PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates — 3270-UR-123

FINAL DECISION

This is the Final Decision on the application of Madison Gas and Electric Company (MGE) for approval of a Settlement Agreement to adjust Wisconsin retail electric and natural gas base rates for test year 2021, and for approval of MGE's 2021 Fuel Cost Plan.

For electric operations test year ending December 31, 2021, MGE shall maintain the same base electric rates as established for 2020 in docket 3270-UR-122. Final overall rate changes for the test year ending December 31, 2021 are authorized consisting of a $6.67 million rate increase for natural gas operations, a 4.1 percent increase, based on a 9.80 percent return on equity (ROE).

Introduction

On June 8, 2020, MGE filed a Notice of Intent to Settle and notified the Commission of its intent to negotiate and enter into a settlement agreement with parties for a 2021 test-year rate case, pursuant to Wis. Stat. § 196.026. (PSC REF#: 391282.) MGE indicated that it had commenced discussions regarding the terms of an anticipated settlement with certain parties expected to intervene in the docket. (*Id.*)

On July 9, 2020, the Commission issued a Notice of Investigation to consider the application of MGE for authority to adjust electric and natural gas rates in the docket. (PSC REF#: 393320). The Commission's Notice indicated that it would review the proposed settlement agreement and supporting documents when filed; solicit comments on the proposals in a format to be determined; and, if needed, schedule a hearing with regard to settlement issues at a later date. The Notice also stated that a hearing on MGE's fuel cost plan, under Wis. Admin. Code § PSC 116.03(3), 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 of the Notice. The following organizations requested and were granted intervention, and therefore are parties in this docket: Citizens Utility Board of Wisconsin (CUB); RENEW Wisconsin (RENEW); Clean Wisconsin; Sierra Club; Board of Regents of the University of Wisconsin System (UW); Airgas Merchant Gases (Airgas); and Wisconsin Industrial Energy Group (WIEG) (collectively, with MGE, the Parties). (PSC REF#: 394669.)

On August 21, 2020, in order to keep the fuel case on track for completion by year end, a Prehearing Conference Memorandum was issued, identifying the issues and schedule, related to the fuel cost plan. (PSC REF#: 395754.)

On August 28, 2020, pursuant to Wis. Stat. § 196.026(4), MGE filed an application for Commission approval of a settlement agreement with four of the six intervenors (CUB, RENEW, UW, and WIEG – collectively Settling Parties) for test-year 2021 (Settlement Agreement). (PSC REF#: 396059.)

On September 24, 2020, a Prehearing Conference Memorandum – Second was issued, to address the issues and schedule relating to the natural gas increase proposed in the settlement. (PSC REF#: 397221.) On September 8, 2020, the Commission notified the Parties that pursuant to Wis. Stat. § 196.026(6), each Party's agreement, objection, or non-objection to the Settlement Agreement was required to be filed with the Commission no later than September 30, 2020. (PSC REF#: 396366.) The Commission's September 8, 2020 notification indicated that the

Commission, for good cause, may set a different date and time for the filing of responses, and invited parties to file any such requests with the Commission by September 9, 2020. (*Id.*) No requests to set a different date or time were received.

As required by Wis. Stat. § 196.026(6), each Party was directed to file and serve the Party's agreement, objection, or non-objection to the Settlement Agreement. MGE and each of the Settling Parties filed responses to the Settlement Agreement reiterating support for the settlement. (PSC REF#: 397477, PSC REF#: 397528, PSC REF#: 397529, PSC REF#: 397531, PSC REF#: 397541.) Clean Wisconsin was not a signatory to the Settlement Agreement, and responded that it did not oppose the Settlement Agreement and took no position on whether it should be approved by the Commission. (PSC REF#: 397501.) Sierra Club filed a response opposing the Settlement Agreement. (PSC REF#: 397533.)

A hearing on both the fuel cost plan issues and the natural gas issues was held on October 8, 2020. (PSC REF#: 397221.)

On November 4, 2020, Commission staff issued a memorandum analyzing the Settlement Agreement and solicited comments from the Parties and the public. (PSC REF#: 399478.)[1] On November 13, 2020, comments on the Commission staff memorandum were submitted jointly by MGE, CUB, WIEG, RENEW, and UW. (PSC REF#: 400001.) The Commission considered the proposed Settlement Agreement and MGE's proposed 2021 Fuel Cost Plan in this matter at its open meeting of November 24, 2020. (PSC REF#: 401076.)

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

[1] This memorandum corrected an internal referencing error in a memorandum that had been issued the day before, on November 3, 2020.

Findings of Fact

1. MGE is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a). MGE provides electric service in the city of Madison and surrounding areas in Dane County, Wisconsin. MGE provides natural gas service in portions of seven counties in central and southern Wisconsin.

2. The procedural and substantive requirements of Wis. Stat. § 196.026(4)-(7) have been satisfied.

3. It is reasonable for MGE to maintain existing base retail electric rates in the 2021 test year in accordance with the terms and conditions of the Settlement Agreement.

4. Presently authorized rates for MGE's Wisconsin retail electric utility operations will produce total operating revenues of $413,017,000 for the test year ending December 31, 2021. This results in an adjusted net operating income of $70,882,000, which is sufficient.

5. For MGE's retail electric operations, the estimated rate of return on average net investment rate base of $1,019,177,000 at current rates for the test year ending December 31, 2021, subject to the Commission's jurisdiction for the test year is 6.95 percent, which is sufficient.

6. MGE's filed electric operating income statement and net investment rate base for the 2021 test year, as adjusted for Commission decisions, are reasonable.

7. Presently authorized rates for MGE's Wisconsin retail natural gas operations will produce total operating revenues of $167,023,000 for the test year ending December 31, 2021. This results in an adjusted net operating income of $15,126,000, which is insufficient.

8. For MGE's retail natural gas operations, the estimated rate of return on average net investment rate base of $282,360,000 at current rates for the test year ending December 31, 2021, subject to the Commission's jurisdiction for the test year is 5.36 percent, which is insufficient.

9. A reasonable increase in operating revenue for the test year to produce a return of 7.07 percent return on MGE's average net investment rate base for MGE's retail natural gas operations for the test year ending December 31, 2021, is $6,636,000.

10. MGE's filed natural gas operating income statement and net investment rate base for the 2021 test year, as adjusted for Commission decisions, are reasonable.

11. A reasonable 2021 fuel cost plan level for total company monitored fuel is $64,142,635. The fuel cost plan year divided by the authorized level of native requirements of 3,211,660 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $19.97, as shown in Appendix D.

12. It is reasonable to update fuel costs to reflect updated pricing for locational marginal pricing, coal contracts, rail contracts, natural gas, and opportunity sales revenues as of October 14, 2020.

13. It is reasonable to accept and incorporate Commission staff's uncontested fuel cost adjustments.

14. It is reasonable for the Commission to set a different fuel cost tolerance annual bandwidth pursuant to Wis. Admin. Code § PSC 116.06(3) at plus or minus 1.00 percent for MGE's Commission-authorized 2021 Fuel Cost Plan.

15. It is reasonable that MGE be required to file a 2022 Fuel Cost Plan in 2021 in accordance with Wis. Admin. Code ch. PSC 116.

16. MGE's operations and maintenance (O&M) expenses as adjusted by this Final Decision are reasonable.

17. It is reasonable to require MGE to file a depreciation study by no later than June 1, 2021.

18. It is reasonable that MGE's 2021 retail revenue requirement include the estimated impacts of joint ownership of the Two Creeks and Badger Hollow I solar projects as approved by the Commission in docket 5-BS-228.

19. It is reasonable that MGE amortize and include in 2021 retail revenue requirements the impacts of the regulatory asset and regulatory liability amortizations as described in the Settlement Agreement and detailed in Appendix E.

20. It is reasonable for MGE to use 100 percent of the remaining electric excess deferred income tax (EDIT) balance resulting from the Tax Cut and Jobs Act (TCJA) as described in the Settlement Agreement and detailed in Appendix E.

21. It is reasonable for the Commission to authorize deferral, with escrow accounting treatment, for MGE's pension and other post-employment benefit (OPEB) costs, including the 2019/2020 pension and OPEB costs deferred in docket 3270-AF-101, for both its electric and natural gas utilities through December 31, 2021.

22. It is reasonable for the Commission to authorize MGE to defer, with escrow accounting treatment, the incremental difference between its actual bad debt expense and the bad debt expense forecasted for the 2020 test year from the Commission's Final Decision in docket

3270-UR-122, ending on December 31, 2021, unless subsequent Commission authorization is granted. It is not reasonable to increase MGE's bad debt expenses by $650,000 over what was authorized in docket 3270-UR-122.

23. It is reasonable for MGE to use escrow accounting treatment for Credit Card Convenience Fees in Account 903 for the 2021 test year ending December 31, 2021 subject to the conditions set forth in this Final Decision.

24. It is reasonable for MGE to continue to capitalize costs related to cloud computing.

25. It is reasonable for MGE to no longer escrow SO2 amortizations, a non-monitored fuel cost, due to the immaterial amount of the balance, which is currently less than $5.

26. The regulatory asset and liability amortizations as reflected in Attachment B, Schedule 10 and revised by this Final Decision in Appendix E are reasonable.

27. It is reasonable for MGE to accrue allowance for funds used during construction (AFUDC) on 100 percent of construction work in progress (CWIP) associated with projects requiring a Certificate of Authority (CA) or a Certificate of Public Convenience and Necessity (CPCN) that were not reflected as current return CWIP projects in this proceeding upon approval of a CA or CPCN by the Commission through December 31, 2021.

28. It is reasonable for MGE to use Commission staff's calculations to determine return on rate base.

29. It is reasonable to maintain MGE's currently authorized ROE of 9.80 percent.

30. It is reasonable to maintain MGE's target level for the test-year average common equity measured on a financial capital structure basis of 55.00 percent.

31. It is reasonable for MGE to maintain a regulatory capital structure and average weighted cost of capital for the 2021 test year consisting of 55.84 percent common equity, 39.39 percent long-term debt and 4.77 percent short-term debt.

32. It is reasonable that MGE's dividend restrictions be based on the financial capital structure in this proceeding.

33. A reasonable weighted average cost of capital (WACC) is 7.21 percent for the 2021 test year.

34. It is reasonable to authorize MGE to implement the Electric Vehicle (EV) Fleet Pilot Program subject to the terms and conditions of this Final Decision.

35. It is reasonable to authorize MGE to implement proposed revisions to the Cg-3, Cg-4, and Cg-5 tariffs as filed and consistent with the terms and conditions of this Final Decision.

36. It is reasonable to authorize MGE to implement interruptible capacity credits, and revenue neutral changes to Sp-3 customer and demand charges as proposed and consistent with the terms and conditions of this Final Decision.

37. It is reasonable to authorize MGE to implement the photovoltaic (PV) Connect tariff as proposed, with the clarification that tariff references to the 5 megawatt (MW) total, and 1.5 MW per customer, capacity ratings be listed in terms of the alternating current (AC) capacity rating in MGE's tariff.

38. It is reasonable to authorize MGE to implement its proposed battery interconnection language within its Sheet E-67, as incorporated into MGE's service rules for

customer-owned generating equipment provided, however, that such changes do not supersede, expand or modify the provisions of Wis. Admin. Code ch. PSC 119.

39. It is reasonable to authorize MGE to implement a renewable flat bill pilot program, subject to the terms and conditions of this Final Decision.

40. It is reasonable to authorize MGE to implement the changes to the Bring Your Own Device program as filed by MGE subject to the terms and conditions of this Final Decision.

41. It is reasonable to authorize MGE to close the Rg-2 class to new customers and open the Rg-2A tariff as a new time-of-use option for residential customers.

42. It is reasonable to authorize MGE to add language to its New Load Market Pricing (NLMP) Rider allowing customers to seek annual reevaluations of their baseline energy and demand consumptions when they implement specified energy or demand reductions measures.

43. It is reasonable to authorize MGE to consolidate all language regarding primary voltage discounts into one schedule.

44. It is reasonable to authorize MGE to make other miscellaneous tariff changes, including minor language changes and the retirement of certain unused schedules.

45. The rate and service changes proposed in the Settlement Agreement, as conditioned by this Final Decision, are reasonable.

46. It is reasonable to require MGE to file a full test year 2022 rate case by May 1, 2021, including (1) a detailed cost of service study (COSS) and rate design for electric and natural gas operations, (2) an analysis of the operations and maintenance fee savings due to the reduced payment processing costs resulting from increased credit card usage that may result from the use of escrow accounting treatment for credit card convenience fees, (3) an analysis of

the impact of the revisions to the Cg-3, Cg-4 and Cg-5 tariffs, (4) an analysis of the Bring Your Own Device Program, (5) a proposed capacity limit, program term limit, and program evaluation and reporting requirements for its Electric Vehicle Fleet Pilot Program (if not provided in a separate tariff filing). It is reasonable to require that future changes to the Sp-3 class distribution demand, and related impacts of revenue and cost allocation to other customer classes, should be addressed in the COSS for that proceeding.

47. The remainder of the provisions of the Settlement Agreement that are not specifically addressed in this Final Decision are reasonable.

48. It is reasonable for all other terms and conditions of the Commission's decision in docket 3270-UR-122 not expressly superseded herein, to continue to apply.

Conclusions of Law

1. The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.026, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, 196.40, 196.70 and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision approving the Settlement Agreement and authorizing MGE to place in effect the rates and rules for electric and natural gas utility service set forth in Appendix B and C, and the fuel costs treatment set forth in Appendix D.

2. The procedural requirements of Wis. Stat. § 196.026(4)-(6) have been satisfied.

3. The Parties have been given a reasonable opportunity to present evidence and arguments in opposition to the Settlement Agreement as required by Wis. Stat. § 196.026(7)(a).

4. No additional evidentiary hearing was required to be held under Wis. Stat. § 196.20(2m) on the electric rate or service components of the Settlement Agreement because

the terms of the Settlement Agreement relating to electric rates and service do not curtail the obligation or undertaking of MGE or constitute an increase in electric rates.

5. The public interest has been adequately represented by the Settling Parties[2] as required by Wis. Stat. § 196.026(7)(b).

6. The Settlement Agreement (PSC REF#: 396059), the terms of which are set forth in Appendix B to this Final Decision, as modified and conditioned by this Final Decision, represents a fair and reasonable resolution of the revenue requirement; is supported by substantial evidence on the record as a whole; and complies with applicable law, including that the rates resulting from the Settlement Agreement are just and reasonable, as required by Wis. Stat. § 196.026(7)(c).

7. The Commission is authorized to set a different fuel cost tolerance annual bandwidth pursuant to Wis. Admin. Code § PSC 116.06(3) at plus or minus 1.00 percent for MGE's Commission-authorized 2021 Fuel Cost Plan.

8. The Commission's determination in this matter is based on the specific facts presented in this application and Settlement Agreement, and is not precedential.

Opinion

MGE and its Business

MGE is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a). It is engaged in the production, distribution, and sale of electric energy to approximately 148,135 retail customers in Madison and the surrounding area in Dane County, Wisconsin. MGE is also engaged in the purchase, transportation, distribution, and sale of natural

[2] MGE, CUB, RENEW, UW, and WIEG.

gas to approximately 152,901 customers in Madison and the surrounding area of Dane County, and in parts of Columbia, Crawford, Iowa, Juneau, Monroe, Pierce, and Vernon Counties. MGE is an operating subsidiary of MGE Energy, Inc., a holding company based in Madison, Wisconsin.

MGE is a co-owner, along with Wisconsin Electric Power Company (WEPCO) and WPPI Energy, of the Elm Road Generating Station located in Oak Creek, Wisconsin (ERGS). MGE also jointly owns, along with managing partner Wisconsin Power and Light Company (WP&L), and Wisconsin Public Service Corporation (WPSC), Columbia Energy Center located in Columbia County, Wisconsin. MGE also jointly owns Forward Wind Energy Center (FWEC) with WP&L and WPSC.

Income Statement

On August 28, 2020, pursuant to Wis. Stat. § 196.026(4), MGE filed an application for Commission approval of a Settlement Agreement between MGE and four of the six Parties (CUB, RENEW, WIEG, and UW) for test year 2021. (PSC REF#: 396059) While Clean Wisconsin was not a signatory to the Settlement Agreement, it responded that it did not oppose the Settlement Agreement and took no position on whether it should be approved by the Commission. (PSC REF#: 397501.) Sierra Club filed a response indicating opposition to the Settlement Agreement. (PSC REF#: 397533.)

As will be discussed more fully herein, the Settlement Agreement results in a zero percent increase in MGE's base electric rates and a 4.1 percent increase in natural gas rates for the 2021 test-year. The Settlement Agreement included a fuel cost estimate for the 2021 Fuel Cost Plan and the final fuel cost plan was established pursuant to the requirements of Wis. Admin. Code ch. PSC 116. The only difference between the fuel costs presented in the Settlement Agreement and the final fuel costs is a decrease of $718,183 to reflect the October 14, 2020 NYMEX adjustment.

MGE filed a single 2021 test year in the Settlement Agreement due in part to the uncertainty created by the ongoing COVID-19 pandemic. Commission staff conducted a high-level review of the filed 2021 test-year information. MGE concluded that its present electric rates were sufficient and proposed a zero percent increase. For natural gas operations, MGE determined that its present natural gas rates were deficient, and a 4.1 percent rate increase would be needed.

The main drivers for the zero percent electric increase are the capital investments such as the Badger Hollow and Two Creeks solar projects approved in docket 5-BS-228 and the customer information system; these cost increases were offset by use of excess deferred income tax (EDIT) savings, sales growth, and lower fuel costs, as well as inclusion of the deferred regulatory liability balance associated with MGE's 2019 fuel cost plan reconciliation. (PSC REF#: 391522.) In addition, MGE requested to defer with escrow accounting treatment the incremental bad debt, pension and OPEB expenses, and credit card convenience fees from those forecasted in the 2019 and 2020 test years in docket 3270-UR-122. With the approval of escrow accounting treatment, any increase or decrease to these expenses would be deferred until MGE's next rate case. Further, MGE proposed that any increase or decrease to the filed zero percent electric rate increase would be offset by adjusting the amortizations identified on Attachment B, Schedule 10 of the Settlement Agreement, thus maintaining a zero percent electric rate increase.

For its natural gas operations, MGE concluded that its present natural gas rates would be insufficient, and therefore a 4.1 percent increase for natural gas rates is required. The main drivers for increased natural gas rates are the capital investments in the customer information system approved in docket 3270-CG-123, locating, and other gas infrastructure costs. Similar to its electric operations, MGE requested to defer with escrow accounting treatment the incremental bad debt, pension and OPEB costs, and credit card convenience fees for its natural gas operations from those forecasted in the 2019 and 2020 test years in docket 3270-UR-122. Further, any increases or decreases to these expenses would be deferred until MGE's next rate case.

Settlement

The Settlement Agreement

In July 2020, while continuing its discussions with CUB, RENEW, WIEG, and UW, MGE began to file detailed responses to Commission staff's initial data requests and follow-up data requests for its 2021 test-year rate case. (PSC REF#: 398964 at 3.) This is not the detailed review that Commission staff would perform in a fully litigated rate case. Instead, the review identified specific trends in costs and revenues with more attention given to large cost items. To assist the parties in negotiations, Commission staff outlined potential revenue requirement adjustments and sensitivities for Parties' consideration based on previous Commission decisions, policies, and practice. (Ex.-PSC-Workbooks at 3.) (PSC REF#: 400085). Commission staff's financial review suggested that MGE's electric operations revenue would likely be excessive and natural gas operations would likely have a revenue deficiency in 2021.

The Settlement Agreement results in no increase to base electric rates and provides for a 4.1 percent increase in base natural gas rates for the test year ending on December 31, 2021.

(PSC REF#: 396059, Attachment A). The provisions of the Settlement Agreement are detailed in Attachment A, attached to this Final Decision as Appendix B. The key components of the settlement include:

Fuel Cost Plan

- The settlement reflected a preliminary 2021 monitored fuel cost estimate of $20.21/MWh.
- Fuel costs shall be subject to update consistent with past Commission practice.
- The Settlement Agreement incorporates a monitored fuel bandwidth of plus or minus 1.0 percent (a proposed change to the plus or minus 2.0 percent provided in Wis. Admin. Code § PSC 116.06(2).

Revenue Requirement

- TCJA – The use of forecasted test-year protected and unprotected EDIT balances and utilization of such balances as shown in Attachment B, Schedule 10 of Appendix B.
- Inclusion of the estimated impacts of joint ownership of the Two Creeks and Badger Hollow I solar projects as approved by the Commission in docket 5-BS-228, and capital investments in the customer information system with such increases offset by the use of EDIT savings, sales growth, lower fuel costs, and inclusion of the deferred regulatory lability balance associated with MGE's 2019 fuel cost plan reconciliation.

Deferrals and Amortizations

- Bad Debt – Requesting escrow and accounting treatment of bad debt expense for all electric and natural gas customers, including an additional $650,000 above the amount authorized in docket 3270-UR-123 for electric operations bad debt.
- Pension and OPEB expenses – Requesting escrow and accounting treatment, including the 2019/2020 pending and OPEB costs deferral authorized in docket 3270-AF-101.
- Credit Card Convenience fees – Requesting permanent authorization to escrow credit card convenience fees for electric and natural gas operations.

- Cloud Computing – Continuation of the capitalization costs associated with cloud computing.

- AFUDC – Accrual of AFUDC on 100 percent of CWIP associated with projects requiring a CA or CPCN.

- Other proposed regulatory asset and liability amortizations as reflected in Attachment B, Schedule 10 to the Settlement Agreement.

Financial Capital Structure and ROE

- A stipulated capital structure consisting of 55.00 percent common equity as measured on a financial basis, which reflects no change from the target level authorized by the Commission in MGE's last rate case proceeding in docket 3270-UR-122. The common equity component of MGE's ratemaking capital structure would decline from 56.06 percent authorized in 3270-UR-122 to 55.84 percent, reflecting a lower off-balance sheet debt equivalency.

- A stipulated ROE of 9.8 percent, which reflects no change from the ROE authorized in MGE's most recent rate case in docket 3270-UR-122.

Rate Design

- Flat Bill Pilot Program where customers would receive a flat monthly bill in lieu of monthly bills that reflect their usage in a given month.

- EV Fleet Charging Pilot Program for customers seeking to charge a fleet of electric vehicles that will receive a dedicated meter.

- PV Connect for customer-owned PV that would be directly interconnected to MGE's distribution system.

- Expansion of MGE's Bring Your Own Device program.

- Incorporation of Interruptible Service into the Sp-3 tariff.

- Modifications to the NLMP to allow a customer to receive an annual re-assessment of its baseline energy and demand if the customer has participated in certain activities that would lower its baseline consumption.

- A proposal to add language to MGE's current service rules for customer-owned generating equipment relating to battery interconnection.

- The closure of existing time-of-use rates for both new residential and new small commercial customers, while opening up new time-of-use offerings.

- Modification to certain natural gas tariffs.

Settlement Law

Prior to 2018, Wisconsin law did not contain a specific statutory provision relating to settlements. On January 31, 2018 the Legislature enacted 2017 Wisconsin Act 136, which created Wis. Stat. § 196.026 governing settlements.[3] The law embodies the substantive

---

[3] **196.026 Settlements.**

(1) All parties to dockets before the commission are encouraged to enter into settlements when possible.

(2) In this section, "docket" means an investigation, proceeding, or other matter opened by a vote of the commission, except for rule making.

(3) Parties to a docket may agree upon some or all of the facts. The agreement shall be evidenced by a written stipulation filed with the commission or entered upon the record. The stipulation shall be regarded and used as evidence in the docket.

(4) Parties to a docket may agree upon a resolution of some or all of the issues. When a written settlement agreement is proposed by some of the parties, those parties shall submit to the commission the settlement agreement and any documents, testimony, or exhibits, including record citations if there is a record, and any other matters those parties consider relevant to the proposed settlement and serve a copy of the settlement agreement upon all parties to the docket.

(5) If a proposed settlement agreement is not supported by all parties, the settling parties shall convene at least one conference with notice and opportunity to participate provided to all parties for the purpose of discussing the proposed settlement agreement. A non-settling party may waive its right to the conference provided in this subsection.

(6) Within 30 days of service of a settlement agreement under sub. (4), each party to the docket shall respond in writing by filing and serving on all parties the party's agreement, objection, or non-objection to the settlement agreement. Failure to respond in writing within 30 days of service, unless a different time is set by the commission for good cause, shall constitute non-objection to the settlement agreement. A party objecting to a settlement agreement shall state all objections with particularity and shall specify how the party would be adversely affected by each provision of the settlement agreement to which the party objects.

(7) The commission may approve a settlement agreement under sub. (4) if all of following conditions are met:

(a) All of the following have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement:

1. Each party that has filed an objection or non-objection to the settlement agreement under sub. (6).

2. Each party whose failure to respond in writing constitutes a non-objection to the settlement agreement under sub. (6).

(b) The commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

(c) The commission finds that the settlement agreement represents a fair and reasonable resolution to the docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including that any rates resulting from the settlement agreement are just and reasonable.

(8) The commission may approve a settlement agreement under sub. (4) in whole or in part and with conditions deemed necessary by the commission. If the settlement agreement does not resolve all of the issues in the docket, the commission shall decide the remaining issues in accordance with applicable law and procedure.

standards under existing law previously applied by the Commission,[4] and added the following additional procedural and substantive criteria:

- Encourages parties to enter into settlements when possible;
- Provides that parties can agree upon some or all of the facts and resolve some or all of the issues;
- Requires that settlements be evidenced in writing, submitted to the Commission along with any documents, testimony or exhibits, and entered upon the record;
- For contested settlements, requires the convening of at least one conference with notice and opportunity to participate provided to all parties;
- Within 30 days after service of the settlement agreement, unless a different date and time is set by the Commission for good cause, requires all parties to respond in writing indicating objection or non-objection to the settlement with the statement of any objections with particularity and specifying how the party would be adversely affected by each objectionable part of the settlement; and
- Provides that a party's failure to respond within the time period provided constitutes non-objection to the settlement.

Wis. Stat. § 196.026(2)–(6).

In addition, the law provides that the Commission may approve a settlement agreement if all of the following are met: (1) each party who has either filed an objection, non-objection or failed to respond has been given reasonable opportunity to present evidence and arguments in opposition to the settlement agreement; (2) the Commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement; and (3) the Commission finds that the settlement agreement represents a fair and reasonable resolution to the

[4] Prior to Wis. Stat. § 196.026, the Commission evaluated settlement proposals under the just and reasonable rates standard reflected in Wis. Stat. §§ 196.03 and 196.37, as well as its authority to issue conditional orders under Wis. Stat. § 196.395. The Commission also evaluated settlement proposals in light of the various judicial review standards reflected in Wis. Stat. § 227.57 that require consideration of whether there is substantial evidence to support any determination regarding the proposal under Wis. Stat. § 227.57(6) and whether such determinations satisfied the erroneous exercise of discretion standard in Wis. Stat. § 227.57(8).

docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including that any rates resulting from the settlement are just and reasonable. Wis. Stat. § 196.026(7). The Commission may approve a settlement agreement in whole or in part and with conditions deemed necessary by the Commission. Wis. Stat. § 196.026(8). If the settlement does not resolve all of the issues in the docket, the Commission shall decide the remaining issues in accordance with applicable law and procedure. (*Id.*)

Approval of the Settlement Agreement

Since enactment of Wisconsin's settlement law, the Commission has approved several rate case settlements applying Wis. Stat. § 196.026. These settlements have resulted in rate freezes, rate decreases, rate increases, or some combination thereof.[5] Rate setting, including approving settlements that maintain or adjust rates, 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*

[5] *Final Decision*, *Application of Wisconsin Power and Light Company for Authority to Adjust Electric and Natural Gas Rates*, No. 6680-UR-121 (Wis. PSC Dec. 20, 2018) (PSC REF#: 355884) (authorizing electric and natural gas base rate freeze for test years 2019 and 2020); *Final Decision, Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates*, No. 3270-UR-122 (Wis. PSC Dec. 20, 2018) (PSC REF#: 355887) (authorizing electric base rate decrease and a natural gas base rate increase); *Final Decision, Application of Kaukauna Utilities, as an Electric Public Utility, for Approval of a Standby Service Tariff*, No. 2800-TE-103 and *Final Decision, Application of the City of Kaukauna, Outagamie County, Wisconsin, as an Electric Public Utility, for Authority to Adjust Electric Rates*, No. 2800-ER-108 (Wis. PSC Jan. 30, 2019) (PSC REF#: 358621) (authorizing rate decrease); *Final Decision, Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, No. 4220-UR-124 (Wis. PSC Dec. 12, 2019) (PSC REF#: 380611)(maintaining base electric rates and decreasing natural gas rates); *Final Decision, Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates*, No. 5-UR-109 (Wis. PSC Dec. 19, 2019) (PSC REF#: 381305)(contested partial settlement resolving revenue requirement); *Final Decision, Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, No. 6690-UR-126 (Wis. PSC Dec. 19, 2019) (PSC REF#: 381325) (contested partial settlement).

(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 and applying the statutory criteria 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.

In applying this experience and expertise, the Commission concludes, for the reasons set forth more fully herein and in the record, that the Settlement Agreement in this docket, as modified and conditioned by this Final Decision, complies with both the procedural and substantive requirements of Wis. Stat. § 196.026.

In addition to the Commission's authority under Wis. Stat. § 196.026, the Commission further finds that approval of this single year test-year filed in light of the COVID-19 pandemic is also reasonable and in the public interest. Wisconsin Stat. § 196.70 authorizes the Commission, when it deems it to be necessary to prevent injury to the business or interests of the people or of any public utility in case of any emergency to be judged by the Commission, to, by order, temporarily alter or amend an existing rates, schedules, and orders of any public utility. The Commission has previously found in its orders in docket 5-UI-120 and 5-AF-105 that the COVID-19 pandemic is an emergency that presents significant injury to the business and interests of the people of the state and to the public utilities. The Commission finds that the COVID-19 pandemic has resulted in a great deal of economic uncertainty, and that this uncertainty adversely affects the utility's ability to accurately project revenues and costs. Further the Commission finds that providing rate stabilization for MGE's electric customers will help prevent injury to the business and interests of MGE's customers and MGE.

Compliance with Procedural Requirements of Wis. Stat. § 196.026(3)–(6) and Wis. Stat. § 196.20(2m)

Pursuant to Wis. Stat. § 196.026(3), parties to a docket may agree upon some or all of the facts. Such an agreement is required to be evidenced by a written stipulation filed with the Commission and entered upon the record. Wisconsin Stat. § 196.026(4) requires that the parties proposing a settlement must submit to the Commission, in addition to the settlement agreement, any documents, testimony or exhibits and other matters those parties consider relevant to the proposed settlement, and serve a copy of the settlement agreement upon all parties to the docket. If a proposed settlement agreement is not supported by all parties, the settling parties are statutorily required to convene at least one conference with notice and an opportunity to participate provided to all parties for the purpose of discussing the proposed settlement agreement. Wis. Stat. § 196.026(5). The law further requires that within 30 days of service of a settlement agreement on the required parties, each party to the docket shall respond in writing by filing and serving the party's agreement, objection, or non-objection to the settlement agreement.

Wis. Stat. § 196.026(6). An objecting party is required to state all objections with particularity and to specify how the party would be adversely affected by each provision of the settlement agreement to which the party objects.

As discussed above, MGE and CUB, RENEW, UW, and WIEG (collectively, Settling Parties), entered into a written Settlement Agreement stipulating to a revenue requirement for a 2021 test year that results in a zero percent increase to electric rates, and a 4.1 percent increase in natural gas rates.[6] A virtual conference to discuss the proposed settlement agreement was held, on August 20, 2020, and all Parties to the docket attended. MGE filed the Settlement Agreement with the Commission, evidenced by a written stipulation of the Settling Parties and along with supporting documentation, and certified that the same were served upon all Parties in this docket. (PSC REF#: 396059.) The Settlement Agreement was entered into the record at the October 8, 2020 hearing.

The Commission notified the Parties that pursuant to Wis. Stat. § 196.026(6), each Party's agreement, objection, or non-objection to the Settlement Agreement was required to be filed with the Commission, and provided the opportunity for the Parties to request an extension of time for such responses. (PSC REF#: 396366.)

MGE and each of the Settling Parties filed responses to the Settlement Agreement reiterating support for the settlement. (PSC REF#: 397477, PSC REF#: 397528, PSC REF#: 397529, PSC REF#: 397531, PSC REF#: 397541.) RENEW stated that MGE's proposal was a "reasonable response to the overhang of uncertainty caused by the ongoing COVID-19 pandemic" because "[w]ithout a clear sense of when and how vigorously the state's economy

[6] The Settlement Agreement contemplated that MGE's 2021 Fuel Cost Plan would be established as required by Wis. Admin. Code ch. PSC 116 after the required hearing.

will recover from the recession now underway, an extension of current electric rates through 2021 shapes up to be the least risky approach going forward." (PSC REF#: 397477.) UW, WIEG and CUB agreed that no change to electric rates for 2021 was a prudent response as everyone continues to battle COVID-19 and the resulting uncertainties. (PSC REF#: 397528, PSC REF#: 397529, PSC REF#: 397541). Clean Wisconsin responded that it did not oppose the Settlement Agreement and took no position on Commission approval. (PSC REF#: 397501.)

Sierra Club filed a response in opposition to the Settlement Agreement. (PSC REF#: 397533.) It was the only party objecting to the Settlement Agreement. Among its objections was a complaint that no hearing was held on MGE's electric rates and tariffs. Sierra Club argued such a hearing was required under Wis. Stat. § 196.20(2m), notwithstanding the fact that the Settlement Agreement did not result in an increase in electric rates or tariff changes that resulted in a diminution in service. The Commission rejects this argument as it is contrary to the plain language of the statute which clearly only requires a hearing where there a change "which constitutes an *increase in rates to consumers* . . . ." (emphasis added.) No such increase in electric rates results from the Settlement Agreement. The application of a credit is not a charge and did not increase electric rates.

Sierra Club's selective citation to certain words in Wis. Stat. 196.20(4)(c)3 is also unavailing as that provision, when read in its entirely only applies to "approval of a fuel cost plan and *any rate adjustment* for fuel costs or refund of over-collected fuel costs . . . ." The Settlement Agreement did not adjust electric rates.

Finally, Sierra Club's suggestion that granting escrow and deferral accounting treatment to certain expenses constitutes a rate increase is simply wrong as the Commission's authorization is for accounting purposes only and does not bind the Commission to any specific treatment for this item in any future proceeding involving rates or other matters before the Commission.

The Commission therefore finds that no hearing is required under Wis. Stat. § 196.20(2m) for the electric rate and tariff components of the Settlement Agreement. A hearing was required, and was held, on the natural gas components of the Settlement Agreement because it results in an increase in natural gas rates.

In light of the activities that have occurred, and as documented in the record for this docket, the Commission concludes that there has been compliance with the procedural requirements of Wis. Stat. § 196.026(3)–(6) and Wis. Stat. § 196.20(2m).

Satisfaction of the Settlement Criteria of Wis. Stat. § 196.026(7)(a) and (7)(b)

Pursuant to Wis. Stat. § 196.026(7), the Commission may approve the Settlement Agreement if all of the following conditions are met:

> (a) All of the following have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement:
>
> 1. Each party that has filed an objection or non-objection to the settlement agreement under sub. (6).
> 2. Each party whose failure to respond in writing constitutes a non-objection to the settlement agreement under sub. (6).
>
> (b) The commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.
>
> (c) The commission finds that the settlement agreement represents a fair and reasonable resolution to the docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including any rates resulting from the settlement agreement that are just and reasonable.

All Parties have been afforded an opportunity to present evidence and arguments in opposition to the Settlement Agreement through the submission of written responses pursuant to Wis. Stat. § 196.026(6). In addition, the Commission provided a further opportunity for the Parties and the public to present evidence and arguments through submittal of written comments on Commission staff's memorandum, and a hearing on aspects of the settlement that required a hearing was held on October 8, 2020. The Commission concludes that each Party that filed an objection, non-objection, or failed to respond has been given a reasonable opportunity to present evidence and arguments in opposition to the Settlement Agreement as required by Wis. Stat. § 196.026(7)(a).[7]

Under Wis. Stat. § 196.026(7)(b), the Commission may approve the Settlement Agreement if it finds that the public interest is adequately represented by the parties who entered into the Settlement Agreement. In this case, CUB, RENEW, UW, and WIEG, who are Parties in this docket, are signatories to the Settlement Agreement with MGE.

CUB is an organization that advocates consumer interests on behalf customers on utility issues. Its 2,000 members consist primarily of Wisconsin residential customers, some of which are also customers of MGE. CUB intends for its advocacy to benefit not just its own members, but all residential and small business ratepayers of the state. (PSC REF#: 394188.) WIEG is a member organization of large industrial customers in the state of Wisconsin. WIEG was organized to educate its members about energy matters and to form ad hoc groups for both intervention and participation in dockets before the Commission and for other matters. Some members of WIEG are customers of MGE and purchase energy to meet their business needs. (PSC REF#: 392258.) One of MGE's larger customers, UW, has also entered into the Settlement

[7] While Wis. Stat. § 196.026(7) focuses on a party's reasonable opportunity to present evidence and arguments in opposition to a settlement agreement, the Commission's determination as to compliance with Wis. Stat. § 196.026(7)(a) may also be informed by the extent to which the parties engaged in negotiations prior to the filing of the settlement agreement. In this case, MGE reports that it commenced settlement negotiations months prior to the filing of the Settlement Agreement. (PSC REF#: 396059 at 1-2.) Commission staff and the Settling Parties were actively involved in these discussions.

Agreement. (PSC REF#: 392299.) CUB, WIEG, and UW represent the residential, small business, and large industrial customers served by MGE.

In addition, RENEW, another signatory to the Settlement Agreement, represents other constituencies. RENEW is a non-profit organization dedicated to the promotion of policies to increase the use of locally and regionally available renewable energy resources to meet Wisconsin's power needs. It advocates for clean renewable energy, and many of its members live and work in MGE's service territory. (PSC REF#: 392931.)

Given this broad representation by the signatories to the Settlement Agreement, each of whom filed in support of the Settlement Agreement, the Commission concludes that the public interest is adequately represented by the Settling Parties.

Compliance with Wis. Stat. § 196.026(7)(c)

The final criterion that must be satisfied before the Commission may approve the Settlement Agreement is a finding that the Settlement Agreement represents a fair and reasonable resolution to the docket; is supported by substantial evidence on the record as a whole; and complies with applicable law, including that any rates resulting from the Settlement Agreement are just and reasonable. The Commission is permitted to approve the Settlement Agreement in whole or in part and with any conditions it deems necessary, or to deny approval of the Settlement Agreement. Wis. Stat. § 196.026(8).

The Settlement Agreement has the support or non-opposition of all Parties to this proceeding with the exception of Sierra Club, which objects to the Settlement Agreement. However, Sierra Club's objections have little to do with what is actually in the settlement. Instead, Sierra Club complained that the Settlement Agreement "perpetuat[es] the current fixed and volumetric charges . . . ” (PSC REF#: 397533 at 8) and devoted a substantial portion of its objections providing the history of fixed charges in Wisconsin and lamenting the Commission’s decisions on the subject from 2012 and 2014. The time to challenge MGE’s fixed charges was back in 2012 and 2014. Sierra Club did not seek judicial review of those decisions. Accordingly, Sierra Club’s attempt to challenge those past decisions here under the guise of objecting to the Settlement Agreement is an impermissible collateral attack. *See, e.g.*, *Zastrow v. American Transmission Company LLC*, 2019 WI App 51, ¶40, 383 Wis. 2d 644, 916 N.W.2d 821*citing Sewerage Comm’n of City of Milwaukee v. DNR,* 102 Wis. 2d 613, 631, 307 N.W.2d 189 (1981). Sierra Club’s challenge the Settlement Agreement on the grounds of “perpetuation” of fixed charges rings particularly hollow here given Sierra Club’s non-objection to MGE’s settlement for test years 2019 and 2020 that similarly did not address fixed charges.

For purposes of this proceeding, the Commission’s analysis is limited to the relevant terms and conditions that are actually in the settlement. When the Commission considers a settlement agreement, nothing is diminished with respect to what parties must demonstrate in order to satisfy the public interest standard or the requirement that rates be just and reasonable. However, the settlement law clearly provides that the Commission is to make its determinations on the settlement agreement as a whole. This differs from the typical manner in which the Commission approaches setting rates, whereby the Commission individually analyzes and makes a separate determination on each component of a rate case in order to ultimately arrive upon a reasonable rate. In reviewing a settlement agreement, the Commission reviews each component of the rate case, but reviews them in tandem. In doing so, the Commission fulfills its duty to ensure that rates are just and reasonable, while simultaneously accommodating the Legislature's intent that parties be given flexibility to negotiate across all components.

As discussed below, Commission staff's memorandum provided a thorough analysis of the record, including record citations and proposed conditions for Commission consideration. The Commission observes that this particular settlement contained more new programs than the Commission is accustomed to seeing in settlements and cautions that, there is a tipping point where there is too much in a settlement agreement than what can be reviewed in sufficient detail under Wis. Stat. § 196.026. The Commission, however, is satisfied that the Settlement Agreement, when considered as a comprehensive package and as conditioned by this Final Decision, strikes a balance between the diverse utility, customer, and stakeholder interests. Components of the Settlement Agreement are consistent with decisions in past rate cases for other investor owned utilities (IOU), other settlements approved by the Commission, and the public interest policies underlying those decisions. To the extent that components of the Settlement Agreement may deviate from past Commission practice or may otherwise have been decided differently by the Commission in a contested case proceeding, the Commission finds that there is a rational basis for those deviations and that those determinations reflect a give-and-take that is embodied in the settlement process. For these reasons, and the further analysis provided below, the Commission finds that the Settlement Agreement, as modified and conditioned by this Final Decision, satisfies Wis. Stat. § 196.026(7)(c). The modifications to the Settlement Agreement, and conditions of this approval are discussed more fully below.

Revenue Requirement

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 case proceeding, or if the utility does not file a general rate case, as a proceeding limited in scope to monitored fuel cost. The fuel cost plan must include a calculation of certain fuel costs as described in Wis. Admin. Code § PSC 116.03(2), as well as the other information required by Wis. Admin. Code § PSC 116.03(2). After a hearing, the Commission approves the utility's fuel cost plan and establishes the utility's rates in accordance with the approved fuel cost plan. Wis. Admin. Code § PSC 116.03(3).

The Settlement Agreement reflected a preliminary fuel cost estimate for the 2021 monitored fuel cost estimate of $20.20/MWh, which is a 10.1 percent reduction from the 2020 Fuel Cost Plan approved by the Commission in docket 3270-ER-100. The Settlement Agreement incorporated a bandwidth of plus or minus 1 percent as opposed to the default 2.0 percent contemplated by the Wisconsin Administrative Code. The Settling Parties agreed that the fuel costs should be subject to update, consistent with Commission practice. Commission staff conducted an audit of MGE's fuel costs and Commission staff's adjustments consisted of updates for more recent information and an adjustment to reflect the impact on fuel costs on Commission staff's electric sales adjustment. A hearing on MGE's 2021 Fuel Cost Plan was required and held on October 8, 2020.

The Commission finds that a reasonable 2021 fuel cost plan level of monitored fuel costs for MGE is $64,142,635, which reflects the fuel cost as defined by Wis. Admin. Code

§ PSC 116.02. These monitored fuel costs divided by the authorized level of native system requirements of 3,211,660 MWh result in an average net monitored fuel cost per MWh of $19.97. This results in a decrease of $718,183 from the filed fuel cost forecast in the Settlement Agreement. It is reasonable that MGE's revenue requirement reflect 2021 monitored fuel costs as approved in this Final Decision for MGE's 2021 Fuel Cost Plan. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

Evaluation of Dispatch of Baseload Units

Sierra Club submitted testimony asserting that MGE is running its coal units uneconomically due in part to its assumptions concerning O&M expenses in its commitment and dispatch decisions. MGE countered that it relies on the variable O&M costs provided by Wisconsin Power and Light Company (WP&L). In docket 6680-UR-122, the Commission reviewed and rejected Sierra Club's challenges to WP&L's dispatch of baseload units. (PSC REF#: 402140 at 16-17.) For the same reasons set forth therein, the Commission rejects those arguments here and accepts MGE's assumptions concerning variable O&M expenses in its commitment and dispatch decisions and declines to lower MGE's fuel costs. The Commission finds that MGE's O&M expenses as adjusted by this Final Decision are reasonable.

1.00 Percent Fuel Bandwidth

Wisconsin Admin. Code § PSC 116.03(3) provides for a plus or minus 2.00 percent bandwidth with respect to a utility's monitored fuel costs. The Code allows the Commission to select a different plus or minus fuel window if the Commission deems it reasonable to do so. As part of the Settlement Agreement, the parties agreed to request a plus or minus 1.00 percent bandwidth for the 2021 Fuel Cost Plan year. Commission staff testified that in the past five years, 2015-2019, MGE has been in a fuel refund position. If this trend were to continue, approving the 1.00 percent window would result in additional funds being returned to ratepayers.

The Commission finds it reasonable to apply the requested plus or minus 1.00 percent bandwidth for MGE's 2021 monitored fuel costs. As noted previously, the proposed change in the bandwidth is part and parcel of a larger settlement, which when considered as a whole is reasonable. Further, while the past is no guarantee of future results, if MGE again finds itself in a fuel refund position, this change will benefit customers.

Uncontested Fuel Adjustments

Commission staff proposed various adjustments to MGE's estimated test-year fuel costs that were not contested by any party. (Direct-PSC-Ritsema-2r-3r, Ex.-PSC-Ritsema-1, Schedule 2.) These uncontested adjustments decreased fuel costs by approximately $2,079,000 compared to MGE's filed fuel costs for the 2021 test year. These adjustments include: (1) an increase of approximately $49,536 to reflect updated planned outage schedule as of July 1, 2020; (2) a decrease of approximately $43,779 to reflect updates to Midcontinent Independent System Operator, Inc. (MISO) rates, charges and credits for July 2019 through June 2020, MISO Planning Resource Auction and Department of Natural Resources environmental fees; (3) an increase of approximately $24,850 to reflect updates to locational marginal price (LMP) differentials for July 2019 through June 2020, net of 2020-2021 Financial Transmission Rights; (4) a decrease of approximately $157,575 to reflect updated market prices for natural gas, LMPs, Wisconsin Electric Power Company purchased power agreement volumes and prices, and mark-to-market values for hedging instruments as of July 15, 2020; (5) an increase of approximately $31,960 to reflect updated wind curtailment costs; (6) a decrease of approximately $3,138,738 to reflect updated coal prices for Columbia and Elm Road; and (7) an increase of approximately $1,154,620 to reflect Commission-audited electric sales forecast. The Commission finds that it is reasonable to accept these uncontested adjustments.

NYMEX and Other Updates

Consistent with past Commission practice, MGE requested to update its 2021 Fuel Cost Plan to reflect updated commodities (coal, natural gas, diesel prices, and electricity prices). Natural gas and electricity prices were based on NYMEX futures as of October 14, 2020. Spot coal prices were updated using the Argus publication dated October 16, 2020. Rail costs were adjusted to reflect updated values for the All Inclusive Index-Less Fuel and the EIA Short-Term Forecast Diesel from October 2020. Commission staff filed a delayed exhibit including this updated information. (Ex.-PSC-Ritsema-2.) The Commission finds that it is reasonable to accept the updated fuel commodities consistent with past Commission practice.

