0.0547	$0.0686	per therm
Interruptible	$0.0547	$0.0676	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm

Large Commercial & Industrial (>7,500,000 therms) GC-6			
Customer Charge	$41.8820	$41.8820	per day
Distribution Charge			
Firm	$0.0404	$0.0503	per therm
Interruptible	$0.0404	$0.0503	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Small Electric Generation Transportation (>15 MW & >300 MCFH) GN-9			
Customer Charge	$36.1598	$36.1598	per day
Distribution Charge			
Firm	$0.1990	$0.2150	per therm
Interruptible	$0.1990	$0.2150	per therm
Seasonal Distribution Service (Agricultural) S-1			
Customer Charge	$1.8902	$1.8902	per day
Distribution Charge			
On Season - All therms	$0.1661	$0.1781	per therm
Off Season - First 1,000 therms	$0.1661	$0.1781	per therm
Off Season - Next 2,000 therms	$0.1661	$0.1210	per therm
Off Season - >3,000 therms	$0.1661	$0.1014	per therm
Gas Supply Acquisition Charge - System Supply Service			
Off Season	$0.0123	$0.0148	per therm
On Season	$0.0123	$0.0148	per therm
Act 141 Distribution Rate*			
Residential		$0.0064	per therm
Non-residential			
GC-1		$0.0017	per therm
GC-2		$0.0017	per therm
GC-3		$0.0017	per therm
GC-4		$0.0017	per therm
GC-5		$0.0017	per therm
GC-6		$0.0017	per therm
GN-9		$0.0017	per therm
S-1		$0.0017	per therm

*Act 141 Rates are embedded into the distribution charge

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GG-1 RESIDENTIAL SERVICE

Present Rates		Authorized Rates	
Daily Chrg.	$0.4113	Daily Chrg.	$0.4113
Volumetric		Volumetric	
Distribution	$0.3012	Distribution	$0.3618
GSAR	0.0129	GSAR	0.0155
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.8037 $ 0.8669

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$12.51	$12.51	$0.00	0.0%
*	**27**	$34.21	$35.92	$1.71	5.0%
	50	$52.70	$55.86	$3.16	6.0%
	75	$72.79	$77.53	$4.74	6.5%
	100	$92.88	$99.20	$6.32	6.8%
	125	$112.97	$120.87	$7.90	7.0%
	Total Non-Winter Consumption (7 months)				
	150	$208.13	$217.61	$9.48	4.6%
**	**190**	$240.28	$252.28	$12.01	5.0%
	250	$288.50	$304.30	$15.80	5.5%

* Average monthly non-winter bill
** Average non-winter cost total period, April-October

Winter

Gas Cost $0.9618 $1.0250

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$12.51	$12.51	$0.00	0.0%
	25	$36.56	$38.14	$1.58	4.3%
*	**114**	$122.16	$129.36	$7.20	5.9%
	200	$204.87	$217.51	$12.64	6.2%
	300	$301.05	$320.01	$18.96	6.3%
	400	$397.23	$422.51	$25.28	6.4%
	Total Winter Consumption (5 months)	$447.27	$481.51	$34.24	7.7%
	400	$447.27	$472.55	$25.28	5.7%
**	**571**	$611.74	$647.83	$36.09	5.9%
	600	$639.63	$677.55	$37.92	5.9%
	800	$831.99	$882.55	$50.56	6.1%
	900	$928.17	$985.05	$56.88	6.1%

* Average monthly winter bill
** Average winter cost total period, November-March

Average Annual Residential Bill

Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase	Avg Monthly Increase
761	$852.02	$900.11	$48.10	**5.6%**	$ 4.01

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER
$71.00

GC-1 SMALL COMMERCIAL & INDUSTRIAL SERVICE

Present Rates		Authorized Rates	
Daily Chrg.	$0.4741	Daily Chrg.	$0.4741
Volumetric		Volumetric	
Distribution	$0.2592	Distribution	$0.3004
GSAR	0.0127	GSAR	0.0152
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.7615 $ 0.8052

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$14.42	$14.42	$0.00	0.0%
	25	$33.46	$34.55	$1.09	3.3%
*	**48**	$51.25	$53.37	$2.11	4.1%
	100	$90.57	$94.94	$4.37	4.8%
	300	$242.87	$255.98	$13.11	5.4%
	500	$395.17	$417.02	$21.85	5.5%

* Average non-winter cost total period, April-October

Winter

Gas Cost $0.9196 $0.9633

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$14.42	$14.42	$0.00	0.0%
	100	$106.38	$110.75	$4.37	4.1%
**	**233**	$228.26	$238.42	$10.16	4.5%
	300	$290.30	$303.41	$13.11	4.5%
	400	$382.26	$399.74	$17.48	4.6%
	800	$750.10	$785.06	$34.96	4.7%

** Average winter cost total period, November-March

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-2 COMMERCIAL & INDUSTRIAL SERVICE 5-20

Present Rates		Authorized Rates	
Daily Chrg.	$1.8902	Daily Chrg.	$1.8902
Volumetric		Volumetric	
Distribution	$0.1363	Distribution	$0.1523
GSAR	0.0127	GSAR	0.0152
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.6386 $ 0.6571