Updated Depreciation Study

Commission staff proposed that MGE be required to file a depreciation study next year at a date to be established by the Commission. A depreciation study has not been done for MGE since 2015 and it is necessary to update net book values and depreciation rates to reflect the current condition of the older generation assets and to incorporate new generation assets recently brought on line. The Commission finds it reasonable to require MGE to file a depreciation study by June 1, 2021.

Commissioner Nowak dissents and would have required the filing by no later than test-year 2023.

Federal Tax Reform

The Tax Cuts and Jobs Act (TCJA) made significant changes to the Federal Tax Code and included changes to individual, business, and international tax provisions. Notably for MGE and the other Wisconsin IOUs, the TCJA reduced the Federal corporate tax rate from a maximum of 35 percent, under the existing graduated rate structure, to a flat 21 percent rate for tax years beginning after 2017. This change is referred to as the income statement component.

Additionally, MGE and the other IOUs were required to revalue their accumulated deferred income taxes (ADIT) based on the reduced corporate tax rate. This is referred to as the balance sheet component. ADIT are the result of differences between tax laws and accounting methods, and a lower corporate tax rate generally creates EDIT. The Internal Revenue Service requires that the portion of the EDIT that is related to the use of accelerated depreciation be amortized no faster than over the life of the underlying assets. The EDIT that are subject to the normalization rules are referred to as "protected" EDIT. The rest of MGE's EDIT are considered to be "unprotected" and may be amortized over a shorter time period or recognized immediately.

Income Statement Component

In docket 5-AF-101, the Commission ordered MGE to issue bill credits based upon 100 percent of its estimates of the first half of the 2018 annual reduction in the revenue requirement as a one-time bill credit to customers, no later than July 31, 2018. Further, the Commission directed that the remaining portion of the estimated 2018 annual savings balance be returned to ratepayers as ongoing, monthly volumetric bill credits, subject to true-up in either the tax reform docket or in a future rate case. With the implementation of new rates in docket 3270-UR-121 (2019 and 2020 Test Year), the bill credits and associated tariffs were removed.

Further, in the Supplemental Order in docket 5-AF-101, MGE was ordered to return the identified remaining electric and natural gas income statement savings as a fixed bill credit, and to defer any remaining balance sheet savings to a future proceeding.

Given that the income statement component was addressed by the Commission in dockets 3270-UR-122 and 5-AF-101, there are no income statement savings included in the MGE Settlement Agreement. However, it should be noted that MGE will require a final true-up of income statement savings, either in docket 5-AF-101 or in a future rate proceeding.

Balance Sheet Component

In docket 5-AF-101, the Commission directed the IOUs to record deferrals for any balance sheet savings that were not addressed in the docket until further Commission action in the same docket or in a future rate proceeding.

The Settlement Agreement includes the 2021 amortization of $4.9 million of protected EDIT for electric operations and $0.4 million of protected EDIT for natural gas operations. Additionally, MGE included the use of the remaining $18.2 million electric regulatory liability balance of unprotected EDIT to maintain a zero percent increase for electric operations. For natural gas operations, MGE proposes to defer the $4.2 million regulatory asset balance of unprotected EDIT to a future rate case. Therefore, no unprotected EDIT related to gas operations is included in the 2021 test year. Similar to the income statement savings, MGE will require a final true-up of balance sheet savings, either in docket 5-AF-101 or in a future rate proceeding. The forecasted test-year protected and unprotected EDIT balances and proposed utilization of such balances is shown in Attachment B, Schedule 10 to the Settlement Agreement.

The Commission finds that the calculation and utilization of the tax savings from the TCJA as described in the Settlement Agreement is reasonable. The use of the tax benefits as proposed provides an immediate and tangible benefit to MGE's electric customers by maintaining a zero percent increase for electric operations.

Two Creeks and Badger Hollow I Solar Projects

The Settlement Agreement reflects the addition of two large solar projects to MGE's generation portfolio—joint ownership of the Two Creeks and Badger Hollow I solar projects. These projects were approved by the Commission in docket 5-BS-228 and inclusion of the costs associated with these authorized projects is reasonable. These projects will help MGE reduce tis fuel costs and the volatility associated with those costs. The inclusion of these costs is offset in part by use of the EDIT savings noted above, sales growth, and lower fuel costs resulting in a zero percent electric increase for 2021 for these capital investments.

Deferred Regulatory Liability Balance – 2019 Fuel Cost Plan Reconciliation

To further offset costs, the Settlement Agreement proposed using the 2019 fuel savings of approximately $1,525,000[8] from the 2019 fuel reconciliation in docket 3270-FR-2019. In that docket, the Commission gave MGE and the parties an opportunity to use the refund as part of its settlement negotiations. While returning fuel reconciliation deferred credit balances to customers via a bill credit is the most common means for addressing the credit balance and the mechanism authorized by Wis. Admin. Code § PSC 116.07(4)(c), the Commission has authorized the use of

[8] The refund plus interest through the end of 2021 is approximately $1,574,000. This is in contrast to the $1,866,160 estimated fuel deferral as shown in Attachment B, Schedule 10 of the Settlement Agreement. The difference is that the $269,014 under-refund from the 2018 fuel reconciliation in docket 3270-FR-2018 plus interest was not incorporated into the 3270-FR-2019 refund calculation. The correct refund amount with interest is not materially different from the $1,866,160 shown in the Settlement Agreement.

fuel cost deferred credit balances for other purposes for the benefit of customers.[9] Here, the Commission concludes that using the credit to offset a base rate increase is reasonable to ensure rate stability and a zero percent change to electric rates.

Pension and OPEB Expense Deferral with Escrow Accounting Treatment

In this proceeding, MGE requested escrow accounting treatment of pension and OPEB costs, including the 2019/2020 pension and OPEB costs deferral authorized in docket 3270-AF-101. (PSC REF#: 373819.) Based on pension and OPEB cost breakdowns provided by MGE, the 2020 pension expense ended with liability balances of $2,849,255 for electric operations and $1,673,375 for natural gas operations. For the 2021 test year MGE is estimating pension expense of $7.2 million for electric operations and $926,000 for natural gas operations. Therefore, the total pension and OPEB costs for the 2021 test year is approximately $4.4 million and $746,000 for electric and natural gas operations respectively.

Given market volatility the costs may vary materially, and such variation is due to circumstances outside MGE's control. More specifically, pension and OPEB costs vary primarily due to financial market conditions, such as the return on assets earned by the funds that back these expenses and the discount rate used to calculate the plans' liabilities. The COVID-19 pandemic has resulted in an unusual increase to market volatility. Using an escrow mechanism would ensure that MGE and its customers remain whole, as an escrow will capture market-driven increased utility costs while also capturing any decreases in costs when the market performs well. MGE has

[9] *See, e.g.*, dockets 3270-UR-119 (credit used to offset future increase and achieve rate freeze), 6630-FR-105, and 6630-FR-2017 (credit used to offset transmission escrow).

stated that it will request authorization from the Commission to continue the escrow treatment in subsequent years, if warranted, in MGE's next full rate proceeding.

Under Staff Accounting Policy Statement of Position (SOP) 94-01, which has been accepted and applied by the Commission pursuant to Commission order,[10] there are several criteria that the Commission uses to evaluate a request for deferral account treatment for a utility expenditure: (1) whether the cost is outside of the utility's control; (2) whether the cost is unusual and infrequently occurring; (3) whether the amount, if recognized in the year of expenditure, would cause the utility serious financial harm or significantly distort the current year's income; and (4) whether the immediate recognition of the expenditure would have a significant impact on ratepayers.

Consistent with SOP 94-01, MGE has no control over the financial markets or the longevity of the plan participants. MGE can only control the asset allocation of its defined benefit plans to manage some risk of its return on assets for the plan; however, all asset allocations are subject to financial market conditions. Additionally, MGE does not have control over the discount rate used to calculate the current liability position of the plan because these discount rates are derived from the financial markets. The amount of pension and OPEB expense is material to the revenue requirement of MGE with an income statement impact of approximately $5,777,847 million for the retail electric utility and a decrease of approximately

[10] *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).

$746,694 for the natural gas utility in the 2021 test year, which means MGE's request meets two of the requirements for authorization of escrow accounting under SOP 94-01.

In addition, the Commission authorized MGE to defer the incremental costs it may incur related to its pension and OPEB costs for both 2019 and 2020 in docket 3270-AF-101. MGE does control the amount and timing of its funding of the various plans, which can affect the expense amount that is realized on MGE's income statement.

The Commission finds it reasonable to authorize MGE to defer, with escrow accounting treatment, pension and OPEB expenses through December 31, 2021. The deferral provides customers assurance that future rates will recover only those actual costs realized by MGE for its pension and OPEB expenses while reducing the risk of a material reduction in MGE's operating income, with a lag. As discussed previously, to maintain a zero percent electric increase, MGE adjusted the amortizations on Appendix B, Schedule 10. Thus to maintain the zero percent increase, electric pension and OPEB costs were increased $650,000 to reflect the Commission's decision related to bad debt expense, which is discussed below and shown on the revised amortization schedule in Appendix E to this Final Decision.

Bad Debt Expense Escrow Accounting Treatment

MGE requested authorization for escrow accounting treatment of bad debt expense for all customer classes in its retail electric and natural gas utilities. Should the economic uncertainty surrounding the COVID-19 pandemic continue through 2021, the financial distress could result in business closures, bankruptcy filing, and increased unemployment in MGE's service territory, thus hindering customers' ability to pay their bills. Absent the deferral with escrow accounting treatment, MGE's net operating income would deteriorate as bad debt expenses increase above the levels currently authorized in MGE's rates.

The escrow accounting treatment allows MGE to accumulate the excess bad debt expense as a regulatory asset on its balance sheet and recover the excess expense from customers in a future rate proceeding. Conversely, should bad debt expense improve to a level below the level authorized in MGE rates, this reduction in expense is accumulated on MGE's balance sheet as a regulatory liability and returned to customers in a future rate proceeding. MGE's requested escrow accounting treatment is symmetrical with regard to ensuring customers pay for the realized expense levels of the utility, with a lag.

The Commission authorized escrow accounting treatment of bad debt expense for WPSC in docket 6690-UR-126 (PSC REF#: 381325) and continued escrow accounting treatment for We Energies in docket 5-UR-109 (PSC REF#: 381305). Additionally, the Commission approved WP&L's request to allow escrow accounting treatment across all rate classes at the open meeting of August 13, 2020. We Energies' authorization for escrow accounting treatment was originally granted in docket 5-GF-144 (PSC REF#: 31202) in conjunction with a low-income pilot program related to the payment of utility service. The escrow treatment for both WPSC and We Energies is limited to the residential class only for Wisconsin retail electric customers and natural gas customers. By contrast, and similar to WP&L, MGE is requesting escrow accounting treatment for bad debts across all rate classes. MGE cited the ongoing financial crises related to the COVID-19 pandemic, resulting in the moratorium on disconnections and the increase in arrears as contributing factors for the request. The request for escrow treatment of bad debt expense is for 2021 only, and MGE would explicitly request an extension of any such treatment in a future proceeding.

The request is reasonable and consistent with SOP 94-01 because the change in bad debt expense is unknowable with the COVID-19 impacts on the economy in MGE's service territory in 2021. Additionally, these economic effects are outside MGE's control, and the magnitude of bad debt expense could be material to the financial performance of MGE. The escrow accounting treatment provides assurance to customers that rates will only reflect the realized bad expenses incurred by MGE with a lag, while reducing the risk to MGE's net operating income through 2021. Therefore, the Commission finds that it is reasonable to authorize MGE to defer, with escrow accounting treatment, the incremental difference between its actual bad debt expense and the bad debt expense forecasted for the 2020 test year from the Commission's Final Decision in docket 3270-UR-122, ending on December 31, 2021 unless subsequent Commission authorization is granted.

In docket 5-AF-105, the Commission authorized all electric, gas, steam, and water public utilities to defer expenditures incurred by the utilities resulting from their compliance with orders by the Commission in docket 5-UI-120 and as otherwise required to ensure the provision of safe, reliable, and affordable access to utility services during the declared public health emergency for COVID-19. The deferral authorization included among other things, the incremental increase in bad debt expense above what is currently authorized in rates. It is noted that bad debt expense included on Appendix B, Schedule 10 of the filed Settlement Agreement does not include COVID-19 costs, but does reflect a $650,000 increase in electric expense over the amount authorized in docket 3270-UR-122.

The Commission does not authorize MGE to increase its bad debt expense by $650,000 over what was authorized in docket 3270-UR-122. To maintain a zero percent electric rate increase, $650,000 of bad debt costs originally included on the filed Appendix B, Schedule 10, was transferred to pension and OPEB costs as reflected on the revised amortization schedule in Appendix E to this Final Decision.

Commissioner Nowak dissents and would have authorized MGE to increase its bad debt expense by $650,000.

Credit Card Convenience Fees Escrow Accounting Treatment

MGE is charging individual customers' credit card payment convenience fees as an O&M expense, which will be recovered through MGE's rates as allowed in the temporary authorization per docket 5-UI-120. Until recently, the Commission historically had disallowed the inclusion of credit card fees in O&M for all investor-owned and municipal utilities. MGE is requesting permanent authorization to defer credit card convenience fees for electric and natural gas.

MGE estimates the credit card convenience fee amounts to be escrowed are $245,000 for electric operations and $255,000 for natural gas operations for the test-year 2021. The escrowed amounts would need to be reviewed and addressed in the next rate case. MGE's proposal maintains the deferral, with escrow accounting treatment, for the incremental difference between 2021 actual credit card fees paid by MGE and the authorized expense carried forward from 2020 into 2021.

Consumers have grown accustomed to an increasingly online and self-service economy where, for nearly every conceivable transaction, electronic payment methods are available, and often even required, without an added fee. The elimination of credit card convenience fees is a component of MGE's larger ongoing effort to make bill payment as easy and convenient as possible for customers. Therefore, the Commission finds that it is reasonable to authorize MGE to defer, with escrow accounting treatment, credit card convenience fees for the test year ending December 31, 2021. In addition and as a condition of approval, the Commission directs MGE to provide an analysis of the O&M fee savings due to the reduced payment processing costs resulting from increased credit card usage in MGE's next rate proceeding.

Commissioner Nowak dissents and would have authorized MGE to use escrow accounting treatment for credit card convenience fees until rescinded by a future Commission order.

Cloud Computing

On January 1, 2019, MGE implemented a new enterprise-wide technology system to modernize its business processes and consolidate many of its systems. This technology transformed the former accounting system to a more project-based system that utilizes tasks and projects. Previously, MGE utilized a 30-year old system, which was included in its O&M, and was expensed over the life of the service contract.

Cloud-based computing systems are arrangements in which a pool of computing resources, such a servers, storage, applications, and services can be rapidly deployed in response to demand. Cloud computing offers utilities the ability to expand their capacity and sophistication with respect to meter data management, emergency notification, advanced meter data analytics, and predictive maintenance, among other functions. Under previous accounting principles, MGE would treat its prior computing system as a capital expense and include it in its rate base, which allowed MGE to gain a return on it. A cloud-based solution, however, is typically a service contract that can be included as an operating expense, which would not earn a rate of return. As such, a utility is not incentivized to adopt cloud-based solutions, which has been found to cause the utility industry to lag behind corporate peers.

In its Settlement Agreement, MGE included four cloud computing service contracts in its electric and gas rate base. The total of the four contracts included in the rate base for the cloud assets is $1.7 million, which is a significant upfront software expenditure that is made to improve reliability of service for MGE’s customers. It is also consistent with Federal Energy Regulatory Commission’s (FERC) ruling in December 2019, as can be seen in FERC Docket No. AI20-1-000. The ruling allows a utility to represent cloud implementation costs as Plant, Property, and Equipment instead of an Other Asset on its financial statements. MGE has adopted this accounting treatment effective December 2019 for its cloud implementation costs. The implementation costs are amortized to FERC 404, Amortization of Limited Term Plant (60 percent to electric and 40 percent to gas).

The Commission finds it reasonable to authorize MGE to continue to capitalize costs related to cloud computing. This accounting treatment further allows MGE to not only receive a return on its investment, but also incentivize the company to take advantage of opportunities that will save costs and enhance operations. In addition, it allows MGE to stay consistent with the FERC ruling, and to earn a return on a large investment.

Allowance for Funds Used During Construction

MGE requested the authority to accrue AFUDC on 100 percent of CWIP associated with projects requiring a CA or CPCN upon approval of a CA or CPCN by the Commission. Similarly to the previous settlement (docket 3270-UR-122), the Parties agreed to include language whereby MGE could accrue AFUDC on CWIP associated with projects requiring a CA or CPCN. Currently there are no new projects included in the Settlement Agreement. The following projects currently have separate CA approval with 100 percent AFUDC.

Table 1 List of Projects with CA approval with 100 percent AFUDC

Project Description	CA	CA Status	AFUDC
EF – Customer to Meter	3270-CG-123	Approved	100%
Badger Hollow Solar Farm	5-BS-228	Approved	100%
Badger Hollow Solar Farm – Phase 2	5-BS-234	Approved	100%
Two Creeks Solar Farm	5-BS-228	Approved	100%

The Commission finds it reasonable to authorize MGE to accrue AFUDC on 100 percent of CWIP associated with projects requiring a CA or CPCN upon approval of a CA or CPCN by the Commission through December 31, 2021.

Elimination of SO_2 Allowance Escrow

As part of the Settlement Agreement, MGE requested permission to eliminate its escrow for SO_2 allowances for 2021 as the current balance was $5. It is reasonable to allow MGE to eliminate its SO_2 allowance escrow due to the immateriality of the costs involved.

Transmission Expense

MGE's forecasted transmission expense was approximately $44,567,000 for the 2021 test year. The amortization of transmission expenditures during 2021 was approximately $36,405,000. Amortizations for 2018 through 2020 totaled approximately $7,700,000 allowing the escrow balance at the end of 2021 to be zero.

Commission staff made the following adjustments to transmission expense: (1) a decrease of approximately $211,000 to reflect a five-year average of American Transmission Company

LLC's (ATC) true-ups to original budgeted costs, (2) a decrease of approximately $185,000 to reflect MISO-updated costs as of July 22, 2020, for 2021, and (3) an increase to transmission expense of approximately $14,000 to reflect an adjustment to MISO Market Administrative costs. The net of these adjustments is approximately $382,000. Taking the MGE-filed amount of $44,567,000 and subtracting the $382,000 of net Commission staff adjustments results in the $44,185,000 shown in the electric operating income statement filed by MGE in its Settlement Agreement per Schedule 1 of Appendix B.

Commission staff made another adjustment to the 2020 amortization level based on the MISO updated costs for 2020 as of July 22, 2020, of a decrease of approximately $224,000. This adjustment only impacts the escrow balance. MGE's escrow balance for transmission will still be zero at the end of 2021.

Refunds associated with the most recent FERC ROE rulings have been incorporated minimally for ATC and not at all for MISO. The exact dollars to be received by MGE are still quite volatile and uncertain. These dollars will be addressed through the transmission escrow in a future rate proceeding.

Conservation

Wisconsin Stat. § 196.374(2)(b)2 requires investor-owned electric and natural gas utilities in Wisconsin to spend 1.2 percent of their annual gross operating revenues on statewide energy efficiency and renewable resource programs known as Focus on Energy (Focus). Annual expenditures are calculated based on a three-year average of annual operating revenues. Schedule 10 of the Settlement Agreement shows MGE's 2021 conservation escrow account expenses to Focus of $4,836,719 for retail electric and $1,974,257 for natural gas. Commission staff finds that these amounts correspond to staff calculations of MGE’s required Focus contributions for 2021. Commission staff does not recommend any adjustments to the conservation escrow expenditures found in Schedule 10 of the Settlement Agreement.

Regulatory Asset and Liability Amortizations

The regulatory asset and liability amortizations as reflected in Attachment B, Schedule 10 and revised by this Final Decision in Appendix E are reasonable.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other adjustments agreed upon by the Settling Parties to arrive at the filed operating income statements are reasonable. Accordingly, per Commission decision, Wisconsin retail electric and natural gas utility operating income statements at present rates for the test year were updated, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2021 Test Year	**Electric (000's)**	**Gas (000's)**
Operating Revenues		
Sales of Electricity	$393,997	
Sales for Resale	3,521	
Sale of Gas		$166,625
Other Operating Revenues	15,499	398
Total Operating Revenues	$413,017	$167,023
Operating Expenses		
Fuel, Purchased Power, and Capacity	$83,444	
Purchased Gas Expense		$83,363
Other Production Expense	71,222	744
Transmission Expense	44,185	
Distribution Expense	17,194	12,705
Customer Accounts Expense	9,484	8,882
Customer Service Expense	10,481	5,428
Administrative and General Expense	42,865	20,282
Total O&M Expense	$278,875	$131,404
Depreciation and Amortization Expense	$59,369	$14,352
Investment Tax Credit	(1,242)	(9)
Taxes Other Than Income Taxes	16,506	3,056
Income Taxes	(11,219)	(1,559)
Deferred Income Taxes	(154)	4,653
Total Operating Expense	$342,135	$151,897
Net Operating Income at Current Rates	$70,882	$15,126

Average Net Investment Rate Base

All agreed-upon adjustments reflected in MGE's filed Settlement Agreement electric and natural gas utility average net investment rate bases are appropriate. Accordingly, the electric and natural gas utility average net investment rate base for the 2021 test year, which is considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

2021 Test Year	**Electric (000's)**	**Gas (000's)**
Utility Plant in Service	$1,684,165	$527,777
Accumulated Depreciation	(571,848)	(214,574)
Net Plant	$1,112,317	$313,203
Accumulated Deferred Income Taxes	(121,642)	(39,630)
Fuel Inventory	8,068	
Gas in Storage		6,408
Materials and Supplies	22,166	4,728
Customer Advances	(1,732)	(2,349)
Investments & Adv. Assoc. Co.		
Average Net Investment Rate Base[11]	$1,019,177	$282,360

Rounding Differences

MGE's application included an adjusted cost of capital to derive the percent return requirement applicable to average net investment rate base for electric and gas operations of 6.90 percent (application page 29, Schedule 6, line 3 for electric operations, and application page 30, Schedule 7, line 3 for gas operations). Commission staff calculated this return to be 6.89 percent. MGE indicated that the difference was due to applying inconsistent rounding calculations. Commission staff used consistent rounding calculations and estimates the required return on net investment rate base would be decreased from 6.96 percent to 6.95 percent for electric operations and from 7.08 percent to 7.07 percent for natural gas operations. The Commission finds it reasonable to require MGE to calculate revenue requirement deficiencies using Commission staff's required return on rate base of 6.95 percent for electric operations and 7.07 percent for natural gas operations.

Commissioner Nowak dissented.

[11] MGE updated the accumulated deferred income taxes for electric from $121,736 to $121,642 due to the impact of the pension change. This changed the net investment rate base for electric from $1,019,083 to $1,019,177.

Capital Structure, Rate of Return, and Dividend Restriction

In determining the appropriate capital structure of MGE, the Commission considers the impact on customer rates and MGE's financial flexibility and creditworthiness at various levels of common equity in MGE's capitalization. Assessing the reasonableness of MGE's capital structure depends upon three important principles. First, capital structure decisions must be based on MGE's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for MGE and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of MGE should be similar to typical electric utility dividend practices as long as MGE is below the estimated test-year common equity ratio.

Generally, under Wis. Stat. § 196.795, MGE's capital needs must take precedence over non-utility needs if ratepayers are to be protected. The identification of utility needs goes beyond foreseeable needs, and MGE must have flexibility to finance both foreseen and unforeseen capital requirements. In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices.

MGE's common equity ratio will remain 55.00 percent, as measured on a financial basis, which will support MGE's debt to total capitalization metric, and is within the long-term range of 55.00 percent to 60.00 percent approved by the Commission in MGE's last rate case proceeding, docket 3270-UR-122.

In its Final Decision in docket 3270-UR-122, the Commission directed MGE not to pay dividends, including pass-through of subsidiary dividends, in excess of the forecasted level of dividends, 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 again finds that it is reasonable to direct MGE not to pay dividends, including any pass-through of subsidiary dividends, in excess of the forecasted level in 2021, if its actual average common equity ratio, on a financial basis, is or will fall below the test-year level of 55.00 percent for 2021.

Return on Equity

The principal factor used to determine the appropriate ROE is the investors' required return. 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 reaching its determination as to the appropriate ROE, the Commission must balance the needs of investors with the needs of consumers, with due considerations to economic and financial conditions, along with public policy considerations.

MGE proposed that it be authorized to maintain the 9.80 percent ROE authorized in MGE's two most recent cases, dockets 3270-UR-121 and 3270-UR-122. The requested ROE falls within the range of ROEs most recently authorized by the Commission for other Wisconsin utilities. In light of the foregoing and in the context of the proposal in its complete form, the Commission finds that maintaining MGE's ROE at 9.80 percent is reasonable.

Required Return on Rate Base

MGE's 7.21 percent WACC for 2021 must be translated into a rate of return that can then be applied to the average NIRB used to compute the overall return requirement in dollars. The estimate of MGE's average net investment rate base plus CWIP to Capital Applicable to Utility Operations and Accumulated Deferred Tax Credits (RATIO) for the 2021 test year is 104.65 percent. This estimate reflects all appropriate adjustments in the Settlement Agreement and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average NIRB.

To allow current returns on the average CWIP balance not accruing AFUDC at 100 percent, an adjustment must be added to the return on NIRB. Given MGE's financing and cash flow requirements in the test year and the forecasted amount of construction activity, the Commission finds it reasonable to allow a current return on 50 percent of CWIP that is not accruing AFUDC for the test year. It is also reasonable to adjust the required return on NIRB to provide a short-term debt return on certain regulatory assets as well as the proration of ADIT.

Accordingly, the Commission finds the required rates of return on average Wisconsin retail electric and natural gas net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

2021 Test Year	Electric	Gas
Weighted Cost of Capital	7.21%	7.21%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	104.65%	104.65%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	6.89%	6.89%
Average CWIP Balance (000's)	65,061	8,833
Remaining CWIP Earning a Current Return (000's)	18,574	3,777
Percentage of Remaining CWIP to Earn a Current Return	0.50%	0.50%
Average CWIP Earning a Current Return	9,287	1,888
Adjustment to Adjusted Cost of Capital to Provide a Current Return on CWIP	0.06%	0.18%
Required Rate of Return on Net Investment Rate Base	6.95%	7.07%

Electric Customer Rates and Tariff Changes

As part of its Settlement Agreement, MGE also proposed a number of specific class-level tariff and rate changes. Those proposed changes are reviewed in detail in Attachment C, Schedules 1-22 of MGE's Settlement Agreement. (PSC REF# 396059). A review of the more significant changes is also provided in the sections below. Ultimately, the Commission finds it reasonable to approve the electric rates and tariff changes proposed by MGE, with modifications discussed herein. It is reasonable to allocate revenue responsibility and designing rates amongst various customer classes in the same manner as in docket 3270-UR-122 (PSC REF#: 355887) to mitigate different rate impacts amongst the classes.

Renewable Flat Bill Pilot Program

MGE has proposed to add a renewable flat bill pilot program, allowing up to 30 customers to enroll during the pilot period. This pilot program would allow customers who voluntarily enroll to have their annual energy consumption assessed, and then MGE would set an appropriate monthly payment based on the method described below that would remain constant for 12 months, barring any significant change to the customer's consumption. Unlike utility budget billing programs, MGE will not annually true-up customers' past bills, and will only reassess and make adjustments to the customers' flat bill amounts prospectively for future bills. Notably, this pilot program has many similarities to the Fixed Amount Bill Rider offered by WP&L, which was approved as a pilot program in docket 6680-UR-120,[12] and subsequently had the customer cap lifted in docket 6680-TE-105.[13] For example, if a customer's energy usage exceeds 50 percent of MGE's estimates over a 6-month period, MGE may, at its discretion, true-up the customers' bills, add a $30 administrative fee, and remove the customer from the flat bill program per the tariff conditions. There are some key differences that the MGE proposal has with WP&L's flat bill program. For example, MGE would place the enrolled customers on its Renewable Energy Program whereas the WP&L program does not do this. Additionally, instead of using an average bill formula for all customers like the WP&L program, MGE will only use a formula for high-usage customers, while customers who have an average monthly consumption below 1000 kilowatt-hours (kWh) per month will be placed into a certain tranche that corresponds to their usage.

The tranche system that MGE has proposed to use would place each customer into one of ten possible tranches based on the customer's average monthly consumption, and that customer would pay the same amount each month for one year, barring any significant changes in the customer's consumption. Each tranche corresponds to a 100 kWh range of usage, starting from 0-100 kWh per month. MGE has proposed to set the rate for each tranche based on the high-end usage for each tranche (e.g. for 100-200 kWh per month, the bill is based off of 200 kWh) which will also include an adder of $0.01/kWh for enrollment on the Renewable Energy Program. For

[12] 6680-UR-120 Final Decision dated December 22, 2016. (PSC ERF#: 295820.)
[13] 6680-TE-105 Final Decision dated October 10, 2019. (PSC ERF#: 377258.)

customers whose average monthly usage is in excess, MGE has proposed to set their monthly bills using the same formula as what is used in WP&L's Fixed Amount Bill Rider, with the only differences being that MGE has a more nuanced breakdown of their energy charges and the addition of the renewable energy adder.

The Commission considered recommendations proposed in Commission staff's memorandum to include reporting requirements for this pilot program. Commission staff proposed the following reporting requirement: customer participation, retention, and annual complaints; customer satisfaction results every two years; the number of company-initiated customer removals from the program each year; the average increase and decrease in electric consumption from program participants; the average dollars saved and average dollars lost for customers enrolled in the program; and copies of all the outreach materials and disclosures sent to customer regarding the Renewable Flat Bill Pilot Program.

Joint comments submitted by the Settling Parties voiced their opposition to the two reporting requirements that request the average increase and decrease in electric consumption from program participants, and the average dollars saved or lost by program participants. The parties state that energy usage can vary year to year based on factors outside of the program, and that the program is not designed to provide savings or surcharges to customers, that its main goal is to provide bill stability.

The Commission finds it reasonable to approve the Renewable Flat Bill Pilot Rider, and further finds that all of the staff-proposed reporting requirements are reasonable, as this is information that the Commission has requested from previous flat bill pilots, and prospective customers may be interested in seeing these data before enrolling in the program.

EV Fleet Pilot Program

Schedule 21 in Attachment C of MGE's application includes a proposed EV Fleet Pilot Program for new customers taking service under the Cg-2 and Cg-4 tariffs. The proposed EV Fleet Pilot Program would offer discounted demand charges to customers who own or lease EVs with charging infrastructure billed on a dedicated meter that is separate from other metered loads. The dedicated EV meter(s) would be eligible to receive an 80 percent discount to both the maximum monthly on-peak 15-minute demand charge, and the customer maximum 15-minute demand charge, starting in the first year. The discounts then decrease by 20 percent each year over a five-year period, after which the customer would be paying full demand charges without any discounts. MGE included one page of proposed tariff language in Schedule 21 of Attachment C to its application. The EV Fleet Pilot Program language lacks several components the Commission has identified as desirable components of EV programs in docket 5-EI-156. (PSC REF#: 402117.) Commission staff raised the following concerns:

1. The proposed tariff language does not clearly define whether program availability is limited to new Cg-2/Cg-4 customers, new EV charging infrastructure, or simply installing new dedicated meters for existing EV charging infrastructure;
2. The proposed EV Fleet Pilot Program does not include any program capacity or customer participation limits;
3. The proposed EV Fleet Pilot Program does not include a term limit;
4. The proposed EV Fleet Pilot Program does not include any evaluation metrics, data collection, or reporting requirements; and
5. The proposed demand charge discounts may result in cross-subsidization by other customer classes.

The Commission considered recommendations proposed in Commission staff's memorandum for clarifying tariff availability language, implementing a program capacity/participation limit, implementing a term limit, and reporting requirements. (PSC REF#: 399478.) MGE's response to Commission staff's data request clarified that; "Any existing or new [Cg-2 or Cg-4] customer with existing and/or new EV charging infrastructure with a dedicated meter will be able to participate in this pilot program." (PSC REF#: 397520) MGE shall revise the proposed tariff language to clearly define customer eligibility for the program to align with this response.

Joint comments submitted by the Settling Parties did not express opposition to Commission staff's recommendations and stated that Commission staff's proposed reporting requirements "are reasonable and will help to develop meaningful information for the program." (PSC REF#: 400001.) Therefore, the Commission finds it reasonable for MGE to work with Commission staff to develop reporting requirements using docket 5-EI-156 and existing EV programs as a guide. Participation and cost information related to the demand charge discounts will provide useful information to facilitate program comparison, and inform future Commission decisions related to program continuation, expansion, or modification. Reporting on participating customers' avoided demand costs in relation to service extension costs paid by the customer upfront, as well as program administration costs, would also be useful for pilot assessment. MGE's response to Commission staff data request TM-1.8 states that program effectiveness will be gauged on both the number of commercial fleets who have installed dedicated charging infrastructure, and the number of EVs incorporated into their respective fleets. MGE also stated that the utility will collect meter data and perform analysis for all program participants.

The Commission considered program capacity/participation limits and term limits, but finds that they are not necessary at this time. The Commission recognizes the value of giving MGE "a leash to get started" with the pilot program, but will require MGE to evaluate and propose capacity/participation limits as part of the utility's next rate case. Data collected from this pilot program will provide valuable insight into program improvement and ensure that other ratepayers are not subsidizing program participants.

PV Connect

MGE proposed to offer a new tariff for customer-owned PV systems that are separately metered and interconnected directly into MGE's distribution system. MGE currently offers parallel generation tariffs for varying sizes of customer-owned generation systems. However, MGE's parallel generation tariffs are for systems behind the customer's meter, in which sometimes the customer-owned generator serves the customer directly for on-site consumption, and sometimes the excess generation from the customer-owned generator is delivered on MGE's distribution system. Since the PV Connect tariff is designed for PV systems directly interconnected to MGE's distribution system, no generation will be consumed on-site as all of the generation will be delivered on MGE's distribution system. MGE has only proposed the tariff for PV resources, and no energy storage devices may be used in combination with the PV interconnection. MGE proposed to cap the tariff offering at a total of 5 MW for the total utility, with an additional 1.5 MW per customer participation limit cap.

Commission staff's memorandum described that the terms and conditions of MGE's proposed PV Connect tariff are similar to MGE's current Pg-1: Parallel Generation tariff; however, PV Connect participating customers must sign a 25-year agreement, which parallel generation participating customers are not required to do. MGE proposes a grid connection and customer service charge of $0.78669 per day for the PV Connect tariff, which is more than twice the charge per day for the Pg-1 tariff if the customer is required to install a separate meter for the parallel generation interconnection ($0.32210 per day for single-phase and $0.38210 per day for three-phase). The buyback rates for energy purchased by MGE would be the same as the buyback energy rates under the Pg-1 tariff, for which the buyback rates are listed under MGE's separate Sheet E-55 in its tariff book.

Commission staff's memorandum also described that MGE proposes a different capacity payment for the PV Connect than is currently offered under MGE's Pg-1 tariff. MGE's Pg-1 tariff offers a capacity payment of $0.00027 per kWh for on-peak generation only, as listed in Sheet E-55. This amount is based on the most recent MISO capacity auction results, which will be reset annually. For the PV Connect tariff, MGE proposed to offer a different capacity payment, the amount for which is based on the MISO Cost of New Entry (CONE), which will be reset annually. The current capacity payment based on the MISO CONE is $0.25167 per kW per day for the accredited capacity amount as listed in MGE's proposed PV Connect tariff.

In response to Commission staff data request TM-1.11, MGE provided information on the difference between the MISO capacity auction and MISO CONE approaches, as well as MGE's rationale for taking an approach for the PV Connect tariff that is different than its current parallel generation tariffs for capacity payment. (PSC REF#: 397520.) MGE responded that the PV Connect tariff includes a customer obligation to provide capacity for the entire 25-year PV Connect Service Agreement, which the parallel generation tariffs do not require. Additionally, if the PV Connect customer terminates the agreement before the end of the 25-year contract, the customer must pay a "Capacity Reprocurement Fee," which represents what MGE would have paid the customer for capacity payments for the rest of the contract after early termination. This assumes that MGE would then need to procure capacity to replace the PV Connect resource. Additionally, MGE stated that parallel generation tariffs allow customers to consume customer-owned generation on-site, which then allows the customer to avoid applicable energy and demand charges in proportion to how much the customer consumes on-site from the customer-owned generator. Since all of the generation under the PV Connect tariff will be delivered on MGE's distribution system, the customer cannot avoid energy and demand charges as no energy will be consumed directly by the customer on-site.

In response to Commission staff's memorandum, the Settling Parties stated that the Commission should approve the PV Connect tariff as proposed, as setting capacity payments at the MISO CONE is consistent with the Commission-approved RER-1 tariff and similar programs for other utilities, which are also contract-based renewable tariffs. The Commission finds that it is reasonable to approve of the PV Connect tariff as proposed, with the clarification that the 5 MW program limit, and the 1.5 MW per customer participation limit, shall be in terms of the PV systems' AC capacity rating. This decision for the MGE PV Connect tariff does not set a policy precedent for future Commission decisions and is based upon the specific facts of this case and the Settlement Agreement as a total package.

Commissioner Nowak dissents and would not have authorized the PV Connect program at this time.

Bring Your Own Device Program

The Settlement Agreement proposed expansion of MGE's Bring your Own Device program to allow more residential customers to participate. Service under this voluntary rider is available to MGE electric customers that have an eligible smart thermostat connected to a central air-conditioning system and who have enrolled via MGE's energy management platform. This service will apply for a minimum of 12 months and any customer that terminates this service after 12 months may not re-enroll in the program for 12 months from the date of termination. Customers enrolled in this program will have their thermostats controlled by MGE in order to reduce electrical demand during high electricity demand periods. These events will typically take place during peak hours in the months of June, July, August, and September. The program is limited to 20 events per year and 4 hours per event. Customers will be able to opt-out of an event at any time unless the event is a Mandatory Event which will occur when the North American Electric Reliability Corporation declares a Level 2 Alert for MGE's service territory. A one-time payment of $50 will be provided to the customer after they have enrolled in the program. Additionally, a payment of $25 will be provided for every summer of participation beginning with the second summer.

The Commission concludes that is reasonable to authorize this program as it may incentivize customers to help reduce system costs. However, further analysis of this program is required. Therefore, as a condition of authorization, MGE shall provide additional analysis of this program as part of its next rate case filing.

Commissioner Huebner dissents and would not have authorized the modifications at this time.

Residential Time-of-Use Tariffs

MGE proposed to close its current residential optional time-of-use rate, Rg-2, to new customers, and open a new residential optional time-of-use rate, Rg-2A. MGE's reasoning for this proposal stems from the desire to move from a penalty-based pricing system for energy, to a cost-based one. As a result of the methodology change that MGE has proposed, the difference between the highest and lowest energy charges is smaller than what the current difference is in the Rg-2 tariff. As MGE is only seeking to close the Rg-2 tariff to new customers, there is no issue with a diminution of service to any customers.

Under MGE's proposal, the base rate, or off-peak period, energy charge would be higher on the Rg-2A rate than on the current Rg-2 rate. As a result of the base rate increasing, the three on-peak periods have been lowered and rebalanced in such a way that the second on-peak period is no longer such a large increase from the other on-peak periods. Commission staff asked MGE whether it had any concern that the cost-based rate design would not send the proper price incentives to customers, and MGE stated that it had no concern about customers not reacting to price signals, as all of the on-peak charges are at least 200 percent greater than the base charge. MGE also stated in its response that this change allows for a more sustainable revenue recovery, as MGE anticipates more customers would be interested in the pricing system established in the Rg-2A proposal.[14]

As the only substantive difference between the current Rg-2 and the proposed Rg-2A rate is the price for the different on-peak periods and the off-peak period, Commission staff requested that MGE provide sample calculations of what a customer's bill would be under Rg-1, Rg-2, and Rg-2A. The results of this analysis show that the sample customer that MGE used, and provided they made no load-altering measures are taken by the customer, the cheapest option remains the flat energy rate. However, the proposed Rg-2A tariff would result in the customer paying less

[14] TM 1.21. (PSC ERF#: 397520.)

than they would on the current Rg-2 tariff. Prospective customers would be able to see even more savings if they have the ability to change their consumption pattern to use more energy during the base period times. The Commission finds this proposed rate design to be reasonable, as it still sends some price incentive for customers to reduce their on-peak energy consumption, and may attract more customers as the surcharges for on-peak energy consumption are lower than the Rg-2 on-peak energy rates.

Commercial and Industrial Tariff Changes

Schedule 5 in Attachment C of MGE's application includes proposed changes to commercial and industrial tariffs. MGE's proposal does not include any changes to energy, demand, or fixed customer charges. The proposed changes involve the interaction and availability of the Cg-3, Cg-4, and Cg-5 tariffs. MGE proposed to close the Cg-3 tariff to new customers, which offers time-of-day pricing to small commercial customers whose monthly demand is lower than 20 kW. This change would affect new customers taking service under the Cg-5 tariff who would rather be charged under time-of-use rates than the Cg-5 flat energy rate. Customers seeking time-of-use rates would be allowed to move into the Cg-4 class as an optional service offering. Option A and Option B under the current Cg-4 tariff are also combined into a single offering since they have been identical for several years.

The Cg-4 tariff is fundamentally different from both Cg-3 and Cg-5 tariffs because it includes both energy charges ($/kWh) and demand charges ($/kW), while the Cg-3 and Cg-5 tariffs only include energy charges. The current Cg-4 tariff and MGE's proposed revisions to the Cg-4 tariff do not clearly state whether a Cg-5 customer who chooses to take service under the Cg-4 tariff would be required to install a demand meter and incur monthly demand charges that they currently do not pay under the Cg-3 and Cg-5 tariffs. MGE's response to Commission staff data request TM-1.5 states that Cg-5 customers taking service under the Cg-4 tariff must have demand meters installed, which are the same meters required for a Cg-3 customer. These Cg-5 customers taking service under the Cg-4 tariff would be required to pay any and all billing charges, such as demand charges. (PSC REF#: 397520.) The Commission finds it reasonable for MGE to revise the proposed Cg-4 tariff language to clearly state that the demand meters are required for opt-in service under the Cg-4 tariff and that demand charges apply to opt-in customers below the 20 kilowatts (kW) threshold for mandatory service under the Cg-4 tariff.

Commission staff analysis showed that closing the Cg-3 tariff to new customers would effectively force those customers to incur demand charges in order to take advantage of time-of-use rates. This may be a worthwhile trade-off for some customers, but it may also result in higher energy bills for customers with lower load factors who currently see lower bills under the Cg-3 tariff. While this change will affect new customers, existing Cg-3 customers will not be forced to take service under the Cg-4 tariff with the potential for higher energy bills. The Commission finds MGE's proposed changes to be reasonable given that service under the Cg-4 time-of-use rate schedule is optional for small commercial customers, as long as customers opting into the Cg-4 rate schedule are made fully aware of their responsibility to pay both energy and demand chargers.

Sp-3 Tariff Proposed Changes

Schedules 2 and 17 in Attachment C of MGE's application proposed two substantive changes to the Sp-3 tariff schedule, whose sole customer is UW. The tariff revisions proposed in Schedule 2 involve the incorporation of an interruptible service component into the Sp-3 tariff that is similar to MGE's existing Is-3 and Is-4 interruptible service riders, both of which are currently available to the Sp-3 class. The incorporation of this language in the Sp-3 tariff serves to streamline the tariff, eliminating the need for UW to apply for service under the Is-3 or Is-4 rider, but also makes participation in the interruptible service program mandatory rather than optional. Joint comments submitted by the Settling Parties stated that the proposed Sp-3 tariff revisions were the result of good faith negotiations. UW also filed a letter in support of the proposed changes stating that it, "appreciates the collaboration with MGE on the development of interruptible rates for the Sp-3 tariff." (PSC REF#: 397528.)

MGE's proposed Sp-3 interruptible service language includes both firm and interruptible nominations of 61,000 kW and 1,000 kW, respectively. This differs from the current Is-3 and Is-4 riders which only provide a single nomination. MGE proposes to take responsibility for notifying UW when an interruption event is to occur, and which nomination (firm or interruptible) UW must curtail. Minimum notice of 4 hours must be provided for the interruptible nomination, and 12 hours' notice must be given for the firm service nomination. This provides UW with greater lead time to plan for service interruptions compared to the Is-3 and Is-4 riders, which do not provide any minimum notice prior to interruption events. The maximum duration of a single interruption may not exceed 8 hours, and there will be no more than 150 hours of cumulative interruptions during a calendar year. The cumulative interruption provision is identical to those included in MGE's current Is-3 and Is-4 riders, but the 8-hour limit on individual interruptions is unique to the proposed Sp-3 program because it was identified as an important restriction during negotiations between MGE and UW. The proposed Sp-3 interruptible credit that will be applied to on-peak demand charges is set at the current Is-4 rate of $0.13151/kW-day. MGE will not be registering either the Sp-3 interruptible load value or the firm load nomination with MISO for the 2021 planning year. Either or both of these interruptible values may be registered with MISO in the 2022 planning year depending on performance in 2021. (PSC REF#: 397520.) The customer must comply with annual testing protocols to ensure that they are capable of reducing load when called upon.

MGE estimates that the interruptible credits will reduce Sp-3 annual revenue by $78,626 in test-year 2021. Any change to Sp-3 class revenue must be accounted for in a cost-of-service study (COSS) during MGE's next full rate case to avoid inter-class cross-subsidization. MGE has also proposed a revenue neutral change in monthly fixed customer charges and maximum measured demand charges. The Customer Charge will decrease from $35,615 per day to $34,931 per day result in a $250,025 reduction in annual revenue. The reduced customer charge is offset by an increase to the Distribution Demand charge from $0.11810/kW-day to $0.12968/kW-day that produces an estimated $250,026 in annual revenue based on test-year 2021 data. The Commission finds the proposed Sp-3 tariff changes to be reasonable while providing the Sp-3 customer with more agency to control their energy costs. Future changes to Sp-3 class distribution demand, and related impacts on revenue and cost allocation to other customer classes, shall be addressed in a COSS during MGE's next full rate case.

Battery Interconnection Rule

MGE proposed to add the following language to its current service rules for customer-owned generating equipment (sheet E-67):

> All customer-owned batteries that are capable of, or intended to be capable of, "parallel operation" as defined in § PSC 119.02 (30) will be subject to any and all service rules and regulations and § PSC 119 rules that pertain to distributed generation facilities.

Chapter PSC 119 implements Wis. Stat. § 196.496, and applies to all distributed generation (DG) facilities with a capacity of 15 MW or less that are interconnected. Wis. Admin. Code § PSC 119.01(12)-(13). DG facility is defined as a "facility for the *generation* of electricity with a capacity of no more than 15 megawatts that is located near the point where the electricity will be used or is in a location that will support the functioning of the electric power distribution grid." Wis. Stat. § 196.496(a) (emphasis added).