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$57.49	$57.49	$0.00	0.0%
	250	$217.14	$221.77	$4.63	2.1%
*	**384**	$302.72	$309.82	$7.10	2.3%
	500	$376.79	$386.04	$9.25	2.5%
	1250	$855.74	$878.87	$23.13	2.7%
	1600	$1,079.25	$1,108.85	$29.60	2.7%

* Average non-winter cost total period, April-October

Winter

Gas Cost $0.7967 $0.8152

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$57.49	$57.49	$0.00	0.0%
	800	$694.85	$709.65	$14.80	2.1%
**	**1383**	$1,159.33	$1,184.92	$25.59	2.2%
	1400	$1,172.87	$1,198.77	$25.90	2.2%
	1500	$1,252.54	$1,280.29	$27.75	2.2%
	1600	$1,332.21	$1,361.81	$29.60	2.2%

** Average winter cost total period, November-March

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-3F/I COMMERCIAL & INDUSTRIAL SERVICE 20-200

Present Rates		Authorized Rates	
Daily Chrg.	$3.0000	Daily Chrg.	$3.0000
Volumetric		Volumetric	
Distribution	$0.1176	Distribution	$0.1307
GSAR Firm	0.0118	GSAR Firm	0.0141
GSAR Inter.	0.0114	GSAR Inter.	0.0137
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Interruptible (excludes Max DD)

Gas Cost $ 0.6186 $ 0.6340

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
1,675	$91.25	$91.25	$0	0.0%
4,200	$2,689.37	$2,754.05	$65	2.4%
9,546	$5,996.12	$6,143.12	$147	2.5%
12,500	$7,823.75	$8,016.25	$192	2.5%
16,250	$10,143.50	$10,393.75	$250	2.5%

Firm-Winter

Gas Cost $0.7771 $0.7925

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
1,675	$91.25	$91.25	$0.00	0.0%
4,200	$3,355.07	$3,419.75	$64.68	1.9%
9,546	$7,509.09	$7,656.09	$147.00	2.0%
12,500	$9,805.00	$9,997.50	$192.50	2.0%
16,250	$12,719.13	$12,969.38	$250.25	2.0%

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-4F/I COMMERCIAL & INDUSTRIAL 200-1300

Present Rates		Authorized Rates	
Daily Chrg.	$21.3500	Daily Chrg.	$21.3500
Volumetric		Volumetric	
Distribution	$0.0782	Distribution	$0.0856
GSAR Firm	0.0118	GSAR Firm	0.0141
GSAR Inter.	0.0114	GSAR Inter.	0.0137
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Interruptible (excludes Max DD)

	Present	Authorized
Gas Cost	$ 0.5792	$ 0.5889

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
20,800	$649	$649	$0	0.0%
36,093	$21,554	$21,905	$350	1.6%
42,000	$24,976	$25,383	$407	1.6%
84,000	$49,302	$50,117	$815	1.7%
105,000	$61,465	$62,484	$1,018	1.7%

Firm-Winter

	Present	Authorized
Gas Cost	$0.7377	$0.7474

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
20,800	$649.40	$649.40	$0.00	0.0%
36,093	$27,275.21	$27,625.32	$350.10	1.3%
42,000	$31,074.65	$32,040.20	$965.55	3.1%
84,000	$62,058.05	$63,431.00	$1,372.95	2.2%
105,000	$77,549.75	$79,126.40	$1,576.65	2.0%

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
SUMMARY OF PRESENT AND PROPOSED MARGIN RATES BY RATE CLASS
Forecasted Sales

	2023	2025							Incremental Change - 2024 to 2025	
Description	Present Rates	Monthly Customers	Authorized Rates	Billing Units	Present Revenues	Authorized Revenues	Change in Revenue	Percent Change	Change in Revenue	Percent Change
GG-1 RESIDENTIAL SERVICE										
Daily Customer Charge	$ 0.4113	183,337	$ 0.4113	66,918,005	27,523,375	$ 27,523,375				
Distribution Charge	$ 0.3012		$ 0.3587	138,807,854	41,808,926	$ 49,790,377				
Gas Supply Acquisition Charge	$ 0.0129		$ 0.0155	138,807,854	1,790,621	$ 2,151,522				
TOTAL GG-1 DISTRIBUTION REVENUES					**71,122,922**	**$ 79,465,274**	$ 8,342,352	**11.7%**	$ (130,455)	**-0.2%**
Commodity	$ 0.4190		$ 0.4190	138,807,854	58,160,491	$ 58,160,491				
Maximum Daily Demand	$ 0.1581		$ 0.1581	103,945,263	16,433,746	$ 16,433,746				
Annual Demand	$ 0.0706		$ 0.0706	138,807,854	9,799,834	$ 9,799,834				
TOTAL GG-1 GAS SUPPLY REVENUES					**84,394,071**	**$ 84,394,071**				
TOTAL GG-1 DISTRIBUTION + GAS SUPPLY REVENUES					**$ 155,516,994**	**$ 163,859,346**	$ 8,342,352	**5.4%**	$ 102,273	**0.1%**
GC-1 SMALL COMMERCIAL & INDUSTRIAL SERVICE										
Daily Customer Charge	$ 0.4741	16,936	$ 0.4741	6,181,640	2,930,716	$ 2,930,716				
Distribution Charge	$ 0.2592		$ 0.2977	25,289,324	6,554,993	$ 7,528,632				
Gas Supply Acquisition Charge	$ 0.0127		$ 0.0152	25,289,324	321,174	$ 384,398				
TOTAL GC-1 DISTRIBUTION REVENUES					9,806,883	**$ 10,843,745**	$ 1,036,862	**10.6%**	$ (42,094)	**-0.4%**
Commodity	$ 0.4190		$ 0.4190	25,289,324	10,596,227	$ 10,596,227				
Maximum Daily Demand	$ 0.1581		$ 0.1581	19,555,279	3,091,690	$ 3,091,690				
Annual Demand	$ 0.0706		$ 0.0706	25,289,324	1,785,426	$ 1,785,426				
TOTAL GC-1 GAS SUPPLY REVENUES					**$ 15,473,343**	**$ 15,473,343**				
TOTAL GC-1 DISTRIBUTION + GAS SUPPLY REVENUES					**$ 25,280,225**	**$ 26,317,088**	$ 1,036,862	**4.1%**	$ (20,592)	**-0.1%**
GC-2 COMMERCIAL & INDUSTRIAL SERVICE 5-20										
Daily Customer Charge	$ 1.8902	3,018	$ 1.8902	1,101,570	2,082,188	$ 2,082,188				
Distribution Charge - Sales	$ 0.1363	2,999	$ 0.1501	28,576,347	3,894,956	$ 4,289,310				
Distribution Charge - Transport	$ 0.1363	19	$ 0.1501	256,162	34,915	$ 38,450				
Transport Administration	$ 2.2700		$ 2.2700	6,935	15,742	$ 15,742				
Transport Remote Metering	$ 1.2400	1	$ 1.2400	365	453	$ 453				
Gas Supply Acquisition Charge	$ 0.0127		$ 0.0152	28,576,347	362,920	$ 434,360				
TOTAL GC-2F DISTRIBUTION REVENUES					**$ 6,391,173**	**$ 6,860,503**	$ 469,329	**7.3%**	$ (41,414)	**-0.6%**
Commodity	$ 0.4190		$ 0.4190	28,576,347	11,973,489	$ 11,973,489				
Maximum Daily Demand	$ 0.1581		$ 0.1581	20,523,992	3,244,843	$ 3,244,843				
Annual Demand	$ 0.0706		$ 0.0706	28,576,347	2,017,490	$ 2,017,490				
TOTAL GC-2F GAS SUPPLY REVENUES					**$ 17,235,823**	**$ 17,235,823**				
TOTAL GC-2F DISTRIBUTION + GAS SUPPLY REVENUES					**$ 23,626,996**	**$ 24,096,325**	$ 469,329	**2.0%**	$ (7,116)	**0.0%**
GC-3F/I COMMERCIAL & INDUSTRIAL SERVICE 20-200										
Customer Charge	$ 3.0000	1,016	$ 3.0000	370,840	1,112,520	$ 1,112,520				
Distribution Charge - Firm Supply	$ 0.1176	811	$ 0.1287	36,823,101	4,330,397	$ 4,739,133				
Distribution Charge - Interruptible Supply	$ 0.1176	14	$ 0.1287	1,609,530	189,281	$ 207,147				
Distribution Charge - Transport	$ 0.1176	191	$ 0.1287	15,352,440	1,805,447	$ 1,975,859				
Transport Administration	$ 2.2700	191	$ 2.2700	69,715	158,253	$ 158,253				
Transport Remote Metering	$ 1.2400	6	$ 1.2400	2,190	2,716	$ 2,716				
Gas Supply Acquisition Charge-Firm	$ 0.0118		$ 0.0141	36,823,101	434,513	$ 519,206				
Gas Supply Acquisition Charge-Interruptible	$ 0.0114		$ 0.0137	1,609,530	18,349	$ 22,051				
TOTAL GC-3F/I DISTRIBUTION REVENUES					**$ 8,051,474**	**$ 8,736,884**	$ 685,409	**8.5%**	$ (56,688)	**-0.6%**
Commodity	$ 0.4190		$ 0.4190	38,432,631	16,103,272	$ 16,103,272				
Maximum Daily Demand	$ 0.1581		$ 0.1581	25,297,400	3,999,519	$ 3,999,519				
Annual Demand	$ 0.0706		$ 0.0706	38,432,631	2,713,344	$ 2,713,344				
TOTAL GC-3F/I GAS SUPPLY REVENUES					**$ 22,816,135**	**$ 22,816,135**				
TOTAL GC-3F/I DISTRIBUTION + GAS SUPPLY REVENUES					**$ 30,867,609**	**$ 31,553,019**	$ 685,409	**2.2%**	$ (2,603)	**0.0%**
GC-4F/I COMMERCIAL & INDUSTRIAL 200-1300										
Customer Charge	$ 21.3500	140	$ 21.3500	51,100	1,090,985	$ 1,090,985				
Distribution Charge - Firm Supply	$ 0.0782	37	$ 0.0837	16,268,769	1,272,218	$ 1,361,696				
Distribution Charge - Interruptible Supply	$ 0.0782	5	$ 0.0837	2,176,450	170,198	$ 182,169				
Distribution Charge - Transport	$ 0.0782	98	$ 0.0837	48,510,060	3,793,487	$ 4,060,292				
Transport Administration	$ 2.2700		$ 2.2700	35,770	81,198	$ 81,198				
Transport Remote Metering	$ 1.2400	26	$ 1.2400	9,490	11,768	$ 11,768				
Gas Supply Acquisition Charge- Firm	$ 0.0118		$ 0.0141	16,268,769	191,971	$ 229,390				
Gas Supply Acquisition Charge-Interruptible	$ 0.0114		$ 0.0137	2,176,450	24,812	$ 29,817				
TOTAL 4F/I DISTRIBUTION REVENUES					**$ 6,636,636**	**$ 7,047,314**	$ 410,678	**6.2%**	$ (48,417)	**-0.7%**
Commodity	$ 0.4190		$ 0.4190	18,445,219	7,728,547	$ 7,728,547				
Maximum Daily Demand	$ 0.1581		$ 0.1581	8,679,691	1,372,259	$ 1,372,259				
Annual Demand	$ 0.0706		$ 0.0706	18,445,219	1,302,232	$ 1,302,232				
TOTAL 4F/I GAS SUPPLY REVENUES					**$ 10,403,038**	**$ 10,403,038**				
TOTAL 4F/I DISTRIBUTION + GAS SUPPLY REVENUES					**$ 17,039,675**	**$ 17,450,353**	$ 410,678	**2.4%**	$ (9,763)	**-0.1%**