Commission staff's memorandum described that MGE's battery interconnection language appears to be seeking authorization to treat customer-owned batteries the same as customer-owned generating equipment under Wis. Admin. Code ch. PSC 119. The language that MGE proposes to add basically states that customer-owned batteries that are capable of "parallel operation" will be subject to the same service rules under Wis. Admin. Code ch. PSC 119, which are the rules for interconnecting DG facilities.

The definition of "parallel operation under the code means the operation "of an on-site DG Facility" under certain circumstances. Wis. Admin. Code. § PSC 119.02(30). In short, to be engaged in parallel operation as it is defined under § 119.02(3), and subject to the rules, the battery must be a DG facility. The Commission could thus interpret the proposed language as saying nothing more than that DG Facilities will have to follow the DG Facility rules.

Chapter PSC 119 describes the technical specifications, safety regulations, insurance requirements, and other standards that customer-owned generation must meet before the equipment may be interconnected with a utility's distribution system. From a technical perspective, even though batteries themselves aren't considered to be generation facilities, applying the same rules to batteries appears to be logical, as batteries are capable of discharging energy onto the grid similar to how a generator delivers energy onto the grid. However, batteries are not specifically listed under Wis. Admin. Code ch. PSC 119, and the title and definitions throughout the code section were written to apply to DG facilities. It appears likely that the lawmakers who originally wrote ch. PSC 119 did not contemplate customer-owned batteries being interconnected with a utility's distribution system at the time. As the cost of batteries has come down, and the need for storage of electricity has gone up, Commission staff's memorandum describes that MGE is likely requesting to add the language in anticipation of customers attempting to interconnect batteries. With no language in ch. PSC 119 or MGE's service rules pertinent to batteries, Commission staff's memorandum describes that the Commission could find that the added proposed language would add clarity and proactively put customers on notice that the code will apply to batteries when those batteries meet the definition of a DG facility. Commission staff also noted that the proposed language could be potentially confusing to the extent it could be read to imply an expansion of Chapter PSC 119's applicability to stand-along batteries.

In response to Commission staff's memorandum, the Settling Parties supported the MGE-proposed battery interconnection language, and stated that the proposed language will allow customers to apply for battery interconnection under an established administrative process, with the understanding that a pending update to the Commission's interconnection rule under ch. PSC 119 may result in changes to this tariff if the rule is updated.

The Commission finds that MGE's proposed language for battery interconnection is reasonable, as it will put customers on notice that Chapter 119 will apply to batteries when those batteries meet the definition of a DG facility. To avoid potential confusion, however, the Commission expressly notes that the approval of MGE's new language in its service rules for customer-owned generating equipment does not explicitly expand the scope of ch. PSC 119.

NLMP Rider Proposal

MGE has proposed to add language into its NLMP rider that would allow customers enrolled on that tariff to file a request that the utility make an adjustment to their baseline demand and energy levels once every 12 months in the second or subsequent years of taking service on this rider. The customer is allowed to request an adjustment to the customer's baseline levels if they have had a systematic decrease in their baseline consumption as a result of energy efficiency or conservation upgrades, process improvements, or the installation of new equipment. This language was recently added to the WEPCO Real Time Market Pricing rider as part of the settlement in docket 5-UR-109.[15]

The Commission finds this request to be reasonable, as it removes a function of this tariff that could be a disincentive for customers seeking to reduce their overall energy and demand consumption. This language serves to benefit both the utility and the customer by providing the right incentive for a customer to efficiently reduce their baseline energy consumption, while still allowing them to receive the full NLMP benefits for their new load.

Primary Voltage Provision (PVP-1)

MGE proposed in the Settlement Agreement to remove all Primary Discount Provision language from the Cg-4, Cg-8, Cg-2, Cg-2A and Cg-6A rate schedules and offer a Primary Voltage provision (PVP-1) to electric customers. MGE also proposed in the Settlement Agreement to modify the availability and applicable of the primary service discounts in the PVP-1 relative to the existing Primary Discount provision in the applicable rate schedules. The Commission concludes these changes are reasonable as it is a miner change that benefits both the

[15] Docket 5-UR-109 Final Decision dated December 19, 2019. (PSC REF#: 381305.)

utility and customers in that it implements consistency and efficiency due to a reduction of repetitive tariff provisions.

Natural Gas Customer Rates and Tariff Changes

As part of its Settlement Agreement, MGE also proposed natural gas tariff and rate changes. Those proposed changes are reviewed in detail in Attachment D of MGE's Settlement Agreement. (PSC REF# 396059). A review of the more significant changes is also provided in the section below. Ultimately, the Commission finds it reasonable to approve the natural gas rates and tariff changes proposed by MGE.

The Settlement Agreement, which includes a 4.1 percent rate increase in natural gas rates, incorporated all of Commission staff's audit adjustments. The revenue requirement for natural gas was uncontested.

When determining and analyzing the final revenue allocation, the Commission has historically used multiple COSS models, as well as other factors, such as customer bill impacts, to determine an appropriate change to the class revenue. While natural gas COSS models were not presented in this case, MGE settled with the Parties on a revenue allocation that raises the margin revenue on all customer classes in a manner comparable to the overall margin revenue increase. The Commission finds this approach to be reasonable as it limits disparate bill impacts across customer classes. It is important to note that under MGE's proposed increase to natural gas rates, the only change to customers' rates comes through the distribution charge, which is assessed on a per therm basis. By limiting the rate increase strictly to volumetric charges as opposed to a fixed charge increase, customers will be able to have more control over their bill and the rate increase they will see.

Natural gas rates as identified in Appendix C of this Final Decision.

SUDS-1

The Settlement Agreement proposed altering the pricing structure of the SUDS-1 tariff from a three-tier declining block rate to a two-tier block rate. It has also proposed to decrease the adder for consumption during peak times of the year. Commission staff stated that the change from a three-tier declining block rate structure to a two-tier declining block rate structure does not significantly impact the overall function of this tariff, nor does it alter the price incentives sent to customers. While the decrease proposed to the on-peak adder is large, the proposed adder of $0.10 per therm still sends a strong incentive to customers to use as little natural gas during peak times of the year as possible. An adder at $0.10 per therm increases the per therm price by 64.8 percent for the first 5,000 therms of sales, and by 71.7 percent for any additional sales of therms. The Commission concludes that this change is reasonable.

Other Settled Rate Design Issues

The Settlement Agreement included provisions relating to certain other rate design issues which were agreed to among the Settlements and included the following:

- MGE agreed to continue to work with CUB and WIEG in 2020 and 2021 on new rates or other innovative programs targeted at industrial, residential, and small commercial customers, respectively.

- MGE agreed to continue to work with CUB and Clean Wisconsin to develop new pilot rate programs and propose any agreed upon pilots to the Commission.

- MGE agreed in its next rate case application to provide CUB with the results of a detailed household burden index analysis which evaluates residential electric and natural gas utility customer bills as a percentage of household income.

Conditions on Approval of Settlement Agreement

Based upon the recommendations from Commission staff, comments received, and the other evidence in the record, the Commission concludes that it is reasonable to condition the Commission's approval of the Settlement Agreement, pursuant to its authority under Wis. Stat. §§ 196.026(8) and 196.395, upon the following:

1. By January 1, 2021, MGE shall revise its existing rates and tariff provisions for both electric and natural gas utility service, substituting the rate modifications and tariff provisions that expand the terms of services, as described in this Final Decision.
2. MGE shall prepare bill messages that properly identify the rates authorized in this Final Decision. MGE shall provide the message to customers no later than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill messages with the Commission before it provides the message to customers.

As discussed elsewhere in this Final Decision, the unique character of a settlement means that the Commission cannot know the specific reasons why a particular provision was included, or how it relates to other aspects of the Settling Parties' agreement. The Commission thus further finds it reasonable to include as a condition an explicit statement about the non-precedential nature of the Commission's approval of the Settlement Agreement:

3. Approval is based upon the specific facts of this case and the negotiated agreement of the Settling Parties, and has no precedential value and shall not be construed as being applicable to any other situation outside of this particular Settlement.

Rate Case Filing and Fuel Cost Plan

The Commission considered, and declined to adopt conditions proposed by Sierra Club. The Commission, however, finds it reasonable to require MGE to file a full rate case, containing particular information that is discussed more particularly above in the discussion of particular aspects of the settlement, no later than May 1, 2021, including: (1) a detailed cost of service study (COSS) and rate design for electric and natural gas operations, (2) an analysis of the operations and maintenance fee savings due to the reduced payment processing costs resulting from increased credit card usage that may result from the use of escrow accounting treatment for credit card convenience fees, (3) an analysis of the impact of the revisions to the Cg-3, Cg-4 and Cg-5 tariffs, (4) an analysis of the Bring Your Own Device Program, (5) a proposed capacity limit, program term limit, and program evaluation and reporting requirements for its Electric Vehicle Fleet Pilot Program (if not provided in a separate tariff filing), and (6) any future changes to the Sp-3 class distribution demand, and related impacts of revenue and cost allocation to other customer classes, should be addressed in the COSS.

As part of that filing, MGE shall also file its 2022 Fuel Cost Plan with the Commission in 2021. The same process will be used to determine the appropriate monitored fuel costs for MGE for 2022. Again, Wis. Admin. Code ch. PSC 116 requires a hearing to take place as part of establishing a record for the Commission to determine monitored fuel costs. As with the 2021 Fuel Cost Plan, the final monitored fuel cost amount for 2022 will be used to determine the final rates for 2022. All non-monitored fuel costs, all revenues, all other expenses and rate base, and other components of the revenue requirement established for 2021 will be addressed by the full rate case filing for the 2022 test year.

Effective Date

This Final Decision constitutes final action on MGE's applicant to adjust Wisconsin retail electric and natural gas base rates for test year 2021, and for approval of MGE's 2021 Fuel Cost Plan. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2021, provided that MGE files these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19, Wis. Admin. Code §§ PSC 113.406(1)(a), and 134.05 by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect on the date they are filed with the Commission and made available to the public. By January 1, 2021, MGE shall file its existing rates and tariff provisions for electric utility service, and substituting the rates and terms of services as shown in Appendices B, C and D.

Unless expressly stated, this Final Decision does not supersede any requirements included in prior Commission orders which remain in full force and effect from prior Commission orders.

Order

1. The Settlement Agreement, as modified and conditioned by this Final Decision, is approved.

2. MGE shall maintain existing base retail electric rates through 2021.

3. By January 1, 2021, MGE shall revise its existing rates and tariff provisions for both electric and natural gas utility service, substituting the rate modifications and tariff provisions that expand the terms of services, as described in this Final Decision (no change to electric rates, see Appendix C for revised natural gas rates). These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

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

5. MGE shall file tariffs consistent with this Final Decision.

6. All 2021 monitored fuel costs shall be monitored using a plus or minus 1.00 percent tolerance band.

7. The electric fuel costs in Appendix D shall be used for monitoring MGE's 2021 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

8. MGE shall file a depreciation study by June 1, 2021.

9. MGE shall separately seek review of its 2022 fuel cost plan consistent with the requirements of Wis. Admin. Code ch. PSC 116 and the Settlement Agreement.

10. All EDIT related bill credits shall be trued-up in accordance with docket 5-AF-101.

11. Any savings from the TCJA not addressed in the Settlement Agreement shall be addressed in docket 5-AF-101 or in a future rate case proceeding.

12. MGE shall defer, with escrow accounting treatment pension and OPEB expense, as set forth in the Settlement Agreement through December 31, 2021.

13. MGE shall defer, with escrow accounting treatment, the incremental difference between its actual bad debt expense and the bad debt expense forecasted for the 2020 test year from the Commission's Final Decision in docket 3270-UR-122, ending on December 31, 2021, unless subsequent Commission authorization is granted.

14. MGE shall defer, with escrow accounting treatment for credit card convenience fees for the 2021 test year ending December 31, 2021. In MGE's next rate case filing, MGE should provide an analysis of the O&M fee savings due to the reduced payment processing costs resulting from increased credit card usage.

15. MGE shall continue to capitalize costs related to cloud computing.

16. MGE shall accrue AFUDC on 100 percent of CWIP associated with projects requiring a CA or CPCN upon approval of a CA or CPCN by the Commission through December 31, 2021.

17. MGE shall eliminate its SO_2 allowance escrow.

18. MGE shall record conservation escrow expenditures as set forth in the Settlement Agreement and detailed in Appendix E.

19. All authorized amortizations shall begin on January 1, 2021 or as of the effective date of this Final Decision, whichever is later.

20. The annual expense amounts itemized in Appendix E shall be recorded for all items listed for 2021 or until the Commission authorizes a different amortization expense to be recorded.

21. MGE shall maintain a long-term range of 55.00 to 60.00 percent for its common equity ratio, on a financial basis.

22. MGE 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 55.00 percent.

23. MGE's proposal to establish an EV Fleet Pilot Program is APPROVED contingent on the conditions listed below:

a. Revise proposed tariff language to clearly state that the program is available to both new and existing Cg-2 and Cg-4 customer who install dedicated meters for new/existing EV charging infrastructure.

b. Work with Commission staff to develop reporting requirements for evaluating pilot success metrics based on docket 5-ER-156 and other existing EV programs.

24. MGE's proposed revisions to the Cg-3, Cg-4, and Cg-5 tariff schedules are APPROVED contingent upon MGE's inclusion of language in the Cg-4 tariff clearly stating the opt-in customers must install demand meters and incur monthly demand charges.

25. MGE's proposed revisions to the Sp-3 tariff schedule are approved as filed.

26. MGE shall offer a PV Connect tariff as shown in the Settlement Agreement (Attachment C, Schedule 8), with the clarification that tariff references to the 5 MW total, and 1.5 MW per customer, capacity ratings be listed in terms of the AC capacity rating.

27. MGE shall revise Sheet E-67 (MGE's service rules for customer-owned generating equipment) within its tariff to implement its proposed battery interconnection language, as shown in the Settlement Agreement (Attachment C, Schedule 19).

28. MGE shall offer a Renewable Flat Bill Pilot as shown in the Settlement Agreement (Attachment C, Schedule 1), and shall report the following to the Commission: customer participation; retention; annual complaints; customer satisfaction results every two years; the number of company-initiated customer removals from the program each year; the average increase and decrease in electric consumption from program participants; the average dollars saved and average dollars lost for customers enrolled in the program; and copies of all outreach materials and disclosures sent to customers regarding the program.

29. MGE shall offer the Bring Your Own Device program as shown in the Settlement Agreement (Attachment C, Schedule 3).

30. MGE shall close the Rg-2 tariff to new customers, and open the Rg-2A tariff, as shown in the Settlement Agreement (Attachment C, Schedule 4).

31. MGE shall add language to its NLMP tariff allowing customers to request a reassessment of their baseline energy and demand consumption when they implement energy or demand reducing measures.

32. MGE shall consolidate all language pertaining to primary voltage discounts into one schedule.

33. MGE shall make other miscellaneous tariff changes as shown in the Settlement Agreement (Attachment C).

34. MGE shall lower the on-peak adder for the SUDS-1 tariff to $0.10 per therm.

35. MGE shall continue to work with CUB and WIEG in 2020 and 2021 on new rates or other innovative programs targeted at industrial, residential, and small commercial customers, respectively.

36. MGE shall to continue to work with CUB and Clean Wisconsin to develop new pilot rate programs and propose any agreed upon pilots to the Commission.

37. MGE shall in its next rate case application to provide CUB with the results of a detailed household burden index analysis which evaluates residential electric and natural gas utility customer bills as a percentage of household income.

38. MGE shall file a full rate case by no later than May 1, 2021, that includes: 1) a detailed cost-of-service study (COSS) and rate design for electric and natural gas operations, 2) an analysis of the operations and maintenance fee savings due to the reduced payment

processing costs resulting from increased credit card usage that may result from the use of escrow accounting treatment for credit card convenience fees, 3) an analysis of the impact of the revisions to the Cg-3, Cg-4 and Cg-5 tariffs, 4) an analysis of the Bring Your Own Device Program, 5) a proposed capacity limit, program term limit, and program evaluation and reporting requirements for its Electric Vehicle Fleet Pilot Program (if not provided in a separate tariff filing); and 6) any future changes to the Sp-3 class distribution demand, and related impacts of revenue and cost allocation to other customer classes, should be addressed in the COSS.

39. Approval is based upon the specific facts of this case and the negotiated agreement of the Settling Parties, and has no precedential value and shall not be constructed as being applicable to any other situation outside of this particular settlement.

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

41. Jurisdiction is retained.

Dated at Madison, Wisconsin, the 29th day of December, 2020.

By the Commission:

Steffany Powell Coker
Secretary to the Commission

SPC:SKB:cmb:jlt:DL: 01775000

Attachments

See attached Notice of Rights

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

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

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

PETITION FOR REHEARING

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

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[16] 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

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

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN
(Not a party but must be served per Wis. Stat. § 227.53)
4822 MADISON YARDS WAY
PO BOX 7854
MADISON, WI 53707

AIR MERCHANT GASES
HEINZEN LAW SC
PO BOX 930370
VERONA WI 53593
USA
STEVE.HEINZEN@HEINZENLAW.COM

AIRGAS USA LLC
BRUCE HEBERTON
259 NORTH RADNOR CHESTER ROAD STE #220
RADNOR PA 19087
USA
BRUCE.HEBERTON@AIRGAS.COM

BOARD OF REGENTS OF THE UNIVERSITY OF WI SYSTEM
ANDREW NORMAN
361 BASCOM HALL 500 LINCOLN DRIVE
MADISON WI 53706
USA
ANDREW.NORMAN@WISC.EDU

CITIZENS UTILITY BOARD
COREY SINGLETARY
6401 ODANA ROAD STE 24
MADISON WI 53719
USA
SINGLETARY@WISCUB.ORG

CITIZENS UTILITY BOARD
KURT RUNZLER
6401 ODANA ROAD STE 24
MADISON WI 53719
USA
RUNZLER@CUBWI.ORG

CITIZENS UTILITY BOARD
THOMAS CONTENT
6401 ODANA ROAD STE 24
MADISON WI 53719
USA
CONTENT@WISCUB.ORG

CLEAN WISCONSIN
EARTHJUSTICE
3916 NAKOMA ROAD
MADISON WI 53711
USA
DBENDER@EARTHJUSTICE.ORG

CLEAN WISCONSIN
KATHRYN NEKOLA
634 WEST MAIN STREET STE 300
MADISON WI 53703
USA
KNEKOLA@CLEANWISCONSIN.ORG

JOHN KRUEGER, MANAGER - RATES
MADISON GAS AND ELECTRIC COMPANY
PO BOX 1231
MADISON WI 53701-1231
USA
MGE@MGE.COM

MADISON GAS AND ELECTRIC COMPANY
SCOTT R SMITH
P.O. BOX 1231
MADISON WI 53701
USA
SSMITH@MGE.COM

MADISON GAS AND ELECTRIC COMPANY
STAFFORD ROSEBAUM LLC
222 WEST WASHINGTON AVENUE STE 900
MADISON WI 53701
USA
BKLEINMAIER@STAFFORDLAW.COM

PUBLIC SERVICE COMMISSION OF WISCONSIN
CHRISTIANNE WHITING
4822 MADISON YARDS PO BOX 7854
MADISON WI 53707
USA
CHRISTIANNE.WHITING@WISCONSIN.GOV

PUBLIC SERVICE COMMISSION OF WISCONSIN
SHEENA BASRA
4822 MADISON YARDS WAY PO BOX 7854
MADISON WI 53707
USA
SHEENA.BASRA@WISCONSIN.GOV

PUBLIC SERVICE COMMISSION OF WISCONSIN
ZACHARY RAMIREZ
4822 MADISON YARDS WAY PO BOX 7854
MADISON WI 53707
USA
ZACHARY.RAMIREZ@WISCONSIN.GOV

RENEW WISCONSIN
MICHAEL VICKERMAN
214 NORTH HAMILTON STREET STE 300
MADISON WI 53703
USA
MVICKERMAN@RENEWWISCONSIN.ORG

SIERRA CLUB
EARTHJUSTICE
3916 NAKOMA ROAD
MADISON WI 53711
USA
DBENDER@EARTHJUSTICE.ORG

SIERRA CLUB
GREG WANNIER
2101 WEBSTER ST STE 1300
OAKLAND CA 94612
USA
GREG.WANNIER@SIERRACLUB.ORG

SIERRA CLUB
KRISTIN HENRY
2101 WEBSTER ST STE 1300
OAKLAND CA 94612
USA
KRISTIN.HENRY@SIERRACLUB.ORG

SIERRA CLUB
MEGAN WACHSPRESS
2101 WEBSTER ST STE 1300
OAKLAND CA 94612
USA
MEGAN.WACHSPRESS@SIERRACLUB.ORG

WISCONSIN INDUSTRIAL ENERGY GROUP
HEINZEN LAW SC
PO BOX 930370
VERONA WI 53593
USA
STEVE.HEINZEN@HEINZENLAW.COM

WISCONSIN INDUSTRIAL ENERGY GROUP
TODD STUART
44 EAST MIFFLIN STREET STE 404
MADISON WI 53703
USA
TSTUART@WIEG.ORG

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates — Docket No. 3270-UR-123

APPLICATION

INTRODUCTION

Madison Gas and Electric Company ("MGE" or the "Company") is pleased to submit its Application for Authority to Change Electric and Natural Gas Rates (the "Application") pursuant to the statutory settlement process outlined in Wis. Stat. § 196.026. MGE and four of the intervening parties in the docket have executed the settlement agreement: Citizens Utility Board (CUB), Wisconsin Industrial Energy Group (WIEG), RENEW Wisconsin (RENEW), and the Board of Regents of the University of Wisconsin System (UW). MGE thanks all intervening parties for engaging in the collaborative settlement process. MGE also thanks Public Service Commission of Wisconsin staff for all of the work performed by staff prior to the filing of the Application. The settlement agreement incorporates all audit adjustments made by Commission staff. Notably, MGE, CUB, WIEG, RENEW, and UW worked together to submit a settlement agreement that includes a zero percent (0%) electric rate increase for customers in 2021 as we continue to battle the COVID-19 pandemic.

The comprehensive settlement is attached to this Application as Exhibit A, and incorporates an Appendix A (Settlement Terms), Appendix B (financial schedules), Appendix C (electric service schedules / tariffs), and Appendix D (natural gas service schedules / tariffs) (collectively, the "Settlement Agreement"). The Settlement Agreement is a carefully constructed agreement generated by MGE and the intervening parties based on rounds of negotiation and compromise, and was facilitated by a thorough review of MGE's financial information by Commission staff.

MGE respectfully requests that the Public Service Commission of Wisconsin (the "Commission") approve the Settlement Agreement in its entirety, without modification, because:

- The four intervening parties that signed the Settlement Agreement adequately represent the public interest;
- The Settlement Agreement represents a fair and reasonable resolution in this rate case docket;
- The Settlement Agreement is supported by substantial evidence on the record as a whole;
- The Settlement Agreement complies with applicable law;
- The rates resulting from the Settlement Agreement are just and reasonable; and
- All parties in the docket will be given a reasonable opportunity to present evidence and arguments in opposition to the Settlement Agreement, to the extent applicable.

OVERVIEW OF SETTLEMENT AGREEMENT TERMS AND CONDITIONS

First and foremost, the Settlement Agreement includes a zero percent (0%) electric rate increase for customers in 2021. MGE again thanks CUB, WIEG, RENEW, UW, and Commission staff for all of the work to get to this result. As everyone continues to battle the COVID-19 pandemic, it was critical to avoid an electric rate increase.

Importantly, the Settlement Agreement also includes the addition of a number of new programs and services for MGE's customers, including, but not limited to:

- A pilot program containing a flat bill rate structure for residential electric customers. This pilot program is available to residential customers who wish to pay a flat monthly rate for electricity powered by renewable energy resources. Please see Attachment C, Schedule 1.

- An expansion of MGE"s Bring Your Own Device program to allow more residential customers to participate. Service under this voluntary program is available to electric customers who have an eligible smart thermostat connected to a central air-conditioning system and who have enrolled via the Company's energy management platform. Please see Attachment C, Schedule 3.

- An Electric Vehicle Fleet Charging Pilot rate for customers who own or lease electric vehicles for fleets. Please see Attachment C, Schedule 21.

Finally, the Settlement Agreement also reflects the addition of two large solar projects to MGE's generation portfolio – joint ownership of the Two Creeks and Badger Hollow I solar projects as approved by the Commission in Docket No. 5-BS-228. Like MGE's Saratoga Wind Farm project in Iowa, which came online in 2019, the Two Creeks and Badger Hollow I solar projects help MGE reduce its fuel costs and the volatility associated with fuel costs.

SETTLEMENT AGREEMENT SATISFIES STATUTORY CRITERIA FOR APPROVAL

MGE, CUB, WIEG, RENEW, and UW present the Settlement Agreement to the Commission for approval. MGE submits that the standards identified in Wis. Stat. § 196.026(7) are met and asks the Commission to approve the Settlement Agreement in its entirety, without modification.

Section 196.026(7) states:

> The commission may approve a settlement agreement under sub. (4) if all of following conditions are met:
>
> (a) All of the following have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement:
>
> 1. Each party that has filed an objection or nonobjection to the settlement agreement under sub. (6).
> 2. Each party whose failure to respond in writing constitutes a nonobjection to the settlement agreement under sub. (6).
>
> (b) The commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

(c) The commission finds that the settlement agreement represents a fair and reasonable resolution to the docket, is supported by substantial evidence on the record as a whole, and complies with applicable law, including that any rates resulting from the settlement agreement are just and reasonable.

MGE, CUB, WIEG, RENEW, and UW support and have executed the Settlement Agreement. These intervening parties blanket the spectrum of customer interests and adequately represent the public interest. Resulting from rounds of negotiations and compromise by all parties, the Settlement Agreement represents a fair and reasonable resolution in this rate case docket. The Settlement Agreement is supported by the substantial evidence contained in the attachments,[1] it complies with applicable law, and the rates contained in the agreement are just and reasonable. Indeed, this docket again demonstrates that the settlement process identified in Wis. Stat. § 196.026 can work efficiently and effectively to resolve matters before the Commission.

Consequently, MGE respectfully requests that the Commission approve the Settlement Agreement in its entirety, without modification.

Dated August 28, 2020.

STAFFORD ROSENBAUM LLP

/s/ Bryan Kleinmaier
By_________________________________
Bryan Kleinmaier
Attorney for Applicant,
Madison Gas and Electric Company

222 West Washington Avenue, Suite 900
P.O. Box 1784
Madison, Wisconsin 53701-1784
608.256.0226

[1] Concurrent with the filing of this Application, Scott Smith and Stacy Rhone of MGE are filing testimony in support of the Settlement Agreement, including verifying all of the information and schedules contained in the appendices.

EXHIBIT A

SETTLEMENT AGREEMENT

SETTLEMENT AGREEMENT

This settlement agreement (Agreement) is entered into as of this 28th day of August, 2020, by and among the following parties: Madison Gas and Electric Company (MGE), Citizens Utility Board (CUB), Wisconsin Industrial Energy Group (WIEG), RENEW Wisconsin (RENEW), and Board of Regents of the University of Wisconsin System (UW) (collectively, the "Parties" and individually a "Party").

RECITALS

A. MGE is an investor-owned public utility, as defined in Wis. Stat. § 196.01(5), which is engaged in the generation and distribution of electricity to approximately 155,000 customers in Dane County, and in the purchase, transportation and distribution of natural gas to customers in Columbia, Crawford, Dane, Iowa, Juneau, Monroe and Vernon Counties.

B. MGE has initiated Docket No. 3270-UR-123 with the Public Service Commission of Wisconsin (PSCW or Commission), which docket is titled the Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates (Proceeding). The Proceeding is for test year 2021.

C. CUB, WIEG, RENEW, UW, Airgas USA LLC, Clean Wisconsin, and Sierra Club have full party status in the Proceeding as intervenors pursuant to Wis. Admin. Code ch. PSC 2.21, and they constitute all of the intervening parties in the Proceeding.

D. The Parties acknowledge that fully litigating the Proceeding would require a substantial investment of time, effort, and expense by each Party in pursuit of its respective interest in the Proceeding.

E. The Parties wish to avoid the time, effort, expense, and uncertainty associated with a fully contested Proceeding by entering into this Agreement pursuant to Wis. Stat. § 196.026.

F. This Agreement has resulted from arms' length negotiations between and among the Parties.

G. The Parties have been advised by counsel and are satisfied that the terms and conditions of this Agreement are fair, adequate, and reasonable.

NOW THEREFORE, in consideration of the promises and the mutual agreements contained in this Agreement, and other good and valuable consideration, the sufficiency of which the Parties acknowledge, the Parties agree as follows:

1. Settlement Terms. The settlement terms contained in **Attachments A**, **B, C, and D** attached hereto (Settlement Terms) comprise the Parties' substantive agreement as to MGE's base revenue requirements for test year 2021; MGE's monitored fuel costs for 2021 pursuant to Wis. Admin Code ch. PSC 116, subject to the standard updates made for a utility fuel plan (*see*

Attachment A, Section C.1.); and rate design for MGE customers for test year 2021. The Settlement Terms represent the Parties' negotiated settlement of issues outstanding in the Proceeding, and are incorporated into, and are part of, this Agreement. The Settlement Terms are intended to address all issues in the Proceeding, subject to the standard updates made for a utility fuel plan (*see* Attachment A, Section C.1.). MGE will propose the Settlement Terms as support for the Commission's findings of fact, conclusions of law, order points, and opinion (as applicable) in the Proceeding.

2. Cooperation of the Parties. MGE will file an application with the PSCW in the Proceeding (Application) attaching this Agreement as an exhibit and seeking an order from the Commission consistent with this Agreement. The Parties will support the Application as reasonably requested by MGE, including by filing supportive testimony, briefing, or correspondence for, or otherwise advocating in favor of, the terms of this Agreement in the Proceeding. Subject to the requirement that the Parties support the Agreement, each Party determines for itself the language it will use in doing so. No Party will oppose, directly or indirectly, any aspect of this Agreement in any venue. If the Commission adopts part, but not all of this Agreement, or imposes one or more conditions on its approval of the Agreement, each Party will, within five business days of the relevant Commission open meeting, notify all of the other Parties whether the Party is willing to accept the Commission's decision. If one or more Parties indicate that they are not willing to accept the Commission's decision, all of the Parties will jointly or individually file a request for Commission rehearing or, alternatively should all the Parties agree, for a contested case evidentiary hearing. In either case, the Parties shall zealously advocate for the Commission's adoption of those portions of the Agreement that the Commission rejected and for the elimination of any conditions that the Commission imposed. If one or more Parties files a motion for rehearing, and such motion is rejected or otherwise denied, then all of the Parties, jointly or individually, will file a motion for a contested case hearing on the rejected portions of the Agreement and the conditions imposed by the Commission, and in such proceeding, shall support the Commission's adoption of those portions of the Agreement and deletion of the imposed conditions in an amended Commission order. Subject to the requirement that the Parties support the Agreement as specified in this Paragraph 2, each Party shall determine in its sole discretion the language contained in its submissions to the Commission or any other venue.

3. Precedential Effect of Settlement Terms. The Parties expressly intend that this Agreement is entered into solely for purposes of settling the outstanding issues in the Proceeding. The Parties agree that the substantive details of this Agreement will have no precedential effect on the Parties in later PSCW proceedings or bind the Commission's future decisions in any way except insofar as necessary to effectuate or enforce the terms of this Agreement.

4. Entire Agreement. This Agreement contains the entire agreement between the Parties with respect to the subjects addressed herein and on a going forward basis supersedes all prior agreements and understandings, express or implied. In entering into this Agreement, no Party is relying on any representation or consideration not expressed herein. Any modification of this Agreement may be made only by an instrument in writing signed by or on behalf of all the Parties hereto.

5. Signature by Counterparts. The Parties agree that this Agreement may be executed in counterparts and a signature by copy, facsimile, or PDF is as binding as an original signature.

6. Authority. The Parties represent and warrant that the individuals signing below for each Party have full power and authority to execute this Agreement.

7. Preamble. The Preamble and Recitals hereto are intended to be an integral part of this Agreement. The Preamble and Recitals hereto (including the definitions set forth therein) are hereby incorporated by reference.

[Signature pages follow]

MADISON GAS AND ELECTRIC COMPANY

By: ______________________________
Name: Scott R. Smith
Title: Assistant Vice President
Business and Regulatory Strategy

CITIZENS UTILITY BOARD

By: ______________________________

Name: Thomas Content

Title: Executive Director

WISCONSIN INDUSTRIAL ENERGY GROUP

By: [signature]
Name: Todd Stuart
Title: executive director
8-28-20

BOARD OF REGENTS OF THE
UNIVERSITY OF WISCONSIN SYSTEM

By: ______________________________
Name: Laurent Heller
Title: Vice Chancellor for Finance and Adminstration

RENEW WISCONSIN

By:

Name: Heather J. Allen

Title: Executive Director

ATTACHMENT A

SETTLEMENT TERMS: PSCW DOCKET NO. 3270-UR-123

A. MGE's Retail Electric Revenue Requirements Generally

1. Overall rate changes for the test year ending December 31, 2021, are authorized consisting of a $0.00 rate change for retail electric operations, a 0.00 percent change. To achieve a 0% rate increase for electric rates, the deferred account balance credit associated with MGE's 2019 fuel cost plan reconciliation has been incorporated into the settlement agreement. In addition, the settlement agreement contains escrow treatment for bad debt expense and pension and other post-employment benefit (OPEB) costs. Any adjustments for fuel that bring the overall revenue request below or above zero shall be offset by reducing or increasing, respectively, the amount of bad debt expense or pension and OPEB costs escrowed to 2022.

2. MGE's filed electric operating income statement, net investment rate base, and required return on net investment rate base for test year 2021, as agreed to by the Parties, are reasonable.

B. MGE's Retail Natural Gas Revenue Requirements Generally

1. Overall rate changes for the test year ending December 31, 2021, are authorized consisting of a $6,670,000 annual increase for retail natural gas operations, a 4.00 percent increase. The settlement agreement contains escrow treatment for pension and OPEB costs. Per the escrow treatment, the increases for pension and OPEB costs are deferred to 2022.

2. MGE's filed natural gas operating income statement, net investment rate base, and required return on net investment rate base for test year 2021, as agreed to by the Parties, are reasonable.

C. MGE's Monitored Fuel Costs for 2021

1. It is reasonable that MGE's revenue requirements under this settlement agreement reflect estimated 2021 monitored fuel costs that will be updated with the following standard updates that occur with utility fuel cost plan filings:

    a. Incorporate market prices for natural gas, oil, Locational Marginal Prices (LMP), Wisconsin Electric Power Company Purchased Power Agreement (PPA) volumes and prices, and anticipated gains or losses on hedging instruments as of a date determined by the Commission.

    b. Reflect an update in MGE's wind curtailment cost forecast to incorporate most recent available data.

c. Update PPA wind hourly generation profiles to most recent available data.

d. Update LMP differential costs, net of Financial Transmission Rights (FTR), to reflect most recent available information.

e. Update planned outage dates for generating units based on most recent available information.

f. Update Midcontinent Independent System Operator, Inc. (MISO) settlement charges, rates, and credits to include most recent available information.

g. Update MISO capacity sales and purchases to reflect the most recent auction.

h. Update dispatch costs because of updates to the variable operations and maintenance expense rates for Blount, West Marinette (M34), and West Campus Cogeneration Facility.

i. Reflect an update to delivered coal prices and heat content for Columbia and Elm Road.

j. Reflect the electric sales and peak demand forecasts per Attachment C – Schedule 1, Electric Rate Design, of the settlement agreement.

k. Update Elm Road Generating Station PROMOD inputs provided by Wisconsin Energy Corporation.

(collectively, the "Fuel Cost Plan Updates").

Any change based on the Fuel Cost Plan Updates approved by the Commission will be reflected in the overall revenue requirement authorized for 2021 monitored fuel costs, and the 2021 monitored fuel cost plan will utilize an annual bandwidth of plus or minus one percent, as provided in Wis. Admin. Code §116.06(3). (See Attachment B, Schedule 11).

2. It is reasonable that, if requested, MGE provide additional information supporting its 2021 fuel cost plan in accordance with Wis. Adm. Code Ch. PSC 116.

D. Material Operating Changes Affecting Revenue Requirements Since MGE's Last Rate Proceeding

1. It is reasonable for MGE to escrow pension and OPEB costs, including the 2019/2020 pension and OPEB costs deferral in Docket No. 3270-AF-101 PSC REF # 373819. The escrow mechanism is a fair mechanism for the customer and the shareholder in the situation where costs vary dramatically from year to year, such as with pension and OPEB costs. MGE will continue to manage the funding of its pension and OPEB plans in line with the Company's current practice. The updated

amount will be deferred to 2022 as reflected in Attachment B, Schedule 10 to this settlement agreement.

2. It is reasonable that MGE's 2021 retail revenue requirement include the estimated impacts of joint ownership of the Two Creeks and Badger Hollow I solar projects as approved by the Commission in Docket No. 5-BS-228 (PSC REF # 364436).

3. It is reasonable for MGE to escrow bad debt expenses, including costs incurred in 2020 per docket 5-AF-105 PSC REF # 389500. (See Attachment B, Schedule 10).

4. It is reasonable for MGE to escrow credit card convenience fees, including costs incurred in 2020 per docket 5-AF-105 PSC REF # 389500. (See Attachment B, Schedule 10).

5. It is reasonable for MGE to defer other costs incurred in 2020 due to the Public Health Emergency not specifically listed above per docket 5-AF-105 PSC REF # 389500 to a future rate proceeding. (See Attachment B, Schedule 10).

6. It is reasonable for MGE to return 100 percent of the electric unprotected balance sheet savings as ordered in Docket No. 5-AF-101 (PSC REF # 373697). (See Attachment B, Schedule 10).

7. It is reasonable for MGE to accrue Allowance for Funds Used During Construction (AFUDC) on 100 percent of Construction Work in Progress (CWIP) associated with projects requiring a Certificate of Authority (CA) or a Certificate of Public Convenience and Necessity (CPCN) that were not reflected as current return CWIP projects in this proceeding upon approval of a CA or CPCN by the Commission.

E. MGE's Operating Income Statement

1. Overall rate changes for the test year ending December 31, 2021, are authorized consisting of a $0.00 rate change for retail electric operations, a 0.00 percent change. To achieve a 0% rate increase for electric rates, the deferred account balance credit associated with MGE's 2019 fuel cost plan reconciliation has been incorporated into the settlement agreement. In addition, the settlement agreement contains escrow treatment for bad debt expense and pension and OPEB costs. Any adjustments for fuel that bring the overall revenue request below or above zero shall be offset by reducing or increasing, respectively, the amount of bad debt expense or pension and OPEB costs escrowed to 2022.

2. Presently authorized rates for MGE's retail electric utility operations will produce total operating revenues of $413,056,000 in test year ending December 31, 2021, which results in an adjusted net operating income of $70,882,000, which is insufficient. (See Attachment B, Schedule 1).

3. For MGE's retail electric operations, the estimated rate of return on average net investment rate base of $1,019,083,000 at current rates subject to the Commission's jurisdiction for the test year is 6.96 percent, which is insufficient. (See Attachment B, Schedule 1 and 3).

4. A reasonable decrease in operating revenue for test year 2021 to produce a return of 6.96 percent return (See Attachment B, Schedule 6) on MGE's average net investment rate base for MGE's retail electric operations is $0 (See Attachment B, Schedule 8).

5. MGE's Retail Electric Operating Income Statement for test year 2021, as reflected in Attachment B, Schedule 1, to this Agreement is reasonable.

6. Presently authorized rates for MGE's retail gas utility operations will produce total operating revenues of $167,023,000 in test year ending December 31, 2021, which results in an adjusted net operating income of $15,126,000, which is insufficient. (See Attachment B, Schedule 2).

7. For MGE's retail gas operations, the estimated rate of return on average net investment rate base of $282,360,000 at current rates in the test year ending 2021, subject to the Commission's jurisdiction for the test year is 5.36 percent, which is insufficient. (See Attachment B, Schedule 2 and 4).

8. A reasonable increase in operating revenue for the test year to produce a return of 7.08 percent return (See Attachment B, Schedule 7) on MGE's average net investment rate base for MGE's retail gas operations for the test year ending 2021 is $6,670,000 (See Attachment B, Schedule 9).

9. MGE's Retail Gas Operating Income Statements for test year 2021, as reflected in Attachment B, Schedule 2, to this Agreement is reasonable.

10. The fuel cost data in Attachment B, Schedule 11 will be used to monitor MGE's 2021 fuel costs. This amount is subject to change based only on the Fuel Cost Plan Updates approved by the Commission.

11. It is reasonable that MGE's revenue requirements under this settlement agreement reflect estimated 2021 monitored fuel costs that will be updated based on the Fuel Cost Plan Updates approved by the Commission. Any change between the estimate and the final approved fuel cost plan will be reflected in the overall revenue requirement authorized for 2021. Monitored fuel costs will utilize an annual bandwidth of plus or minus one percent, as provided in Wis. Admin. Code §116.06 (3). (See Attachment B, Schedule 11).

12. It is reasonable that, if requested, MGE provide additional information supporting its 2021 fuel cost plan in accordance with Wis. Adm. Code Ch. PSC 116.

13. MGE's Operating and Maintenance (O&M) expenses are reasonable. (See Attachment B, Schedule 1 and 2).

14. It is reasonable to maintain escrow treatment for the retail share of all of MGE's transmission costs in Account 565. (See Attachment B, Schedule 10).

15. It is reasonable to authorize escrow treatment for Pension and OPEB Costs in Account 926. (See Attachment B, Schedule 10).

16. It is reasonable to authorize escrow treatment for Bad Debt Expense in Account 904. (See Attachment B, Schedule 10).

17. It is reasonable to authorize escrow treatment for Credit Card Convenience Fees in Account 903. (See Attachment B, Schedule 10).

18. MGE is requesting recovery of capital expenditures related to combustion turbines over a four-year period. (See Attachment B, Schedule 10).

19. It is reasonable to no longer escrow SO2 amortizations which is a non-monitored fuel cost due to the immaterial amount of the balance which is currently less than $5.

20. MGE has incorporated into settlement agreement the deferred account balance credit associated with MGE's 2019 fuel cost plan reconciliation per docket 3270-FR-2019 (PSC REF # 394952). (See Attachment B, Schedule 10).

21. Regulatory asset and liability amortizations as reflected in Attachment B, Schedule 10, are reasonable.

F. MGE's Capital Structure, Return on Equity, and Dividend Restriction

1. It is reasonable for MGE to maintain its currently authorized Return on Equity of 9.8 percent.[1] (See Attachment B, Schedule 5).

2. It is reasonable for MGE to maintain a target level for the test-year average common equity measured on a financial capital structure basis of 55.00 percent. (See Attachment B, Schedule 12).

3. It is reasonable for MGE to maintain a regulatory capital structure and average weighted cost of capital for the 2021 test-year period as shown in Attachment B, Schedule 5.

[1] Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates, Final Decision, PSCW Docket No. 3270-UR-122 (December 20, 2018) (PSC REF # 355887).

4. It is reasonable that MGE's dividend restrictions be based on the financial capital structure in this proceeding.

5. A reasonable weighted average composite cost (WACC) of capital is 7.21 percent for 2021. (See Attachment B, Schedule 5).

G. Rate and Service Changes with Associated Revenue Adjustments

1. It is reasonable to allocate revenue responsibility and designing rates amongst the various customer classes in the same manner as in Docket No. 3270-UR-122 (PSC REF # 355887) to mitigate different rate impacts amongst the classes. It is reasonable to implement the electric rate design changes proposed in Attachment C, Schedule 1 and natural gas rate design changes proposed in Attachment D, Schedule 1.

2. It is reasonable for MGE to pilot a flat bill rate structure for residential electric customers. (See Attachment C, Schedule 1).

3. It is reasonable for MGE to include interruptible service in the Sp-3 rate schedule and to revise the Customer Maximum Demand Charge and Customer Maximum 15 minute Demand Charge in a revenue neutral manner as agreed to with the customer that receives service on this schedule. (See Attachment C, Schedule 2).

4. It is reasonable for MGE to offer a Bring Your Own Device program to electric customers. (See Attachment C, Schedule 3).

5. It is reasonable for MGE to remove the mandatory service requirement in the Residential Time-of-Use Rate (Rg-2) and allow each mandatory service customer the choice of remaining on Rg-2 or enrolling in a different rate schedule under which they qualify for service. (See Attachment C, Schedule 4).

6. It is reasonable for MGE to close the Residential Time-of-Use Rate (Rg-2) to new customers and allow existing customers to remain on Rg-2. (See Attachment C, Schedule 4).

7. It is reasonable for MGE to offer a Residential Optional Time-of-Use Rate (Rg-2A) to residential electric customers. (See Attachment C, Schedule 4).

8. It is reasonable for MGE to close the Small Commercial and Industrial Optional Time-of-Use Rate (Cg-3) to new customers and allow existing customers to remain on Cg-3. (See Attachment C, Schedule 5).

9. It is reasonable for MGE to include optional service under the Commercial and Industrial Time-of-Use Rate (Cg-4) to any customer that would otherwise receive service under the Cg-5, Cg-3, or Cg-7 rate schedules. (See Attachment C, Schedule 5).

10. It is reasonable for MGE to remove Level A and Level B from the Cg-4 rate schedule. (See Attachment C, Schedule 5).

11. It is reasonable for MGE to remove all Primary Discount Provision language from the Cg-4, Cg-8, Cg-2, Cg-2A, Cg-6, and Cg-6A rate schedules and offer a Primary Voltage Provision (PVP-1) to electric customers. (See Attachment C, Schedule 7).

12. It is reasonable for MGE to modify the availability and applicability of primary service discounts in the Primary Voltage Provision (PVP-1) relative to the existing Primary Discount Provision in the applicable rate schedules. (See Attachment C, Schedule 7).

13. It is reasonable for MGE to offer a PV Connect (PV-1) rate to electric customers. (See Attachment C, Schedule 8).

14. It is reasonable for MGE to terminate the Cg-2A, Cg-6A, Is-1, Is-2, SCS, MBP, VGC, and AGS rate schedules. (See Attachment C, Schedule 9).

15. It is reasonable for MGE to modify its Electric Service Rules and Regulations: Customer-Owned Generating Equipment (E-67) and include a clarification on the interconnection of customer-owned batteries. (See Attachment C, Schedule 19).

16. It is reasonable for MGE to modify BGS tariff language to clarify the available initial term language and applicability (See Attachment C, Schedule 6).

17. It is reasonable for MGE offer an Electric Vehicle Fleet Charging Pilot rate for customers who own or lease electric vehicles for fleets. (See Attachment C, Schedule 21).

18. It is reasonable for MGE to amend electric service tariffs as reflected throughout Attachment C.

19. It is reasonable for MGE to issue a new Electric Rates and Rules volume with a new sheet numbering system and reordered tariffs. (See Attachment C, Schedule 10).

20. It is reasonable for MGE to amend natural gas service tariffs as reflected throughout Attachment D.

21. It is reasonable for MGE to continue to work with the Citizens Utility Board and the Wisconsin Industrial Energy Group in 2020 and 2021 on new rates or other innovative utility programs targeted at industrial, residential, and small commercial customers, respectively.