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
SUMMARY OF PRESENT AND PROPOSED MARGIN RATES BY RATE CLASS
Forecasted Sales

	2023	2025								Incremental Change - 2024 to 2025	
Description	Present Rates	Monthly Customers	Authorized Rates	Billing Units	Present Revenues	Authorized Revenues	Change in Revenue	Percent Change		Change in Revenue	Percent Change
GC-5F/I COMMERCIAL & INDUSTRIAL 1300-7500											
Customer Charge	$ 36.2500	23	$ 36.2500	8,395	304,319	$ 304,319					
Distribution Charge - Firm Supply	$ 0.0547	-	$ 0.0666	-	0	$ -					
Distribution Charge - Transport	$ 0.0547	23	$ 0.0656	56,984,526	3,117,054	$ 3,738,185					
Transport Administration	$ 2.2700		$ 2.2700	8,395	19,057	$ 19,057					
Transport Remote Metering	$ 1.2400	5	$ 1.2400	1,825	2,263	$ 2,263					
Gas Supply Acquisition Charge Firm	$ 0.0118		$ 0.0141	-	0	$ -					
Gas Supply Acquisition Charge Interruptible	$ 0.0114		$ 0.0137	-	0	$ -					
TOTAL GC-5 DISTRIBUTION REVENUES					**$ 3,442,692**	**$ 4,063,823**	$ 621,131	**18.0%**		$ (61,805)	**-1.5%**
Commodity	$ 0.4190		$ 0.4190	-		$ -					
Maximum Daily Demand	$ 0.1581		$ 0.1581	-		$ -					
Annual Demand	$ 0.0706		$ 0.0706	-		$ -					
TOTAL 4F/I GAS SUPPLY REVENUES						**$ -**					
TOTAL 5F/I DISTRIBUTION + GAS SUPPLY REVENUES					**$ 3,442,692**	**$ 4,063,823**	$ 621,131	**18.0%**		$ (61,805)	**-1.5%**
GC-6F/I LARGE COMMERCIAL & INDUSTRIAL >7500											
Customer Charge	$ 41.8820	1	$ 41.8820	365	15,287	$ 15,287					
Distribution Charge - Transport	$ 0.0404	1	$ 0.0483	24,643,501	995,597	$ 1,190,281					
Transport Administration	$ 2.2700		$ 2.2700	365	829	$ 829					
Transport Remote Metering	$ 1.2400	1	$ 1.2400	365	453	$ 453					
Gas Supply Acquisition Charge Firm	$ 0.0118		$ 0.0141	-	0	$ -					
Gas Supply Acquisition Charge Interruptible	$ 0.0114		$ 0.0137	-	0	$ -					
TOTAL 6F/I DISTRIBUTION + GAS SUPPLY REVENUES					**$ 1,012,166**	**$ 1,206,849**	$ 194,684	**19.2%**		$ (32,266)	**-2.6%**
GN-9 SMALL GENERATION > 200,000											
Customer Charge	$ 36.1598	4	$ 36.1598	1,460	52,793	$ 52,793					
Distribution Charge - Transport	$ 0.1990	4	$ 0.2125	885,929	176,300	$ 188,260					
Transport Administration	$ 2.2700		$ 2.2700	1,460	3,314	$ 3,314					
Transport Remote Metering	$ 1.2400		$ 1.2400								
TOTAL GN-9 GENERATION DISTRIBUTION REVENUES					**$ 232,407**	**$ 244,367**	$ 11,960	**5.1%**		$ (339,886)	**-58.2%**
S-1 SEASONAL SERVICE											
Customer Charge	$ 1.8902	268	$ 1.8902	97,820	184,899	$ 184,899					
On-Season Distribution Charge	$ 0.1661		$ 0.1767	251,667	41,802	$ 44,470					
Block 1 Off-Season Dist. Chg.	$ 0.1661		$ 0.1767	548,050	91,031	$ 96,840					
Block 2 Off-Season Dist. Chg.	$ 0.1138		$ 0.1196	747,340	85,047	$ 89,382					
Block 3 Off-Season Dist. Chg.	$ 0.0954		$ 0.1000	3,686,879	351,728	$ 368,688					
Gas Supply Acquisition Charge	$ 0.0123		$ 0.0148	5,233,936	64,377	$ 77,462					
TOTAL S-1 DISTRIBUTION REVENUES					**$ 818,885**	**$ 861,741**	$ 42,856	**5.2%**		$ 12,252	**1.4%**
Commodity	$ 0.4190		$ 0.4190	5,233,936	2,193,019	$ 2,193,019					
Annual Demand	$ 0.0706		$ 0.0706	5,233,936	369,516	$ 369,516					
TOTAL S-1 GAS SUPPLY REVENUES					**$ 2,562,535**	**$ 2,562,535**					
TOTAL S-1 DISTRIBUTION + GAS SUPPLY REVENUES					**$ 3,381,420**	**$ 3,424,276**	$ 42,856	**1.3%**		$ 72,203	**2.2%**
CONTRACT RATE REVENUES [1]					**$ 1,321,954**	$ 1,304,592					
RIVERSIDE AND WEST RIVERSIDE				471,035,310	2,651,510	$ 2,982,684					
TOTAL DISTRIBUTION REVENUES					**$ 111,488,703**	**$ 123,617,778**	**$ 12,129,074**	**10.9%**		**$ (740,773)**	**-0.6%**
GAS SUPPLY REVENUES					**$ 152,884,945**	**$ 152,884,945**	**$ -**	**0.3%**		**$ 441,218**	**0.3%**
TOTAL DISTRIB. REV. + GAS SUPPLY REV.					**$ 264,373,648**	**$ 276,502,723**	**$ 12,129,074**	**4.6%**		**$ (299,555)**	**-0.1%**
TOTAL THROUGHPUT				**401,417,929**							
TOTAL GAS SALES (therms)				**254,785,311**							