22. It is reasonable for MGE to continue to work with the Citizens Utility Board and Clean Wisconsin to develop new pilot rate programs and propose any agreed upon pilots to the Commission.

23. It is reasonable for MGE to build upon its existing practice and, prior to its next rate application filing, provide CUB with the results of a detailed household burden index analysis. This analysis shall evaluate residential electric and natural gas utility customer bills as a percentage of household income.

24. It is reasonable to include Real Time Pricing and Other Tariff-Cleanup relating to the customer baseline (CBL) used to determine the portion of a customer's load that can be subject to the New Load Market Pricing (NLMP) tariff for energy and/or billing demands, as defined in the tariff. The revisions provided that the CBL may be permanently decreased when the customer reduces its load through the implementation of energy efficiency, conservation, or process improvement measures, or via the installation of new equipment (i.e. behind the meter generation) so as to remove a disincentive for undertaking these activities. (See Attachment C, Schedule 22).

ATTACHMENT B
FINANCIAL SCHEDULES:
PSCW DOCKET NO. 3270-UR-123

Attachment B

Schedule 1: Income Statement Applicable to Net Investment Rate Base – Electric

Schedule 2: Income Statement Applicable to Net Investment Rate Base – Gas

Schedule 3: Average Net Investment Rate Base – Electric

Schedule 4: Average Net Investment Rate Base – Gas

Schedule 5: Weighted Cost of Capital

Schedule 6: Percent Return Requirement on Net Investment Rate Base – Electric

Schedule 7: Percent Return Requirement on Net Investment Rate Base – Gas

Schedule 8: Revenue Requirement – Electric

Schedule 9: Revenue Requirement – Gas

Schedule 10: Amortization Schedule

Schedule 11: Monitored Fuel Costs

Schedule 12: Financial Capital Structure

Madison Gas and Electric Company
Docket No. 3270-UR-123
Income Statement Applicable to Net Investment Rate Base
Electric

line no.			UR-123 Test Year 2021 ($000's)
	Operating Revenues:		
1	Sales of electricity	$	393,997
2	Sales for resale		3,561
3	Other operating revenues		15,498
4	Total Operating Revenues	$	413,056
	O&M Expenses		
	Power Production Expenses		
5	-Fuel and Purchased Power	$	84,201
6	-Other production expenses		71,222
7	Transmission expenses		44,185
8	Distribution expenses		17,194
9	Customer accounts expenses		10,134
10	Customer service expenses		10,481
11	Administrative & general		41,497
12	Total Operation and Maintenance Expense	$	278,914
13	Depreciation and amortization	$	59,369
14	Taxes other than income		16,506
15	Deferred income taxes		219
16	Income taxes		(11,592)
17	Investment tax credit		(1,242)
18	Total Operating Expenses	$	342,174
19	Net Operating Income - Electric	$	70,882
20	Average rate base ($000)	$	1,019,083
21	Return on investment in rate base		6.96%

Madison Gas and Electric Company
Docket No. 3270-UR-123
Income Statement Applicable to Net Investment Rate Base
Gas

line no.		UR-123 Test Year 2021 ($000's)
	Operating Revenues:	
1	Sales of gas	$ 166,625
2	Other operating revenues	398
3	Total Operating Revenues	$ 167,023
	O&M Expenses:	
	Gas Production Expenses	
4	-Purchased gas	$ 83,363
5	-Other	744
6	Distribution expenses	12,705
7	Customer accounts expenses	8,882
8	Customer Services Expenses	5,428
9	Administrative & general	20,282
10	Total O&M Expense	$ 131,404
11	Depreciation and amortization	$ 14,352
12	Taxes other than income	3,056
13	Deferred income taxes	4,653
14	Income taxes	(1,559)
15	Investment tax credit	(9)
16	Total Operating Expenses	$ 151,897
17	Net Operating Income - Gas	$ 15,126
18	Average rate base ($000)	$ 282,360
19	Return on investment in rate base	5.36%

Madison Gas and Electric Company
Docket No. 3270-UR-123
Average Net Investment Rate Base
Electric

line no.		**UR-123 Test Year 2021** ($000's)
1	Utility Plant in Service	$ 1,684,165
2	Less: Accumulated Depreciation	571,848
3	Net Utility Plant in Service	$ 1,112,317
4	Add: Fuel Inventory	8,068
5	Materials and Supplies	22,166
6	Less: Accumulated Deferred Income Taxes	121,736
7	Customer Advances	1,732
8	Average Net Investment Ratebase	$ 1,019,083

Madison Gas and Electric Company
Docket No. 3270-UR-123
Average Net Investment Rate Base
Gas

line no.		UR-123 Test Year 2021 ($000's)
1	Utility Plant in Service	$ 527,777
2	Less: Accumulated Depreciation	214,574
3	Net Utility Plant in Service	$ 313,203
4	Add: Gas in Storage Inventory	6,408
5	Materials and Supplies	4,728
6	Less: Accumulated Deferred Income Taxes	39,630
7	Customer Advances	2,349
8	Average Net Investment Ratebase	$ 282,360

Madison Gas and Electric Company
Docket No. 3270-UR-123
Weighted Cost of Capital Calculation
(2021 Test Year Period)

		2021			
line no.	**Capital Structure Component**	**Amount (000's)**	**Percentage of Capital Structure**	**Capital Cost Rates**	**Weighted Cost of Capital**
1	Common Stock Equity	720,651	55.84%	9.80%	5.47%
2	Long Term Debt	508,149	39.37%	4.29%	1.69%
3	Short Term Debt	61,779	4.79%	1.00%	0.05%
4	Weighted Cost of Capital (WACC)	1,290,579	100.00%		7.21%
5	Income Taxes on Equity Component				2.05%
6	Ratepayer Cost of Capital				9.26%
	Interest Coverages				
7	Before Tax Coverage				5.32
8	After Tax Coverage				4.14

Madison Gas and Electric Company
Docket No. 3270-UR-123
Percent Return Requirement on Net Investment Rate Base
Electric

line no.		UR-123 Test Year 2021
1	Weighted Cost of Capital	7.21%
2	Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	104.59%
3	Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	6.90%
4	Average CWIP Balance (000's)	65,061
5	Less: CWIP Earnings 100% AFUDC	46,487
6	Remaining CWIP Earning a Current Return	18,574
7	Percentage of Remaining CWIP to Earn a Current Return	50%
8	Average CWIP Earning a Current Return	9,287
9	Adj. to Adj. Weighted Cost of Capital to Provide a Current Return on CWIP	0.06%
10	Required Return on Net Investment Rate Base	6.96%

Madison Gas and Electric Company
Docket No. 3270-UR-123
Percent Return Requirement on Net Investment Rate Base
Gas

line no.		UR-123 Test Year 2021
1	Weighted Cost of Capital	7.21%
2	Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	104.59%
3	Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	6.90%
4	Average CWIP Balance (000's)	17,319
5	Less: CWIP Earnings 100% AFUDC	2,378
6	Remaining CWIP Earning a Current Return	14,941
7	Percentage of Remaining CWIP to Earn a Current Return	50%
8	Average CWIP Earning a Current Return	7,471
9	Adj. to Adj. Weighted Cost of Capital to Provide a Current Return on CWIP	0.18%
10	Required Return on Net Investment Rate Base	7.08%

Madison Gas and Electric Company
Docket No. 3270-UR-123
Revenue Requirement
Electric

line no.		UR-123 Test Year 2021
1	Pro Forma Return on Average Net Investment Rate Base at Present Rates	6.96%
2	Required Return on Average Net Investment Rate Base	6.96%
3	Earnings (Excess) Deficiency as a Percent of Average Net Investment Rate Base	0.00%
4	Average Net Investment Rate Base (000's)	$ 1,019,083
5	Amount of Earnings (Excess) Deficiency on Average Net Investment Rate Base (000's)	$ -
6	Revenue (Excess) Deficiency to Provide for Earnings (Excess) Deficiency Plus Federal and State Income Taxes (000's)	$ -

Madison Gas and Electric Company
Docket No. 3270-UR-123
Revenue Requirement
Gas

line no.		UR-123 Test Year 2021
1	Pro Forma Return on Average Net Investment Rate Base at Present Rates	5.36%
2	Required Return on Average Net Investment Rate Base	7.08%
3	Earnings (Excess) Deficiency as a Percent of Average Net Investment Rate Base	1.72%
4	Average Net Investment Rate Base (000's)	$ 282,360
5	Amount of Earnings (Excess) Deficiency on Average Net Investment Rate Base (000's)	$ 4,853
6	Revenue (Excess) Deficiency to Provide for Earnings (Excess) Deficiency Plus Federal and State Income Taxes (000's)	$ 6,670

Madison Gas and Electric Company
Amortization Schedule
3270-UR-123

	PSCW Escrow Authorization	Notes	Amortization Period	Test Year 2021 Amortization Amount Electric	Gas	Estimated Balance at 12/31/2021 Deferral Balance (Gross of Tax) Electric	Gas
ERGS	3270-GF-110	1	2021	30,245,644	-	(1)	-
Transmission	Various	1	2021	35,784,442	-	1	-
Conservation Escrow (Focus on Energy)	Various	1	2021	4,836,719	1,974,257	(1)	-
Columbia Agreement	05-BS-214	1	2021	(2,315)	-	-	-
Columbia Percentage Ownership	3270-UR-121	1	2021	(433,367)	-	(1)	-
Combustion Turbine	Requesting		2021 - 2024	298,512	-	895,536	-
Forward Wind Farm	5-BS-226	1	2021	41,765	-	-	-
Pension and OPEB Costs	3270-AF-101 & Requesting		2021	4,409,664	(746,694)	5,020,311	6,341,531
Public Health Emergency - Credit Card Convenience Fees	5-AF-105 & Requesting	2	2021	245,000	255,000	-	-
Public Health Emergency - Bad Debt Expenses	5-AF-105 & Requesting	2	2021	1,825,000	375,000	-	-
Public Health Emergency - Late Payments	5-AF-105	2		-	-	-	-
Public Health Emergency - Other	5-AF-105	2		-	-	-	-
Excess Deferred Taxes - Estimated Protected (Tax Reform)	5-AF-101		2021	(4,874,291)	(436,839)	(75,057,563)	(28,438,803)
Excess Deferred Taxes - Estimated Unprotected (Tax Reform)	5-AF-101	3	2021	(18,195,254)	-	-	4,188,050
2019 Fuel Rules Deferral	3270-FR-2019		2021	(1,866,160)	-	-	-
Miscellaneous Liability	Various		2021	(464,055)	(53,387)	-	-
Totals				$ 51,851,303	$1,367,338	$ (69,141,718)	$ (17,909,222)

(1) MGE true-ups the prior year balance each rate case.
(2) 2020 amounts are currently accruing and not included in the 2021 ending balance.
(3) MGE is proposing to recover the gas unprotected excess deferred taxes in a future rate case.

Negative = Regulatory Liability
Positive = Regulatory Asset

Negative = Reduction of expense
Positive = Addition of expense

Madison Gas and Electric Company
Docket 3270-UR-123
Monthly Fuel Data for Monitoring Fuel Costs
January 2021 through December 2021 Test Year
Based on the PSC-Audited 2021 Fuel Cost Plan (2021CaseE)

Month	Fuel Costs	kWh	$/kWh	Cumulative $/kWh
January	$ 5,527,617	273,016,519	$ 0.020246	$ 0.020246
February	$ 4,923,495	241,696,389	$ 0.020371	$ 0.020305
March	$ 5,446,997	256,938,931	$ 0.021200	$ 0.020603
April	$ 4,967,331	240,071,556	$ 0.020691	$ 0.020624
May	$ 4,918,507	254,230,396	$ 0.019347	$ 0.020367
June	$ 5,602,593	284,180,801	$ 0.019715	$ 0.020248
July	$ 6,557,098	316,785,135	$ 0.020699	$ 0.020324
August	$ 6,123,189	305,816,147	$ 0.020022	$ 0.020282
September	$ 5,655,860	283,854,256	$ 0.019925	$ 0.020241
October	$ 5,029,458	249,368,553	$ 0.020169	$ 0.020234
November	$ 4,702,962	243,342,134	$ 0.019327	$ 0.020159
December	$ 5,405,709	262,358,907	$ 0.020604	$ 0.020195
Total	$ 64,860,818	3,211,659,723	$ 0.020195	

Madison Gas and Electric Company
3270-UR-123
Financial Capital Structure

The Commission's long-standing policy of supporting MGE's commitment to credit quality for the benefit of both its customers and its shareholders has been recognized by the credit rating agencies and the financial markets. MGE believes its 55 percent test-year average common equity as measured on a financial capital structure basis is the cornerstone to this policy and remains reasonable.[1]

MGE made a conscious commitment to strong credit ratings decades ago. Likewise, MGE believes that the Commission, through its long-standing financial capital structure policy limiting MGE's leverage to 45 percent, has shown a similar level of support of a healthy MGE balance sheet. MGE believes these long-term commitments to MGE's strong financial foundation have protected MGE and its customers during times of severe financial market volatility, such as what we are currently experiencing with the COVID-19 outbreak. In times of financial stress, ***access to the capital markets is critical***. MGE believes that, for a smaller sized utility, it's even more critical to have access to capital, than say larger sized utility, with a significantly bigger balance sheet. MGE believes that, given its strong credit rating, it is able to offset the small issuer premium assessed by the market. This allows MGE access to the market and issue debt at a lower cost, at similar coupons to what a larger issuer would receive. Given our current economic state, and the uncertainty of how long and how deep the current recession will be, the investment community places more importance now more than ever on a companies' respective capital structures and return on equity

MGE believes its capital structure provides a credit quality differentiation from its industry peers, a very important factor when raising capital. Capital markets view capital structure and required returns holistically when evaluating an investment. The required returns for both equity and debt will increase as leverage grows within a capital structure. The Commission's long-standing support of MGE's strong capital structure and excellent credit quality has thereby benefited both its customers and shareholders.

Below are excerpts from **<u>Moody's</u>** Credit Summary for MGE dated October 2019.

"We view the Wisconsin regulatory environment as well as MG&E's constructive relationship with the PSCW as ***highly credit supportive****". The positive regulatory environment and a constructive relationship between MG&E and the PSCW allow for good revenue and cash flow visibility and timely operating and capital cost recovery. These regulatory factors have*

[1] Per 3270-UR-121 (PSC REF # 295447) Order point #20 states: MGE shall submit in its next rate application, information to assist the Commission in determining whether the 55 percent target for the test-year average common equity measured on a financial capital structure basis remains reasonable.

historically supported healthy credit metrics, including a cash flow from operations pre-working capital (CFO pre-WC) to debt ratio averaging around 30% for the three years ending 31 December 2017.

Factors that Could Lead to a Downgrade

- *The rating of MG&E could be lowered if the credit supportiveness of its regulatory environment deteriorates or if financial metrics experience a marked and sustained downward revision relative to our current view, including cash flow from operations pre-working capital (CFO Pre-WC) to debt below 25% on a sustained basis."*

S&P's Credit Summary of MGE dated March 2020 reflected similar support:

> "*We rate MG&E one notch higher than the 'A+' GCP because of the strength of its stand-alone credit profile and the* ***regulatory and structural protections****, insulating MG&E from its parent."*
>
> ***Downside Scenario***
>
> - *"We could lower our ratings on MG&E over the next 12 to 24 months if MG&E's stand-alone financial measures weaken."*

MGE believes the 55 to 60 percent target range for the test-year average common equity measured on a financial capital structure basis remains reasonable for MGE for the following reasons.

1. Reducing the targeted equity range would weaken MGE's credit metrics and likely trigger a downgrade to MGE's credit ratings. A credit rating downgrade for MGE would result in higher cost of debt and reduce MGE's access to the capital markets during periods of financial market volatility.
2. A lower equity range could signal to the respective Rating Agencies deterioration in the credit supportiveness of the regulatory environment. The perceived supportiveness of Wisconsin's regulatory environment by the ratings agencies would likely have long standing ramifications on all rated utilities that operate in Wisconsin. The respective financial metrics for all rated utilities in the state would thereafter be held to a higher standard to maintain existing ratings. These more stringent financial requirements could be sufficient to trigger downgrades for other Wisconsin utilities – increasing the cost of debt and equity financings for the state moving forward.
3. A downgrade in MGE's credit rating would increase more than the cost of debt. It would also increase fees MGE pays for its credit facilities and may require MGE to post additional collateral to its counterparties. A requirement to tie-up cash as collateral would further weaken MGE's liquidity rating with the Rating Agencies and create additional negative pressure on MGE's credit ratings.

Given all the reasons stated above, MGE believes a 55 percent test-year average common equity measured on a financial capital structure basis remains reasonable and provides for a stronger utility, which in the long-run benefits its ratepayers.

Madison Gas and Electric Company

Docket 3270-UR-123

ATTACHMENT C

Attachment C Index - Page 1 of 2

Schedule #:	Schedule Name:	Pages:	Documents
1	Flat Bill Pilot	1	Program Description
		2-4	Tariff Language
2	SP-3 Credit for Capacity Availability	1	Program Description
		2	Tariff Language
3	Bring Your Own Device Service	1	Program Description
		2-3	Tariff Language
4	Residential Service Changes	1	Description of Changes
		2-3	Rg-2 tariff language
		4-6	Rg-2a new tariff
5	Commercial and Industrial Tariff Changes	1	Description of Changes
		2-3	Cg-5 tariff language
		4-5	Cg-3 tariff language
		6-8	Cg-4 tariff language
6	BGS Update	1	Description of Change
		2-4	BGS tariff language
7	Primary Voltage Discount	1	Description of Changes
		2-5	Tariff Provision Language
8	PV-1	1	Program Description
		2-5	PV-1 tariff language
9	Retired Schedules	1	List of Unused Tariffs being Retired
10	Tariff Reorganization	1	Statement of Tariff Organization Plan

Madison Gas and Electric Company
Docket 3270-UR-123
ATTACHMENT C
Attachment C Index - Page 2 of 2

Schedule #:	Schedule Name:	Pages:	Documents
11	Electric Revenue Summary	1	Overall Description of Rates and Unbundled Study
		2	Summary of Revenue by Class
12	Residential Rates	1	Residential Rate Design Description
		2	Unbundled Cost of Service Study - Residential Page
		3	Rg-1 Rate Design Sheet
		4	Rg-2 (Closed) Rate Design Sheet
		5	Rg-2A Design Sheet
		6	Rg-2a Rate Components
		7	Rw-1 (Closed) Rate Design Sheet
		8	Rg-7 (Closed) Rate Design Sheet
13	Small Commercial and Industrial Rates	1	Cg-5 Rate Design Sheet
		2	Cg-3 (Closed) Rate Design Sheet
		3	Cg-7 (Closed) Rate Design Sheet
14	Medium Commercial and Industrial Rates	1	Cg-4 Rate Design Description
		2	Cg-4 Rate Design Sheet (A and B combined)
		3	Cg-4 Components compared with Cg-2, 6 at Proposed
		4	Cg-8 (Closed) Rate Design Sheet
15	Large Commercial and Industrial Rates	1	Large C&I Rate Design Description
		2	Cg-2 Rate Design Sheet
		3	Cg-6 Rate Design Sheet
16	Cp-1	1	Cp-1 Rate Design Description
		2	Cp-1 Rate Design Sheet
17	Sp-3	1	SP-3 Rate Design Description
		2-3	Sp-3 Rate Design Sheet
18	Streetlighting and Outdoor Overhead Lighting	1-8	SL-1, 2, 3 Rate Design Sheet
		9	OL-1 Rate Design Sheet
19	Application Process for Battery Interconnection	1	Summary of proposed change
		2	Rule Section language
20	Other Lighting and Miscellaneous	1	Gf-1 Rate Design Sheet
		2	Mg-2 Rate Design Sheet
		3	MLS Rate Design Sheet
21	Electric Vehicle Fleet Pilot 1	1	Description of Service
		2	Proposed tariff
22	RNL-1 Energy Reduction Adjustment	1-6	Proposed tariff change

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 1

Flat Bill Pilot

Renewable Flat Bill Pilot Program

RFB

New Program

Tariff Changes

Clarifications: No
Program Changes: New Program

Summary Points:

- Flat Monthly Rate
- Tranche Billing
- Renewable Overlay

Overview:

This pilot program is available to residential customers that voluntarily wish to pay a flat monthly rate for electricity powered by renewable energy resources. Availability is (initially) capped at 30 accepted Renewable Flat Bill amount bill offers. Enrolled customers will pay a monthly Flat Bill in lieu of the Grid Connection and Customer Service Charge, the Distribution Service Charge, and the Electricity Service Charge under rate schedule Rg-1 for a 12-month period. Customers electing to take service under this program will automatically be enrolled in the Company's Residential Renewable Energy Program and will pay the associated incremental Renewable Energy Charge for the maximum kWh of their Service Category.

Eligible residential customers will be placed into a specific service category (based on expected usage) for the duration of a 12-month period. On a yearly basis, the Company will re-analyze each customers usage, which will then be used to determine the Flat Bill Service Category the participating customers will belong to in the coming year.

Customers with monthly usage in excess of the Flat Bill Service Categories may participate in the Voluntary Pilot Program at the discretion of the Company. A Monthly Flat Bill will be personalized in consideration of individual historic usage characteristics, applicable rates, and risk profile as determined at the Company's discretion.

We expect continuous evaluation of program performance. As MGE's new billing system is implemented, we may file for expansion of the RFB program at a future date.

Tranche Billable kWh	Customer Charge $ per day $0.62466	Distribution Charge $ per kWh $0.03378	Summer Electric Charge $ per kWh $0.10472	Winter Electric Charge $ per kWh $0.09355	GPT Charge $ per kWh $0.01000	Calculated Rate $ per month	Proposed Rate $ per month
100	$19.00	$3.38	$3.49	$6.24	$1.00	$33.11	$33.50
200	$19.00	$6.76	$6.98	$12.47	$2.00	$47.21	$47.50
300	$19.00	$10.13	$10.47	$18.71	$3.00	$61.32	$61.50
400	$19.00	$13.51	$13.96	$24.95	$4.00	$75.42	$75.50
500	$19.00	$16.89	$17.45	$31.18	$5.00	$89.53	$90.00
600	$19.00	$20.27	$20.94	$37.42	$6.00	$103.63	$104.00
700	$19.00	$23.65	$24.43	$43.66	$7.00	$117.74	$118.00
800	$19.00	$27.02	$27.93	$49.89	$8.00	$131.84	$132.00
900	$19.00	$30.40	$31.42	$56.13	$9.00	$145.95	$146.00
1000	$19.00	$33.78	$34.91	$62.37	$10.00	$160.05	$160.50

High Usage Formula:

$$\boldsymbol{Flat\ Bill} = \frac{\left[\left(\sum_{Mo\,1}^{Mo\,12}\{[\boldsymbol{Qm}(\mathbf{1} + \boldsymbol{Qf})] \times (\boldsymbol{Ec} + \boldsymbol{Dc} + \boldsymbol{Rc})\}\right) + \mathbf{365}(\boldsymbol{CGc})\right] \times (\mathbf{1} + \boldsymbol{Rp})}{\mathbf{12}}$$

**Ec will be a weighted average of the seasonal Summer and Winter Electricity Service Rates*

Flat Bill Adders		Billable kWh	Calculated Rate
Usage Deviation	5%	1500	$245.98
Guaranteed Adder	2%	2000	$321.52

AVAILABILITY

This schedule is available to residential customers that voluntarily wish to pay a flat monthly rate for electricity powered by renewable energy resources. To be eligible, customers must have electric service at their premise for a minimum of 12 consecutive prior billing months. Participation is limited to customers in good standing with the Company. Customers must be eligible to receive service under rate schedule Rg-1.

This is a voluntary pilot program. Availability is capped at 30 accepted Renewable Flat Bill amount bill offers. Offers will be made at the sole discretion of the Company. This program can be modified by the Company subject to approval by the Public Service Commission of Wisconsin.

RATE

Customers will pay a monthly Flat Bill in lieu of the Grid Connection and Customer Service Charge, the Distribution Service Charge, and the Electricity Service Charge under rate schedule Rg-1 for a 12-month period. Customers electing to take service under this program will automatically be enrolled in the Company's Residential Renewable Energy Program and will pay the associated incremental Renewable Energy Charge for the maximum kWh of their Service Category. Customers taking service under this program are not subject to additional fuel adjustment surcharges otherwise applicable under rate schedule Rg-1. All other terms of service for rate schedule Rg-1 are applicable.

MONTHLY FLAT BILL

A Monthly Flat Bill amount bill offer will be tailored in consideration of the individual customer's historic usage characteristics and applicable Rg-1 Residential Service rates. Eligible residential customers will be placed into a specific service category for the duration of a 12-month period. On a yearly basis, the Company will re-analyze each customers usage, which will then be used to determine the Flat Bill Service Category the participating customers will belong to in the coming year.

FLAT BILL SERVICE CATEGORIES AND MONTHLY RATES

Average kWh 0-100	Average kWh 101-200	Average kWh 201-300	Average kWh 301-400	Average kWh 401-500	Average kWh 501-600	Average kWh 601-700	Average kWh 701-800	Average kWh 801-900	Average kWh 901-1000
$33.50	$47.50	$61.50	$75.50	$90.00	$104.00	$118.00	$132.00	$146.00	$160.50

HIGH USAGE CUTOMERS

Customers with monthly usage in excess of the Flat Bill Service Categories may participate in the Voluntary Pilot Program at the discretion of the Company. A Monthly Flat Bill will be personalized in consideration of individual historic usage characteristics, applicable rates, and risk profile as determined at the Company's discretion. The Monthly Flat Bill will be developed using the following factors.

a. Qm = Weather normalized usage

b. Qf = Usage deviation risk adjustment

c. Ec = Weighted Seasonal Electricity Service charges from rate schedule Rg-1

d. Dc = Distribution Service charge from rate schedule Rg-1

d. Rc = Renewable Energy Charge from rate schedule RWE-1

e. CGc = Daily Customer Service and Grid Connection charges from rate schedule Rg-1

f. Rp = Guaranteed amount adder at a maximum value of 10 percent or less

Formula:

$$\boldsymbol{Flat\ Bill} = \frac{\left[\left(\sum_{Mo\ 1}^{Mo\ 12}\{[\boldsymbol{Qm}(\boldsymbol{1} + \boldsymbol{Qf})] \times (\boldsymbol{Ec} + \boldsymbol{Dc} + \boldsymbol{Rc})\}\right) + \boldsymbol{365}(\boldsymbol{CGc})\right] \times (\boldsymbol{1} + \boldsymbol{Rp})}{\boldsymbol{12}}$$

CONTRACT DURATION AND RENEWAL

Contract Terms will be for a period of 12 consecutive billing months. All contracts will be evaluated and updated on an annual basis, and customers that are eligible for a renewal contract offer will automatically be enrolled in the following consecutive Contract Term unless they notify the Company of their option to terminate service under this program within 30 days of receiving the renewal contract offer.

SPECIAL TERMS AND PROVISIONS

1. Customers that move from their service address prior to the end of the contract term will be trued up to the difference between their actual usage under rate schedule Rg-1 and the amount billed under this program. If customers overpaid, they will be refunded. If customers underpaid, they will be billed the difference.

2. Customers who remain at their service address who wish to withdraw from the program prior to the end of the contract term may do so. They will be placed on Rg-1 service and be required to pay an administrative fee of $30. Their bills for the time they were on the annual contract prior to withdrawal from the program will be trued up to the difference between their actual usage under rate schedule Rg-1 and the amount billed under this program. If customers overpaid, they will be refunded. If customers underpaid, they will be billed the difference.

3. If customer's recorded kWh use at the end of 6 months exceeds expected usage by at least 50 percent, the Company may at its discretion remove the customer from the program and place the customer on RG-1 service prior to the end of the contract term. The customer will be required to pay an administrative fee of $30. Their bills for the time they were on the annual contract prior to prior to being removed from the program will be trued up to the difference between their actual usage under rate schedule Rg-1 and the amount billed under this program. Customers that underpaid will be billed the difference.

4. In the 11th month of the program, customers will be notified on their new monthly Flat Bill amount and will have the option of declining enrollment for the upcoming year.

5. This program is subject to the Special Terms and Provisions specified in Rate Schedule, RWE-1.

WAIVER

Any customer choosing to be served under this program thereby waives all rights to any billing adjustments arising from a claim that a bill for a customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under Wisconsin Administrative Code PSC 113.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 2

Sp-3 Credit for Capacity Availability

University of Wisconsin Time-of-Use Rate

Sp-3

Existing Program

Tariff Changes

Clarifications: No
Program Changes: Yes

Summary Points:

- Interruptible service will be incorporated into the Sp-3 schedule.
- As requested by the customer, $250,000 of revenue recovery has been moved from the Customer and Grid Connection Charge to the Customer Maximum 15-Minute Demand Charge

Overview:

The Sp-3 schedule will be modified to include interruptible service. This interruptible service will be structured similarly to MGE's current interruptible programs, Is-3 and Is-4.

This interruptible service will include both a firm and interruptible nomination. MGE will be responsible for notifying the customer when an interruption is to occur and which nomination the customer is responsible for, firm or interruptible. The monthly interruptible credit will use the current Is-4 rate and will apply to the greater interruptible demand using both nominations.

The University of Wisconsin, the single customer in this rate class, requested that Customer and Grid Connection Charge be decreased somewhat and the projected amount of revenue reduction from that change be picked up in demand charges. The Company has agreed to shift revenue recovery of approximately $250,000 from the Customer and Grid Connection Charge to the Customer Maximum 15-Minute Demand Charge. This change has no change in overall revenue recovery at forecasted demand levels in this case. If, however, the customer is able to reduce their maximum 15-Minute Demand level from what is forecasted, they could achieve savings in the test year.

The following language will be added to Sp-3:

INTERRUPTIBLE CREDIT

The on-peak demand charges for electricity service will be reduced by $0.13151 per kW per day for the amount of interruptible demand as described in the Determination of Demand provision.

DETERMINATION OF DEMAND

4. The amount of generation used to determine the generation credit is the amount of generation nominated by the customer for each calendar month up to the kW capacity of its generator. The nomination is due from the customer each year 15 days prior to the end of February for the subsequent calendar year. If the customer does not provide a nomination by the February deadline, the most recent effective nomination will prevail, subject to the testing provisions contained in Special Terms and Provisions No. 2.

5. The amount of interruptible demand used to determine the interruptible credit will be the greater of the following:

    a. The difference between the maximum on-peak 15-minute demand and the nominated firm demand level ("firm nomination") to a minimum of zero.

    ~~a.~~b. The lesser of the maximum on-peak 15-minute demand and the nominated interruptible demand level ("interruptible nomination").

~~5.~~6. Power Factor. The customer will maintain a power factor during periods of on-peak energy use of not less than 85 percent as determined by measurement or test. If the power factor determined by such test or measurement is less than 85 percent, the customer will be so notified in writing. If, within 240 days of such notice, the customer has not installed such power factor corrective devices of proper type as are required to bring the power factor during periods of on-peak energy use up to 85 percent, the measured on-peak kW demands used for billing purposes thereafter will be determined by multiplying the registered on-peak demand in kW by the ratio: 85 percent/actual power factor.

SPECIAL TERMS AND PROVISIONS

7. The customer will be subject to interruptions at the sole discretion of the Company. An interruption will be called by the Company in order to maintain the reliability of the power system or to reduce system costs that may have otherwise been incurred. The customer will not be able to buy out of an interruption.

    a. The customer's nomination includes both a firm demand level ("firm nomination") and an interruptible demand level ("interruptible nomination").

        i. The customer's firm nomination is 61,000 kW.

        ii. The customer's interruptible nomination is 1,000 kW.

    b. The customer will be notified by the Company when an interruption is to occur. The Company will have the sole discretion on the length of interruption and the amount of time between notification and actual interruption with the following conditions:

        i. The length of an interruption may not exceed 8 hours unless an extension to the interruption is agreed to by the customer.

ii. The customer's firm nomination is only applicable when notification is provided at least 12 hours in advance of the actual interruption.

iii. The customer's interruptible nomination is only applicable when notification is provided at least 4 hours in advance of the actual interruption.

iv. There will be no more than 150 hours of interruptions in a calendar year (not including test interruptions). Interruptions due to lightning, wind, necessary MGE system maintenance repairs, and other causes other than intentional load curtailment interruptions by the Company will not be considered in determining the hours of interruption. If the total hours of requested interruptions exceed 80 percent of the maximum hours of interruption during any calendar year, the Company reserves the right to manage the remaining available interruptible hours to best meet the Company's capacity needs for the remainder of the year.

c. After receiving notification by the Company of an interruption, the customer must reduce their demand according to whichever nomination, firm or interruptible, was called for by the Company.

d. The Company will perform periodic testing (on average annually) of the customer's ability to interrupt the amount of demand stated in this schedule. Failure to successfully comply with a test interruption may result in adjustments to the customer's interruptible nomination. The customer will pay the full demand charge (no interruptible credit will be applied) to the level of capacity that was not interrupted in the test until the customer successfully complies with a Company authorized interruption test for the entire contracted interruption capacity at a later date. Failure of an initial test will not affect the charges for unauthorized use included below.

e. The customer may schedule up to two weeks of annual maintenance for any equipment necessary to comply with these provisions. During this period, the Company will not exercise its right to interrupt electric service to the customer. The customer must notify the Company at least two weeks prior to any maintenance periods. Maintenance periods must be approved by the Company and will not be scheduled during the months of June, July, August, or September. Scheduled annual maintenance will not reduce any interruptible demand credits to the customer.

f. The customer will, at the customer's expense, install all apparatus and materials necessary for the proper utilization of the power furnished by the Company including disconnect mains and monitoring equipment. All such apparatus will conform to the Company's rules and regulations and will be kept in suitable operating conditions at all times.

g. The customer will pay the full demand charge (no interruptible credit will be applied) for the first instance of unauthorized use of electricity during an interruption. The monthly credit will not be applied to the associated level of demand until the customer successfully complies with a Company-authorized interruption test for the entire contracted interruption capacity. Along with the loss of the monthly credit, the customer will also pay $25 per kilowatt for each additional instance during any continuous 12-month period of unauthorized use of electricity during a period of interruption of service ordered by the Company. The Company may suspend the interruptible portion of this service if the customer uses service during period of interruption.

h. The customer will pay, in advance of construction, all costs estimated by the Company for facilities to serve the interruptible load.

~~a.~~i. Interruptible service will not be used as standby for any other forms of energy or fuel.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 3

Bring Your Own Device Service

Bring Your Own Device Service Rider

BYOD-1

New Program

Summary Points:

- Incentives for MGE control of customer-owned smart thermostats.
- A demand response program.

Overview:

Service under this voluntary rider is available to MGE electric customers that have an eligible smart thermostat connected to a central air-conditioning system and who have enrolled via the Company's energy management platform. This service will apply for a minimum of 12 months and any customer that terminates this service after 12 months may not re-enroll in the program for 12 months from the date of termination.

Customers enrolled in this program will have their thermostats controlled by the Company in order to reduce electrical demand during high electricity demand periods ("Events"). These events will typically take place during peak hours in the months of June, July, August, and September. The program is limited to 20 events per year and 4 hours per event. Customers will be able to opt-out of an event at any time unless the event is a Mandatory Event which will occur when the North American Electric Reliability Corporation ("NERC") declares a Level 2 Alert for the Company's service territory.

A one-time payment of $50 will be provided to the customer after they have enrolled in the program. Additionally, a payment of $25 will be provided for every summer of participation beginning with the second summer. These payments are designed to incentivize customers to help reduce system costs by providing them value for their contribution less any costs to administrate the program.

AVAILABILITY

This is an optional rate schedule available to customers on Rate Schedules Rg-1 and Rg-2 who have installed a "Qualified Device".

QUALIFIED DEVICE

For the purposes of this tariff, a Qualified Device is defined as a device that satisfies each of the following criteria:

1. The device is compatible and enrolled with the Company's energy management platform (the "Platform"). A list of compatible devices is made available on the Company's website.
2. The device is owned by the customer responsible for the electric account from which the device is served.
3. The device is connected to a reliable Internet connection.
4. The device meets all the applicable Additional Qualifications listed in this schedule.

ADDITIONAL QUALIFICATIONS

Option 1: Smart Thermostat:

1. There is a participation limit of 2,500 devices under this option.
2. The thermostat controls a functioning central air-conditioning system.
2. Customers may enroll multiple thermostats but incentives will be provided per air conditioning unit controlled. Customers with multiple air conditioning units may be eligible for multiple incentives.

RATE

All deliveries from the Company to the customer will be billed in accordance with the customer's otherwise applicable rate schedules.

The customer will receive an incentive for each Qualified Device enrolled in the Platform according to the following rates:

Option 1: Smart Thermostat:

One-time enrollment, per device $50.00
Summer participation, per device per summer* $25.00

*The one-time enrollment incentive includes the first summer participation incentive. A summer participation incentive will not be provided separately for the first summer of enrollment.

INTERNET ACCESS

Communication between Qualified Devices and the Company is achieved via the Platform by using the customer's Internet connection, which the customer will maintain.

EQUIPMENT CONTROL

The customer agrees to provide the Company with the ability to control the Qualified Device, via the Platform, in order to reduce electrical demand during high electricity demand periods ("Events").

Option 1: Smart Thermostat:

1. Events will typically take place during peak hours on non-holiday weekdays between June 1 and September 30.
2. Mandatory Events may take place in other months and/or at other times of the day.
3. Some events may be preceded by a decrease in the thermostat in order to pre-cool the customer's home.
4. No more than 20 events will be called per customer per year.
5. An event will last no more than 4 hours.
6. Customers may opt-out of an event at any time unless the event is a Mandatory Event as defined below.

MANDATORY EVENT

The Company will only dispatch a Mandatory Event if the North American Electric Reliability Corporation ("NERC") declares Level 2 Alerts for the Company's service territory, as defined by NERC's Reliability Standard EOP-002-2.

SPECIAL TERMS AND PROVISIONS

Option 1: Smart Thermostat:

1. This option will apply for a minimum of 12 months, starting with the first full billing month after the customer enrolls via the Platform.
2. If a customer has previously enrolled in this option and withdrawn, they may not reenroll until 12 full billing months after they last withdrew.
3. The one-time enrollment incentive will be provided once per customer per residence. Customers with multiple air conditioning units may be eligible for multiple incentives.
4. For the purposes of this option summer is defined as June 1 through September 30. Customers are eligible for the summer participation credit if they enrolled on or before September 30 and remained enrolled until October 1. The summer participation incentive will not be provided or prorated for customers that withdraw from the rate schedule before October 1.
5. The Company, in its sole discretion, may remove the customer from this option in the case of poor performance whether the performance in question was intentional or due to equipment malfunction.
6. The Company, in its sole discretion, may terminate this option at any time.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 4

Residential Service Tariffs

Residential Services

Rg-2, Rg-2a

New Program

Tariff Changes

Clarifications: Yes
Program Changes: Yes

Summary Points:

- Move to more cost-based rates in new service along with frozen rates for existing rate classes in this case
- New cost-based Time of Use service opened. Old penalty rate based Time of Use closed but available to existing customers in class who choose to remain
- Both TOU schedules changed to Optional-only (no Mandatory)

Overview:

As noted in schedule 12, the unbundled cost of service study was used to guide rate design for new service, with options provided to customers. Rather than trying to affect customer use patterns through rate design, MGE is moving to optional services to provide rewards for actions that help reduce overall cost or resource impacts that benefit all customers and moving away from peak period rates that are substantially higher than cost. BYOD (Schedule 2) was developed to provide a reward-based service. A new time-of-use rate schedule, Rg-2A, has been developed to better follow costs with its rate design. The old time-of-use schedule will not be eliminated but will be closed to new customers, allowing existing customers to decide which service to choose. All time-of-use service will be optional for customers, as cost impacts for large use customers are not commodity related.

Existing rates will remain unchanged in this rate proceeding.

AVAILABILITY

This rate schedule is for residential customers, subject to conditions of availability as specified in Rate Schedule Rg-1, as follows:

~~**Mandatory:** This rate schedule is mandatory for nonfarm, single-family, residential units with average daily usage of 130 kWh per day or more during the summer billing season.~~
This rate schedule is closed to new applicants on and after January 1, 2021.
~~**Optional:**~~ This rate schedule is optional for all ~~other residential~~ customers who qualify for residential service on this rate schedule, were on this service prior to January 1, 2021 and wish to remain on this service. ~~Those customers who wish to be served on this rate schedule on an optional basis must apply to the Company for service. Once an optional customer begins service on this rate schedule, that customer will remain on the rate for a minimum of one year. In 2015, optional customers on this rate schedule can move to the Rg-7 rate schedule prior to being on the rate for a minimum of one year.~~

RATE

	Summer	Winter
Grid connection and customer service charge per day	$0.62466	$0.62466
Distribution service: All kWh, per kWh	$0.03378	$0.03378
Electricity service:		
On-peak period 1 energy adder, per kWh	$0.18522	$0.14546
On-peak period 2 energy adder, per kWh	$0.22088	$0.13800
On-peak period 3 energy adder, per kWh	$0.18320	$0.17167
Base energy all kWh, per kWh	$0.04122	$0.04122

Summer rates are effective from June 1 through September 30. All other times of the year winter rates are effective.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the grid connection and customer service charge multiplied by the number of days in the billing period.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

PRICING PERIOD DEFINITIONS

On-Peak Period 1	10 a.m. through 1 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 2	1 p.m. through 6 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 3	6 p.m. through 9 p.m.: Monday through Friday, excluding holidays.
Base Energy Period	Includes all hours of all days.
Holidays	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

CHARACTER OF SERVICE

A customer will be classified as residential in accordance with the Company's standard classifications set forth in its rates and rules and will receive service in conformance with all rules and regulations pertaining to that classification.

SPECIAL TERMS AND PROVISIONS

1. This rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated.

2. Any customer choosing to be served on this rate schedule thereby waives all rights to any billing adjustments arising from a claim that the bill for the customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under Wis. Admin. Code § PSC 113.0406(4), Reg. January 2004, No. 577.

3. If the time-of-use customer does not have an outside meter, a key must be provided to the Company or other provisions must be made to ensure access to the meter by Company personnel during normal working hours.

~~4. If an optional customer moves or is forced to move, the customer has the option to retain time-of-use billing at the new premises. If the customer decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.~~

~~5. If an optional customer, upon expiration of a full year on this rate schedule, decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.~~

4~~6~~. Where two or more residential units are on a single meter, one customer charge will be applied for each four residential units or fraction thereof in the premises.

~~7. The mandatory time-of-use rate will no longer apply to a residential unit served under this rate in the following cases:~~

~~a. Customers on the mandatory time-of-use rate who maintain an average daily usage below 100 kWh over four consecutive billing months in one summer may, at their option, be transferred to the residential service Rate Schedule Rg-1.~~

~~b. Customers moving into a residence that has been served on the mandatory time-of-use rate may, at their option, be transferred to the residential service Rg-1 rate schedule if their average usage is below 130 kWh per day after a minimum of four consecutive summer billing months of consumption under the time-of-use rate.~~

~~8. Customers required to be served under this rate schedule after June 8, 1981, will be billed immediately under this rate schedule. After six- and 12-month intervals, the Company will provide a billing comparison between the time-of-use rate and the residential service rate based on the customer's actual usage. The Company will also provide the customer with information on how usage patterns could be changed to benefit the customer under the time-of-use rate.~~

5~~9~~. Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used. Thereafter, the customer will no longer be eligible to receive service under this rate schedule but may choose to be served under other rate schedules they qualify to receive service under at the time the meter is turned back on.

6~~10~~. Other special terms and provisions are specified in Rate Schedule Rg-1.

AVAILABILITY

This rate schedule is for residential customers, subject to conditions of availability as specified in Rate Schedule Rg-1, as follows:

This rate schedule is optional for customers who qualify for residential service under Rate Schedule Rg-1. Those customers who wish to be served on this rate schedule must apply to the Company for service. Customers will be placed on this rate on a first-come first-served basis as the appropriate meters become available. Once an optional customer begins service on this rate schedule, that customer will remain on the rate for a minimum of one year.

RATE

	Summer	Winter
Grid connection and customer service charge per day	$0.62466	$0.62466
Distribution service: All kWh, per kWh	$0.03378	$0.03378
Electricity service:		
On-peak period 1 energy adder, per kWh	$0.11328	$0.11196
On-peak period 2 energy adder, per kWh	$0.12292	$0.11003
On-peak period 3 energy adder, per kWh	$0.11587	$0.11377
Base energy all kWh, per kWh	$0.05959	$0.05959

Summer rates are effective from June 1 through September 30. All other times of the year winter rates are effective.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the grid connection and customer service charge multiplied by the number of days in the billing period.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

PRICING PERIOD DEFINITIONS

On-Peak Period 1	10 a.m. through 1 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 2	1 p.m. through 6 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 3	6 p.m. through 9 p.m.: Monday through Friday, excluding holidays.
Base Energy Period	Includes all hours of all days.
Holidays	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

CUSTOMER’S ENERGY RATE

The customer’s energy rate, as defined in schedule Pg-2, for customers served on this schedule will be determined below according to the customer’s net metering date (NM Date). The customer’s NM Date will be determined by the customer’s application date for parallel generation interconnection (“Application Date”) and the date that the Company signed the Interconnection Agreement (“Interconnection Date”). If the Interconnection Date is within 180 days of the Application Date then the Application Date will be used as the Net Metering Date, otherwise the Interconnection Date will be used.

1. Only complete interconnection applications will be considered for determination of the Application Date.

2. In the case that significant delays are caused by the Company then the Application Date will be used provided that the Interconnection Date is within 270 days instead of 180 days.

Net Metering Date	Customer's Energy Rate
Prior to 1/1/2021	• Rg-1 distribution service charge • Rg-1 electricity service charge • Any applicable adjustment for cost of Rg-1 service
1/1/2021 – 12/31/2021	• Rg-1 distribution service charge • Rg-1 electricity service charge • Any applicable adjustment for cost of Rg-1 service
1/1/2022 – 12/31/2022	• Rg-1 distribution service charge • Rg-1 electricity service charge • Any applicable adjustment for cost of Rg-1 service

CHARACTER OF SERVICE

A customer will be classified as residential in accordance with the Company's standard classifications set forth in its rates and rules and will receive service in conformance with all rules and regulations pertaining to that classification.

SPECIAL TERMS AND PROVISIONS

1. This rate schedule will apply for a minimum of one year from the date consumption under this tariff is initiated.

2. Any customer choosing to be served on this rate schedule thereby waives all rights to any billing adjustments arising from a claim that the bill for the customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under Wis. Admin. Code § PSC 113.0406(4), Reg. January 2004, No. 577.

3. If the time-of-use customer does not have an outside meter, a key must be provided to the Company or other provisions must be made to ensure access to the meter by Company personnel during normal working hours.

4. If a customer who is served under this rate schedule moves to a premises within the Company's service territory that qualifies for this service, the customer has the option to retain this service at the new premises. If the customer decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.

5. If a customer, upon expiration of a full year on this rate schedule, decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.

6. Where two or more residential units are on a single meter, one customer charge will be applied for each four residential units or fraction thereof in the premises.

7. Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used.