[1] Includes revenue from REC as regulated by FERC

WISCONSIN POWER AND LIGHT COMPANY
6680-UR-124
GAS RATES

Summary of Present and Proposed Rates

	Present Rates	2025 Authorized Rates	Billing Unit
Residential Service GG-1			
Customer Charge	$0.4113	$0.4113	per day
Distribution Charge	$0.3012	$0.3587	per therm
Gas Supply Acquisition Charge	$0.0129	$0.0155	per therm
Small Commercial & Industrial (<5,000 therms) GC-1			
Customer Charge	$0.4741	$0.4741	per day
Distribution Charge	$0.2592	$0.2977	per therm
Gas Supply Acquisition Charge - System Supply Service	$0.0127	$0.0152	per therm
Commercial & Industrial (5,000-20,000 therms) GC-2			
Customer Charge	$1.8902	$1.8902	per day
Distribution Charge	$0.1363	$0.1501	per therm
Gas Supply Acquisition Charge - System Supply Service	$0.0127	$0.0152	per therm
Commercial & Industrial (20,000-200,000 therms) GC-3			
Customer Charge	$3.0000	$3.0000	per day
Distribution Charge			
Firm	$0.1176	$0.1287	per therm
Interruptible	$0.1176	$0.1287	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Commercial & Industrial (200,000-1,300,000 therms) GC-4			
Customer Charge	$21.3500	$21.3500	per day
Distribution Charge			
Firm	$0.0782	$0.0837	per therm
Interruptible	$0.0782	$0.0837	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Commercial & Industrial (1,300,000-7,500,000 therms) GC-5			
Customer Charge	$36.2500	$36.2500	per day
Distribution Charge			
Firm	$0.0547	$0.0666	per therm
Interruptible	$0.0547	$0.0656	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm

Large Commercial & Industrial (>7,500,000 therms) GC-6			
Customer Charge	$41.8820	$41.8820	per day
Distribution Charge			
Firm	$0.0404	$0.0483	per therm
Interruptible	$0.0404	$0.0483	per therm
Gas Supply Acquisition Charge - System Supply Service			
Firm	$0.0118	$0.0141	per therm
Interruptible	$0.0114	$0.0137	per therm
Small Electric Generation Transportation (>15 MW & >300 MCFH) GN-9			
Customer Charge	$36.1598	$36.1598	per day
Distribution Charge			
Firm	$0.1990	$0.2125	per therm
Interruptible	$0.1990	$0.2125	per therm
Seasonal Distribution Service (Agricultural) S-1			
Customer Charge	$1.8902	$1.8902	per day
Distribution Charge			
On Season - All therms	$0.1661	$0.1767	per therm
Off Season - First 1,000 therms	$0.1661	$0.1767	per therm
Off Season - Next 2,000 therms	$0.1661	$0.1196	per therm
Off Season - >3,000 therms	$0.1661	$0.1000	per therm
Gas Supply Acquisition Charge - System Supply Service			
Off Season	$0.0123	$0.0148	per therm
On Season	$0.0123	$0.0148	per therm
Act 141 Distribution Rate*			
Residential		$0.0064	per therm
Non-residential			
GC-1		$0.0018	per therm
GC-2		$0.0018	per therm
GC-3		$0.0018	per therm
GC-4		$0.0018	per therm
GC-5		$0.0018	per therm
GC-6		$0.0018	per therm
GN-9		$0.0018	per therm
S-1		$0.0018	per therm