8. Other special terms and provisions are as specified in Rate Schedule Rg-1.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 5

Commercial and Industrial Tariff Changes

Commercial and Industrial Services

Cg-5, Cg-3, Cg-4

Tariff Changes

Clarifications:	Yes
Program Changes:	Yes

Summary Points:

- All rates remain the same for these classes
- Cg-3 closed but available to existing customers in class
- Cg-4 applicability and availability updated. Schedule optional for smaller C&I demand customers who desire a time-of-use option
- Cg-4A and Cg-4B also consolidated as rates have been the same and there has been no reason to maintain separate categories

Overview:

Schedules 12 and 14-16 show rates being maintained at the same level for the small, medium and large commercial and industrial classes.

Customers who wish to have a rate with Time of Use rate levels will now be allowed to move to Cg-4 as an optional service. The Cg-5 tariff is also changed to reflect changes for customers affected by Cg-3 closing and by changes to the availability clause of Cg-4. The Cg-3 tariff is modified to show the proposed closing versus modifying rates to a cost-based service since Cg-4 is a cost based alternative.

Elimination of the A and B categories in Cg-4 is also proposed since rates have remained the same for several years and there is no need for separate categories in the tariff.

AVAILABILITY

To any commercial customer using single-phase, 60-cycle alternating current for lighting, heating, and small motors (individual motors 7.5 horsepower or less) and all other appliances (including ranges) which do not interfere with lighting service; and for combined lighting and three-phase, 60-cycle, alternating current power service provided the single-phase load is distributed between the phases so that it will not unbalance the current per phase more than 10 percent.

This rate schedule applies to customers whose demand is 20 kW or less. A new customer initiating service with less than an estimated or actual demand of 50 kW will initially be placed on Cg-5 until the customer's demand exceeds the required demand for Cg-4, Cg-2 or Cg-6 ~~Level A or Level B~~ in at least four out of 12 months, exceeds 50 kW of demand within the first 12 months of service or otherwise qualifi~~es for Cg-4, Cg-2 or~~ Cg-6 Level A or Level B.

RATE

	Summer	Winter
Grid connection and customer service charge per day......	$0.78669	$0.78669
Distribution service: All kWh, per kWh	$0.02295	$0.02295
Electricity charge: All kWh, per kWh	$0.10224	$0.09082

Summer rates are effective from June 1 through September 30. All other times of the year winter rates are effective.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the grid connection and customer service charge multiplied by the number of days in the billing period.

COMMERCIAL TEMPORARY SERVICE

When supplying service for a short period of time to commercial customers, such as carnivals, fairs, and festivals, the following terms and provisions apply:

1. Customer will deposit in advance of starting installation or construction work the estimated cost thereof plus the estimated cost of electrical energy to be consumed.

2. Customer will be charged for cost, including labor and materials used, plus usual charge for overhead, of making and removing the temporary connections.

3. Energy used may be measured or estimated at the option of the Company. If energy used is estimated, the estimate will be determined by multiplying the connected load by the probable number of hours' use.

4. Final adjustment of charge to customer will be made after removal of temporary construction.

CATV AMPLIFIERS

Customers with Company-metered CATV amplifiers that wish to be served on Rate Schedule Cg-3 but lack a time-of-use meter and would otherwise qualify for service on Rate Schedule Cg-3 may instead receive a billing adjustment. This adjustment will be designed to compensate the customer the difference between what the customer was charged under this service and what they would have been charged under Rate Schedule Cg-3. This adjustment will be estimated annually by the Company and will use the most recent year of time-of-use consumption from a representative sample of customer-owned CATV amplifiers to develop a scalable time-of-use profile for a CATV amplifier. Availability of service under this provision is further limited to the availability of such a sample provided that such sample also demonstrates each CATV amplifier to have usage that is constant and relatively consistent. This service option will be closed to new customers as of January 1, 2021.

- The Company may install a time-of-use meter at any time; in this case the customer will be moved to ~~the Cg-3~~the available rate schedule they qualify for service under.

SPECIAL TERMS AND PROVISIONS

Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used.

AVAILABILITY

This rate schedule is optional to commercial and industrial customers with a maximum monthly 15-minute demand of 20 kW or less who would otherwise qualify for Rate Schedule Cg-5. ~~Those customers who wish to be served on this rate schedule on an optional basis must apply to the Company for service. Customers will be placed on this rate on a first-come first-served basis as the appropriate meters become available. Once an optional customer begins service on this rate schedule, that customer must remain on the rate for a minimum of one year. In 2015, optional customers on this rate schedule can move to the Cg-7 rate schedule prior to being on the rate for a minimum of one year~~This rate schedule is closed to new customers on and after January 1, 2021. Customers who had been taking service on this schedule on that date and continue to qualify for service on this schedule may continue to do so or take service on rate schedules Cg-4 or Cg-5. Customers who discontinue service on or after January 1, 2021 will not be eligible for service on this schedule thereafter.

RATE

	Summer	Winter
Grid connection and customer service charge		
Single-phase service per day……………………………..	$0.73249	$0.73249
Three-phase service per day……………………………..	$1.00249	$1.00249
Distribution service: All kWh, per kWh	$0.02295	$0.02295
Electricity service:		
On-peak period 1 energy adder, per kWh......................	$0.16932	$0.13067
On-peak period 2 energy adder, per kWh......................	$0.17719	$0.12032
On-peak period 3 energy adder, per kWh......................	$0.15239	$0.15257
Base energy all kWh, per kWh......................................	$0.04573	$0.04573

Summer rates are effective from June 1 through September 30. Winter rates are all times of the year other than the defined summer season.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the grid connection and customer service charge multiplied by the number of days in the billing period.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

PRICING PERIOD DEFINITIONS

On-Peak Period 1	10 a.m. through 1 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 2	1 p.m. through 6 p.m.: Monday through Friday, excluding holidays.
On-Peak Period 3	6 p.m. through 9 p.m.: Monday through Friday, excluding holidays.
Base Energy Period	Includes all hours of all days.
Holidays:	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

CHARACTER OF SERVICE

A customer will be classified as commercial in accordance with the Company's standard classifications set forth in its rates and rules and will receive service in conformance with all rules and regulations pertaining to that classification.

SPECIAL TERMS AND PROVISIONS

1. Any customer choosing to be served on this rate schedule thereby waives all rights to any billing adjustments arising from a claim that the bill for the customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under Wis. Admin. Code § PSC 113.0406(4), Reg. July 2014, No. 703.

2. The meter must be located outside or in a location that is readily accessible by Company personnel during normal working hours.

~~3. If the customer moves or is forced to move, the customer has the option to retain time-of-use billing at the new premises. If the customer decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.~~

~~4. If the customer, upon expiration of a full year on this rate schedule, decides to discontinue time-of-use billing, the Company will offer time-of-use billing to the next customer on the waiting list.~~

~~5~~3. Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used. Thereafter, the customer will no longer be eligible to receive service under this rate schedule but may choose to be served under other rate schedules they qualify to receive service under at the time service is resumed.

AVAILABILITY

Mandatory Service Provision:

This rate schedule is mandatory to new commercial and industrial customers with a maximum 15-minute demand in excess of 20 kW.

If a customer's demand fluctuates above and below 20 kW, the Cg-4 rate schedule is mandatory if the 15-minute demand exceeds 20 kW in at least four out of the last 12 months. In addition, a new customer initiating service with an estimated demand ~~of 50 kW or greater will be placed on~~ of 50 kW or greateer (within the first 12 months of service) will be placed on this rate. Once the customer is on this rate, the customer will remain on this rate as long as they have at least one month in the last 12 months where their 15-minute demand is greater than 20 kW. If the customer's 15-minute demand remains below 20 kW for 12 consecutive months, the customer will be notified that they can opt to stay on the Cg-4 rate or be moved to the Cg-3 or Cg-5 rate at their option as long as their ~~demand~~ remains below the level requiring mandatory service on this rate schedule. Customers that do not choose to be moved to Cg-5 service when they can opt to do so will be subject to the Optional Service Provision. The customer will have 15 days to ~~respond to the notification. If the customer does not respond within 15 days of notification, the customer will be moved to the Cg-5 rate schedule.~~

Optional Service Provision:

Customers who do not qualify for service under the mandatory provision of this service, or service Availability requirements of other rate schedules (such as Cg-2 or Cg-6 for example), who wish to select this rate schedule as a service option may do so. A customer selecting this rate schedule under this option thereby waives all rights to any billing adjustments arising from a claim that the bill for the customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under Wis. Admin. Code § PSC 113.0406(4), Reg. January 2004, No. 577.

RATE

	Summer	Winter
Grid connection and customer service charge:		
Single-phase service per day	$6.19251	$6.19251
Three-phase service per day	$6.32048	$6.32048
Distribution service:		
Customer maximum 15-minute demand per kW per day	$0.08480	$0.08480
Distribution charge, per kWh	$0.01001	$0.01001
Electricity service:		
Maximum monthly on-peak 15-minute demand per kW per day	$0.42653	$0.34931
On-peak period 1 energy adder, per kWh	$0.05545	$0.04245
On-peak period 2 energy adder, per kWh	$0.06177	$0.04175
On-peak period 3 energy adder, per kWh	$0.05402	$0.04631
Base energy: All kWh, per kWh	$0.04148	$0.04148

Summer rates are effective from June 1 through September 30. Winter rates are all times of the year other than the defined summer season.

N **RATE PROVISIONS**

If a customer satisfies the availability requirements for any or all of the following provisions, and service under such provision(s) would reduce the customer's bill, then the customer will automatically be served on such provision(s).

Provision	Sheet
Low Load Factor Provision...	E-32

M **MINIMUM MONTHLY CHARGE**

The minimum monthly charge will be the grid connection and customer service charge plus the demand charge for the customer maximum 15-minute demand multiplied by the number of days in the billing period.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

PRICING PERIOD DEFINITIONS

R	On-Peak Period 1	10 a.m. through 1 p.m.: Monday through Friday, excluding holidays.
	On-Peak Period 2	1 p.m. through 6 p.m.: Monday through Friday, excluding holidays.
R	On-Peak Period 3	6 p.m. through 9 p.m.: Monday through Friday, excluding holidays.
	Base Energy Period	Includes all hours of all days.
	Holidays	New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas.

DETERMINATION OF DEMAND

1. All monthly demand and energy usage will be measured by meters installed and maintained by the Company. Estimates made by the Company, based on historic records plus known load characteristics, will be used for billing purposes if meter failure occurs.

2. The customer maximum 15-minute demand will be the greatest rate at which electrical energy has been used during any period of 15 consecutive minutes in the current or preceding 11 months.

3. The maximum on-peak 15-minute demand will be the greatest rate at which electrical energy has been used in 15 consecutive minutes during on-peak periods of the billing month.

SPECIAL TERMS AND PROVISIONS

1. This rate schedule will remain in effect for a minimum of one year from the date consumption is initiated.

~~2. Any customer choosing to be served on this rate schedule thereby waives all rights to any billing adjustments arising from a claim that the bill for the customer's service would be cheaper on any alternative rate schedule for any period of time, including any rights under the Wis. Admin. Code § PSC 113.0406(4), Reg. July 2014, No. 703.~~

2~~3~~. The meter must be located outside or in a location that is readily accessible by Company personnel during normal working hours.

3~~4~~. Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 6

BGS Tariff Update

Commercial and Industrial Services

BGS

Tariff Changes

Clarification: Yes
Program Changes: No

Summary Points:

- Tariff language revised to refer to the minimum and maximum term length in one section of the tariff.
- Term length language revised from "five years" to "five or more years" in the Availability section of the tariff.

Overview:

The clarification above is proposed for the service.

AVAILABILITY

Service under this voluntary schedule is available to customers on demand-metered Rate Schedules Cg-2,
R Cg-4, Cg-6, Cg-8, Sp-3, and Sp-4 who contract for service for an initial period of five or more years. Participation in this program will be limited to a 50 MW total customer load.

If the customer maximum 15-minute demand level falls below 75 kW, the Company will determine if it is reasonable to remove the BGS generator from the customer and discontinue BGS at that site or retain BGS at the customer site and charge for BGS based on the minimum demand volume determined in the rate provision below. Factors such as generator size, potential use of the generator elsewhere, future customer demand, and special usage circumstances will be considered in making this decision. If the Company determines it is appropriate to keep the BGS generator at the customer location, the customer may choose to continue BGS service but must agree to the minimum demand charge as described under the rate provision below.

RATE

R All the provisions of the applicable Cg-2, Cg-4, Cg-6, Cg-8, Sp-3, and Sp-4 rate schedules will apply. In addition:

1. Customers taking firm service under this schedule will have an additional charge for backup service applied to the customer maximum 15-minute demand as follows:

    a. Customers who initiated service prior to July 1, 2006, will have the charge designated below applied to the greater of the customer maximum 15-minute demand or 75 kW.

    b. Customers who initiated service on and after July 1, 2006, will have the charge designated below applied to the greater of the customer maximum 15-demand, 50 percent of the highest customer maximum 15-minute demand experienced by the customer during the time period the customer is served under this rate schedule, or 75 kW.

    c. Customers who request redundant on-site BGS capacity, and such added capacity is available to the Company under the existing terms of the tariff, will have the charge designated below applied to the standby-rated capacity of the redundant generator. Redundant on-site BGS capacity in this rate schedule means any BGS generator(s) in addition to the generator(s) deemed appropriate by the Company to supply the customer maximum 15-minute demand at the time of installation.

2. Customers taking interruptible or supplemental service will have an additional charge for backup service applied to the minimum contract firm demand level.

3. The firm demand level charges are as follows:

    a. For diesel-fueled generators, $0.04932 per kW per day for continuing agreements that became effective prior to March 1, 2003.

    b. For diesel-fueled generators, $0.06575 per kW per day for agreements that became effective on or after March 1, 2003, and prior to January 1, 2010.

    c. For diesel-fueled generators, $0.09863 per kW per day for agreements that became effective on or after January 1, 2010.

    d. For natural gas-fueled generators, $0.16438 per kW per day for agreements that became effective on or after January 1, 2010.

CONDITIONS OF DELIVERY

1. A customer receiving service under this rider must enter into a contract that identifies the size of the generator specified and installed by the Company and the customer's expected annual maximum load.

2. A customer that receives electric service through more than one distribution service feed at a single location (premise) may choose to take backup service under this schedule for all or only some of the service feeds at that location. The Company may require the customer to pay in advance of installation for any additional metering or measurement equipment necessary for the customer to take backup service for less than the entire premise.

   a. For firm service customers, backup generation service must be taken for the entire load at each distribution service chosen. For purposes of this schedule, the customer maximum 15-minute demand will be the greatest rate at which electrical energy has been used for the distribution service feeds chosen during any 15 consecutive minutes in the current or preceding 11 billing months.

   b. For interruptible and supplemental service customers, backup generation service must be taken for the full amount of the customer's minimum contract firm demand level. For purposes of this schedule, the contract firm demand level will be the customer's contract firm demand level in effect at the time the customer enters into the BGS contract with the Company.

3. The contract will have an initial term ~~of five or more years~~ in accordance with the Availability Clause of this schedule. At the end of the initial term the contract will be automatically renewed on an annual basis unless written notice from either party is delivered to the other party no later than 180 days prior to the end of the contract term.

4. The authorized rate in effect at the time the initial contract term begins for a customer will remain fixed for that customer for the entire initial contract term, regardless of other changes that may from time to time be approved by the Public Service Commission of Wisconsin. At the end of the initial term, service will be charged at the authorized rate in effect at the time.

5. The Company will work with the customer to determine where to install the generator and associated equipment. The facilities will comply with Wisconsin State Electrical Code, local ordinances, and accepted engineering and planning practices and will be connected to the Company's system over the most direct route as determined by the Company. The Company is responsible for maintaining facilities in compliance with applicable regulations and ordinances that may change over the term of the contract.

6. The customer will provide or will be responsible for the cost of all right-of-way easements and building permits necessary for the Company to connect the generator to the Company's system and to install, maintain, or replace distribution facilities where necessary.

7. The customer will supply the space for the generator and a concrete pad as specified by the Company. The customer will either clear and grade such property and pour the pad or pay the Company to clear and grade such property and pour the pad.

CONDITIONS OF DELIVERY (continued)

8. The Company is responsible for installation and backfilling as necessary. The customer is responsible for the cost of restoration of the property after the Company has completed installation and backfilling where applicable.

9. If the generator installation requires nonstandard service facilities or if the customer requests nonstandard facilities or design, including but not limited to aesthetics, noise attenuation, exhaust ventilation, or location on the customer's premise, the Company will require the customer to pay a contribution in advance of construction for the cost of the facilities in excess of standard design.

10. The customer will be required to make the Company equipment available and permit entry upon the property by Company personnel at reasonable times for the purposes of testing, maintenance, and replacement of the equipment. The Company will be responsible for testing the generator at least once a year to ensure the equipment is in proper working condition.

11. The Company reserves the right to operate the generator to meet system load requirements.

12. The availability of service under this schedule may be limited at the discretion of the Company. Service under this schedule may be refused if the Company believes the customer presents an unacceptable credit risk or cannot provide or meet suitable generator siting requirements, including physical and environmental restrictions and liability limitations.

13. Service under this schedule will be furnished only in accordance with the Electric Service Rules and Regulations of the Company.

14. Energy furnished under this schedule will not be resold by the Customer.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 7

Primary Voltage Discount

Primary Voltage Provision

PVP-1

Existing Program; New Tariff

Tariff Changes

Clarifications: Yes
Program Changes: Yes

Summary Points:

- Primary discount provision language is being struck from individual tariffs.
- Available provision language is being added to individual tariffs.
- A new tariff sheet is being created to consolidate all language regarding primary voltage discounts.
- The new provision will no longer have demand requirements for receiving a discount.
- The new provision will require that customers be served at the highest distribution voltage available.

Overview:

Primary voltage discounts currently exist in various commercial and industrial rate schedules. These discounts are being moved to one location under a service provision tariff similar to the Low Load Factor Provision which was implemented in 3270-UR-122. This relocation will help to consolidate and remove redundant language.

Additionally, two changes are being implemented. The first change is the removal of any demand requirement for primary voltage customers in order to receive the primary voltage discount. Previously a minimum demand of 200 kW was required for customers served at 2,400 Volts or 4,160 Volts and a minimum demand of 500 kW for customers served at 13,800 Volts.

The second change is redefining “primary voltage” to be a relative voltage rather than an absolute voltage. The current provision applies to customers served at 2,400 Volts, 4,160 Volts, and 13,800 Volts whether the customer’s service is being stepped-down from a higher voltage. The discount is meant to compensate customers at high voltages for having fewer losses from step-down transformation. Customers receiving service at 4,160 Volts that has been stepped-down from 13,800 Volts experience nearly as many step-down losses as customers that receive service at 480 Volts that has been stepped-down from 13,800 Volts.

The following language will be struck from Cg-4 and Cg-8:

~~**PRIMARY DISCOUNT PROVISION**~~

~~Available to customer not served by the low-voltage network.~~

1. ~~For delivery at 2,400 volts or 4,160 volts as available to customers with demands of 200 kW or more.~~

   ~~$0.00328 per kW per day of customer maximum 15-minute billed demand plus $0.001 per month per kWh.~~

2. ~~For customers qualifying under No. 1. who provide the transformers and associated equipment necessary for converting the available primary service to the secondary voltage required by the customer.~~

   ~~$0.00328 per kW per day of customer maximum 15-minute billed demand.~~

3. ~~Customers taking service at primary voltage will provide all the necessary delivery, control, and regulating facilities on the load side of the transformers.~~

The following language will be struck from Cg-2 and Cg-2A:

~~**PRIMARY DISCOUNT PROVISION**~~

~~Available to customer not served by the low-voltage network.~~

1. ~~For delivery at:~~

   a. ~~2,400 volts or 4,160 volts as available to customers with demands of 200 kW or more.~~

   b. ~~13,800 volts where available to customers with demands of 500 kW or more.~~

   ~~$0.00328 per kW per day of customer maximum 15-minute billed demand plus $0.001 per month per kWh.~~

2. ~~For customers qualifying under No. 1.a. and 1.b. who provide the transformers and associated equipment necessary for converting the available primary service to the secondary voltage required by the customer.~~

   ~~$0.00328 per kW per day of customer maximum 15-minute billed demand.~~

3. ~~Customers taking service at primary voltage will provide all the necessary delivery, control, and regulating facilities on the load side of the transformers.~~

The following language will be struck from Cg-6 and Cg-6A:

~~**PRIMARY DISCOUNT PROVISION**~~

~~Available to customer not served by the low-voltage network.~~

1. ~~For delivery at:~~

   a. ~~2,400 volts or 4,160 volts as available.~~

~~b. 13,800 volts where available.~~

~~$0.00328 per kW per day of customer maximum 15-minute billed demand plus $0.001 per month per kWh.~~

~~2. For customers qualifying under No. 1. who provide the transformers and associated equipment necessary for converting the available primary service to the secondary voltage required by the customer.~~

~~$0.00328 per kW per day of customer maximum 15-minute billed demand.~~

~~3. Customers taking service at primary voltage will provide all the necessary delivery, control, and regulating facilities on the load side of the transformers.~~

The following language will be added to Cg-4, Cg-2, Cg-2A, Cg-6, and Cg-6A.

RATE PROVISIONS

If a new customer satisfies the availability requirements for any or all of the following provisions, and service under such provision(s) would reduce the customer's bill, then the customer will automatically be served on such provision(s).

Provision	Sheet
Low Load Factor Provision..	E-32
Primary Voltage Provision..	E-

AVAILABILITY

Available to customers on Rate Schedules Cg-4, Cg-2, or Cg-6 that are metered by the Company's electric distribution grid at the highest distribution voltage available in the customer's vicinity.

RATE

All the provisions of customer's otherwise applicable rate schedule will apply with the additional credits listed below.

Primary voltage energy discount per kWh $0.00100
Primary voltage demand discount per kW per day $0.00328

Customers who provide the transformers and associated equipment necessary for converting the available primary voltage to the secondary voltage required by the customer will also receive the credit listed below in addition to the credits listed above.

Transformer demand discount per kW per day....................... $0.00328

DETERMINATION OF DEMAND

1. The primary voltage demand will be determined by the customer maximum 15-minute demand as defined in the customer's otherwise applicable rate schedule.

2. The transformer demand will be determined by the customer maximum 15-minute demand as defined in the customer's otherwise applicable rate schedule.

SPECIAL TERMS AND PROVISIONS

1. Customers eligible for this provision will automatically be served on this provision.

2. The highest distribution voltage available in the customer's vicinity will be determined at the Company's sole discretion.

3. In the case that the Company upgrades the electric distribution grid to a higher voltage such that a previously eligible customer is no longer metered at the highest distribution voltage available then they will be removed from this provision.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 8

PV-1 : PV Connect

PV Connect

PV-1

New Program

Summary Points:

- Available to customer-owned photovoltaic systems connected directly to the grid (the generation is not consumed on-site).
- Energy credits will be LMP based and capacity credits will be CONE based.
- Includes a customer service and grid connection charge in addition to energy charges for “station use”.

Overview:

This offering is a standalone service and not a rider to an existing service. Service will be provided through a dedicated meter and is only available to eligible photovoltaic systems connected directly to MGE’s distribution grid. In order to be considered eligible the photovoltaic system cannot provide energy to any customer for on-site consumption other than what is necessary to operate the photovoltaic system and any relevant safety equipment. This offering will have an initial program limit of 5 MW and an individual customer limit of 1.5 MW.

Under this program, customers will be billed a customer service and grid connection charge for their meter and connection to the grid. Distribution and electricity service charges will also apply to any deliveries from MGE.

Energy delivered from the customer’s photovoltaic system to the grid will be purchased according to the non-capacity rates in the Parallel Generation Buyback Rates on Sheet E-55 of the Company’s tariff book. The customer will also receive a monthly capacity credit for their photovoltaic system according to the MISO accredited capacity of the system. The credit rate will be the value of CONE that is in effect when the photovoltaic system if first energized. This credit rate will be locked in for the life of the photovoltaic system.

MGE believes that the most likely customers to use this service are customers that are unable to interconnect their photovoltaic system behind their existing load due to unique electrical issues. MGE’s currently open parallel generation tariffs are designed to compensate customers under the assumption that they are interconnected behind existing load. Under these types of interconnections the customer is already self-consuming some of their production in addition to using their generation to “peak shave”.

AVAILABILITY

Available to Eligible Facilities, as defined in this schedule, served by the Company's electric distribution system. There is a participation limit of 1.5 MW of nameplate capacity per entity and a total program limit of 5 MW.

DETERMINATION OF ELIGIBLE FACILITY

For the purposes of this schedule, an Eligible Facility must:

1. Have a fully executed Interconnection Agreement.

2. Generate energy via a solar photovoltaic process. No other process, including those used by energy storage devices, may be used.

3. Interconnect via a metered service that measures only the solar photovoltaic equipment and any necessary equipment for safe operation of the solar photovoltaic equipment.

4. Have a fully executed PV Connect Service Agreement.

RATE

The following charges will apply to deliveries from the Company to the customer. The grid connection and customer service charge will still apply in the absence of any deliveries either to or from the customer.

Grid connection and customer service charge per day............ $0.78669
Distribution service: All kWh, per kWh $0.02295
Electricity charge: All kWh, per kWh $0.10224

Deliveries from the customer to the Company will be credited according to the time-of-use Parallel Generation Buyback Rates (Sheet E-55) less any capacity adders. These deliveries are exempt from fuel cost surcharges and credits.

Additionally, the customer will receive a monthly capacity credit according to the accredited capacity of the Eligible Facility. The monthly capacity credit will be the accredited capacity multiplied by the number of days in the billing month and the capacity credit rate as stated below according to the date that the Eligible Facility is first energized outside of testing purposes. This date may be negotiated in the PV Connect Service Agreement if, through no fault of the customer or the customer's installer, the interconnection is delayed by a third party or the Company.

Accredited capacity per kW per day:
6/1/2019 – 5/30/2020 .... $0.23882
6/1/2020 – 5/30/2021 .... $0.25167

These rates are set annually based on the Midcontinent Independent System Operator (MISO) Cost of New Entry (CONE) for the relevant Local Resource Zone, which at present is Eastern Wisconsin and Upper Michigan (LRZ 2).

DETERMINATION OF ACCREDITED CAPACITY

The accredited capacity of the Eligible Facility will be set annually on January 1st according to the MISO accredited capacity of the Eligible Facility. This accredited capacity definition is subject to change.

In the case that the Eligible Facility ceases to operate as designed, outside of scheduled maintenance, then the capacity credit may be suspended until the Eligible Facility is operating as designed.

In the case that the Eligible Facility is modified such that the designed capacity is altered then

1. The customer must undergo any applicable interconnection procedures, as set by the Company and in compliance with PSC 119, and

2. If the designed capacity is altered by more than 10%, the accredited capacity will be calculated going forward as if the date the modifications are completed is the first date of operation for the Eligible Facility and

3. If the designed capacity is altered by 10% or less, the accredited capacity will continue to be calculated as it was before the modifications and

4. The capacity credit rate will remain unchanged.

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

Customers with a net account credit may request a check to be issued by the Company. All checks issued by the Company will be in the amount of the customer's net account credit. Checks may be requested no more frequently than once every 12 months with the following exceptions:

1. The net account credit is greater than $100.

2. The account is closed.

SERVICE COMPATIBILITY

The customer will be subject to the same electric service rules as are the general service customers of the Company.

Safety of the physical well-being of all persons will be paramount under all considerations and aspects of the construction, operation, and maintenance of generating equipment operated in parallel with the Company's system.

METERING AND SERVICE FACILITIES

The customer will provide, in writing, proof of compliance with all applicable local, state, and national electrical and safety codes. The customer will pay for the cost of building and/or rebuilding any Company facilities required to adequately accommodate, meter, and/or bill the parallel generation system. These costs may be paid by the customer over a time period not to exceed 24 months from billing by the Company. A finance charge will be added to all amounts not paid within 30 days of billing.

INTERCONNECTION FACILITIES

The customer will furnish, install, operate, and maintain facilities such as manual lockable disconnect(s), relays, switches, synchronizing equipment, monitoring equipment, and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities and schemes will be reviewed and approved by the Company prior to interconnection. Interconnection equipment designed to isolate the customer's generation from the Company's system will be accessible at all times to authorized Company personnel. All other equipment will be accessible to the Company periodically for routine testing.

Customer generation equipment will be of such design as to prevent undesirable effects upon the operation of standard services or equipment of the Company, its customers, or other utilities or agencies (for example, telephone, radio, or television interference, etc.). In all respects, the generation equipment and its connection to the Company's system will conform to the guidelines and interconnection rules in Wis. Admin. Code § PSC 119.04.

CONTRACT

The Company will require two contracts. One contract (the Interconnection Agreement) specifying technical and operating aspects of parallel generation. Another contract (the PV Connect Service Agreement) specifying that the customer understands and agrees to the terms and conditions of this schedule. Customers have the right to appeal to the PSCW if they believe that either contract required by the Company is unreasonable.

LIABILITY OF THE PARTIES

The customer will secure and maintain liability insurance that provides protection against claims for damages resulting from (1) bodily injury, including wrongful death and (2) property damage arising out of customer's ownership and/or operation of the facility. The limits of the policy, at the lowest, will be the greater of $300,000 per occurrence or the per occurrence level shown in Wis. Admin. Code § PSC 119.05 or the customer will prove financial responsibility by another method acceptable, and approved in writing, by the Company. The failure of the customer or the Company to enforce the minimum levels of insurance does not relieve the customer from maintaining such levels of insurance or relieve the customer of any liability. The customer will provide the Company with a certificate of insurance containing a minimum 30-day notice of cancellation prior to execution of this agreement.

Each of the parties will indemnify and save harmless the other party against any and all damages to persons or property occasioned, without the negligence of such other party, by the maintenance and operation by such parties of their respective lines and other electrical equipment.

RENEWABLE ENERGY CREDITS

All renewable energy credits and benefits, emissions allowances, or other renewable energy, air emissions, or environmental benefits for which the customer's generation project qualifies under any existing or future applicable law relating to the project will remain the property of the customer for any energy for which the customer receives an energy credit on its monthly bill.

1. The ownership of any and all renewable energy credits may be negotiated in the PV Connect Service Agreement.

SPECIAL TERMS AND PROVISIONS

1. Schedules Pg-1 and Pg-2 may not be used in conjunction with this schedule.

2. Customers who have their meters turned off and back on within a 12-month period will pay the minimum monthly charges, applicable to the customer, for the months while service was not being used.

3. The term of the PV Connect Service Agreement, and subsequently service under this schedule, shall be 25 years. At the end of this term the customer may enroll in any of the Company's schedules that they are eligible for at that time.

4. Customers may terminate their PV Connect Service Agreement, and subsequently service under this schedule, prior to the end of the 25-year term pursuant to providing a Capacity Reprocurement Fee to the Company. The Capacity Reprocurement Fee shall be the total expected amount that would have been paid by the Company to the customer for the accredited capacity credit included in this schedule for the lesser of 5 years following the customer's termination of the PV Connect Service Agreement or the remainder of the 25-year term.

5. Due to the nature of a contracted rate for capacity, the Company, in its sole discretion, may deny eligibility to this schedule when it believes that there is significant risk that a Eligible Facility will not remain interconnected, operational, and/or well maintained for the duration of the contracted term.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 9

Retired Schedules List

The following Rate Schedules are being terminated prior to electric tariff book reorganization and implementation of the new billing system. They are either closed or no used and or marketable:

Cg-2A

Cg-6A

Is-1

Is-2

SCS

MBP

VGC

AGS

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 10

Electric Tariff Reorganization Statement of Intent

The existing Electric Tariff Volume has a numbering system that limits the ability to add new services and provisions and includes duplicative terms that apply in multiple schedules. MGE plans to reorganize the tariff book after changes to tariffs filed in this case are considered in this docket. Typos will also be fixed. This will not affect any of the decisions made or content and terms of services approved in this docket. The new format should make navigation through the tariff volume easier to follow and modify in the future.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 11

Electric Revenue Summary

Electric Cost of Service & Revenue Summary

Summary Points:

- Because of the number of accounts netted to a zero increase, COSS could not be reliably performed with current data
- Since no shifts in revenue between classes are proposed, a current COSS not necessary for class to class revenue allocation
- All rates kept at the same level, except as agreed upon for Sp-3 with the single customer (see Schedule 2).

Overview:

Because of the large amount of cost netting performed to result in no revenue increase in this case, reliable data for a current cost of service study is not available.

Forecasted volumes were updated for annual LEC credit forecast update.

Rate components were kept at the same level in each rate schedule except as requested by the single customer served under Sp-3 (see Schedules 2 and 17).

MADISON GAS & ELECTRIC COMPANY
ESTIMATED ELECTRIC RETAIL REVENUE SUMMARY
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021
3270-UR-123

	RATE CLASS	Service Sales KWH [3]	PRESENT REVENUES	2021 PROPOSED REVENUES	PROPOSED DOLLAR INCREASE	PROPOSED PERCENT INCREASE
Rg-1	Residential	769,091,607	$133,650,726	$133,650,726	$0	0.00%
Rg-2	Residential Time-of-Use	11,793,185	$1,707,659	$1,707,659	$0	0.00%
Rw-1	Residential Controlled Water Heating (Closed)	48,500	$5,810	$5,810	$0	0.00%
Rg-7	Residential Renewable Generation Net Metering Rate	86,572	$17,677	$17,677	$0	0.00%
	TOTAL RESIDENTIAL REVENUE	781,019,864	$135,381,872	$135,381,872	$0	0.00%
Cg-5	Small C&I Lighting and Power (<20 kW)	189,454,459	$26,715,332	$26,715,332	$0	0.00%
Cg-3	Small C&I Optional Time-of-Use (<20 kW)	8,774,577	$1,116,676	$1,116,676	$0	0.00%
Cg-7	Small C&I Renewable Generation Net Metering Rate	49,086	$6,982	$6,982	$0	0.00%
	TOTAL SMALL COMMERCIAL & INDUSTRIAL REVENUE	198,278,121	$27,838,990	$27,838,990	$0	0.00%
Cg-8	Medium C&I Renewable Generation Net Metering Rate	826,170	$136,988	$136,988	$0	0.00%
Cg-4	C&I Time-of-Use (20-200 kW)	628,397,626	$80,806,351	$80,806,351	$0	0.00%
Cg-2	C&I Lighting and Power Time-of-Use (>200 kW)	784,094,894	$85,366,238	$85,366,238	$0	0.00%
Cg-2A	C&I Lighting and Power Critical Peak Pricing (>200 kW)	0	$0	$0	$0	0.00%
Cg-6	C&I Lighting and Power Large Annual High Load Factor (>1000 kW)	232,160,489	$20,736,533	$20,736,533	$0	0.00%
Cg-6A	C&I Lighting and Power Large Ann. High Load Factor - CPP (>1000 kW)	-	$0	$0	$0	0.00%
	TOTAL MEDIUM & LARGE COMMERCIAL & INDUSTRIAL REVENUE	1,645,479,178	$187,046,110	$187,046,110	$0	0.00%
Cp-1	C&I High Load Factor Direct Control Interruptible - Transmission Volt.	97,690,096	$4,868,470	$4,868,470	$0	0.00%
Sp-3	University of Wisconsin Time-of-Use	353,757,734	$33,712,224	$33,633,599	($78,625)	-0.23%
	TOTAL CONTRACT SERVICES REVENUE	451,447,830	$38,580,694	$38,502,069	($78,625)	-0.20%
	Primary Voltage Discount (kW)		($50,582)	($50,582)	$0	0.00%
	Primary Voltage Discount (kWh)		($190,200)	($190,200)	$0	0.00%
	Transformer Equipment Discount (kW)		($18,107)	($18,107)	$0	0.00%
	TOTAL DISCOUNTS [1]		($258,889)	($258,889)	$0	0.00%
Cs-1	Community Shared Solar Electricity Service and Transmission Revenue		$ 780,190	$ 780,190	$0	0.00%
RER-1	Renewable Resource Revenue	21,637,607	$ 1,261,734	$ 1,261,734	$0	0.00%
RWE-1	Green Power Tomorrow (Residential)	54,330,727	$ 543,307	$ 543,307	$0	0.00%
BWE-1	Green Power Tomorrow (Commercial/Industrial, Interdepartmental)	17,139,265	$171,391	$171,391	$0	0.00%
	TOTAL GPT, SS & RER REVENUE [2]	93,107,599	$2,756,622	$2,756,622		
Is-3	Interruptible Service Rider		($609,522)	($609,522)	$0	0.00%
Is-4	Direct Control Interruptible Service Rider		($427,242)	($427,242)	$0	0.00%
SCS	Summer Curtailable Service		$0	$0	$0	0.00%
	TOTAL INTERRUPTIBLE CREDITS [1]		($1,036,764)	($1,036,764)	$0	0.00%
Gf-1	General Flat Rate	1,566,765	$202,301	$202,301	$0	0.00%
Mg-2	Secondary Service for Municipal Defense Sirens	0	$1,075	$1,075	$0	0.00%
MLS	Athletic Field Lighting	468,034	$66,046	$66,046	$0	0.00%
OL-1	Outdoor Overhead Lighting Service - Private Unmetered	1,508,040	$583,830	$583,830	$0	0.00%
EV-1	Home Electric Vehicle Charging Stations		$23,393	$23,393	$0	0.00%
EV-2	Electric Vehicle Public Charging Pilot Rider		$31,257	$31,257	$0	0.00%
	TOTAL MISCELLANEOUS AND LIGHTING	3,542,839	$907,901	$907,901	$0	0.00%
SL-1	Streetlighting Service - Company-Owned and Company-Maintained	650,436	$194,766	$194,766	$0	0.00%
SL-2	Streetlighting Service - Customer-Owned and Customer-Maintained	0	$436,559	$436,559	$0	0.00%
SL-3	Streetlighting Service - Customer-Owned and Company-Maintained	4,690,248	$810,028	$810,028	$0	0.00%
	TOTAL STREETLIGHTING SERVICE	5,340,684	$1,441,353	$1,441,353	$0	0.00%
BGS	Backup Generation Service		$2,402,824	$2,402,824	$0	0.00%
AGS	Alternative Generation Schedule		$0	$0	$0	0.00%
TOTAL ELECTRIC RETAIL REVENUE		3,085,108,516	$393,599,745	$393,521,120	($78,625)	-0.02%
	Interdepartmental	2,939,598	$397,196	$397,196	$0	0.00%
TOTAL ELECTRIC RETAIL REVENUE W/ INTERDEPART.		3,088,048,114	**$393,996,941**	**$393,918,316**	($78,625)	-0.02%

Notes
[1] Discounts and interruptible credits are listed here for reference. They are already subtracted from the appropriate Commercial and Industrial Class revenue totals.
[2] Residential and Business Wind Energy and Community Solar electric service rate revenues are included in their rate class totals and are represented here for reference.
[3] Service Sales do not include Shared Solar kWh or RER kWh.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 12

Residential Service Rates

Residential Rate Design

Rg-1, Rg-2, Rg-2a, Rw-1, Rg-7

Tariff Changes

See Schedule 4

Summary Points:

- Unbundled Cost Study used for rate component design for new time of use service
- Time of use COSS method followed for recovery of fixed generation and transmission costs in energy rate components for new time of use rates
- Rates in current rate schedules remain unchanged

Overview:

The unbundled cost study from the last rate proceeding was used to guide rate design for the new time of use rate class. As noted in Schedule 4, the company is moving towards rate designs with cost-based components while desired use changes are encouraged through rewards. A new Time of Use rate schedule (Rg-2A) has a base energy rate based on average variable energy costs plus a portion of fixed generation and transmission costs allocated in a manner similar to the basis of the Time of Use cost study (40%). The cost adders for the peak periods are based on the difference of average market energy in those periods from annual average costs (average LMPs during the different periods) plus and allocation of the remaining (60%) fixed generation and transmission costs. The resulting costs per pricing period are more cost based and more comparable to time of use designs throughout the state.

Rates for existing rate classes (Rg-1, Rg-2, Rw-1, Rg-7) will remain unchanged in this proceeding.

SUMMARY:

Madison Gas and Electric Co.
Unbundled Cost of Service - Standard COSS
TOTAL RESIDENTIAL
Summary of Cost Categories

PSCW Account	Total Costs	Customer Costs	Grid Connection	Dist Demand Costs	Gen Tran Demand	Energy Costs
			Distribution		Generation and Transmission	
Production Plant - Net Value						
Steam Plant	$63,053,912					
Other Plant	$9,108,086					
Renewable Plant - Wind	$41,403,298					
Renewable Plant - Solar	$2,206,260					
Distribution Plant - Net Value						
Customer Related	$52,585,944					
Demand Related	$185,637,573					
Other Plant - Net Value	$21,332,875					
Return on Plant (allocated based on Plant)						
Production Return Steam Plant	$3,949,503				$3,949,503	$0
Production Return Other Plant	$570,502				$570,502	$0
Production Return Renewable Plant - Wind	$2,593,375				$259,338	$2,334,038
Production Return Renewable Plant - Solar	$138,193				$69,097	$69,097
Distribution Return (Customer Related)	$3,293,822		$3,293,822			
Distribution Return (Demand Related)	$11,627,766			$11,627,766		
Other Plant, Material and Supplies, Cust Adv and Def Taxes F	$1,336,226	$574,113	$237,170	$301,181	$194,649	$29,112
Depreciation Expense (allocated based on Plant)						
Production Depreciation Exp Steam Plant	$5,037,003	$0	$0	$0	$5,037,003	$0
Production Depreciation Exp Other Plant	$1,932,603	$0	$0	$0	$1,932,603	$0
Production Depreciation Exp Renewable Plant - Wind	$2,376,571	$0	$0	$0	$285,163	$2,091,408
Production Depreciation Exp Renewable Plant - Solar	$161,231	$0	$0	$0	$88,838	$72,394
Distribution Depreciation Exp (Customer Related)	$2,450,791	$0	$2,450,791	$0	$0	$0
Distribution Depreciation Exp (Demand Related)	$5,217,579	$0	$0	$5,217,579	$0	$0
Other Plant Depreciation Exp	$2,039,039	$49,795	$306,253	$1,034,633	$437,402	$210,956
Operation and Maintenance Expense						
Fuel	$11,985,640	$0	$0	$0	$0	$11,985,640
Other	$34,778,829	$0	$0	$0	$24,196,903	$10,581,926
Production O&M Expense	$46,764,469	$0	$0	$0	$24,196,903	$22,567,566
Transmission O&M Expense	$12,314,042	$0	$0	$0	$12,314,042	$0
Distribution O&M Expense	$7,000,164	$0	$2,826,650	$4,173,514	$0	$0
Other Costs and Revenues						
Other Operating Revenues	($1,406,722)	$0	$0	$0	$0	($1,406,722)
Customer Account Expense	$7,626,390	$7,626,390	$0	$0	$0	$0
Customer Service Expense	$3,910,593	$3,910,593	$0	$0	$0	$0
Administratie & General Expense	$13,344,700	$5,253,038	$2,098,277	$2,680,338	$2,584,646	$728,400
Taxes						
Taxes Other Than Income	$6,335,642	$2,722,127	$1,124,530	$1,428,034	$922,919	$138,031
Deferred Taxes	$3,380,669	$423,854	$332,575	$736,345	$1,261,160	$626,736
Federal and State Income Taxes	($1,118,445)	($140,226)	($110,027)	($243,609)	($417,236)	($207,346)
Total Investment Tax Credit	($24,858)	($3,117)	($2,445)	($5,414)	($9,273)	($4,608)
Incremental Income Tax (with Revenue Change)	($586,850)	($73,577)	($57,732)	($127,822)	($218,925)	($108,795)
Grand Total	$140,263,997	$20,342,991	$12,499,863	$26,822,545	$53,458,333	$27,140,264
Transmission Costs					$12,314,042	
60% G&T to be recovered through fixed rates / 40% thru variable rates					$32,075,000	$21,383,333
Recovered through on-peak demand rates						
Remainder of Fixed G/T in On-Peak Adder Rates (if negative value, reduction in Energy Base adder)					$32,075,000	$0
Net G&T to be added to Base Energy Rates						$21,383,333

	Customer Costs	Grid Connection	Demand Costs	Gen Tran Demand	Energy Costs
		Distribution		Generation and Transmission	
Per Day charges (Individual)	$0.41477	$0.25486			
Individual Customer and Grid Connection Charges shown as Monthly	$12.62	$7.75			
Total Customer and Grid Connection (monthly)		$20.37			
Distribution Demand Costs: (Cost Based Customer Max Demand)			$ 2.56402		
Distribution Demand Costs: (If recovered entirley through per kWh charge)			$0.03294		
Generation / Transmission Costs through On-Peak Demand Charges				$6.57681	
Generation / Transmission Costs (if recovered enteriley through per kWh charges)				$0.06566	
Energy (with 40% Fixed G&T in Base)					
Base Energy Cost					$ 0.03333
Fixed G&T not recovered through On-Peak Demand or On-Peak Energy Adders					$ 0.02626
Fixed G&T not in Base, if recovered on total Energy				$ 0.03940	
Base Energy Rate					$ 0.05960
Energy if Trans 100% Base and G 40% Base					
Base Energy Cost					$ 0.03333
Fixed G&T not recovered through On-Peak Demand or On-Peak Energy Adders					$ 0.03534
Fixed G&T not in Base, if recovered on total Energy				$ 0.03032	
Base Energy Rate (Alt 2)					$ 0.06867
Cost above Average LMP during On Peak hours:					
OP 1 Winter					$ 0.00512
OP 1 Summer					$ 0.00644
OP 2 Winter					$ 0.00319
OP 2 Summer					$ 0.01608
OP 3 Winter					$ 0.00693
OP 3 Summer					$ 0.00903

Bill Statistics	Customers	Customers	Ratchet Demand	On Peak Demand	KWH (000)
	134,449	134,449	10,461,137	8,128,303	814,189