*Act 141 Rates are embedded into the distribution charge

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GG-1 RESIDENTIAL SERVICE

Present Rates		Authorized Rates	
Daily Chrg.	$0.4113	Daily Chrg.	$0.4113
Volumetric		Volumetric	
Distribution	$0.3012	Distribution	$0.3587
GSAR	0.0129	GSAR	0.0155
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.8037 $ 0.8638

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$12.51	$12.51	$0.00	0.0%
*	**27**	$34.21	$35.83	$1.62	4.7%
	50	$52.70	$55.70	$3.01	5.7%
	75	$72.79	$77.30	$4.51	6.2%
	100	$92.88	$98.89	$6.01	6.5%
	125	$112.97	$120.49	$7.51	6.6%
	Total Non-Winter Consumption (7 months)				
	150	$208.13	$217.14	$9.01	4.3%
**	**190**	$240.28	$251.69	$11.42	4.8%
	250	$288.50	$303.52	$15.03	5.2%

* Average monthly non-winter bill
** Average non-winter cost total period, April-October

Winter

Gas Cost $0.9618 $1.0219

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$12.51	$12.51	$0.00	0.0%
	25	$36.56	$38.06	$1.50	4.1%
*	**114**	$122.16	$129.01	$6.85	5.6%
	200	$204.87	$216.89	$12.02	5.9%
	300	$301.05	$319.08	$18.03	6.0%
	400	$397.23	$421.27	$24.04	6.1%
	Total Winter	$447.27	$481.51	$34.24	7.7%
	Consumption (5 months)				
	400	$447.27	$471.31	$24.04	5.4%
**	**571**	$611.74	$646.06	$34.32	5.6%
	600	$639.63	$675.69	$36.06	5.6%
	800	$831.99	$880.07	$48.08	5.8%
	900	$928.17	$982.26	$54.09	5.8%

* Average monthly winter bill
** Average winter cost total period, November-March

Average Annual Residential Bill

Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase	Avg Monthly Increase
761	$852.02	$897.75	$45.74	**5.4%**	$ 3.81

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-1 SMALL COMMERCIAL & INDUSTRIAL SERVICE

Present Rates		Authorized Rates	
Daily Chrg.	$0.4741	Daily Chrg.	$0.4741
Volumetric		Volumetric	
Distribution	$0.2592	Distribution	$0.2977
GSAR	0.0127	GSAR	0.0152
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.7615 $ 0.8025

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$14.42	$14.42	$0.00	0.0%
	25	$33.46	$34.48	$1.03	3.1%
*	**48**	$51.25	$53.24	$1.98	3.9%
	100	$90.57	$94.67	$4.10	4.5%
	300	$242.87	$255.17	$12.30	5.1%
	500	$395.17	$415.67	$20.50	5.2%

* Average non-winter cost total period, April-October

Winter

Gas Cost $0.9196 $0.9606

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$14.42	$14.42	$0.00	0.0%
	100	$106.38	$110.48	$4.10	3.9%
**	**233**	$228.26	$237.79	$9.53	4.2%
	300	$290.30	$302.60	$12.30	4.2%
	400	$382.26	$398.66	$16.40	4.3%
	800	$750.10	$782.90	$32.80	4.4%

** Average winter cost total period, November-March

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-2 COMMERCIAL & INDUSTRIAL SERVICE 5-20

Present Rates		Authorized Rates	
Daily Chrg.	$1.8902	Daily Chrg.	$1.8902
Volumetric		Volumetric	
Distribution	$0.1363	Distribution	$0.1501
GSAR	0.0127	GSAR	0.0152
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Non-Winter (excludes Max DD)

Gas Cost $ 0.6386 $ 0.6549

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$57.49	$57.49	$0.00	0.0%
	250	$217.14	$221.22	$4.08	1.9%
*	**384**	$302.72	$308.98	$6.26	2.1%
	500	$376.79	$384.94	$8.15	2.2%
	1250	$855.74	$876.12	$20.38	2.4%
	1600	$1,079.25	$1,105.33	$26.08	2.4%

* Average non-winter cost total period, April-October

Winter

Gas Cost $0.7967 $0.8130

	Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
	0	$57.49	$57.49	$0.00	0.0%
	800	$694.85	$707.89	$13.04	1.9%
**	**1383**	$1,159.33	$1,181.87	$22.54	1.9%
	1400	$1,172.87	$1,195.69	$22.82	1.9%
	1500	$1,252.54	$1,276.99	$24.45	2.0%
	1600	$1,332.21	$1,358.29	$26.08	2.0%

** Average winter cost total period, November-March

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-3F/I COMMERCIAL & INDUSTRIAL SERVICE 20-200

Present Rates		Authorized Rates	
Daily Chrg.	$3.0000	Daily Chrg.	$3.0000
Volumetric		Volumetric	
Distribution	$0.1176	Distribution	$0.1287
GSAR Firm	0.0118	GSAR Firm	0.0141
GSAR Inter.	0.0114	GSAR Inter.	0.0137
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Interruptible (excludes Max DD)