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES			PRESENT REVENUES	2021 PROPOSED RATES			2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
RESIDENTIAL SERVICE Rg-1												
CUSTOMER CHARGE	Bills	1,646,591	$0.62466	per bill per day		$31,285,352	$0.62466	per bill per day		$31,285,352		
	Days	365	$19.00	per bill per month			$19.00	per bill per month				
DISTRIBUTION SERVICE												
Distribution Charge	kWh	773,572,023	$0.03378	per kWh		$26,132,346	$0.03378	per kWh		$26,132,346		
DISTRIBUTION SERVICE TOTAL						$26,132,346				$26,132,346		
ELECTRICITY SERVICE												
Winter Electricity	kWh	477,220,071	$0.09355	per kWh		$44,643,938	$0.09355	per kWh		$44,643,938		
Summer Electricity	kWh	291,871,537	$0.10472	per kWh		$30,564,787	$0.10472	per kWh		$30,564,787		
Shared Solar Transmission Revenue		4,480,415	$0.00800	per kWh		$35,843	$0.00800	per kWh		$35,843		
Renewable Resource Revenue - Shared Solar	kWh		$0.10170	per kWh		$455,676	$0.10170	per kWh		$455,676		
25-Year Levelized Rate (Net of Transmission)	kWh		$0.07653	per kWh	$342,885		$0.07653	per kWh	$342,885			
25-Year Locked-in Standby Rate	kWh		$0.02517	per kWh	$112,791		$0.02517	per kWh	$112,791			
GPT	kWh	53,353,990	$0.01000	per kWh		$533,540	$0.01000	per kWh		$533,540		
Act 141 Fixed Charge	Fixed					$11				$11		
Act 141 Credit		317,154	($0.00242)			($768)	($0.00242)			($768)		
ELECTRICITY SERVICE TOTAL		769,091,607				$76,233,028				$76,233,028		
TOTAL Rg-1		773,572,023				$133,650,726				$133,650,726	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES			PRESENT REVENUES	2021 PROPOSED RATES			2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
RESIDENTIAL TIME OF USE Rg-2												
CUSTOMER CHARGE	Bills	7,821	$0.62466	per bill per day		$148,600	$0.62466	per bill per day		$148,600		
	Days	365	$19.00	per bill per month			$19.00	per bill per month				
DISTRIBUTION SERVICE												
Distribution Charge	kWh	11,864,302	$0.03378	per kWh		$400,776	$0.03378	per kWh		$400,776		
DISTRIBUTION SERVICE TOTAL		11,864,302				$400,776				$400,776		
ELECTRICITY SERVICE												
On-Peak 1 Energy Adder												
Winter	kWh	559,085	$0.14546	per kWh		$81,325	$0.14546	per kWh		$81,325		
Summer	kWh	365,753	$0.18522	per kWh		$67,745	$0.18522	per kWh		$67,745		
On-Peak 1 Energy Adder Subtotal		924,838				$149,070				$149,070		
On-Peak 2 Energy Adder												
Winter	kWh	993,336	$0.13800	per kWh		$137,080	$0.13800	per kWh		$137,080		
Summer	kWh	701,033	$0.22088	per kWh		$154,844	$0.22088	per kWh		$154,844		
On-Peak 2 Energy Adder Subtotal		1,694,368				$291,924				$291,924		
On-Peak 3 Energy Adder												
Winter	kWh	750,225	$0.17167	per kWh		$128,791	$0.17167	per kWh		$128,791		
Summer	kWh	469,529	$0.18320	per kWh		$86,018	$0.18320	per kWh		$86,018		
On-Peak 3 Energy Adder Subtotal		1,219,754				$214,809				$214,809		
Base Energy												
Winter	kWh	7,212,745	$0.04122	per kWh		$297,309	$0.04122	per kWh		$297,309		
Summer	kWh	4,580,440	$0.04122	per kWh		$188,806	$0.04122	per kWh		$188,806		
Base Energy Subtotal		11,793,185				$486,115				$486,115		
Shared Solar Transmission Revenue		71,118	$0.00800	per kWh		$569	$0.00800	per kWh		$569		
Renewable Resource Revenue - Shared Sola	kWh		$0.10170	per kWh		$7,233	$0.10170	per kWh		$7,233		
25-Year Levelized Rate (Net of Transmission)	kWh		$0.07653	per kWh	$5,443		$0.07653	per kWh	$5,443			
25-Year Locked-in Standby Rate	kWh		$0.02517	per kWh	$1,790		$0.02517	per kWh	$1,790			
GPT	kWh	947,827	$0.01000	per kWh		$9,478	$0.01000	per kWh		$9,478		
Act 141 Fixed Charge	Fixed					$16				$16		
Act 141 Credit	kWh	384,840	($0.00242)	per kWh		($931)	($0.00242)			($931)		
ELECTRICITY SERVICE TOTAL		11,793,185				$1,158,283				$1,158,283		
TOTAL Rg-2		11,793,185				$1,707,659				$1,707,659	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
NEW RESIDENTIAL TIME OF USE Rg-2A										
CUSTOMER CHARGE	Bills	0	$0.62466	per bill per day	$0	$0.62466	per bill per day	$0		
	Days	365	$19.00	per bill per month		$19.00	per bill per month			
DISTRIBUTION SERVICE										
Distribution Charge	kWh	0	$0.03378	per kWh	$0	$0.03378	per kWh	$0		
DISTRIBUTION SERVICE TOTAL		0			$0			$0		
ELECTRICITY SERVICE										
On-Peak 1 Energy Adder										
Winter	kWh	0	$0.14546	per kWh	$0	$0.11196	per kWh	$0		
Summer	kWh	0	$0.18522	per kWh	$0	$0.11328	per kWh	$0		
On-Peak 1 Energy Adder Subtotal		0			$0			$0		
On-Peak 2 Energy Adder										
Winter	kWh	0	$0.13800	per kWh	$0	$0.11003	per kWh	$0		
Summer	kWh	0	$0.22088	per kWh	$0	$0.12292	per kWh	$0		
On-Peak 2 Energy Adder Subtotal		0			$0			$0		
On-Peak 3 Energy Adder										
Winter	kWh	0	$0.17167	per kWh	$0	$0.11377	per kWh	$0		
Summer	kWh	0	$0.18320	per kWh	$0	$0.11587	per kWh	$0		
On-Peak 3 Energy Adder Subtotal		0			$0			$0		
Base Energy										
Winter	kWh	0	$0.04122	per kWh	$0	$0.05959	per kWh	$0		
Summer	kWh	0	$0.04122	per kWh	$0	$0.05959	per kWh	$0		
Base Energy Subtotal		0			$0			$0		
Shared Solar Transmission Revenue			$0.00800	per kWh	$0	$0.00800	per kWh	$0		
Renewable Resource Revenue - Shared Sola	kWh		$0.10170	per kWh	$0	$0.10170	per kWh	$0		
25-Year Levelized Rate (Net of Transmission)	kWh		$0.07653	per kWh	$0	$0.07653	per kWh	$0		
25-Year Locked-in Standby Rate	kWh		$0.02517	per kWh	$0	$0.02517	per kWh	$0		
GPT	kWh		$0.01000	per kWh	$0	$0.01000	per kWh	$0		
Act 141 Fixed Charge	Fixed									
Act 141 Credit	kWh		($0.00242)	per kWh						
ELECTRICITY SERVICE TOTAL		0			$0			$0		
TOTAL Rg-2		0			$0			$0	$0	

RG-2A Rated Design Components **Base Generation / Transmission Adder set at 40% as in TOU Cost Study**

	MGE		WPL		WEPCO		WPS		NSP		MGE	
	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three
Fixed Charge	19.00	19.00	15.00	22.50	16.00	16.00	21.00	21.00	17.00	20.50	19.00	19.00

Variable Charge Cost Components:		Summer	Winter
1 Distribution Rate		0.03378	0.03378
2 TOU Base Gen/Tran Adder (40%)		0.02626	0.02626
2a Base Adder Adjustment - lowers (2) to:	40%	(0.00001)	(0.00001)
3 Gen / Tran Demand costs added to peaks		0.10684	0.10684
4 Base Energy (includes allocated costs)		0.03333	0.03333
5 LMP differential - morning peak		0.00644	0.00512
6 LMP differential - midday peak		0.01608	0.00319
7 LMP differential - dusk peak		0.00903	0.00693

	Proposed MGE		WPL		WEPCO		WPS		NSP		Current MGE Rg-2	
Total Variable Charges by Period:	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Morning peak (1+2+2a+3+4+5)	0.20665	0.20533	0.17900	0.13660	0.19625	0.19625	0.10708	0.10708	0.20200	0.17700	0.26022	0.22046
Mid-day peak (1+2+2a+3+4+6)	0.21629	0.20340	0.17900	0.13660	0.19625	0.19625	0.24627	0.24627	0.20200	0.17700	0.29588	0.21300
Dusk peak (1+2+2a+3+4+7)	0.20924	0.20714	0.13660	0.17900	0.19625	0.19625	0.10708	0.10708	0.20200	0.17700	0.25820	0.24667
Evening (off-peak) (1+2+2a+4)	0.09337	0.09337	0.07400	0.07400	0.08868	0.08868	0.06185	0.06185	0.07775	0.07775	0.07500	0.07500

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
RESIDENTIAL CONTROLLED WATER HEATING Rw-1										
CUSTOMER CHARGE	Bills	329	$0.28000	per bill per day	$2,802	$0.28000	per bill per day	$2,802		
	Day	365	$8.52	per bill per month		$8.52	per bill per month			
DISTRIBUTION SERVICE										
Distribution Charge	kWh	48,500	$0.02985	per kWh	$1,448	$0.02985	per kWh	$1,448		
DISTRIBUTION SERVICE TOTAL		48,500			$1,448			$1,448		
ELECTRICITY SERVICE										
Winter Energy	kWh	34,169	$0.03033	per kWh	$1,036	$0.03033	per kWh	$1,036		
Summer Energy	kWh	14,330	$0.03654	per kWh	$524	$0.03654	per kWh	$524		
ELECTRICITY SERVICE TOTAL		48,500			$1,560			$1,560		
TOTAL Rw-1		48,500			$5,810			$5,810	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
RESIDENTIAL RENEWABLE GENERATION NET METERING: Rg-7										
CUSTOMER CHARGE	Bills	439	$0.35512	per day per bill	$4,742	$0.35512	per day per bill	$4,742		
	Days	365	$10.80	per bill per month		$10.80	per bill per month			
DISTRIBUTION SERVICE										
Distribution Charge	kWh	86,572	$0.03208	per kWh	$2,777	$0.03208	per kWh	$2,777		
DISTRIBUTION SERVICE TOTAL		86,572			$2,777			$2,777		
ELECTRICITY SERVICE										
Winter	kWh	78,126	$0.11258	per kWh	$8,795	$0.11258	per kWh	$8,795		
Summer	kWh	8,446	$0.12711	per kWh	$1,074	$0.12711	per kWh	$1,074		
Base Energy		86,572			$9,869			$9,869		
GPT		28,910	$0.01000	per kWh	$289	$0.01000	per kWh	$289		
ELECTRICITY SERVICE TOTAL		86,572			$10,158			$10,158		
TOTAL Rg-7		115,482			$17,677			$17,677	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 13

Small Commercial and Industrial Rates

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES			PRESENT REVENUES	2021 PROPOSED RATES			2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
SMALL C/I LIGHTING AND POWER Cg-5 (0-20 kW)												
CUSTOMER CHARGE	Bills	181,235	$0.78669	per day per bill		$4,336,679	$0.78669	per day per bill		$4,336,679		
	Day	365	$23.93	per bill per month			$23.93	per bill per month				
DISTRIBUTION SERVICE												
Distribution Charge	kWh	190,023,400	$0.02295	per kWh		$4,361,037	$0.02295	per kWh		$4,361,037		
DISTRIBUTION SERVICE TOTAL		190,023,400				$4,361,037				$4,361,037		
ELECTRICITY SERVICE												
Winter Electricity	kWh	123,780,390	$0.09082	per kWh		$11,241,735	$0.09082	per kWh		$11,241,735		
Summer Electricity	kWh	65,674,069	$0.10224	per kWh		$6,714,517	$0.10224	per kWh		$6,714,517		
Shared Solar Transmission Revenue		568,942	$0.00800	per kWh		$4,552	$0.00800	per kWh		$4,552		
Renewable Resource Revenue - Shared S	kWh		$0.10170	per kWh		$57,864	$0.10170	per kWh		$57,864		
25-Year Levelized Rate (Net of Transmiss	kWh		$0.07653	per kWh	$43,541		$0.07653	per kWh	$43,541			
25-Year Locked-in Standby Rate	kWh		$0.02517	per kWh	$14,323		$0.02517	per kWh	$14,323			
GPT	kWh	1,621,333	$0.01000	per kWh		$16,213	$0.01000	per kWh		$16,213		
Act 141 Fixed Charge	Fixed					$ 296				$ 296		
Act 141 Credit	kWh	7,668,468	($0.00229)	per kWh		($17,561)	($0.00229)			($17,561)		
ELECTRICITY SERVICE TOTAL		189,454,459				$18,017,616				$18,017,616		
						$26,715,332				$26,715,332	$0	0.00%
TOTAL Cg-5		190,023,400				$26,699,119						

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
SMALL C/I OPTIONAL TIME OF USE Cg-3 (<20 kW)										
CUSTOMER CHARGE (1 PHASE)	Bills	5,671	$0.73249	per day per bill	$126,349	$0.73249	per day per bill	$126,349		
	Days	365	$22.28	per bill per month		$22.28	per bill per month			
CUSTOMER CHARGE (3 PHASE)	Bills	699	$1.00249	per day per bill	$21,314	$1.00249	per day per bill	$21,314		
	Days	365	$30.49	per bill per month		$30.49	per bill per month			
TOTAL CUSTOMER		6,370			$147,663			$147,663	$0	
		2,325,050								
DISTRIBUTION SERVICE										
Distribution Charge	kWh	8,774,577	$0.02295	per kWh	$201,359	$0.02295	per kWh	$201,359		
DISTRIBUTION SERVICE TOTAL		8,774,577			$201,359			$201,359		
ELECTRICITY SERVICE										
On-Peak 1 Energy Adder										
Winter	kWh	405,581	$0.13067	per kWh	$52,997	$0.13067	per kWh	$52,997		
Summer	kWh	205,791	$0.16932	per kWh	$34,845	$0.16932	per kWh	$34,845		
On-Peak Energy 1 Adder Subtotal		611,372			$87,842			$87,842		
On-Peak 2 Energy Adder										
Winter	kWh	728,364	$0.12032	per kWh	$87,637	$0.12032	per kWh	$87,637		
Summer	kWh	352,032	$0.17719	per kWh	$62,377	$0.17719	per kWh	$62,377		
On-Peak 2 Energy Adder Subtotal		1,080,396			$150,014			$150,014		
On-Peak 3 Energy Adder										
Winter	kWh	611,724	$0.15257	per kWh	$93,331	$0.15257	per kWh	$93,331		
Summer	kWh	237,267	$0.15239	per kWh	$36,157	$0.15239	per kWh	$36,157		
On-Peak 3 Energy Adder Subtotal		848,990			$129,488			$129,488		
Base Energy										
Winter	kWh	5,965,453	$0.04573	per kWh	$272,800	$0.04573	per kWh	$272,800		
Summer	kWh	2,809,124	$0.04573	per kWh	$128,461	$0.04573	per kWh	$128,461		
Base Energy Subtotal		8,774,577			$401,261			$401,261		
GPT	kWh	114,792	$0.01000	per kWh	$1,148	$0.01000	per kWh	$1,148		
Act 141 Fixed Charge	Fixed				$ 38			$ 38		
Act 141 Credit	kWh	932,909	($0.00229)	per kWh	($2,136)	($0.00229)	per kWh	($2,136)		
ELECTRICITY SERVICE TOTAL		8,774,577			$767,654			$767,654		
TOTAL Cg-3		8,774,577			$1,116,676			$1,116,676	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
SMALL COMMERCIAL & INDUSTRIAL RENEWABLE GENERATION NET METERING: Cg-7										
CUSTOMER CHARGE	Bills	48	$0.34308	per day per bill	$501	$0.34308	per day per bill	$501		
	Days	365	$10.44	per bill per month		$10.44	per bill per month			
DISTRIBUTION SERVICE										
Distribution Charge	kWh	49,086	$0.01780	per kWh	$874	$0.01780	per kWh	$874		
DISTRIBUTION SERVICE TOTAL		49,086			$874			$874		
ELECTRICITY SERVICE										
Winter	kWh	33,452	$0.10856	per kWh	$3,632	$0.10856	per kWh	$3,632		
Summer	kWh	15,633	$0.12007	per kWh	$1,877	$0.12007	per kWh	$1,877		
Base Energy		49,086			$5,509			$5,509		
GPT		9,813	$0.01000	per kWh	$98	$0.01000	per kWh	$98		
ELECTRICITY SERVICE TOTAL		49,086			$5,607			$5,607		
TOTAL Cg-7		49,086			$6,982			$6,982	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 14

Medium Commercial and Industrial Rates

Medium Commercial and Industrial Rate Design

Cg-4 , Cg-8

Tariff Changes

See Schedule 5

Summary Points:

- Rate components and revenue for Cg-4 retained at the same level
- Reference to Level A and Level B is eliminated as rates at these levels have been the same for several years and will continue to be so.
- Comparison of total rate components with Cg-2 and Cg-6 illustrates non-linear progression of per-kWh rates that remains between these classes.
- Cg-8 has no rate changes

Overview:

Legacy rate design has anomalies between rates in this class and the large commercial and industrial rate classes. These are illustrated in the comparison sheet. Since no rate changes are being proposed in this proceeding, only the combination of Level A and Level B in the Cg-4 class is being done in this proceeding as this does not change any rate components or class revenue.

Cg-8 has no rate changes.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
C/I LIGHTING AND POWER TIME-OF-USE SERVICE Cg-4								
CUSTOMER CHARGE								
Single Phase	Bills	3,223	$6.19251 per day per bill	$607,070	$6.19251 per day per bill	$607,070		
	Day	365	$188.36 per bill per month		$188.36 per bill per month			
Three Phase	Bills	40,159	$6.32048 per day per bill	$7,720,485	$6.32048 per day per bill	$7,720,485		
	Day	365	$192.25 per bill per month		$192.25 per bill per month			
TOTAL CUSTOMER		43,382	$6.31097	$8,327,555		$8,327,555	$0	
DISTRIBUTION SERVICE								
Customer Maximum Demand	kW	2,591,893	$0.08480 per kW per day	$6,685,357	$0.08480 per kW per day	$6,685,357		
			$2.58 per kW		$2.58 per kW			
Distribution Charge	kWh	633,762,474	$0.01001 per kWh	$6,343,962	$0.01001 per kWh	$6,343,962		
Primary Voltage Discount	kW	0	($0.00328) per kW per day	$0	($0.00328) per kW per day	$0		
			$0.00000 per kW		($0.10000) per kW			
Primary Voltage Discount	kWh	0	($0.00100) per kWh	$0	($0.00100) per kWh	$0		
Transformer Equipment Discount	kW	0	($0.00328) per kW per day	$0	($0.00328) per kW per day	$0		
			$0.00000 per kW		($0.10000) per kW			
DISTRIBUTION SERVICE TOTAL				$13,029,319		$13,029,319		
ELECTRICITY SERVICE								
Maximum Monthly On-Peak Demand:								
Winter	kW	1,167,321	$0.34931 per kW per day	$12,402,606	$0.34931 per kW per day	$12,402,606		
			$10.62 per kW		$10.62 per kW			
Summer	kW	697,766	$0.42653 per kW per day	$9,052,548	$0.42653 per kW per day	$9,052,548		
			$12.97 per kW		$12.97 per kW			
Maximum Monthly On-Peak Demand: Subtotal		1,865,087	$0.37820	$21,455,154	$0.37820	$21,455,154		
On-Peak 1 Energy Adder								
Winter	kWh	45,497,657	$0.04245 per kWh	$1,931,376	$0.04245 per kWh	$1,931,376		
Summer	kWh	26,537,281	$0.05545 per kWh	$1,471,493	$0.05545 per kWh	$1,471,493		
On-Peak 1 Energy Adder Subtotal		72,034,938		$3,402,869		$3,402,869		
On-Peak 2 Energy Adder								
Winter	kWh	72,427,412	$0.04175 per kWh	$3,023,844	$0.04175 per kWh	$3,023,844		
Summer	kWh	43,964,962	$0.06177 per kWh	$2,715,716	$0.06177 per kWh	$2,715,716		
On-Peak 2 Energy Adder Subtotal		116,392,373		$5,739,560		$5,739,560		
On-Peak 3 Energy Adder								
Winter	kWh	37,516,618	$0.04631 per kWh	$1,737,395	$0.04631 per kWh	$1,737,395		
Summer	kWh	21,423,973	$0.05402 per kWh	$1,157,323	$0.05402 per kWh	$1,157,323		
On-Peak 3 Energy Adder Subtotal		58,940,591		$2,894,718		$2,894,718		
Maximum Monthly On-Peak Demand Discount for LLF Customers								
Winter	kW	27,396		($145,543)	($0.17466)	($145,543)		
Summer	kW	18,557		($120,378)	($0.21327)	($120,378)		
Base Energy								
Winter	kWh	400,622,751	$0.04148 per kWh	$16,617,832	$0.04148 per kWh	$16,617,832		
Summer	kWh	227,774,875	$0.04148 per kWh	$9,448,101	$0.04148 per kWh	$9,448,101		
Base Energy Subtotal		628,397,626		$26,065,933		$26,065,933		
Interruptible Credit								
IS-4 Demand	kW	4,263	($0.13151) per kW per day	($17,052)	($0.13151) per kW per day	($17,052)		
			($4.00) per kW		($4.00) per kW			
SCS Demand	kW	0	$0.00000 per kW per day	$0	$0.00000 per kW per day	$0		
			$0.00 per kW		$0.00 per kW			
Interruptible Credit Subtotal		4,263		($17,052)		($17,052)		
Shared Solar Transmission Revenue		1,991,296	$0.00800 per kWh	$15,930	$0.00800 per kWh	$15,930		
Renewable Resource Revenue - Shared Solar	kWh		$0.10170 per kWh	$202,523	$0.10170 per kWh	$202,523		
25-Year Levelized Rate (Net of Transmission)	kWh		$0.07653 per kWh		$0.07653 per kWh			
25-Year Locked-in Standby Rate	kWh		$0.02517 per kWh		$0.02517 per kWh			
ER Renewable Resource Revenue - Assigned kWh	kWh	3,373,552	Variable per project	$0	Variable per project	$0		
R Renewable Resource Revenue - Unassigned kWh	kWh	285,015	Variable per project	$215,785	Variable per project	$215,785		
GPT	kWh	6,150,975	$0.01000 per kWh	$61,509	$0.01000 per kWh	$61,509		
Act 141 Fixed Charge	Fixed			$ 1,145		$ 1,145		
Act 141 Credit	kWh	46,677,377		($106,891)		($106,891)		
ELECTRICITY SERVICE TOTAL		628,397,626		$59,449,477		$59,449,477	$0	
TOTAL C/I LIGHTING AND POWER TIME-OF-USE SERVICE Cg-4		628,397,626		$80,806,351	$136,988	$80,806,351	$0	0.00%

	CG-4		CG-2		CG-6		CG2 vs CG4		CG6 vs CG2	
	Single	Three	Single	Three	Single	Three	Single	Three	Single	Three
Fixed Charge (per Month equivalent)	188.36	192.25	441.04	441.04	771.06	771.06	252.68	248.79	330.02	330.02
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Distribution (Cust Max) Demand Rate (per KW)	2.58	2.58	3.22	3.22	3.22	3.22	0.64	0.64	0.00	0.00
G&T (Onpeak) Demand Rate (per KW)	12.97	10.62	13.75	11.36	13.75	11.36	0.78	0.74	0.00	0.00
Variable Charge Cost Components:	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1 Distribution Rate	0.01001	0.01001	0.01022	0.01022	0.00549	0.00549	0.00021	0.00021	(0.00473)	(0.00473)
2 Base Energy (includes allocated costs)	0.04148	0.04148	0.04930	0.04930	0.04935	0.04935	0.00782	0.00782	0.00005	0.00005
3 Morning Peak Adder	0.05545	0.04245	0.02802	0.01747	0.03319	0.01927	(0.02743)	(0.02498)	0.00517	0.00180
4 Mid-day Peak Adder	0.06177	0.04175	0.04595	0.01596	0.03776	0.01796	(0.01582)	(0.02579)	(0.00819)	0.00200
5 Dusk Peak Adder	0.05402	0.04631	0.02668	0.02270	0.02707	0.02588	(0.02734)	(0.02361)	0.00039	0.00318
	Proposed MGE		Proposed MGE		Proposed MGE		Proposed MGE		Proposed MGE	
Total Variable Charges by Period:	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Morning peak (1+2+3)	0.10694	0.09394	0.08754	0.07699	0.08803	0.07411	-0.01940	-0.01695	0.00049	-0.00288
Mid-day peak (1+2+4)	0.11326	0.09324	0.10547	0.07548	0.09260	0.07280	-0.00779	-0.01776	-0.01287	-0.00268
Dusk peak (1+2+5)	0.10551	0.09780	0.08620	0.08222	0.08191	0.08072	-0.01931	-0.01558	-0.00429	-0.00150
Evening (off-peak) (1+2)	0.05149	0.05149	0.05952	0.05952	0.05484	0.05484	0.00803	0.00803	-0.00468	-0.00468

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
MEDIUM COMMERCIAL & INDUSTRIAL RENEWABLE GENERATION NET METERING: Cg-8										
CUSTOMER CHARGE										
Single Phase	Bills	12	$1.63742	per day per bill	$598	$1.63742	per day per bill	$598		
	Day	365	$49.80	per bill per month		$49.80	per bill per month			
Three Phase	Bills	84	$1.76215	per day per bill	$4,502	$1.76215	per day per bill	$4,502		
	Day	365	$53.60	per bill per month		$53.60	per bill per month			
TOTAL CUSTOMER		96			$5,100			$5,100		
DISTRIBUTION SERVICE										
Transitional Customer Maximum Demand	kW	5,786	$0.08533	per kW per day	$15,017	$0.08533	per kW per day	$15,017		
			$2.60	per kW		$2.60	per kW			
Distribution Charge	kWh	826,170	$0.01135	per kWh	$9,377	$0.01135	per kWh	$9,377		
DISTRIBUTION SERVICE TOTAL		826,170			$24,394			$24,394		
ELECTRICITY SERVICE										
Maximum Monthly On-Peak Demand:										
Winter	kW	2,858	$0.34794	per kW per day	$30,251	$0.34794	per kW per day	$30,251		
			$10.58	per kW		$10.58	per kW			
Summer	kW	1,680	$0.42677	per kW per day	$21,804	$0.42677	per kW per day	$21,804		
			$12.98	per kW		$12.98	per kW			
Maximum Monthly On-Peak Demand: Subtotal		4,538			$52,055			$52,055		
On-Peak 1 Energy Adder										
Winter	kWh	51,706	$0.05092	per kWh	$2,633	$0.05092	per kWh	$2,633		
Summer	kWh	30,067	$0.05758	per kWh	$1,731	$0.05758	per kWh	$1,731		
On-Peak 1 Energy Adder Subtotal		81,773			$4,364			$4,364		
On-Peak 2 Energy Adder										
Winter	kWh	91,563	$0.05044	per kWh	$4,618	$0.05044	per kWh	$4,618		
Summer	kWh	52,544	$0.06270	per kWh	$3,295	$0.06270	per kWh	$3,295		
On-Peak 2 Energy Adder Subtotal		144,107			$7,913			$7,913		
On-Peak 3 Energy Adder										
Winter	kWh	53,890	$0.05118	per kWh	$2,758	$0.05118	per kWh	$2,758		
Summer	kWh	33,193	$0.05758	per kWh	$1,911	$0.05758	per kWh	$1,911		
On-Peak 3 Energy Adder Subtotal		87,083			$4,669			$4,669		
Base Energy										
Winter	kWh	521,827	$0.04646	per kWh	$24,244	$0.04646	per kWh	$24,244		
Summer	kWh	304,343	$0.04646	per kWh	$14,140	$0.04646	per kWh	$14,140		
Base Energy Subtotal		826,170			$38,384			$38,384		
GPT		10,914	$0.01000	per kWh	$109	$0.01000		$109		
Pg-1 Revenues		0	$0.03150	per kWh	$0	$0.03150	per kWh	$0		
ELECTRICITY SERVICE TOTAL		826,170			$107,494			$107,494		
TOTAL Cg-8		826,170			$136,988			$136,988	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 15

Large Commercial and Industrial Rates

Large Commercial and Industrial Rate Design

Cg-2, Cg-6

Tariff Changes

None

Summary Points:

- The rates and the revenue requirements for the classes are being retained at the same levels in this proceeding.

Overview:

See Schedule 14 description.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
C/I LIGHTING AND POWER SERVICE TIME-OF-USE CG-2 (OVER 200 kW)								
CUSTOMER CHARGE	Bills	4,701	$14.50000 per day per bill	$2,073,337	$14.50000 per day per bill	$2,073,337		
	Days	365	$441.04 per bill per month		$441.04 per bill per month			
DISTRIBUTION SERVICE								
Customer Maximum Demand	kW	2,529,663	$0.10600 per kW per day	$8,156,055	$0.10600 per kW per day	$8,156,055		
			$3.22 per kW		$3.22 per kW			
Distribution Charge	kWh	794,386,291	$0.01022 per kWh	$8,118,628	$0.01022 per kWh	$8,118,628		
Primary Voltage Discount	kW	303,878	($0.00328) per kW per day	($30,317)	($0.00328) per kW per day	($30,317)		
			$0.00000 per kW		($0.10000) per kW			
Primary Voltage Discount	kWh	95,210,974	($0.00100) per kWh	($95,211)	($0.00100) per kWh	($95,211)		
Transformer Equipment Discount	kW	79,567	($0.00328) per kW per day	($7,938)	($0.00328) per kW per day	($7,938)		
			$0.00000 per kW		($0.10000) per kW			
DISTRIBUTION SERVICE TOTAL				$16,141,217		$16,141,217		
				$18,214,554		$18,214,554	$0	
ELECTRICITY SERVICE								
Maximum Monthly On-Peak Demand:								
Winter	kW	1,146,230	$0.37362 per kW per day	$13,026,071	$0.37362 per kW per day	$13,026,071		
			$11.36 per kW		$11.36 per kW			
Summer	kW	711,017	$0.45203 per kW per day	$9,775,950	$0.45203 per kW per day	$9,775,950		
			$13.75 per kW		$13.75 per kW			
Maximum Monthly On-Peak Demand: Subtotal		1,857,247	$0.40364	$22,802,021	$0.40364	$22,802,021		
On-Peak 1 Energy Adder								
Winter	kWh	51,670,938	$0.01747 per kWh	$902,691	$0.01747 per kWh	$902,691		
Summer	kWh	31,232,014	$0.02802 per kWh	$875,121	$0.02802 per kWh	$875,121		
On-Peak Energy Subtotal		82,902,952		$1,777,812		$1,777,812		
On-Peak 2 Energy Adder								
Winter	kWh	82,499,627	$0.01596 per kWh	$1,316,694	$0.01596 per kWh	$1,316,694		
Summer	kWh	51,395,473	$0.04595 per kWh	$2,361,622	$0.04595 per kWh	$2,361,622		
On-Peak 2 Energy Adder Subtotal		133,895,100		$3,678,316		$3,678,316		
On-Peak 3 Energy Adder								
Winter	kWh	44,814,504	$0.02270 per kWh	$1,017,289	$0.02270 per kWh	$1,017,289		
Summer	kWh	27,410,834	$0.02668 per kWh	$731,321	$0.02668 per kWh	$731,321		
On-Peak 3 Energy Adder Subtotal		72,225,339		$1,748,610		$1,748,610		
Maximum Monthly On-Peak Demand Discount for LLF Customers								
Winter	kW	19,718	($0.18681)	($112,040)	($0.18681)	($112,040)		
Summer	kW	8,789	($0.22602)	($60,422)	($0.22602)	($60,422)		
Base Energy								
Winter	kWh	486,626,398	$0.04930 per kWh	$23,990,681	$0.04930 per kWh	$23,990,681		
Summer	kWh	297,468,496	$0.04930 per kWh	$14,665,197	$0.04930 per kWh	$14,665,197		
Base Energy Subtotal		784,094,894		$38,655,878		$38,655,878		
Interruptible Credit								
IS-3 Demand	kW	86,309	($0.12329) per kW per day	($323,665)	($0.12329) per kW per day	($323,665)		
			($3.75) per kW		($3.75) per kW			
IS-4 Demand	kW	75,627	($0.13151) per kW per day	($302,515)	($0.13151) per kW per day	($302,515)		
			($4.00) per kW		($4.00) per kW			
SCS Demand	kW	0	$0.00000 per kW per day	$0	$0.00000 per kW per day	$0		
			$0.00 per kW		$0.00 per kW			
Interruptible Credit Subtotal		161,936		($626,180)		($626,180)		
RER Renewable Resource Revenue - Assigned kWh	kWh	10,291,397	Variable by project	$0	Variable by project	$0		
RER Renewable Resource Revenue - Unassigned kWh	kWh	989,407	Variable by project	$657,452	Variable by project	$657,452		
GPT	kWh	7,143,419	$0.01000 per kWh	$71,434	$0.01000 per kWh	$71,434		
Act 141 Fixed Charge	Fixed			$ 9,310		$ 9,310		
Act 141 Credit	kWh	346,312,191	($0.00229) per kWh	($793,055)	($0.00229)	($793,055)		
ELECTRICITY SERVICE TOTAL		784,094,894		$67,151,684		$67,151,684	$0	
TOTAL C/I LIGHTING AND POWER SERVICE TIME-OF-USE CG-2 (OVER 200 kW)		784,094,894		$85,366,238		$85,366,238	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	AMOUNT	PROPOS INCREASE PERCENT
C/I LIGHTING AND POWER SERVICE TIME-OF-USE HLF CG-6 (OVER 1,000 kW)								
CUSTOMER CHARGE	Bills	228	$25.35000 per day per bill	$175,802	$25.35000 per day per bill	$175,802		
	Days	365	$771.06 per bill per month		$771.06 per bill per month			
DISTRIBUTION SERVICE								
Customer Maximum Demand	kW	495,019	$0.10600 per kW per day	$1,596,023	$0.10600 per kW per day	$1,596,023		
			$3.22 per kW		$3.22 per kW			
Distribution Charge	kWh	238,147,517	$0.00549 per kWh	$1,307,430	$0.00549 per kWh	$1,307,430		
Primary Voltage Discount	kW	203,122	($0.00328) per kW per day	($20,265)	($0.00328) per kW per day	($20,265)		
			$0.00000 per kW		($0.10000) per kW			
Primary Voltage Discount	kWh	94,988,888	($0.00100) per kWh	($94,989)	($0.00100) per kWh	($94,989)		
Transformer Equipment Discount	kW	101,927	($0.00328) per kW per day	($10,169)	($0.00328) per kW per day	($10,169)		
			$0.00000 per kW		($0.10000) per kW			
DISTRIBUTION SERVICE TOTAL				$2,778,030		$2,778,030		
				$2,953,832		$2,953,832	$0	
ELECTRICITY SERVICE								
Maximum Monthly On-Peak Demand:								
Winter	kW	273,497	$0.37362 per kW per day	$3,108,097	$0.37362 per kW per day	$3,108,097		
			$11.36 per kW		$11.36 per kW			
Summer	kW	151,346	$0.45203 per kW per day	$2,080,892	$0.45203 per kW per day	$2,080,892		
			$13.75 per kW		$13.75 per kW			
Maximum Monthly On-Peak Demand: Subtotal		424,843	$0.40155	$5,188,989		$5,188,989		
On-Peak 1 Energy Adder								
Winter	kWh	13,911,271	$0.01927 per kWh	$268,070	$0.01927 per kWh	$268,070		
Summer	kWh	7,751,779	$0.03319 per kWh	$257,282	$0.03319 per kWh	$257,282		
On-Peak 1 Energy Adder Subtotal		21,663,050		$525,352		$525,352		
On-Peak 2 Energy Adder								
Winter	kWh	23,035,914	$0.01796 per kWh	$413,725	$0.01796 per kWh	$413,725		
Summer	kWh	12,875,820	$0.03776 per kWh	$486,191	$0.03776 per kWh	$486,191		
On-Peak 2 Energy Adder Subtotal		35,911,734		$899,916		$899,916		
On-Peak 3 Energy Adder								
Winter	kWh	13,719,900	$0.02588 per kWh	$355,071	$0.02588 per kWh	$355,071		
Summer	kWh	7,592,092	$0.02707 per kWh	$205,518	$0.02707 per kWh	$205,518		
On-Peak 3 Energy Adder Subtotal		21,311,992		$560,589		$560,589		
Base Energy								
Winter	kWh	149,799,961	$0.04935 per kWh	$7,392,628	$0.04935 per kWh	$7,392,628		
Summer	kWh	82,360,527	$0.04935 per kWh	$4,064,492	$0.04935 per kWh	$4,064,492		
Base Energy Subtotal		232,160,489		$11,457,120		$11,457,120		
Interruptible Credit								
IS-3 Demand	kW	76,227	($0.12329) per kW per day	($285,857)	($0.12329) per kW per day	($285,857)		
			($3.75) per kW		($3.75) per kW			
IS-4 Demand	kW	26,918	($0.13151) per kW per day	($107,675)	($0.13151) per kW per day	($107,675)		
			($4.00) per kW		($4.00) per kW			
SCS Demand	kW	0	$0.00000 per kW per day	$0	$0.00000 per kW per day	$0		
			$0.00 per kW		$0.00 per kW			
Interruptible Credit Subtotal		103,145		($393,532)		($393,532)		
GPT	kWh	1,551,112	$0.01000 per kWh	$15,511	$0.01000 per kWh	$15,511		
Renewable Resource Revenue - Assigned kWh	kWh	5,987,029	Variable per project	$0	Variable per project	$0		
newable Resource Revenue - Unassigned kWh	kWh	711,207	Variable per project	$388,498	Variable per project	$388,498		
Act 141 Fixed Charge	Fixed			$ 3,022		$ 3,022		
Act 141 Credit	kWh	207,103,200	($0.00229) per kWh	($474,266)	($0.00229)	($474,266)		
ELECTRICITY SERVICE TOTAL		232,160,489		$17,782,701		$17,782,701	$0	
TOTAL C/I LIGHTING AND POWER SERVICE TIME-OF-USE HLF CG-6 (OVER 1,000 kW)		232,160,489		$20,736,533		$20,736,533	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 16

CP-1 Rates

C&I High Load Factor Direct Control Interruptible Service for Transmission Voltage Rate Design

Cp-1

Tariff Changes

None

Summary Points:

- Consistent with the overall goal of no increases per rate class, rates remain the same and no changes are proposed for this class for this case

Overview:

Consistent with the goal of having no increase in this rate case, no change in rates is proposed.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
C/I HIGH LOAD FACTOR DIRECT CONTROL INTERRUPTIBLE SERVICE - TRANSMISSION VOLTAGE Cp-1								
CUSTOMER CHARGE	Bills	12	$31.82000 per day per bill	$11,614	$31.82000 per day per bill	$11,614		
	Days	365	$967.86 per bill per month		$967.86 per bill per month			
ELECTRICITY SERVICE								
Monthly Maximum Demand								
Winter	kW	91,050	$0.13300 per kW per day	$368,335	$0.13300 per kW per day	$368,335		
			$4.05 per kW		$4.05 per kW			
Summer	kW	45,535	$0.15600 per kW per day	$216,063	$0.15600 per kW per day	$216,063		
			$4.75 per kW		$4.75 per kW			
Monthly Maximum Demand Subtotal		136,585	$4.27864	$584,398		$584,398		
On-Peak 1 Energy Adder								
Winter	kWh	5,599,939	$0.01317 per kWh	$73,751	$0.01317 per kWh	$73,751		
Summer	kWh	2,864,293	$0.02240 per kWh	$64,160	$0.02240 per kWh	$64,160		
On-Peak1 Energy Adder Subtotal		8,464,232		$137,911		$137,911		
On-Peak 2 Energy Adder								
Winter	kWh	9,343,761	$0.01274 per kWh	$119,040	$0.01274 per kWh	$119,040		
Summer	kWh	4,768,726	$0.02496 per kWh	$119,027	$0.02496 per kWh	$119,027		
On-Peak 2 Energy Adder Subtotal		14,112,488		$238,067		$238,067		
On-Peak 3 Energy Adder								
Winter	kWh	5,626,378	$0.01755 per kWh	$98,743	$0.01755 per kWh	$98,743		
Summer	kWh	2,857,618	$0.01824 per kWh	$52,123	$0.01824 per kWh	$52,123		
On-Peak 3 Energy Adder Subtotal		8,483,996		$150,866		$150,866		
Base Energy								
Winter	kWh	64,963,416	$0.03833 per kWh	$2,490,048	$0.03833 per kWh	$2,490,048		
Summer	kWh	32,726,679	$0.03833 per kWh	$1,254,414	$0.03833 per kWh	$1,254,414		
Base Energy Subtotal		97,690,096		$3,744,462		$3,744,462		
Buy-Through Revenue				$0		$0		
Act 141 Fixed Charge				1,152		$1,152		
ELECTRICITY SERVICE TOTAL		97,690,096		$4,856,856		$4,856,856		
TOTAL C/I HIGH LOAD FACTOR DIRECT CONTROL INTERRUPTIBLE SERVICE - TRANSMISSION VOLTAGE Cp-1		97,690,096		$4,868,470		$4,868,470	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 17

Sp-3 Rates

University of Wisconsin Rates

Sp-3

Tariff Changes See Schedule 2

Summary Points:

- Rate design is consistent with changes discussed in Schedule 2

Overview:

A new interruptible option is added in rate design. The Customer and Grid Connection Charge was decreased by $250,000 and the On-Peak Demand rate was increased by the same amount as requested by the customer. No other rate components were changed.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

UNIVERSITY OF WISCONSIN TIME-OF-USE SP-3

	Present			Proposed		
Rate Component	Rate	Units	Revenue	Rate	Revenue	Difference
(1)	(2)	(3)	(4)	(5)	(7)	(8)
Customer Charge	**$ 35,616**	365	$ 12,999,840	**$ 34,931**	$ 12,749,815	$ (250,025)
Grid Connection Service	$ -	365	$ -	**$ -**	$ -	$ -
Distribution Service Demand	**$ 0.11810**	709,846	$ 2,549,916	**$ 0.12968**	$ 2,799,942	$ 250,026
Winter On-Peak Demand	**$ 0.46681**	432,949	$ 6,147,353	**$ 0.46681**	$ 6,147,353	$ -
Summer On-Peak Demand	**$ 0.46681**	229,312	$ 3,255,955	**$ 0.46681**	$ 3,255,955	$ -
Generation Credit	**$ (0.46681)**	108,000	$ (1,533,471)	**$ (0.46681)**	$ (1,533,471)	$ -
Interruptible Credit		19,656		**$ (0.13151)**	$ (78,626)	$ (78,626)
Subtotal Demand and Customer			$ 23,419,594		$ 23,340,969	$ (78,625)
UW Energy						
Winter On-Peak Energy	**$ 0.03672**	77,272,956	$ 2,837,463	**$ 0.03672**	$ 2,837,463	$ -
Summer On-Peak Energy	**$ 0.03822**	43,450,431	$ 1,660,675	**$ 0.03822**	$ 1,660,675	$ -
``	**$ 0.02462**	213,821,399	$ 5,264,283	**$ 0.02462**	$ 5,264,283	$ -
Total UW Energy		334,544,786	$ 9,762,421		$ 9,762,421	$ -
Chiller Energy-January Heating						
Winter On-Peak Energy	**$ 0.03392**	2,604	$ 88	**$ 0.03392**	$ 88	$ -
Winter Off-Peak Energy	**$ 0.02462**	3,193	$ 79	**$ 0.02462**	$ 79	$ -
Total Chiller Energy-January Heating		5,797	$ 167		$ 167	$ -
Chiller Energy-February Heating						
Winter On-Peak Energy	**$ 0.03392**	161,902	$ 5,492	**$ 0.03392**	$ 5,492	$ -
Winter Off-Peak Energy	**$ 0.02462**	23,395	$ 576	**$ 0.02462**	$ 576	$ -
Total Chiller Energy-February Heating		185,297	$ 6,068		$ 6,068	$ -
Chiller Energy-March Heating						
Winter On-Peak Energy	**$ 0.03392**	35,670	$ 1,210	**$ 0.03392**	$ 1,210	$ -
Winter Off-Peak Energy	**$ 0.02462**	147,126	$ 3,622	**$ 0.02462**	$ 3,622	$ -
Total Chiller Energy-March Heating		182,795	$ 4,832		$ 4,832	$ -
Chiller Energy-April Heating						
Winter On-Peak Energy	**$ 0.03392**	1,030,947	$ 34,970	**$ 0.03392**	$ 34,970	$ -
Winter Off-Peak Energy	**$ 0.02462**	1,404,420	$ 34,577	**$ 0.02462**	$ 34,577	$ -
Total Chiller Energy-April Heating		2,435,367	$ 69,547		$ 69,547	$ -
Chiller Energy-April Cooling						
Winter On-Peak Energy	**$ 0.03362**	-	$ -	**$ 0.03362**	$ -	$ -
Winter Off-Peak Energy	**$ 0.02462**	-	$ -	**$ 0.02462**	$ -	$ -
Total Chiller Energy-April Cooling		-	$ -		$ -	$ -
Chiller Energy-May Cooling						
Winter On-Peak Energy	**$ 0.03362**	1,136,279	$ 38,202	**$ 0.03362**	$ 38,202	$ -
Winter Off-Peak Energy	**$ 0.02462**	1,953,249	$ 48,089	**$ 0.02462**	$ 48,089	$ -
Total Chiller Energy-May Cooling		3,089,527	$ 86,291		$ 86,291	$ -
Chiller Energy-June Cooling						
Summer On-Peak Energy	**$ 0.03362**	1,048,867	$ 35,263	**$ 0.03362**	$ 35,263	$ -
Summer Off-Peak Energy	**$ 0.02462**	5,220,624	$ 128,532	**$ 0.02462**	$ 128,532	$ -
Total Chiller Energy-June Cooling		6,269,491	$ 163,795		$ 163,795	$ -
Chiller Energy-July Cooling						
Summer On-Peak Energy	**$ 0.03362**	799,190	$ 26,869	**$ 0.03362**	$ 26,869	$ -
Summer Off-Peak Energy	**$ 0.02462**	3,395,588	$ 83,599	**$ 0.02462**	$ 83,599	$ -
Total Chiller Energy-July Cooling		4,194,778	$ 110,468		$ 110,468	$ -

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

UNIVERSITY OF WISCONSIN TIME-OF-USE SP-3

	Present			Proposed			
Rate Component	Rate	Units	Revenue	Rate	Revenue	Difference	
(1)	(2)	(3)	(4)	(5)	(7)	(8)	
Chiller Energy-August Cooling							
Summer On-Peak Energy	$ 0.03362	70,791	$ 2,380	$ 0.03362	$ 2,380	$ -	
Summer Off-Peak Energy	$ 0.02462	434,424	$ 10,696	$ 0.02462	$ 10,696	$ -	
Total Chiller Energy-August Cooling		505,216	$ 13,076		$ 13,076	$ -	
Chiller Energy-September Cooling							
Summer On-Peak Energy	$ 0.03362	259,457	$ 8,723	$ 0.03362	$ 8,723	$ -	
Summer Off-Peak Energy	$ 0.02462	229,982	$ 5,662	$ 0.02462	$ 5,662	$ -	
Total Chiller Energy-September Cooling		489,439	$ 14,385		$ 14,385	$ -	
Chiller Energy-October Cooling							
Winter On-Peak Energy	$ 0.03362	-	$ -	$ 0.03362	$ -	$ -	
Winter Off-Peak Energy	$ 0.02462	-	$ -	$ 0.02462	$ -	$ -	
Total Chiller Energy-October Cooling		-	$ -		$ -	$ -	
Chiller Energy-October Heating							
Winter On-Peak Energy	$ 0.03392	759,667	$ 25,768	$ 0.03392	$ 25,768	$ -	
Winter Off-Peak Energy	$ 0.02462	716,200	$ 17,633	$ 0.02462	$ 17,633	$ -	
Total Chiller Energy-October Heating		1,475,867	$ 43,401		$ 43,401	$ -	
Chiller Energy-November Heating							
Winter On-Peak Energy	$ 0.03392	36,467	$ 1,237	$ 0.03392	$ 1,237	$ -	
Winter Off-Peak Energy	$ 0.02462	100,143	$ 2,466	$ 0.02462	$ 2,466	$ -	
Total Chiller Energy-November Heating		136,610	$ 3,702		$ 3,702	$ -	
Chiller Energy-December Heating							
Winter On-Peak Energy	$ 0.03392	114,166	$ 3,873	$ 0.03392	$ 3,873	$ -	
Winter Off-Peak Energy	$ 0.02462	128,599	$ 3,166	$ 0.02462	$ 3,166	$ -	
Total Chiller Energy-December Heating		242,765	$ 7,039		$ 7,039	$ -	
Total Chiller		19,212,948	$ 522,769		$ 522,769		
Sp-3 Energy		353,757,734	$ 10,285,191		$ 10,285,191	$ -	
Act 141 Fixed Charge			$ 7,440		$ 7,440	$ -	
Total			$ 33,712,224		$ 33,633,599	$ (78,625)	-0.23%
			$ 33,712,224				
LMP Estimate - Amount per MWh - Day Ahead			$ -				

Pricing Period	2018 (Est.)	Total MISO LMP Costs*
Winter On-Peak	$33.32	$33.80
Summer On-Peak	$33.27	$33.75
Annual Off-Peak	$24.46	$24.94

*Other LMP Related Costs (See Below)

Other LMP Related Costs - Per MWh

Revenue Sufficiency Guarantee Costs	$0.07
Revenue Neutrality Costs	$0.17
Administrative Cost	$0.15
Ancillary Services Market Costs	$0.09
Total Other LMP Costs	$0.48

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 18

Streetlighting and Outdoor Overhead Lighting Rates

MADISON GAS AND ELECTRIC COMPANY

SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

			DISTRIBUTION SERVICE		ELECTRICITY SERVICE					FACILITIES FEE		TOTAL PRESENT MONTHLY RATE						PROPOSED REVENUE INCREASE	
TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PRESENT DISTRIBUTION SERVICE RATE	BILLING UNITS	PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	PRESENT FACILITIES RATE	BILLING UNITS	PRESENT RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	FACILITIES FEE REVENUE	PRESENT REVENUES	AMOUNT	PERCENT
STREETLIGHTING SERVICE - COMPANY OWNED AND COMPANY MAINTAINED SL-1																			
OVERHEAD SERVICE																			
175 WATT MV ANEN (CLOSED)	/Lamp	1,728	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$7.90	/Lamp	$15.98	/Lamp	$5,530	$8,433	$13,651	$27,614		
250 WATT MV ANEN (CLOSED)	/Lamp	336	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$8.00	/Lamp	$18.12	/Lamp	$1,075	$2,325	$2,688	$6,088		
400 WATT MV ANEN (CLOSED)	/Lamp	576	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$8.40	/Lamp	$22.74	/Lamp	$1,843	$6,417	$4,838	$13,098		
SUBTOTAL MV ANEN		2,640					315							$8,448	$17,175	$21,177	$46,800		
400 WATT MV MN	/Lamp	36	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$8.40	/Lamp	$17.21	/Lamp	$115	$202	$302	$619		
SUBTOTAL MV MN		36					77							$115	$202	$302	$619		
70 WATT HPS ANEN	/Lamp	636	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$7.60	/Lamp	$12.69	/Lamp	$2,035	$1,202	$4,834	$8,071		
100 WATT HPS ANEN	/Lamp	3,180	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$7.60	/Lamp	$13.57	/Lamp	$10,176	$8,809	$24,168	$43,153		
150 WATT HPS ANEN	/Lamp	1,848	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$7.60	/Lamp	$15.02	/Lamp	$5,914	$7,799	$14,045	$27,758		
200 WATT HPS ANEN	/Lamp	24	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$7.80	/Lamp	$16.61	/Lamp	$77	$135	$187	$399		
250 WATT HPS ANEN	/Lamp	228	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$8.40	/Lamp	$18.52	/Lamp	$730	$1,578	$1,915	$4,223		
SUBTOTAL HPS ANEN		5,916					294							$18,932	$19,523	$45,149	$83,604		
300 WATT SUSP TYPE ANEN (CL(	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	115	$8.37	/Lamp	$7.70	/Lamp	$19.27	/Lamp	$0	$0	$0	$0		
100 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$12.50	/Lamp	$16.43	/Lamp	$0	$0	$0	$0		
150 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$14.40	/Lamp	$18.84	/Lamp	$0	$0	$0	$0		
250 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$16.60	/Lamp	$22.20	/Lamp	$0	$0	$0	$0		
SUBTOTAL HPS ANEN		0					175							$0	$0	$0	$0		
TOTAL OVERHEAD SERVICE		8,592					801							$27,495	$36,900	$66,628	$131,023		
UNDERGROUND SERVICE																			
70 WATT HPS ANEN	/Lamp	576	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$12.50	/Lamp	$17.59	/Lamp	$1,843	$1,089	$7,200	$10,132		
100 WATT HPS ANEN	/Lamp	1,656	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$12.60	/Lamp	$18.57	/Lamp	$5,299	$4,587	$20,866	$30,752		
150 WATT HPS ANEN	/Lamp	1,056	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$12.70	/Lamp	$20.12	/Lamp	$3,379	$4,456	$13,411	$21,246		
200 WATT HPS ANEN	/Lamp	60	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$13.00	/Lamp	$21.81	/Lamp	$192	$337	$780	$1,309		
250 WATT HPS ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$13.40	/Lamp	$23.52	/Lamp	$0	$0	$0	$0		
SUBTOTAL HPS ANEN		3,348					294							$10,713	$10,469	$42,257	$63,439		
39 WATT EQUIV. LED ANEN	/Lamp	24	$3.20	/Lamp	$0.07280	/kWh/lamp	13	$1.06	/Lamp	$16.90	/Lamp	$21.16	/Lamp	$77	$25	$406	$508		
100 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$16.90	/Lamp	$20.83	/Lamp	$0	$0	$0	$0		
150 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$18.70	/Lamp	$23.14	/Lamp	$0	$0	$0	$0		
250 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$21.00	/Lamp	$26.60	/Lamp	$0	$0	$0	$0		
SUBTOTAL LED ANEN		24					73							$77	$25	$406	$508		
TOTAL UNDERGROUND SERVICE		3,372					367							$10,790	$10,494	$42,663	$63,947		
Act 141 Fixed Charge															$1		$0		
Act 141 Credit		13,642	kWh		($0.00229)	per kWh									($31)		($204)		
Fuel Credit					($0.00108)														
TOTAL PRESENT SL-1		11,964	Lamps				14,016							$38,285	$47,364	$109,291	$194,766		

MADISON GAS AND ELECTRIC COMPANY

SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

			DISTRIBUTION SERVICE		ELECTRICITY SERVICE					FACILITIES FEE		TOTAL PROPOSED MONTHLY RATE						PROPOSED REVENUE INCREASE	
TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PROPOSED DISTRIBUTION SERVICE RATE	BILLING UNITS	PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	PROPOSED FACILITIES RATE	BILLING UNITS	2021 PROPOSED RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	FACILITIES FEE REVENUE	2021 PROPOSED REVENUES	AMOUNT	PERCENT
STREETLIGHTING SERVICE - COMPANY OWNED AND COMPANY MAINTAINED SL-1																			
OVERHEAD SERVICE																			
175 WATT MV ANEN (CLOSED)	/Lamp	1,728	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$7.90	/Lamp	$15.98	/Lamp	$5,530	$8,433	$13,651	$27,614	$0	0.00%
250 WATT MV ANEN (CLOSED)	/Lamp	336	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$8.00	/Lamp	$18.12	/Lamp	$1,075	$2,325	$2,688	$6,088	$0	0.00%
400 WATT MV ANEN (CLOSED)	/Lamp	576	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$8.40	/Lamp	$22.74	/Lamp	$1,843	$6,417	$4,838	$13,098	$0	0.00%
SUBTOTAL MV ANEN		2,640					315							$8,448	$17,175	$21,177	$46,800	$0	0.00%
400 WATT MV MN (CLOSED)	/Lamp	36	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$8.40	/Lamp	$17.21	/Lamp	$115	$202	$302	$619	$0	0.00%
SUBTOTAL MV MN		36					77							$115	$202	$302	$619	$0	0.00%
70 WATT HPS ANEN	/Lamp	636	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$7.60	/Lamp	$12.69	/Lamp	$2,035	$1,202	$4,834	$8,071	$0	0.00%
100 WATT HPS ANEN	/Lamp	3,180	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$7.60	/Lamp	$13.57	/Lamp	$10,176	$8,809	$24,168	$43,153	$0	0.00%
150 WATT HPS ANEN	/Lamp	1,848	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$7.60	/Lamp	$15.02	/Lamp	$5,914	$7,799	$14,045	$27,758	$0	0.00%
200 WATT HPS ANEN	/Lamp	24	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$7.80	/Lamp	$16.61	/Lamp	$77	$135	$187	$399	$0	0.00%
250 WATT HPS ANEN	/Lamp	228	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$8.40	/Lamp	$18.52	/Lamp	$730	$1,578	$1,915	$4,223	$0	0.00%
SUBTOTAL HPS ANEN		5,916					294							$18,932	$19,523	$45,149	$83,604	$0	0.00%
300 WATT SUSP TYPE ANEN (CL(	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	115	$8.37	/Lamp	$7.70	/Lamp	$19.27	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
100 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$12.50	/Lamp	$16.43	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
150 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$14.40	/Lamp	$18.84	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
250 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$16.60	/Lamp	$22.20	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
SUBTOTAL HPS ANEN		0					175							$0	$0	$0	$0	$0	#DIV/0!
TOTAL OVERHEAD SERVICE		8,592					976							$27,495	$36,900	$66,628	$131,023	$0	0.00%
UNDERGROUND SERVICE																			
70 WATT HPS ANEN	/Lamp	576	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$12.50	/Lamp	$17.59	/Lamp	$1,843	$1,089	$7,200	$10,132	$0	0.00%
100 WATT HPS ANEN	/Lamp	1,656	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$12.60	/Lamp	$18.57	/Lamp	$5,299	$4,587	$20,866	$30,752	$0	0.00%
150 WATT HPS ANEN	/Lamp	1,056	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$12.70	/Lamp	$20.12	/Lamp	$3,379	$4,456	$13,411	$21,246	$0	0.00%
200 WATT HPS ANEN	/Lamp	60	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$13.00	/Lamp	$21.81	/Lamp	$192	$337	$780	$1,309	$0	0.00%
250 WATT HPS ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$13.40	/Lamp	$23.52	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
SUBTOTAL HPS ANEN		3,348					294							$10,713	$10,469	$42,257	$63,439	$0	0.00%
39 WATT EQUIV. LED ANEN	/Lamp	24	$3.20	/Lamp	$0.07280	/kWh/lamp	13	$1.06	/Lamp	$16.90	/Lamp	$21.16	/Lamp	$77	$25	$406	$508	$508	#DIV/0!
100 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$16.90	/Lamp	$20.83	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
150 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$18.70	/Lamp	$23.14	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
250 WATT EQUIV. LED ANEN	/Lamp	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$21.00	/Lamp	$26.60	/Lamp	$0	$0	$0	$0	$0	#DIV/0!
SUBTOTAL LED ANEN		24					73							$77	$25	$406	$0 $508	$0	0.00%
TOTAL UNDERGROUND SERVICE		3,372					367							$10,790	$10,494	$42,663	$63,947	$0	0.00%
Act 141 Fixed Charge															$ 5.43		$ -	$0	#DIV/0!
Act 141 Credit present		104,905	Units		($0.00229)	per kWh											($204)	$0	0.00%
Act 141 Credit proposed																			
TOTAL PROPOSED SL-1		11,964	Lamps											$38,285	$47,399	$109,291	$194,766	$0	

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	DISTRIBUTION SERVICE: PRESENT DISTRIBUTION SERVICE RATE	DISTRIBUTION SERVICE: BILLING UNITS	ELECTRICITY SERVICE: PRESENT ELECTRICITY SERVICE RATE	ELECTRICITY SERVICE: BILLING UNITS	ELECTRICITY SERVICE: NUMBER OF BILLING UNITS (MO. KWH)	ELECTRICITY SERVICE: TOTAL PRESENT ELECTRICITY SERVICE RATE	ELECTRICITY SERVICE: BILLING UNITS	TOTAL PRESENT MONTHLY RATE: PRESENT RATES	TOTAL PRESENT MONTHLY RATE: BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	PRESENT REVENUES	PROPOSED REVENUE INCREASE: AMOUNT	PROPOSED REVENUE INCREASE: PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND CUSTOMER MAINTAINED SL-2																
100 WATT MV ANEN (CLOSED)	Lamps	324	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$5.97	/Lamp	$1,037	$897	$1,934		
175 WATT MV ANEN (CLOSED)	Lamps	288	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$8.08	/Lamp	$922	$1,405	$2,327		
250 WATT MV ANEN (CLOSED)	Lamps	528	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$10.12	/Lamp	$1,690	$3,654	$5,344		
400 WATT MV ANEN (CLOSED)	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$14.34	/Lamp	$38	$134	$172		
SUBTOTAL MV ALLNIGHT SCHEDULE		1,152					353					$3,687	$6,090	$9,777		
250 WATT MV MN (CLOSED)	Lamps	36	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$6.69	/Lamp	$115	$126	$241		
400 WATT MV MN (CLOSED)	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$8.81	/Lamp	$77	$135	$212		
SUBTOTAL MV MIDNIGHT SCHEDULE		60					125					$192	$261	$453		
400 WATT MV 10:30 (CLOSED)	Lamps	120	$3.20	/Lamp	$0.07280	/kWh/lamp	55	$4.00	/Lamp	$7.20	/Lamp	$384	$480	$864		
SUBTOTAL MV 10:30 SCHEDULE		120					55					$384	$480	$864		
100 WATT MV 3AM (CLOSED)	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$5.31	/Lamp	$154	$101	$255		
SUBTOTAL MV 3AM SCHEDULE		48					29					$154	$101	$255		
TOTAL MV LAMPS		1,380					562					$4,417	$6,932	$11,349		
70 WATT HPS ANEN	Lamps	984	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$5.09	/Lamp	$3,149	$1,860	$5,009		
100 WATT HPS ANEN	Lamps	3,924	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$5.97	/Lamp	$12,557	$10,869	$23,426		
150 WATT HPS ANEN	Lamps	18,108	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$7.42	/Lamp	$57,946	$76,416	$134,362		
100 WATT HPS UG ANEN	Lamps	72	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$5.97	/Lamp	$230	$199	$429		
150 WATT HPS UG ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$7.42	/Lamp	$38	$51	$89		
200 WATT HPS ANEN	Lamps	2,580	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$8.81	/Lamp	$8,256	$14,474	$22,730		
250 WATT HPS ANEN	Lamps	8,856	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$10.12	/Lamp	$28,339	$61,284	$89,623		
400 WATT HPS ANEN	Lamps	3,336	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$14.34	/Lamp	$10,675	$37,163	$47,838		
SUTOTAL HPS ALLNIGHT SCHEDULE		37,872					543					$121,190	$202,316	$323,506		
70 WATT HPS MN	Lamps	636	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$4.22	/Lamp	$2,035	$649	$2,684		
100 WATT HPS MN	Lamps	720	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$4.66	/Lamp	$2,304	$1,051	$3,355		
150 WATT HPS MN	Lamps	5,616	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$5.31	/Lamp	$17,971	$11,850	$29,821		
200 WATT HPS MN	Lamps	120	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$5.97	/Lamp	$384	$332	$716		
250 WATT HPS MN	Lamps	1,104	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$6.69	/Lamp	$3,533	$3,853	$7,386		
400 WATT HPS MN	Lamps	732	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$8.81	/Lamp	$2,342	$4,107	$6,449		
SUBTOTAL HPS MIDNIGHT SCHEDULE		8,928					226					$28,569	$21,842	$50,411		
70 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.66	/Lamp	$3.86	/Lamp	$0	$0	$0		
100 WATT HPS 10:30	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$4.22	/Lamp	$77	$24	$101		
150 WATT HPS 10:30	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$4.73	/Lamp	$38	$18	$56		
200 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.04	/Lamp	$5.24	/Lamp	$0	$0	$0		
250 WATT HPS 10:30	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	35	$2.55	/Lamp	$5.75	/Lamp	$154	$122	$276		
400 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	55	$4.00	/Lamp	$7.20	/Lamp	$0	$0	$0		
SUBTOTAL HPS 10:30 SCHEDULE		84					162					$269	$164	$433		
70 WATT HPS 3AM	Lamps	624	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$4.73	/Lamp	$1,997	$955	$2,952		
100 WATT HPS 3AM	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$5.31	/Lamp	$154	$101	$255		
150 WATT HPS 3AM	Lamps	1,284	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.20	/Lamp	$6.40	/Lamp	$4,109	$4,109	$8,218		
200 WATT HPS 3AM	Lamps	468	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$7.42	/Lamp	$1,498	$1,975	$3,473		
250 WATT HPS 3AM	Lamps	420	$3.20	/Lamp	$0.07280	/kWh/lamp	72	$5.24	/Lamp	$8.44	/Lamp	$1,344	$2,201	$3,545		
400 WATT HPS 3AM	Lamps	492	$3.20	/Lamp	$0.07280	/kWh/lamp	115	$8.37	/Lamp	$11.57	/Lamp	$1,574	$4,118	$5,692		
SUBTOTAL HPS 3AM SCHEDULE		3,336					339					$10,676	$13,459	$24,135		
TOTAL HPS LAMPS		50,220					1,270					$160,704	$237,781	$398,485		

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	DISTRIBUTION SERVICE PRESENT DISTRIBUTION SERVICE RATE	BILLING UNITS	ELECTRICITY SERVICE PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	TOTAL PRESENT MONTHLY RATE PRESENT RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	PRESENT REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND CUSTOMER MAINTAINED SL-2																
35 WATT LPS ANEN	Lamps	132	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$4.22	/Lamp	$422	$135	$557		
55 WATT LPS ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$4.66	/Lamp	$0	$0	$0		
90 WATT LPS ANEN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	35	$2.55	/Lamp	$5.75	/Lamp	$806	$643	$1,449		
SUBTOTAL LPS ALL-NIGHT SCHEDULE		384					69					$1,228	$778	$2,006		
35 WATT LPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	7	$0.51	/Lamp	$3.71	/Lamp	$0	$0	$0		
55 WATT LPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.66	/Lamp	$3.86	/Lamp	$0	$0	$0		
90 WATT LPS MN	Lamps	156	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$4.44	/Lamp	$499	$193	$692		
SUBTOTAL LPS MIDNIGHT SCHEDULE		156					33					$499	$193	$692		
TOTAL LPS LAMPS		540					102					$1,727	$971	$2,698		
50 WATT MH ANEN	Lamps	360	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$4.66	/Lamp	$1,152	$526	$1,678		
70 WATT MH ANEN	Lamps	912	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$5.09	/Lamp	$2,918	$1,724	$4,642		
100 WATT MH ANEN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$5.97	/Lamp	$806	$698	$1,504		
175 WATT MH ANEN	Lamps	360	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$8.08	/Lamp	$1,152	$1,757	$2,909		
250 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$10.12	/Lamp	$0	$0	$0		
SUBTOTAL MH ALL-NIGHT SCHEDULE		1,884					246					$6,028	$4,705	$10,733		
50 WATT MH MN	Lamps	204	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.66	/Lamp	$3.86	/Lamp	$653	$135	$788		
70 WATT MH MN	Lamps	696	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$4.22	/Lamp	$2,227	$710	$2,937		
100 WATT MH MN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$4.66	/Lamp	$38	$18	$56		
175 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$5.60	/Lamp	$0	$0	$0		
SUBTOTAL MH MIDNIGHT SCHEDULE		708					67					$2,918	$863	$3,781		
70 WATT MH 3AM	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$4.73	/Lamp	$154	$73	$227		
100 WATT MH 3AM	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$5.31	/Lamp	$0	$0	$0		
175 WATT MH 3AM	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	51	$3.71	/Lamp	$6.91	/Lamp	$0	$0	$0		
SUBTOTAL MH 3AM SCHEDULE		48					101					$154	$73	$227		
TOTAL MH LAMPS		2,640					414					$9,100	$5,641	$14,741		
10 WATT LED-underground All Night		1,020	$3.20	/Lamp	$0.07280	/kWh/lamp	3	$0.220	/Lamp	$3.42	/Lamp	$3,264	$224	$3,488		
84 WATT LED ANEN	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.040	/Lamp	$5.24	/Lamp	$77	$49	$126		
133 WATT LED All Night		36	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.200	/Lamp	$6.40	/Lamp	$115	$115	$230		
150 WATT LED-underground All Night		96	$3.20	/Lamp	$0.07280	/kWh/lamp	50	$3.640	/Lamp	$6.84	/Lamp	$307	$349	$656		
156 WATT LED-underground All Night		648	$3.20	/Lamp	$0.07280	/kWh/lamp	52	$3.790	/Lamp	$6.99	/Lamp	$2,074	$2,456	$4,530		
95 WATT LED ANEN	Lamps	84	$3.20	/Lamp	$0.07280	/kWh/lamp	32	$2.330	/Lamp	$5.53	/Lamp	$269	$196	$465		
TOTAL LED LAMPS	Lamps	1,908	$3.20	/Lamp	0.0728	/kWh/lamp	209	15.22	/Lamp	$18.420	/Lamp	$6,106	$3,389	$9,495		
Act 141 Fixed Charge													($3)	($3)		
Act 141 Credit		90,036			($0.00229)	per kWh							($206)	($206)		
TOTAL PRESENT SL-2 REVENUE		56,688					30,684					$182,054	$254,505	$436,559		

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-117
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

			DISTRIBUTION SERVICE		ELECTRICITY SERVICE					TOTAL PROPOSED MONTHLY RATE					PROPOSED REVENUE INCREASE	
TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PROPOSED DISTRIBUTION SERVICE RATE	BILLING UNITS	PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	2021 PROPOSED RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	2021 PROPOSED REVENUES	AMOUNT	PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND CUSTOMER MAINTAINED SL-2																
100 WATT MV ANEN	Lamps	324	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.770	/Lamp	$5.97	/Lamp	$1,037	$897	$1,934	0	0.00%
175 WATT MV ANEN	Lamps	288	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.880	/Lamp	$8.08	/Lamp	$922	$1,405	$2,327	0	0.00%
250 WATT MV ANEN	Lamps	528	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.920	/Lamp	$10.12	/Lamp	$1,690	$3,654	$5,344	0	0.00%
400 WATT MV ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.140	/Lamp	$14.34	/Lamp	$38	$134	$172	0	0.00%
SUBTOTAL MV ALLNIGHT SCHEDULE		1,152					353					$3,687	$6,090	$9,777	0	0.00%
250 WATT MV MN	Lamps	36	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.490	/Lamp	$6.69	/Lamp	$115	$126	$241	0	0.00%
400 WATT MV MN	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.610	/Lamp	$8.81	/Lamp	$77	$135	$212	0	0.00%
SUBTOTAL MV MIDNIGHT SCHEDULE		60					125					$192	$261	$453	0	0.00%
400 WATT MV 10:30	Lamps	120	$3.20	/Lamp	$0.07280	/kWh/lamp	55	$4.000	/Lamp	$7.20	/Lamp	$384	$480	$864	0	0.00%
SUBTOTAL MV 10:30 SCHEDULE		120					55					$384	$480	$864	0	0.00%
100 WATT MV 3AM	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.110	/Lamp	$5.31	/Lamp	$154	$101	$255	0	0.00%
SUBTOTAL MV 3AM SCHEDULE		48					29					$154	$101	$255	0	0.00%
TOTAL MV LAMPS		1,380					562					$4,417	$6,932	$11,349	0	0.00%
70 WATT HPS ANEN	Lamps	984	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.890	/Lamp	$5.09	/Lamp	$3,149	$1,860	$5,009	0	0.00%
100 WATT HPS ANEN	Lamps	3,924	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.770	/Lamp	$5.97	/Lamp	$12,557	$10,869	$23,426	0	0.00%
150 WATT HPS ANEN	Lamps	18,108	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.220	/Lamp	$7.42	/Lamp	$57,946	$76,416	$134,362	0	0.00%
100 WATT HPS UG ANEN	Lamps	72	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.770	/Lamp	$5.97	/Lamp	$230	$199	$429	0	0.00%
150 WATT HPS UG ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.220	/Lamp	$7.42	/Lamp	$38	$51	$89	0	0.00%
200 WATT HPS ANEN	Lamps	2,580	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.610	/Lamp	$8.81	/Lamp	$8,256	$14,474	$22,730	0	0.00%
250 WATT HPS ANEN	Lamps	8,856	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.920	/Lamp	$10.12	/Lamp	$28,339	$61,284	$89,623	0	0.00%
400 WATT HPS ANEN	Lamps	3,336	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.140	/Lamp	$14.34	/Lamp	$10,675	$37,163	$47,838	0	0.00%
SUTOTAL HPS ALLNIGHT SCHEDULE		37,872					543					$121,190	$202,316	$323,506	0	0.00%
70 WATT HPS MN	Lamps	636	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.020	/Lamp	$4.22	/Lamp	$2,035	$649	$2,684	0	0.00%
100 WATT HPS MN	Lamps	720	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.460	/Lamp	$4.66	/Lamp	$2,304	$1,051	$3,355	0	0.00%
150 WATT HPS MN	Lamps	5,616	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.110	/Lamp	$5.31	/Lamp	$17,971	$11,850	$29,821	0	0.00%
200 WATT HPS MN	Lamps	120	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.770	/Lamp	$5.97	/Lamp	$384	$332	$716	0	0.00%
250 WATT HPS MN	Lamps	1,104	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.490	/Lamp	$6.69	/Lamp	$3,533	$3,853	$7,386	0	0.00%
400 WATT HPS MN	Lamps	732	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.610	/Lamp	$8.81	/Lamp	$2,342	$4,107	$6,449	0	0.00%
SUBTOTAL HPS MIDNIGHT SCHEDULE		8,928					226					$28,569	$21,842	$50,411	0	0.00%
70 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.660	/Lamp	$3.86	/Lamp	$0	$0	$0	0	#DIV/0!
100 WATT HPS 10:30	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.020	/Lamp	$4.22	/Lamp	$77	$24	$101	0	0.00%
150 WATT HPS 10:30	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.530	/Lamp	$4.73	/Lamp	$38	$18	$56	0	0.00%
200 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.040	/Lamp	$5.24	/Lamp	$0	$0	$0	0	#DIV/0!
250 WATT HPS 10:30	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	35	$2.550	/Lamp	$5.75	/Lamp	$154	$122	$276	0	0.00%
400 WATT HPS 10:30	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	55	$4.000	/Lamp	$7.20	/Lamp	$0	$0	$0	0	#DIV/0!
SUBTOTAL HPS 10:30 SCHEDULE		84					162					$269	$164	$433	0	0.00%
70 WATT HPS 3AM	Lamps	624	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.530	/Lamp	$4.73	/Lamp	$1,997	$955	$2,952	0	0.00%
100 WATT HPS 3AM	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.110	/Lamp	$5.31	/Lamp	$154	$101	$255	0	0.00%
150 WATT HPS 3AM	Lamps	1,284	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.200	/Lamp	$6.40	/Lamp	$4,109	$4,109	$8,218	0	0.00%
200 WATT HPS 3AM	Lamps	468	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.220	/Lamp	$7.42	/Lamp	$1,498	$1,975	$3,473	0	0.00%
250 WATT HPS 3AM	Lamps	420	$3.20	/Lamp	$0.07280	/kWh/lamp	72	$5.240	/Lamp	$8.44	/Lamp	$1,344	$2,201	$3,545	0	0.00%
400 WATT HPS 3AM	Lamps	492	$3.20	/Lamp	$0.07280	/kWh/lamp	115	$8.370	/Lamp	$11.57	/Lamp	$1,574	$4,118	$5,692	0	0.00%
SUBTOTAL HPS 3AM SCHEDULE		3,336					339					$10,676	$13,459	$24,135	0	0.00%
TOTAL HPS LAMPS		50,220					1,270					$160,704	$237,781	$398,485	0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-117
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	DISTRIBUTION SERVICE PROPOSED DISTRIBUTION SERVICE RATE	BILLING UNITS	ELECTRICITY SERVICE PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	TOTAL PROPOSED MONTHLY RATE 2021 PROPOSED RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND CUSTOMER MAINTAINED SL-2																
35 WATT LPS ANEN	Lamps	132	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.020	/Lamp	$4.22	/Lamp	$422	$135	$557	0	0.00%
55 WATT LPS ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.460	/Lamp	$4.66	/Lamp	$0	$0	$0	0	#DIV/0!
90 WATT LPS ANEN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	35	$2.550	/Lamp	$5.75	/Lamp	$806	$643	$1,449	0	0.00%
SUBTOTAL LPS ALL-NIGHT SCHEDULE		384					69					$1,228	$778	$2,006	0	0.00%
35 WATT LPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	7	$0.510	/Lamp	$3.71	/Lamp	$0	$0	$0	0	#DIV/0!
55 WATT LPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.660	/Lamp	$3.86	/Lamp	$0	$0	$0	0	#DIV/0!
90 WATT LPS MN	Lamps	156	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.240	/Lamp	$4.44	/Lamp	$499	$193	$692	0	0.00%
SUBTOTAL LPS MIDNIGHT SCHEDULE		156					33					$499	$193	$692	0	0.00%
TOTAL LPS LAMPS		540					102					$1,727	$971	$2,698	0	0.00%
50 WATT MH ANEN	Lamps	360	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.460	/Lamp	$4.66	/Lamp	$1,152	$526	$1,678	0	0.00%
70 WATT MH ANEN	Lamps	912	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.890	/Lamp	$5.09	/Lamp	$2,918	$1,724	$4,642	0	0.00%
100 WATT MH ANEN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.770	/Lamp	$5.97	/Lamp	$806	$698	$1,504	0	0.00%
175 WATT MH ANEN	Lamps	360	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.880	/Lamp	$8.08	/Lamp	$1,152	$1,757	$2,909	0	0.00%
250 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.920	/Lamp	$10.12	/Lamp	$0	$0	$0	0	#DIV/0!
SUBTOTAL MH ALL-NIGHT SCHEDULE		1,884					246					$6,028	$4,705	$10,733	0	0.00%
50 WATT MH MN	Lamps	204	$3.20	/Lamp	$0.07280	/kWh/lamp	9	$0.660	/Lamp	$3.86	/Lamp	$653	$135	$788	0	0.00%
70 WATT MH MN	Lamps	696	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.020	/Lamp	$4.22	/Lamp	$2,227	$710	$2,937	0	0.00%
100 WATT MH MN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.460	/Lamp	$4.66	/Lamp	$38	$18	$56	0	0.00%
175 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.400	/Lamp	$5.60	/Lamp	$0	$0	$0	0	#DIV/0!
SUBTOTAL MH MIDNIGHT SCHEDULE		912					67					$2,918	$863	$3,781	0	0.00%
70 WATT MH 3AM	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.530	/Lamp	$4.73	/Lamp	$154	$73	$227	0	0.00%
100 WATT MH 3AM	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.110	/Lamp	$5.31	/Lamp	$0	$0	$0	0	#DIV/0!
175 WATT MH 3AM	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	51	$3.710	/Lamp	$6.91	/Lamp	$0	$0	$0	0	#DIV/0!
SUBTOTAL MH 3AM SCHEDULE		48					101					$154	$73	$227	0	0.00%
TOTAL MH LAMPS		2,844					414					$9,100	$5,641	$14,741	0	0.00%
10 WATT LED-underground All Night	Lamps	1,020	$3.20	/Lamp	$0.07280	/kWh/lamp	3	$0.220	/Lamp	$3.42	/Lamp	$3,264	$224	$3,488		
84 WATT LED ANEN	Lamps	24	$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.040	/Lamp	$5.24	/Lamp	$77	$49	$126	0	0.00%
133 WATT LED All Night	Lamps	36	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.200	/Lamp	$6.40	/Lamp	$115	$115	$230		
150 WATT LED-underground All Night	Lamps	96	$3.20	/Lamp	$0.07280	/kWh/lamp	50	$3.640	/Lamp	$6.84	/Lamp	$307	$349	$656		
156 WATT LED-underground All Night	Lamps	648	$3.20	/Lamp	$0.07280	/kWh/lamp	52	$3.790	/Lamp	$6.99	/Lamp	$2,074	$2,456	$4,530		
95 WATT LED ANEN	Lamps	84	$3.20	/Lamp	$0.07280	/kWh/lamp	32	$2.330	/Lamp	$5.53	/Lamp	$269	$196	$465	0	0.00%
TOTAL LED LAMPS	Lamps	1,908	$3.20	/Lamp	$ 0.07280	/kWh/lamp	209	$ 15.220	/Lamp	$18.420	/Lamp	$6,106	$3,389	$9,495	0	0.00%
Act 141 Fixed Charge														$ (3)	0	0.00%
Act 141 Credit Present		90,036	Units		($0.00229)	per kWh								$ (206)	0	0.00%
TOTAL PRESENT SL-2 REVENUE		56,892					30,684					$182,054	$254,714	$436,559	0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

			DISTRIBUTION SERVICE		ELECTRICITY SERVICE					MAINTENANCE SERVICE		TOTAL PRESENT MONTHLY RATE							
TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PRESENT DISTRIBUTION SERVICE RATE	BILLING UNITS	PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PRESENT ELECTRICITY SERVICE RATE	BILLING UNITS	PRESENT MAINTENANCE RATE	BILLING UNITS	PRESENT RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	MAINTENANCE FEE REVENUE	PRESENT REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND COMPANY MAINTAINED SL-3																			
OVERHEAD SERVICE																			
70 WATT HPS ANEN	Lamps	9,000	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$28,800	$17,010	$9,000	$54,810		
100 WATT HPS ANEN	Lamps	35,892	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$114,854	$99,421	$35,892	$250,167		
150 WATT HPS ANEN	Lamps	5,148	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$16,474	$21,725	$5,148	$43,347		
200 WATT HPS ANEN	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$1.00	/Lamp	$9.81	/Lamp	$154	$269	$48	$471		
250 WATT HPS ANEN	Lamps	468	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$1,498	$3,239	$468	$5,205		
SUBTOTAL HPS ALLNIGHT SCHEDULE		50,556												$161,780	$141,664	$50,556	$354,000		
70 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0	$0		
100 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0	$0		
150 WATT HPS MN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$806	$532	$252	$1,590		
200 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$0	$0	$0	$0		
250 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0	$0		
SUBTOTAL HPS MIDNIGHT SCHEDULE		252												$806	$532	$252	$1,590		
70 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$0	$0	$0	$0		
150 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$0	$0	$0	$0		
250 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$0	$0	$0	$0		
SUBTOTAL MH ALLNIGHT SCHEDULE		0												$0	$0	$0	$0		
70 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0	$0		
150 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0	$0		
250 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0	$0		
SUBTOTAL MH MIDNIGHT SCHEDULE		0												$0	$0	$0	$0		
30 WATT LED ANEN	Lamps	60	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$1.00	/Lamp	$4.93	/Lamp	$192	$44	$60	$296		
34 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	11	$0.80	/Lamp	$1.00	/Lamp	$5.00	/Lamp	$38	$10	$12	$60		
53 WATT LED ANEN	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	18	$1.31	/Lamp	$1.00	/Lamp	$5.51	/Lamp	$154	$63	$48	$265		
56 WATT LED ANEN	Lamps	132	$3.20	/Lamp	$0.07280	/kWh/lamp	19	$1.38	/Lamp	$1.00	/Lamp	$5.58	/Lamp	$422	$182	$132	$736		
64 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$1.00	/Lamp	$5.73	/Lamp	$38	$18	$12	$68		
73 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	24	$1.75	/Lamp	$1.00	/Lamp	$5.95	/Lamp	$38	$21	$12	$71		
76 WATT LED ANEN	Lamps	264	$3.20	/Lamp	$0.07280	/kWh/lamp	25	$1.82	/Lamp	$1.00	/Lamp	$6.02	/Lamp	$845	$480	$264	$1,589		
95 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	32	$2.33	/Lamp	$1.00	/Lamp	$6.53	/Lamp	$38	$28	$12	$78		
100 WATT LED ANEN	Lamps	96	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$307	$230	$96	$633		
110 WATT LED ANEN	Lamps	60	$3.20	/Lamp	$0.07280	/kWh/lamp	37	$2.69	/Lamp	$1.00	/Lamp	$6.89	/Lamp	$192	$161	$60	$413		
150 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	50	$3.64	/Lamp	$1.00	/Lamp	$7.84	/Lamp	$38	$44	$12	$94		
SUBTOTAL LED ALLNIGHT SCHEDULE		720												$2,302	$1,281	$720	$4,303		
TOTAL OVERHEAD		51,528												$164,888	$143,477	$51,528	$359,893		
UNDERGROUND SERVICE																			
70 WATT HPS ANEN	Lamps	3,360	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$10,752	$6,350	$3,360	$20,462		
71.2 WATT HPS ANEN	Lamps		$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.04	/Lamp	$1.00	/Lamp	$6.24	/Lamp	$0	$0	$0	$0		
76 WATT HPS ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0	$0		
82 WATT HPS ANEN	Lamps		$3.20	/Lamp	$0.07280	/kWh/lamp	31	$2.26	/Lamp	$1.00	/Lamp	$6.46	/Lamp	$0	$0	$0	$0		
100 WATT HPS ANEN	Lamps	30,276	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$96,883	$83,865	$30,276	$211,024		
150 WATT HPS ANEN	Lamps	11,952	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$38,246	$50,437	$11,952	$100,635		
200 WATT HPS ANEN	Lamps	936	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$1.00	/Lamp	$9.81	/Lamp	$2,995	$5,251	$936	$9,182		
250 WATT HPS ANEN	Lamps	1,188	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$3,802	$8,221	$1,188	$13,211		
400 WATT HPS ANEN	Lamps	96	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$1.00	/Lamp	$15.34	/Lamp	$307	$1,069	$96	$1,472		
SUBTOTAL HPS ALLNIGHT SCHEDULE		47,808												$152,985	$155,193	$47,808	$355,986		
100 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0	$0		
150 WATT HPS MN	Lamps	420	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$1,344	$886	$420	$2,650		
250 WATT HPS MN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$38	$42	$12	$92		
SUBTOTAL HPS MIDNIGHT SCHEDULE		432												$1,382	$928	$432	$2,742		
175 WATT MV ANEN	Lamps	4,056	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$1.00	/Lamp	$9.08	/Lamp	$12,979	$19,793	$4,056	$36,828		
250 WATT MV ANEN	Lamps	456	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$1,459	$3,156	$456	$5,071		
SUBTOTAL MV ALLNIGHT SCHEDULE		4,512												$14,438	$22,949	$4,512	$41,899		
70 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$0	$0	$0	$0		
100 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$0	$0	$0	$0		
150 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$0	$0	$0	$0		
175 WATT MH ANEN	Lamps	1,068	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$1.00	/Lamp	$9.08	/Lamp	$3,418	$5,212	$1,068	$9,698		
250 WATT MH ANEN	Lamps	108	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$346	$747	$108	$1,201		
SUBTOTAL MH ALLNIGHT SCHEDULE		1,176												$3,764	$5,959	$1,176	$10,899		
70 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0	$0		
100 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0	$0		
150 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0	$0		
175 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$0	$0	$0	$0		
250 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0	$0		
SUBTOTAL MH MIDNIGHT SCHEDULE		0												$0	$0	$0	$0		
30 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$1.00	/Lamp	$4.93	/Lamp	$0	$0	$0	$0		
34 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	11	$0.80	/Lamp	$1.00	/Lamp	$5.00	/Lamp	$0	$0	$0	$0		
39 WATT LED ANEN		192	$3.20	/Lamp	$0.07280	/kWh/lamp	13	$0.95	/Lamp	$1.00	/Lamp	$5.15	/Lamp	$614	$182	$192	$988		
42 WATT LED ANEN		168	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$538	$171	$168	$877		
48 WATT LED ANEN		312	$3.20	/Lamp	$0.07280	/kWh/lamp	16	$1.16	/Lamp	$1.00	/Lamp	$5.36	/Lamp	$998	$362	$312	$1,672		
53 WATT LED ANEN		132	$3.20	/Lamp	$0.07280	/kWh/lamp	18	$1.31	/Lamp	$1.00	/Lamp	$5.51	/Lamp	$422	$173	$132	$727		
56 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	19	$1.38	/Lamp	$1.00	/Lamp	$5.58	/Lamp	$0	$0	$0	$0		
64 WATT LED ANEN		72	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$1.00	/Lamp	$5.73	/Lamp	$230	$110	$72	$412		
66 WATT LED ANEN		180	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$576	$288	$180	$1,044		
70 WATT LED ANEN		444	$3.20	/Lamp	$0.07280	/kWh/lamp	23	$1.67	/Lamp	$1.00	/Lamp	$5.87	/Lamp	$1,421	$741	$444	$2,606		
71.2 WATT LED ANEN		144	$3.20	/Lamp	$0.07280	/kWh/lamp	24	$1.75	/Lamp	$1.00	/Lamp	$5.95	/Lamp	$461	$252	$144	$857		
76 WATT LED ANEN		72	$3.20	/Lamp	$0.07280	/kWh/lamp	25	$1.82	/Lamp	$1.00	/Lamp	$6.02	/Lamp	$230	$131	$72	$433		
80 WATT LED ANEN		132	$3.20	/Lamp	$0.07280	/kWh/lamp	27	$1.97	/Lamp	$1.00	/Lamp	$6.17	/Lamp	$422	$260	$132	$814		
82 WATT LED ANEN		48	$3.20	/Lamp	$0.07280	/kWh/lamp	27	$1.97	/Lamp	$1.00	/Lamp	$6.17	/Lamp	$154	$95	$48	$297		
92 WATT LED ANEN		888	$3.20	/Lamp	$0.07280	/kWh/lamp	31	$2.26	/Lamp	$1.00	/Lamp	$6.46	/Lamp	$2,842	$2,007	$888	$5,737		
100 WATT LED ANEN		156	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$499	$374	$156	$1,029		
101 WATT LED ANEN		900	$3.20	/Lamp	$0.07280	/kWh/lamp	34	$2.48	/Lamp	$1.00	/Lamp	$6.68	/Lamp	$2,880	$2,232	$900	$6,012		
130 WATT LED ANEN		96	$3.20	/Lamp	$0.07280	/kWh/lamp	43	$3.13	/Lamp	$1.00	/Lamp	$7.33	/Lamp	$307	$300	$96	$703		
132 WATT LED ANEN		240	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.20	/Lamp	$1.00	/Lamp	$7.40	/Lamp	$768	$768	$240	$1,776		
133 WATT LED ANEN		1,080	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.20	/Lamp	$1.00	/Lamp	$7.40	/Lamp	$3,456	$3,456	$1,080	$7,992		
SUBTOTAL LED ALLNIGHT SCHEDULE		5,256												$16,818	$11,902	$5,256 0	$33,976		
101 WATT LED MN		300	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$1.00	/Lamp	$5.44	/Lamp	$960	$372	$300	$1,632		
130 WATT LED MN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$0	$0	$0	$0		
133 WATT LED MN		480	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$1,536	$768	$480	$2,784		
TOTAL UNDERGROUND		59,964												$191,883	$198,071	$59,964 0	$449,918		

300 WATT Incandescent W-Susp ANI	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	100	$7.28	/Lamp	$7.70	/Lamp	$18.18	/Lamp	$38	$87	$92		$217		
Act 141 Fixed Charge															$0			$0		
Act 141 Credit		0	kWh		($0.00229)	per kWh									$0			$0		
TOTAL PRESENT SL-3 REVENUE		111,504	Lamps											$356,809	$341,635	$111,584	0	$810,028		