Gas Cost $ 0.6186 $ 0.6320

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
1,675	$91.25	$91.25	$0	0.0%
4,200	$2,689.37	$2,745.65	$56	2.1%
9,546	$5,996.12	$6,124.03	$128	2.1%
12,500	$7,823.75	$7,991.25	$167	2.1%
16,250	$10,143.50	$10,361.25	$218	2.1%

Firm-Winter

Gas Cost $0.7771 $0.7905

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
1,675	$91.25	$91.25	$0.00	0.0%
4,200	$3,355.07	$3,411.35	$56.28	1.7%
9,546	$7,509.09	$7,637.00	$127.91	1.7%
12,500	$9,805.00	$9,972.50	$167.50	1.7%
16,250	$12,719.13	$12,936.88	$217.75	1.7%

WISCONSIN POWER AND LIGHT COMPANY
NATURAL GAS SERVICE
BILL COMPARISONS/WINTER & NON-WINTER

GC-4F/I COMMERCIAL & INDUSTRIAL 200-1300

Present Rates		Authorized Rates	
Daily Chrg.	$21.3500	Daily Chrg.	$21.3500
Volumetric		Volumetric	
Distribution	$0.0782	Distribution	$0.0856
GSAR Firm	0.0118	GSAR Firm	0.0141
GSAR Inter.	0.0114	GSAR Inter.	0.0137
Max DD	0.1581	Max DD	0.1581
AD	0.0706	AD	0.0706
Gas Cost	0.4190	Gas Cost	0.4190

Interruptible (excludes Max DD)

Gas Cost $ 0.5792 $ 0.5889

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
20,800	$649	$649	$0	0.0%
36,093	$21,554	$21,905	$350	1.6%
42,000	$24,976	$25,383	$407	1.6%
84,000	$49,302	$50,117	$815	1.7%
105,000	$61,465	$62,484	$1,018	1.7%

Firm-Winter

Gas Cost $0.7377 $0.7474

Monthly Consumption	Revenues at Present Rates	Revenues at Authorized Rates	Change	Percentage Increase
20,800	$649.40	$649.40	$0.00	0.0%
36,093	$27,275.21	$27,625.32	$350.10	1.3%
42,000	$31,074.65	$32,040.20	$965.55	3.1%
84,000	$62,058.05	$63,431.00	$1,372.95	2.2%
105,000	$77,549.75	$79,126.40	$1,576.65	2.0%

Wisconsin Power and Light Company
Docket 6680-UR-124
2024 Fuel Cost Plan Year
Monitoring Ranges for Monitored Fuel Costs for Calendar Year 2024

Month	Fuel Costs	MWh	Fuel Costs / MWh	Cumulative Fuel Costs / MWh
January	$ 22,553,717	1,183,128	$ 19.06	$ 19.06
February	$ 21,482,138	1,107,641	19.39	19.22
March	$ 19,882,027	1,105,081	17.99	18.82
April	$ 21,831,628	1,003,972	21.75	19.49
May	$ 17,148,987	1,034,669	16.57	18.93
June	$ 13,862,537	1,128,447	12.28	17.79
July	$ 14,576,790	1,320,219	11.04	16.66
August	$ 17,420,637	1,297,028	13.43	16.20
September	$ 19,878,917	1,142,134	17.41	16.34
October	$ 23,617,124	1,123,660	21.02	16.80
November	$ 24,218,625	1,092,826	22.16	17.26
December	$ 26,564,725	1,163,075	22.84	17.74
Totals	$243,037,852	13,701,880	$ 17.74	

Wisconsin Power and Light Company
Docket No. 6680-UR-124
IDR-36 Regulatory Assets, Liabilities and Escrows

Line No.	Allocation	Deferrals	YE 2023	Amortization	New Deferral/Escrow	YE 2024	Amortization
1	**Electric**	Earnings Sharing	(0)			(0)	
2		Bad Debt Reserve	6,480,308	3,240,154		3,240,154	3,240,154
3		COVID - 19	784,068	392,034		392,034	392,034
4		Credit Card Fees - Escrow	967,992	483,996		483,996	483,996
5		CWIP Return - UR-122 Settlement					
6		Edgewater Retirement	31,178,597	8,500,000		22,678,597	22,678,597
7		Late Payment Revenues - Escrow	(222,630)	(111,315)		(111,315)	(111,315)
8		OPEB & Pension Escrow	16,034,483	8,017,242		8,017,242	8,017,242
9		Nelson Dewey Salvage	2,918,350	1,459,175		1,459,175	1,459,175
10		Schd 2 Reactive Power	4,300,000	2,150,000		2,150,000	2,150,000
11		Solar CA1_CA2	(27,428,265)	(27,428,265)		(0)	
12		Solar Precertification	(402,618)	(201,309)		(201,309)	(201,309)
13		Tax Reform Refunds	(236)	(118)		(118)	(118)
14		Transmission Escrow Balance Amortization	2,207,465	1,103,733		1,103,733	1,103,733
15		West Riverside Buy-In	(2,417,621)	(1,208,811)		(1,208,811)	(1,208,811)
16		West Riverside Liquidated Damages	(416,823)	(208,412)		(208,412)	(208,412)
17		**Subtotal Regulatory Amortizations (Excl. Conservation & Farm Wiring)**	33,983,070	(3,811,896)		37,794,966	37,794,966
18							
19		Conservation Escrow	1,651,164	16,700,999	15,597,646	547,811	16,608,749
20		Farm Wiring Escrow	603,831	2,419,844	2,076,940	260,927	2,419,844
21		**Subtotal Electric Conservation and Farm Wiring**	2,254,995	19,120,843	17,674,586	808,738	19,028,593
22							
23		**Total Electric Amortizations**	**36,238,064**	**15,308,947**	**17,674,586**	**38,603,703**	**56,823,559**
24							
25	**Gas**	Earnings Sharing					
26		Bad Debt Reserve	(935,672)	(467,836)		(467,836)	(467,836)
27		COVID - 19	83,963	41,981		41,982	41,981
28		Credit Card Fees - Escrow	210,307	105,153		105,154	105,154
29		Late Payment Revenues - Escrow	75,523	37,762		37,761	37,762
30		OPEB & Pension Escrow	2,680,813	1,340,407		1,340,407	1,340,407
31		Tax Reform Refunds	549,068	274,534		274,534	274,534
32		Western Wisconsin Gas Expansion Deferral	4,568,671	4,084,336		484,335	484,336
33		Subtotal Regulatory Amortizations (Excl. Conservation, MGP and WWGE CIAC)	7,232,673	5,416,336		1,816,337	1,816,337
34							
35		Conservation Escrow	(859,346)	3,385,645	3,615,617	(629,374)	3,355,395
36		Manufactured Gas Plant Cleanup	4,078,844	214,330		3,864,514	214,330
37							
38		**Total Gas Amortizations**	**10,452,171**	**9,016,311**	**3,615,617**	**5,051,477**	**5,386,062**

Wisconsin Power and Light Company
Docket No. 6680-UR-124
IDR-36 Regulatory Assets, Liabilities and Escrows

Line No.	Allocation	Deferrals	New Deferral/Escrow	YE 2025
1	**Electric**	Earnings Sharing		(0)
2		Bad Debt Reserve		0
3		COVID - 19		
4		Credit Card Fees - Escrow		0
5		CWIP Return - UR-122 Settlement		
6		Edgewater Retirement		0
7		Late Payment Revenues - Escrow		
8		OPEB & Pension Escrow		0
9		Nelson Dewey Salvage		(0)
10		Schd 2 Reactive Power		(0)
11		Solar CA1_CA2		(0)
12		Solar Precertification		
13		Tax Reform Refunds		(0)
14		Transmission Escrow Balance Amortization		(0)
15		West Riverside Buy-In		0
16		West Riverside Liquidated Damages		(0)
17		**Subtotal Regulatory Amortizations (Excl. Conservation & Farm Wiring)**		(1)
18				
19		Conservation Escrow	16,060,938	(0)
20		Farm Wiring Escrow	2,158,917	
21		**Subtotal Electric Conservation and Farm Wiring**	18,219,855	(0)
22				
23		**Total Electric Amortizations**	**18,219,855**	**(1)**
24				
25	**Gas**	Earnings Sharing		
26		Bad Debt Reserve		(0)
27		COVID - 19		0
28		Credit Card Fees - Escrow		0
29		Late Payment Revenues - Escrow		(0)
30		OPEB & Pension Escrow		(0)
31		Tax Reform Refunds		0
32		Western Wisconsin Gas Expansion Deferral		(0)
33		Subtotal Regulatory Amortizations (Excl. Conservation, MGP and WWGE CIAC)		(0)
34				
35		Conservation Escrow	3,984,769	(0)
36		Manufactured Gas Plant Cleanup		3,650,184
37				
38		**Total Gas Amortizations**	**3,984,769**	**3,650,184**

Wisconsin Power and Light Company
Docket No. 6680-UR-124
IDR-36 Regulatory Assets, Liabilities and Escrows

Line No.	Allocation	Deferrals
1	**Electric**	Earnings Sharing
2		Bad Debt Reserve
3		COVID - 19
4		Credit Card Fees - Escrow
5		CWIP Return - UR-122 Settlement
6		Edgewater Retirement
7		Late Payment Revenues - Escrow
8		OPEB & Pension Escrow
9		Nelson Dewey Salvage
10		Schd 2 Reactive Power
11		Solar CA1_CA2
12		Solar Precertification
13		Tax Reform Refunds
14		Transmission Escrow Balance Amortization
15		West Riverside Buy-In
16		West Riverside Liquidated Damages
17		**Subtotal Regulatory Amortizations (Excl. Conservation & Farm Wiring)**
18		
19		Conservation Escrow
20		Farm Wiring Escrow
21		**Subtotal Electric Conservation and Farm Wiring**
22		
23		**Total Electric Amortizations**
24		
25	**Gas**	Earnings Sharing
26		Bad Debt Reserve
27		COVID - 19
28		Credit Card Fees - Escrow
29		Late Payment Revenues - Escrow
30		OPEB & Pension Escrow
31		Tax Reform Refunds
32		Western Wisconsin Gas Expansion Deferral
33		Subtotal Regulatory Amortizations (Excl. Conservation, MGP and WWGE CIAC)
34		
35		Conservation Escrow
36		Manufactured Gas Plant Cleanup
37		
38		**Total Gas Amortizations**