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

			DISTRIBUTION SERVICE		ELECTRICITY SERVICE					MAINTENANCE SERVICE 0		TOTAL PROPOSED MONTHLY RATE 0								
TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PROPOSED DISTRIBUTION SERVICE RATE	BILLING UNITS	PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	NUMBER OF BILLING UNITS (MO. KWH)	TOTAL PROPOSED ELECTRICITY SERVICE RATE	BILLING UNITS	PROPOSED MAINTENANCE RATE	BILLING UNITS	PROPOSED RATES	BILLING UNITS	DISTRIBUTION REVENUE	ELECTRICITY REVENUE	MAINTENANCE FEE REVENUE		PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
STREETLIGHTING SERVICE - CUSTOMER OWNED AND COMPANY MAINTAINED SL-3																				
OVERHEAD SERVICE																				
70 WATT HPS ANEN	Lamps	9,000	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$28,800	$17,010	$9,000		$54,810	0	0.00%
100 WATT HPS ANEN	Lamps	35,892	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$114,854	$99,421	$35,892		$250,167	0	0.00%
150 WATT HPS ANEN	Lamps	5,148	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$16,474	$21,725	$5,148		$43,347	0	0.00%
200 WATT HPS ANEN	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$1.00	/Lamp	$9.81	/Lamp	$154	$269	$48		$471	0	0.00%
250 WATT HPS ANEN	Lamps	468	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$1,498	$3,239	$468		$5,205	0	0.00%
SUBTOTAL HPS ALLNIGHT SCHEDULE		50,556												$161,780	$141,664	$50,556		$354,000	0	0.00%
70 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0		$0	0	#DIV/0!
100 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT HPS MN	Lamps	252	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$806	$532	$252		$1,590	0	0.00%
200 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$0	$0	$0		$0	0	#DIV/0!
250 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0		$0	0	#DIV/0!
SUBTOTAL HPS MIDNIGHT SCHEDULE		252												$806	$532	$252		$1,590	0	0.00%
70 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$0	$0	$0		$0	0	#DIV/0!
250 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$0	$0	$0		$0	0	#DIV/0!
SUBTOTAL MH ALLNIGHT SCHEDULE		0												$0	$0	$0		$0	0	#DIV/0!
70 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0		$0	0	#DIV/0!
250 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0		$0	0	#DIV/0!
SUBTOTAL MH MIDNIGHT SCHEDULE		0												$0	$0	$0		$0	0	#DIV/0!
30 WATT LED ANEN	Lamps	60	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$1.00	/Lamp	$4.93	/Lamp	$192	$44	$60		$296	0	0.00%
34 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	11	$0.80	/Lamp	$1.00	/Lamp	$5.00	/Lamp	$38	$10	$12		$60	0	0.00%
53 WATT LED ANEN	Lamps	48	$3.20	/Lamp	$0.07280	/kWh/lamp	18	$1.31	/Lamp	$1.00	/Lamp	$5.51	/Lamp	$154	$63	$48		$265	0	0.00%
56 WATT LED ANEN	Lamps	132	$3.20	/Lamp	$0.07280	/kWh/lamp	19	$1.38	/Lamp	$1.00	/Lamp	$5.58	/Lamp	$422	$182	$132		$736	0	0.00%
64 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$1.00	/Lamp	$5.73	/Lamp	$38	$18	$12		$68	0	0.00%
73 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	24	$1.75	/Lamp	$1.00	/Lamp	$5.95	/Lamp	$38	$21	$12		$71	0	0.00%
76 WATT LED ANEN	Lamps	264	$3.20	/Lamp	$0.07280	/kWh/lamp	25	$1.82	/Lamp	$1.00	/Lamp	$6.02	/Lamp	$845	$480	$264		$1,589	0	0.00%
95 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	32	$2.33	/Lamp	$1.00	/Lamp	$6.53	/Lamp	$38	$28	$12		$78	0	0.00%
100 WATT LED ANEN	Lamps	96	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$307	$230	$96		$633	0	0.00%
110 WATT LED ANEN	Lamps	60	$3.20	/Lamp	$0.07280	/kWh/lamp	37	$2.69	/Lamp	$1.00	/Lamp	$6.89	/Lamp	$192	$161	$60		$413	0	0.00%
150 WATT LED ANEN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	50	$3.64	/Lamp	$1.00	/Lamp	$7.84	/Lamp	$38	$44	$12		$94	0	0.00%
SUBTOTAL LED ALLNIGHT SCHEDULE		720												$2,302	$1,281	$720		$4,303	0	0.00%
TOTAL OVERHEAD		51,528												$164,888	$143,477	$51,528		$359,893	0	0.00%
UNDERGROUND SERVICE																				
70 WATT HPS ANEN	Lamps	3,360	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$10,752	$6,350	$3,360		$20,462	0	0.00%
71.2 WATT HPS ANEN	Lamps		$3.20	/Lamp	$0.07280	/kWh/lamp	28	$2.04	/Lamp	$1.00	/Lamp	$6.24	/Lamp	$0	$0	$0		$0	0	#DIV/0!
76 WATT HPS ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0		$0	0	#DIV/0!
82 WATT HPS ANEN	Lamps		$3.20	/Lamp	$0.07280	/kWh/lamp	31	$2.26	/Lamp	$1.00	/Lamp	$6.46	/Lamp	$0	$0	$0		$0	0	#DIV/0!
100 WATT HPS ANEN	Lamps	30,276	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$96,883	$83,865	$30,276		$211,024	0	0.00%
150 WATT HPS ANEN	Lamps	11,952	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$38,246	$50,437	$11,952		$100,635	0	0.00%
200 WATT HPS ANEN	Lamps	936	$3.20	/Lamp	$0.07280	/kWh/lamp	77	$5.61	/Lamp	$1.00	/Lamp	$9.81	/Lamp	$2,995	$5,251	$936		$9,182	0	0.00%
250 WATT HPS ANEN	Lamps	1,188	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$3,802	$8,221	$1,188		$13,211	0	0.00%
400 WATT HPS ANEN	Lamps	96	$3.20	/Lamp	$0.07280	/kWh/lamp	153	$11.14	/Lamp	$1.00	/Lamp	$15.34	/Lamp	$307	$1,069	$96		$1,472	0	0.00%
SUBTOTAL HPS ALLNIGHT SCHEDULE		47,808												$152,985	$155,193	$47,808		$355,986	0	0.00%
100 WATT HPS MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT HPS MN	Lamps	420	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$1,344	$886	$420		$2,650	0	0.00%
250 WATT HPS MN	Lamps	12	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$38	$42	$12		$92	0	0.00%
SUBTOTAL HPS MIDNIGHT SCHEDULE		432												$1,382	$928	$432		$2,742	0	0.00%
175 WATT MV ANEN	Lamps	4,056	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$1.00	/Lamp	$9.08	/Lamp	$12,979	$19,793	$4,056		$36,828	0	0.00%
250 WATT MV ANEN	Lamps	456	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$1,459	$3,156	$456		$5,071	0	0.00%
SUBTOTAL MV ALLNIGHT SCHEDULE		4,512												$14,438	$22,949	$4,512		$41,899	0	0.00%
70 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	26	$1.89	/Lamp	$1.00	/Lamp	$6.09	/Lamp	$0	$0	$0		$0	0	#DIV/0!
100 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	38	$2.77	/Lamp	$1.00	/Lamp	$6.97	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT MH ANEN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	58	$4.22	/Lamp	$1.00	/Lamp	$8.42	/Lamp	$0	$0	$0		$0	0	#DIV/0!
175 WATT MH ANEN	Lamps	1,068	$3.20	/Lamp	$0.07280	/kWh/lamp	67	$4.88	/Lamp	$1.00	/Lamp	$9.08	/Lamp	$3,418	$5,212	$1,068		$9,698	0	0.00%
250 WATT MH ANEN	Lamps	108	$3.20	/Lamp	$0.07280	/kWh/lamp	95	$6.92	/Lamp	$1.00	/Lamp	$11.12	/Lamp	$346	$747	$108		$1,201	0	0.00%
SUBTOTAL MH ALLNIGHT SCHEDULE		1,176												$3,764	$5,959	$1,176		$10,899	0	0.00%
70 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$0	$0	$0		$0	0	#DIV/0!
100 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	20	$1.46	/Lamp	$1.00	/Lamp	$5.66	/Lamp	$0	$0	$0		$0	0	#DIV/0!
150 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	29	$2.11	/Lamp	$1.00	/Lamp	$6.31	/Lamp	$0	$0	$0		$0	0	#DIV/0!
175 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$0	$0	$0		$0	0	#DIV/0!
250 WATT MH MN	Lamps	0	$3.20	/Lamp	$0.07280	/kWh/lamp	48	$3.49	/Lamp	$1.00	/Lamp	$7.69	/Lamp	$0	$0	$0		$0	0	#DIV/0!
SUBTOTAL MH MIDNIGHT SCHEDULE		0												$0	$0	$0		$0	0	#DIV/0!
30 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	10	$0.73	/Lamp	$1.00	/Lamp	$4.93	/Lamp	$0	$0	$0		$0	0	#DIV/0!
34 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	11	$0.80	/Lamp	$1.00	/Lamp	$5.00	/Lamp	$0	$0	$0		$0	0	#DIV/0!
39 WATT LED ANEN		192	$3.20	/Lamp	$0.07280	/kWh/lamp	13	$0.95	/Lamp	$1.00	/Lamp	$5.15	/Lamp	$614	$182	$192		$988	0	0.00%
42 WATT LED ANEN		168	$3.20	/Lamp	$0.07280	/kWh/lamp	14	$1.02	/Lamp	$1.00	/Lamp	$5.22	/Lamp	$538	$171	$168		$877	0	0.00%
48 WATT LED ANEN		312	$3.20	/Lamp	$0.07280	/kWh/lamp	16	$1.16	/Lamp	$1.00	/Lamp	$5.36	/Lamp	$998	$362	$312		$1,672	0	0.00%
53 WATT LED ANEN		132	$3.20	/Lamp	$0.07280	/kWh/lamp	18	$1.31	/Lamp	$1.00	/Lamp	$5.51	/Lamp	$422	$173	$132		$727	0	0.00%
56 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	19	$1.38	/Lamp	$1.00	/Lamp	$5.58	/Lamp	$0	$0	$0		$0	0	#DIV/0!
64 WATT LED ANEN		72	$3.20	/Lamp	$0.07280	/kWh/lamp	21	$1.53	/Lamp	$1.00	/Lamp	$5.73	/Lamp	$230	$110	$72		$412	0	0.00%
66 WATT LED ANEN		180	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$576	$288	$180		$1,044	0	0.00%
70 WATT LED ANEN		444	$3.20	/Lamp	$0.07280	/kWh/lamp	23	$1.67	/Lamp	$1.00	/Lamp	$5.87	/Lamp	$1,421	$741	$444		$2,606	0	0.00%
71.2 WATT LED ANEN		144	$3.20	/Lamp	$0.07280	/kWh/lamp	24	$1.75	/Lamp	$1.00	/Lamp	$5.95	/Lamp	$461	$252	$144		$857	0	0.00%
76 WATT LED ANEN		72	$3.20	/Lamp	$0.07280	/kWh/lamp	25	$1.82	/Lamp	$1.00	/Lamp	$6.02	/Lamp	$230	$131	$72		$433	0	0.00%
80 WATT LED ANEN		132	$3.20	/Lamp	$0.07280	/kWh/lamp	27	$1.97	/Lamp	$1.00	/Lamp	$6.17	/Lamp	$422	$260	$132		$814	0	0.00%
82 WATT LED ANEN		48	$3.20	/Lamp	$0.07280	/kWh/lamp	27	$1.97	/Lamp	$1.00	/Lamp	$6.17	/Lamp	$154	$95	$48		$297	0	0.00%
92 WATT LED ANEN		888	$3.20	/Lamp	$0.07280	/kWh/lamp	31	$2.26	/Lamp	$1.00	/Lamp	$6.46	/Lamp	$2,842	$2,007	$888		$5,737	0	0.00%
100 WATT LED ANEN		156	$3.20	/Lamp	$0.07280	/kWh/lamp	33	$2.40	/Lamp	$1.00	/Lamp	$6.60	/Lamp	$499	$374	$156		$1,029	0	0.00%
101 WATT LED ANEN		900	$3.20	/Lamp	$0.07280	/kWh/lamp	34	$2.48	/Lamp	$1.00	/Lamp	$6.68	/Lamp	$2,880	$2,232	$900		$6,012	0	0.00%
130 WATT LED ANEN		96	$3.20	/Lamp	$0.07280	/kWh/lamp	43	$3.13	/Lamp	$1.00	/Lamp	$7.33	/Lamp	$307	$300	$96		$703	0	0.00%
132 WATT LED ANEN		240	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.20	/Lamp	$1.00	/Lamp	$7.40	/Lamp	$768	$768	$240		$1,776	0	0.00%
133 WATT LED ANEN		1,080	$3.20	/Lamp	$0.07280	/kWh/lamp	44	$3.20	/Lamp	$1.00	/Lamp	$7.40	/Lamp	$3,456	$3,456	$1,080		$7,992	0	0.00%
SUBTOTAL LED ALLNIGHT SCHEDULE		5,256												$16,818	$11,902	$5,256	0	$33,976	0	0.00%
101 WATT LED MN		300	$3.20	/Lamp	$0.07280	/kWh/lamp	17	$1.24	/Lamp	$1.00	/Lamp	$5.44	/Lamp	$960	$372	$300		$1,632	0	0.00%
101 WATT LED ANEN		0	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$0	$0	$0		$0	0	#DIV/0!
133 WATT LED MN		480	$3.20	/Lamp	$0.07280	/kWh/lamp	22	$1.60	/Lamp	$1.00	/Lamp	$5.80	/Lamp	$1,536	$768	$480		$2,784	0	0.00%
TOTAL UNDERGROUND		59,964												$191,883	$198,071	$59,964	0	$449,918	0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS (LAMPS)	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
OUTDOOR OVERHEAD LIGHTING SERVICE - PRIVATE UNMETERED OL-1										
DUSK-TO-DAWN YARD LIGHTING										
70 WATT HPS LAMPS	Lamps	1,608	$12.61	per lamp	$20,277	$12.61	per lamp	$20,277		
100 WATT HPS LAMPS	Lamps	2,100	$13.67	per lamp	$28,707	$13.67	per lamp	$28,707		
150 WATT HPS LAMPS	Lamps	8,316	$15.50	per lamp	$128,898	$15.50	per lamp	$128,898		
SUBTOTAL HPS LAMPS		12,024			$177,882			$177,882		
175 WATT MV LAMPS (CLOSED)	Lamps	396	$15.20	per lamp	$6,019	$15.20	per lamp	$6,019		
250 WATT MV LAMPS (CLOSED)	Lamps	24	$17.12	per lamp	$411	$17.12	per lamp	$411		
400 WATT MV LAMPS (CLOSED)	Lamps	108	$21.25	per lamp	$2,295	$21.25	per lamp	$2,295		
SUBTOTAL MV LAMPS		528			$8,725			$8,725		
TOTAL DUSK-TO-DAWN LIGHTING		12,552			$186,607			$186,607		
OUTDOOR OVERHEAD LIGHTING										
70 WATT HPS LAMPS	Lamps	1,692	$14.44	per lamp	$24,432	$14.44	per lamp	$24,432		
150 WATT HPS LAMPS	Lamps	4,824	$17.70	per lamp	$85,385	$17.70	per lamp	$85,385		
250 WATT HPS LAMPS	Lamps	3,264	$20.67	per lamp	$67,467	$20.67	per lamp	$67,467		
400 WATT HPS LAMPS	Lamps	1,164	$24.90	per lamp	$28,984	$24.90	per lamp	$28,984		
SUBTOTAL HPS LAMPS		10,944			$206,268			$206,268		
70 WATT MH LAMPS	Lamps	0	$15.20	per lamp	$0	$15.20	per lamp	$0		
150 WATT MH LAMPS	Lamps	0	$17.60	per lamp	$0	$17.60	per lamp	$0		
250 WATT MH LAMPS	Lamps	468	$20.39	per lamp	$9,543	$20.39	per lamp	$9,543		
400 WATT MH LAMPS	Lamps	660	$24.32	per lamp	$16,051	$24.32	per lamp	$16,051		
SUBTOTAL MH LAMPS		1,128			$25,594			$25,594		
70 WATT EQUIVALENT LED LAMPS	Lamps	252	$15.50	per lamp	$3,906	$15.50	per lamp	$3,906		
150 WATT EQUIVALENT LED LAMPS	Lamps	396	$16.08	per lamp	$6,368	$16.08	per lamp	$6,368		
250 WATT EQUIVALENT LED LAMPS	Lamps	660	$18.56	per lamp	$12,250	$18.56	per lamp	$12,250		
400 WATT EQUIVALENT LED LAMPS	Lamps	372	$23.17	per lamp	$8,619	$23.17	per lamp	$8,619		
SUBTOTAL LED LAMPS		1,680			$31,143			$31,143		
TOTAL OUTDOOR OVERHEAD LIGHTING		13,752			$263,005			$263,005		
Act 141 Fixed Charge	Fixed				$10			$ 10		
Act 141 Credit	KWH	104,073	($0.00229)	per kWh	($238)	($0.00229)	per kWh	($238)		
WOOD POLES	Poles	11,076	$8.85	per pole	$98,023	$8.85	per pole	$98,023		
NONWOOD POLES	Poles	2,556	$14.25	per pole	$36,423	$14.25	per pole	$36,423		
TOTAL POLES		13,632			$134,446			$134,446		
TOTAL OL-1		26,304			$583,830			$583,830	$0	0.00%
					$583,830					

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 19

Battery Interconnection

Service Rules

Summary Points:

- One service rule clarification pertaining to the application process for interconnecting batteries.

Overview:

Clarifying language will be added to the Company's service rules under Electric Service Rules and Regulations: Customer-Owned Generating Equipment (sheet E-67). This language will clarify that customer-owned batteries designed for parallel operation will be treated as distributed generation facilities for all purposes relating to MGE service rules and §PSC 119.

MGE feels it is reasonable to review and modify this language should universally recognized standards be developed for batteries designed for parallel operation while simultaneously restricting any generated energy from being "pushed" back onto the grid and §PSC 119 is amended to allow such exceptions.

The following will be added to sheet E-67:

All customer-owned batteries that are capable of, or intended to be capable of, “parallel operation” as defined in §PSC 119.02 (30) will be subject to any and all service rules and regulations and §PSC 119 rules that pertain to distributed generation facilities.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 20

Other Lighting and Miscellaneous

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
GENERAL FLAT RATES Gf-1										
LEVEL II CATV Amplifiers	Each	0	$76.50	each per bill	$0	$76.50	each per bill	$0		
LEVEL II CATV Amplifiers Total		0			$0			$0		
LEVEL III Unmetered Service										
Customer Charge	Bills	654	$0.65420	per bill per day	$13,014	$0.65420	per bill per day	$13,014		
	Days	365	$19.90			$19.90				
Distribution Service	kWh	1,566,765	$0.0300	per kWh	$47,003	$0.0300	per kWh	$47,003		
Electricity Service	kWh	1,566,765	$0.09082	per kWh	$142,294	$0.09082	per kWh	$142,294		
Act 141 Credit	Each	4,380	($0.00229)	per kWh	($10)	($0.00229)	per kWh	($10)		
LEVEL III Unmetered Service TOTAL					$202,301			$202,301		
TOTAL Gf-1 REVENUES					$202,301			$202,301	$0	0.00%
					$202,301					

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PROPOSED REVENUE INCREASE PERCENT
SECONDARY SERVICE FOR MUNICIPAL DEFENSE SIRENS Mg-2										
MOTOR-DRIVEN SIRENS (2 Hp)	siren	57	$4.05	each	$231	$4.05	each	$231	$0	0.00%
ELECTRONIC SIRENS	siren	144	$5.86	each	$844	$5.86	each	$844	$0	0.00%
TOTAL Mg-2 REVENUES					$1,075 $1,075			$1,075	$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
SUMMARY OF ESTIMATED
ELECTRIC BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

TYPE OF SERVICE	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	PROPOSED REVENUE INCREASE AMOUNT	PERCENT
ATHLETIC FIELD LIGHTING MLS										
CUSTOMER CHARGE	Bills	302	$0.78669	per day per bill	$7,226	$0.78669	per day per bill	$7,226		
	Days	365	$23.93			$23.93				
DISTRIBUTION CHARGE	kWh	468,034	$0.0300	per kWh	$14,041	$0.0300	per kWh	$14,041		
ELECTRICITY CHARGE	kWh	468,034	$0.09656	per kWh	$45,193	$0.09656	per kWh	$45,193		
Act 141 Fixed Charge	Fixed				$5			$5		
Act 141 Credit	kWh	183,040	($0.00229)	per kWh	($419)	($0.00229)		($419)		
TOTAL MLS		468,034			$66,046			$66,046	$0	0.00%

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 21

Electric Vehicle Fleet Pilot 1

Electric Vehicle Fleet Pilot 1

EVF

Tariff Changes

New Program

Summary Points:

- This service is for new customers on Cg-2 or 4 that have a dedicated meter for electric consumption for charging infrastructure for fuel for customer owned or leased electric vehicles.
- The service applies a discount to the customers demand charge that starts at 80% and reduces each year as the customer gains experience and charging infrastructure use.

Overview:

This is a new pilot for customers who own or lease electric vehicles. If they have charging infrastructure that is on a separate meter, that meter can receive discounts of 80% starting in the first year and decreasing over time until there is no more discount to the demand charges they receive on either Cg-4 or Cg-2 in year. This gives the customer the opportunity to bring new load on and learn about the charging patterns with out having large bill impacts in the first years of electric service.

AVAILABILITY

Service under this voluntary schedule is available to customers on Rate Schedules Cg-4 and Cg-2 who have a dedicated meter for the charging infrastructure utilized by the customer to exclusively fuel its customer-owned and/or leased electric vehicles. Assets not dedicated to the process of charging vehicles shall not be taking service from said dedicated meter.

RATE

All the provisions of the otherwise applicable rate schedule(s) will apply with the exception that a customer served on this rider will have a reduction to both the maximum monthly on-peak 15-minute demand and the customer maximum 15-minute demand charges for a period of five years based on when service commences at the meter.

Customers taking service under this schedule will have a reduction in demand charges on the following schedule:

1. Year 1 reduction: 80%
2. Year 2 reduction: 60%
3. Year 3 reduction: 40%
4. Year 4 reduction: 20%
5. Year 5 reduction: 0%

PAYMENT

Payment is due not later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's electric service rules under Late Payment Charge.

CONDITIONS OF DELIVERY

1. A customer receiving service under this rider must contact the Company to review charging configuration to ensure service is dedicated exclusively to charging infrastructure.

2. The availability of service under this rate may be limited at the discretion of the Company. Service under this rate may be refused if the Company believes the load is serving load not dedicated to the charging electric vehicles.

3. The customer will, at customer's expense, install all apparatus and materials necessary for the proper utilization of power furnished by the Company.

4. The customer will pay, in advance of construction, all costs estimated by the Company for facilities to serve the charging load.

5. The Company will not be liable for any damages sustained by the customer because of interruptions, deficiencies, or imperfections of electric service provided under this rate.

6. Service under this rate will be furnished only in accordance with the Electric Service Rules and Regulations of the Company.
7. Energy furnished under this rate will not be resold.

8. Service under this schedule may not be combined with service under Is-3, Is-4, the Low Load Factor Provision, or combined metering.

Madison Gas and Electric Company

Docket 3270-UR-123

Attachment C

Schedule 22

Addition of Energy Reduction Measures and Baseline Levels Language to the RNL-1 Tariff

New Load Market Pricing Rider (Experimental)

AVAILABILITY

The New Load Market Pricing Rider (Rider) is available in all territory served by the Company.

The Rider participation limit is a program maximum of 75 MW total load (baseline plus forecasted new load). Applications will be considered on a first-come, first-served basis.

This Rider is available to customers served under Rate Schedule Cg-2, Cg-6, or Cp-1. A customer under this Rider shall maintain a minimum of 400 kW of load above Demand Baseline Levels for eight out of the 12 months in each of the contract service years. A customer's expected load must meet this criterion to be eligible for service under this Rider. Failure to meet this criterion will result in the customer being removed from this rate.

This Rider is not available to customers or potential customers transferring load from a different electricity provider in Wisconsin to the Company.

Availability of this Rider is subject to availability of adequate transmission and generation capacity to serve the load.

This Rider is an experimental pilot program. The terms and conditions of this Rider may be modified outside of a rate proceeding, subject to approval by the Public Service Commission of Wisconsin (PSCW).

RATE

Each customer will have unique Baseline Levels for energy and demand usage as outlined in the Baseline Determination section of this Rider. A customer will be charged according to the applicable standard tariff distribution and electricity service rates for their usage and demands up to and including their Baseline Levels. The customer will also pay the Grid Connection and Customer Service Charge of the applicable standard tariff that they qualify for service on. Incremental usage and demands above the Baseline Levels will be charged at market-based energy and incremental demand rates specified in this Rider.

1. **Administrative Charge per Day:** $6.00

2. **Baseline Level Charges.** The applicable Schedule Cg-2, Cg-6, or Cp-1 rates, definitions, rules and riders apply to all energy and demand consumption that does not exceed the Baseline Levels that occur throughout the billing period.

3. **Above Baseline Level Charges.** The following charges shall apply to all energy and demand consumption in excess of the Baseline Levels as they apply throughout the billing period.

   a. Incremental Energy Rate (IER). If the customer's energy consumed exceeds Baseline Levels in any hour of the billing month, the incremental energy above the Baseline Levels will be charged the following IER components:

      (1) The hourly Midcontinent Independent System Operator, Inc. (MISO) Day-Ahead Locational Marginal Pricing for the MGE.MGE pricing load zone.

(Continued on Sheet E-33.1)

RATE (continued)

(2) Transaction costs charged and credited to the Company by MISO. These charges include, but are not limited to:

(a) Regulation Cost Distribution Amount (MISO Schedule 3),

(b) Spinning Reserves Cost Distribution Amount (MISO Schedule 5),

(c) Supplemental Cost Distribution Amount (MISO Schedule 6),

(d) Revenue Sufficiency Guarantee Distribution Amount,

(e) Revenue Neutrality Uplift Expense, and

(f) Distribution of Losses Credit.

(3) Energy-based transmission and dispatch operation costs charged to the Company by American Transmission Company (ATC), MISO, or their successors for costs to provide transmission service to the customer. These charges include, but are not limited to:

(a) Multi-Value Project (MVP) Expense (MISO Schedule 26A, as well as MVP true-up adjustments),

(b) MISO Administrative Expenses (MISO Schedule 17), and

(c) Control Area Operator Cost (MISO Schedule 24).

(4) Margin on Energy at $0.0005/kWh.

(5) Distribution Energy Loss rates applicable for respective primary and secondary voltage services will be applied to IER components (1) through (4).

(6) Gross Receipts Tax applied to IER components (1) through (5) at 3.19%.

The IER will not be less than $0.007/kWh in any hour. IER components (1) and (2), as well as the associated losses from component (6) will be treated as fuel-related energy costs.

b. Incremental Demand Rate (IDR). If the customer's coincident demand at the time of ATC system peak exceeds Baseline Levels for the month, the incremental demand above the Baseline Levels will be charged the following IDR components:

(1) Resource Adequacy Charge based on the latest Auction Clearing price for the Local Resource Zone in which the Company is located. This charge only applies to firm load. See the Non-firm Load section of this Rider for additional details and requirements.

(2) ATC Network Transmission Charge. This charge will be based on the estimated rate provided by ATC (MISO Schedule 9).

(Continued on Sheet E-33.2)

New Load Market Pricing Rider (Experimental)

RATE (continued)

(3) Demand-based transmission costs charged to the Company from ATC, MISO, or their successors for costs to provide transmission service. The Company will use the base rate case cost estimates to determine a per unit rate including recovery of escrow accounting cost adjustments. These charges include, but are not limited to the following:

(a) Scheduling/Dispatch (MISO Schedule 1),

(b) Voltage/Reactive Expense and Revenue (MISO Schedule 2),

(c) Independent System Operator Cost Recovery (MISO Schedule 10),

(d) FERC Administrative (MISO Schedule 10-FERC),

(e) Wholesale Distribution Service (MISO Schedule 11),

(f) Network Upgrade Expense (MISO Schedule 26),

(g) Blackstart Service (MISO Schedule 33),

(h) System Support Resources (MISO Schedule 43),

(i) PJM Charges, and

(j) Direct Network Upgrade Charges.

(4) Distribution Loss rates applicable for respective primary and secondary voltage services will be applied to IDR components (1) through (3).

(5) Gross Receipts Tax applied to IDR components (1) through (4) at 3.19%.

c. Distribution Service Customer Demand: A Customer Maximum 15-minute Demand billing option will be selected by the customer for the contract period for demand above Baseline Levels as follows:

(1) Option 1: Distribution Service Demand above Baseline Levels, in addition to Distribution Service Demand at or below Baseline Levels, will be subject to the customer demand charges applied in Baseline Level Charges. A customer that selects Option 1 will receive a construction allowance per the Company's Extension Rules schedules.

(2) Option 2: Distribution Service Demand above Baseline Levels will not be subject to the customer demand charges applied in Baseline Level Charges. A customer that selects Option 2 will not receive a construction allowance per the Company's Extension Rules schedules and will be responsible to pay for the entire cost of required distribution upgrades.

d. Any other credits or charges that may be authorized or mandated by the PSCW from time to time that would apply to incremental usage, including applicable Act 141 obligations.

(Continued on Sheet E-33.3)

New Load Market Pricing Rider (Experimental)

RATE (continued)

4. Determination of Baseline Levels.

A customer's Baseline Levels shall be based on a Baseline Period. The customer's Baseline Period represents a recent, historical 12-month time period. Historical usage patterns and demand levels derived from the Baseline Period make up Energy and Demand Baseline Levels and are used for billing the corresponding months of the Contract Period. Energy and Demand Baseline Levels will be contracted prior to beginning service under this Rider and will be applicable for the duration of the Contract Period. The following Baseline Levels will be established as a part of contracted service under this Rider:

- 15-minute energy use for every interval of the Baseline Period. This data will be used to determine the Baseline and above-Baseline Demand Levels for distinct intervals during each billing period for billing purposes.

- The 15-minute energy use will also be used to determine the hourly energy usage for every hour of the Baseline Period. This data will be used to determine the Baseline and above-Baseline Hourly Use Levels for the distinct hours during each billing period for billing purposes.

Energy and Demand Baseline Level for Existing Customers with Forecasted New Load

The Baseline Energy and Demand Levels will be 100% of the energy and demand levels in the Baseline Period for contracts with terms from one to four years. Regarding historical use, adjustments to the strict actual historical consumption patterns may be made by the Company to eliminate data anomalies in the Baseline Period that are not expected to reoccur, or to accommodate unique production patterns as demonstrated in historical data from the last 24 months (e.g., if production is commonly reduced during a specific day of the week or for infrequent maintenance shutdown).

Energy and Demand Baseline Levels for New Customers

Energy and Demand Baseline Levels for new customer accounts with less than 12 months of usage history will be based on a realistic forecast of new energy and demand levels by increment for the first contract year, supplied by the new customer, of usage and demand for the new facility. The new customer must demonstrate how the new facility differs from existing or prior facilities served by the Company such that consumption patterns or levels at the new facility are dissimilar to that of existing or past facilities. Corporate name changes, change in ownership of a facility or a corporation, the formation of subsidiaries, or similar actions will not qualify a customer as a new customer for purposes of Baseline Levels determination.

The customer forecast must be approved by the Company and may be revised at the Company's discretion after the first year of service. The approved forecast of energy and demand levels will be multiplied by the appropriate percent value in the baseline Percent Table in this rider to determine the Baseline Level values that will be used for billing under this rider.

(Continued on Sheet E-33.4)

RATE (continued)

Baseline Percent Table for New Customers

Year	1	2	3	4	5
5 Year Contract Base %	40	50	60	70	75
4 Year Contract Base %	50	60	70	75	--
3 Year Contract Base %	65	70	75	--	--
2 Year Contract Base %	70	75	--	--	--

Energy Reduction Measures and Baseline Levels

For existing customers and new customers in the second or subsequent years of service under this schedule, the Baseline may be adjusted to reflect a systematic and permanent change in Customer production levels as a result of the implementation of energy efficiency, conservation, and process improvement measures, or through the installation of new equipment as these measures relate to the Baseline, The Customer must request a review of their historical Baseline period and provide the Company with supporting documentation, which in the judgement of the Company, after its review and verification indicates that the reduction is permanent and due to the aforementioned measures. This adjustment will not take effect until the beginning of the billing period following the execution of an amended contract. Baseline adjustments upon Customer request and pursuant to this condition will not occur more than once in a 12-month period.

5. **Contract Requirements.**

   a. **Existing customers with added load.** An existing customer that is adding load under this rider, shall enter into a contract for a term of one to four years of service under this rider. A fifth year of service may be added to the contract with baseline levels set at the higher of the originally set level or 80% of the year-4 maximum customer demand. An existing customer that adds load under this rider may discontinue this service on each anniversary date of its contract with 30 days' written notice to MGE.

   b. **New customers.** A new customer subscribing to this Rider shall enter into a contract for a term of one, two, three, four or five years. If a customer wishes to terminate service prior to the contract term end, the customer will forfeit the Guaranteed Load Provision. A new customer that subscribes to this rider may discontinue service under this rider on each anniversary date of its contract with 30 days' written notice to MGE. A customer that terminates service under this Rider will not be allowed back on the Rider for one year from the time that prior service ended under this schedule. Each contract will have Baseline Levels that reflect recent historical consumption at the time that each contract term begins.

6. **Guaranteed Load Provision.**

The Company may require that a new customer furnish the Company a Load Financial Security Instrument (LFSI) satisfactory to the Company in its sole discretion prior to the Customer taking service under this rider. The LFSI may take the form of a surety bond, letter of credit, or similar financial instrument payable to MGE, and will be in an amount agreeable to the Company.

The full amount of the LFSI will be collectible by MGE if, at any time from the date the customer first subscribes to this Rider until the second anniversary of the customer's discontinuation of service under this Rider, the customer's total annual demand load falls below the required minimum demand to qualify for service under this rider. The amount recovered will be no less than the difference in the amount that would have been paid in the prior two years had the service been billed at the baseline percent rate level of the next shorter-term contract and what was actually billed the customer during that time.

(Continued on E-33.5)

New Load Market Pricing Rider (Experimental)

RATE (continued)

7. Non-firm Load Requirements.

Customers subscribing to interruptible rider schedules Is-3, Is-4, or Cp-1 for Baseline Levels usage are eligible for the non-firm options of this Rider. Customers who elect non-firm service will not pay the Resource Adequacy Charge underlying the IDR rate component of Above Baseline Charges. Customers subscribing to the non-firm load option under this Rider will be subject to the curtailment or interruption terms, provisions, and penalties outlined in the underlying Baseline interruptible rider. Baseline Levels and Rider pricing, terms, and conditions do not apply to any energy consumed during the curtailment or interruption event. Once a curtailment or interruption event is over, pricing, terms, and conditions of delivery revert to those of this Rider.

8. Billing Cycle Accommodations.

Customers taking service under this Rider will be billed on a calendar month basis. The Company reserves the right to bill IDR and IER charges on a one-month lag to allow for final determination of the coincident peak hour-related and other transmission company or independent system operator billing factors to be determined for the calendar month. Participants will start on the Rider at the beginning of the billing period after a contract is signed and price communication processes are functioning.

(Next Sheet is E-34)

Madison Gas and Electric Company
Docket 3270-UR-123
ATTACHMENT D - GAS SERVICE, RATES AND REVENUE
Attachment D Index

Schedule #:	Schedule Name:	Pages:	Documents
1	Seasonal Use Distribution Service	1	Program Description
		2-3	Tariff Language
2	Revenue Summary and Rates	1	Revenue Summary
		2-9	Rate Schedules
3	Base Cost of Gas Rate Calculation	1	Test Year 2021 Calculation

Seasonal Use Distribution Service

SUDS-1

Existing Program

Tariff Changes

Clarifications: Yes
Program Changes: No

Rate Design Changes

Rate Design: Yes

Summary Points:

- New Rate Design
- Typo Correction

Overview:

The Company's SUDS-1 seasonal-use tariff was authorized in the Settlement Agreement in docket 3270-UR-122 as a replacement to the now canceled seasonal-use SD-1 and SD-2 tariffs. The tariff was primarily designed for agricultural grain drying operations and offers year-round firm distribution service supplied with interruptible gas service (IS-1). The SUDS-1 tariff features incentive based pricing during the months of April – December with an incremental per therm adder for any on-peak consumption during the winter heating season months of January – March. The incremental adder is intended to discourage usage when system demand for space-heating is at its peak.

Under its current rate structure, SUDS-1 offers a three-tier declining block rate structure. MGE is proposing to modify the existing three-tier declining block rate approach to include only a two-tier rate structure in this proceeding. The current three-tier rate structure offers a reduced per therm rate for billing cycle consumption between 0 – 2,000 therms, 2,000 – 20,000 therms and 20,000 plus therms. The proposed two-tier approach includes two reduced per therm pricing for billing cycle consumption of 0 – 5,000 therms and 5,000 plus therms. The modified two-tier rate structure has been designed to mitigate adverse bill impacts to existing SUDS-1 customers. Moreover, the current incremental $0.50 per therm adder for on-peak consumption has been reduced to $0.10 per therm with the expectation that the added $0.10 per therm cost will continue to provide a price signal that encourages usage during the on-peak months.

In addition to the revisions to the SUDS-1 declining block rate structure, the Company is proposing to revise some of the existing tariff language for clarification purposes along with other housekeeping matters like typos.

AVAILABILITY

For commercial and industrial customers ~~with annual consumption greater than 2,000 therms~~ who anticipate a vast majority of their natural gas consumption will take place during the off-peak period of April 1 through December 31. Examples of such business ventures include but should not be limited to agricultural canning and grain drying operations, gas used in the manufacturing process of asphalt for road paving and/or repair. While SUDS-1 service is available year-round, incentive pricing is in place to discourage consumption during the on-peak period of January 1 through March 31.

This rate schedule applies to gas distributed to one customer at one location through one meter. For those customers where, at the Company's sole discretion, two or more meters are required for service, all such meters will be combined and the system connection and customer service charge will be the same as though one meter was installed.

~~The Company may, at its sole discretion, transfer customers who fall short of the minimum consumption requirement to the appropriate commercial and industrial class.~~

SUDS-1 is an optional rate schedule which requires a written contract with the Company. Customers who choose to be served under this rate schedule must provide the Company with their request and, if approved, shall remain on this schedule for a minimum of one year.

APPLICABILITY AND CHARACTER OF SERVICE

The Company will provide distribution service for the delivery of gas supply through the Company's facilities to eligible customers.

Distribution service by the Company under this rate schedule will be on a firm basis.

RATE

System connection and customer service charge per day [1].....	$1.50
Distribution rates per cycle bill:	
Distribution service per therm (first 5,000 therms)	$0.1544
~~Distribution service per therm (next 18,000 therms) ....~~	~~$0.1140~~
Distribution service per therm (all therms > 5,000 therms)	$0.1394

Distribution service during the period of January 1 through March 31 will pay the same declining block rates illustrated above plus an incremental $0.10 per therm.

[1] The system connection and customer service charge will be applied year-round regardless of consumption.

METERING

Service furnished hereunder will be separately metered. Meter reading will be done on a monthly basis according to the customer's billing cycle. Each SUDS-1 meter must be equipped with a data-logging Encoder Receiver Transmitter (ERT) which allows for accurate billing of both off-peak and on-peak period consumption.

PAYMENT

Payment is due no later than the due date shown on the bill. Any Company billing charges unpaid after the due date will be subject to a late payment charge as described in the Company's gas service rules under Late Payment Charge.

GAS SERVICE OPTIONS

Customers taking service under this rate schedule will receive their gas supply service under the Company's Interruptible Gas Sales Service (Rate Schedule IS-1) unless the customer contracts for service under the Company's Daily Balancing Service (Rate Schedule DBS-1).

SPECIAL TERMS AND PROVISIONS

1. Customers who have their meters turned off and back on within a 12-month period will pay the system connection and customer service charge applicable to the customer for the period while service was not being used.

2. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

3. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

4. If special equipment, such as motor-operated valves, metering bypass, flow restrictors, and remote control is required to monitor gas service, such special equipment will be installed by the Company at the customer's expense. This requirement will not apply to ERT equipment necessary for service under this schedule or equipment required for IS-1, IS-2, or DBS-1 gas supply if the customer elects this supply option. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

5. For any natural gas supply which is not furnished by Company, customer warrants for itself, its successors and assigns, that it has or will have at the time of the delivery of the gas to Company for distribution hereunder, good title to such gas and the right to cause the gas to be delivered to Company for distribution. Customer warrants for itself, its successors and assigns, that the gas it furnishes to Company for distribution hereunder will be free and clear of all liens, encumbrances, or claims, and that it will indemnify and save Company harmless from all suits, actions, damages, costs, losses, and expenses, including reasonable attorney's fees, arising out of or from any adverse claims of any and all persons to the gas, or to any claims of royalties, taxes, license fees, or charges thereon which are directly applicable to the delivery of the gas, and further that customer will indemnify and save Company harmless from all taxes or assessments, and any costs associated therewith, including reasonable attorney's fees, which may be directly levied and assessed upon such delivery and which are by law payable and the obligation of the party making such delivery.

6. Service under this rate schedule will commence following approval of the customer's application for service by the Company.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

	Rate Class	Volumes Therms	[1] Authorized COG Revenues	Present Margin Revenues	TOTAL Revenues	2021 Proposed COG Revenues	2021 Proposed Margin Revenues	2021 Proposed TOTAL Revenues	Proposed Dollar Adjustment	[2] Proposed Percentage Adjustment
RD-1	Residential Distribution - Firm Sales	106,300,022		$55,370,605			$59,802,761		$4,432,156	8.00%
	TOTAL RESIDENTIAL DISTRIBUTION REVENUE	**106,300,022**	**$40,714,502**	**$55,370,050**	**$96,084,552**	**$40,606,862**	**$59,802,761**	**$100,409,623**	**$4,325,071**	**4.50%**
GSD-1	Firm Sales (FS-1)	55,456,703		$14,104,758			$15,230,529		$1,125,771	7.98%
GSD-1	Interruptible Sales (IS-1)	16,655		$3,427			$3,765		$338	9.86%
GSD-1	Daily Balancing Service (DBS-1)	82,437		$23,123			$24,796		$1,673	7.24%
GSD-1	Interdepartmental with Firm Sales (FS-1)	104,294		$25,103			$27,220		$2,117	8.43%
	Act 141 - Fixed Amount			$1,513			$1,513			
	Act 141 - Credit Amount			-$50,045			-$50,045			
	TOTAL SMALL COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**55,660,089**	**$21,497,828**	**$14,107,879**	**$35,605,707**	**$21,168,400**	**$15,237,778**	**$36,406,178**	**$800,471**	**2.25%**
GSD-2	Firm Sales (FS-1)	30,028,073		$4,832,505			$5,216,865		$384,360	7.95%
GSD-2	Interruptible Sales (IS-1)	563,668		$85,591			$92,806		$7,215	8.43%
GSD-2	Interruptible Sales and Firm Sales Nomination - Firm	172,463		$22,610			$24,817		$2,207	9.76%
GSD-2	Interruptible Sales and Firm Sales Nomination - Interruptible	370,376		$61,821			$66,562		$4,741	7.67%
GSD-2	Daily Balancing Service (DBS-1)	8,355,678		$1,374,735			$1,481,687		$106,952	7.78%
GSD-2	Interdepartmental with Firm Sales (FS-1)	66,157		$11,388			$12,235		$847	7.44%
	Act 141 - Fixed Amount			$2,065			$2,065			
	Act 141 - Credit Amount			-$111,649			-$111,649			
	TOTAL MEDIUM COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**39,556,415**	**$10,410,026**	**$6,279,066**	**$16,689,092**	**$11,739,603**	**$6,785,388**	**$18,524,990**	**$1,835,899**	**11.00%**
GSD-3	Firm Sales (FS-1)	4,473,219		$559,418			$593,414		$33,996	6.08%
GSD-3	Interruptible Sales (IS-1)	1,672,808		$188,589			$201,302		$12,713	6.74%
GSD-3	Interruptible Sales and Firm Sales Nomination - Firm	213,525		$18,854			$20,477		$1,623	8.61%
GSD-3	Interruptible Sales and Firm Sales Nomination - Interruptible	545,078		$58,352			$62,494		$4,142	7.10%
GSD-3	Daily Balancing Service (DBS-1)	28,416,097		$2,764,698			$2,980,660		$215,962	7.81%
	Act 141 - Fixed Amount			$1,120			$1,120			
	Act 141 - Credit Amount			-$239,004			-$239,004			
	TOTAL LARGE COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**35,320,726**	**$2,330,147**	**$3,352,027**	**$5,682,174**	**$2,398,516**	**$3,620,463**	**$6,018,979**	**$336,805**	**5.93%**
GSD-3D	Firm Sales (FS-1)	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales (IS-1)	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales and Firm Sales Nomination - Firm	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales and Firm Sales Nomination - Interruptible	-		$0			$0		$0	0.00%
GSD-3D	Daily Balancing Service (DBS-1)	-		$0			$0		$0	0.00%
	Act 141 - Fixed Amount			$0			$0			
	Act 141 - Credit Amount			$0			$0			
	TOTAL LARGE COMMERICAL & INDUSTRIAL DEMAND DISTRIBUTION REVENUE	**-**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**0.00%**
IGD-1	Interruptible Generation with IS-2 Sales	813,595		$468,785			$471,958		$3,173	0.68%
IGD-1	Interruptible Generation with Daily Balancing Service	37,792,641		$1,391,125			$1,538,517		$147,392	10.60%
IGD-1	Interruptible Generation with LS-1 Sales	-		$0			$0		$0	0.00%
	Act 141 Charge			$9,269			$9,269			
	TOTAL INTERRUPTIBLE GENERATION DISTRIBUTION REVENUE	**38,606,236**	**$234,053**	**$1,869,179**	**$2,103,232**	**$220,917**	**$2,019,744**	**$2,240,661**	**$137,429**	**6.53%**
SP-1	Large Annual Use Gas Sales (LS-1)	21,257,397		$1,726,646			$1,864,819		$138,173	8.00%
	Act 141 Charge			$8,112			$8,112			
	TOTAL STEAM AND POWER GENERATION GAS DISTIBUTION REVENUE	**21,257,397**	**$8,394,040**	**$1,734,758**	**$10,128,798**	**$6,276,892**	**$1,872,931**	**$8,149,823**	**-$1,978,975**	**-19.54%**
SUDS-1	Interruptible Sales (IS-1)	82,093		$466,018			$503,761		$37,743	8.10%
SUDS-1	Daily Balancing Service (DBS-1)	29,364		$86,877			$93,200		$6,323	7.28%
	Act 141 - Fixed Amount			$67			$67			
	Act 141 - Credit Amount			-$3,751			-$3,751			
	TOTAL SEASONAL USE DISTRIBUTION REVENUES	**3,841,970**	**$784,064**	**$549,211**	**$1,333,275**	**$951,897**	**$593,277**	**$1,545,174**	**$211,899**	**15.89%**
	Company Use	243,437								
TOTAL VOLUMES AND REVENUES		**300,786,293**	**$84,364,660**	**$83,262,170**	**$167,626,830**	**$83,363,086**	**$89,932,342**	**$173,295,428**	**$5,668,598**	**3.38%**

[1] Authorized Cost of Gas from Commission Final Decision in 3270-UR-122 for Test Year 2020.
[2] The proposed percentage adjustment for individual rate class categories does not include Act 141 fixed or credit amounts. The percentage adjustment also excludes cost of gas revenues.
The total class level revenues does include Act 141 fixed and credit amounts and cost of gas revenues.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	Percentage Change
RESIDENTIAL DISTRIBUTION SERVICE RD-1									
CUSTOMER CHARGE	Bills	1,788,878	$0.7195	per bill per day	$39,149,222	$0.7195	per bill per day	$39,149,222	
	Days	365	$21.88	per bill per month		$21.88	per bill per month		
DISTRIBUTION SERVICE CHARGE	Therms	106,300,022	$0.1382	per therm	$14,690,663	$0.1799	per therm	$19,123,374	
ADMINISTRATIVE CHARGE	Therms	106,300,022	$0.0144	per therm	$1,530,720	$0.0144	per therm	$1,530,720	
Act 141 Fixed Charge	Fixed				$38			$38	
Act 141 Credit	Therms	63,091	($0.0094)	per therm	($593)	($0.0094)	per therm	($593)	
TOTAL MARGIN		106,300,022			$55,370,050			$ 59,802,761	
GAS COST [1]					$40,714,502			$40,606,862	
TOTAL REVENUES					$96,084,552			$ 100,409,623	4.50%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	
SMALL COMMERCIAL AND INDUSTRIAL DISTRIBUTION GSD-1									
CUSTOMER CHARGE									
Firm Sales (FS-1)	Bills	190,615	$0.8000	per bill per day	$4,638,298	$0.8000	per bill per day	$4,638,298	
Interruptible Sales (IS-1)	Bills	24	$0.8000	per bill per day	$584	$0.8000	per bill per day	$584	
Daily Balancing Service (DBS-1)	Bills	51	$0.8000	per bill per day	$1,241	$0.8000	per bill per day	$1,241	
Interdepartmental with Firm Sales (FS-1)	Bills	300	$0.8000	per bill per day	$7,300	$0.8000	per bill per day	$7,300	
	Days	365	$24.33	per bill per month		$24.33	per bill per month		
DAILY ADMINISTRATIVE FEES									
DBS-1 Administrative Charge	Bills	51	$4.30	per bill per day	$6,670	$4.30	per bill per day	$6,670	
DBS-1 Telemetering Charge	Bills	51	$1.50	per bill per day	$2,327	$1.50	per bill per day	$2,327	
DISTRIBUTION SERVICE CHARGE									
Firm Sales (FS-1)	Therms	55,456,703	$0.1563	per therm	$8,667,883	$0.1766	per therm	$9,793,654	
Interruptible Sales (IS-1)	Therms	16,655	$0.1563	per therm	$2,603	$0.1766	per therm	$2,941	
Daily Balancing Service (DBS-1)	Therms	82,437	$0.1563	per therm	$12,885	$0.1766	per therm	$14,558	
Interdepartmental with Firm Sales (FS-1)	Therms	104,294	$0.1563	per therm	$16,301	$0.1766	per therm	$18,418	
Company Use	Therms	243,437							
ADMINISTRATIVE CHARGE									
Firm Sales (FS-1)	Therms	55,456,703	$0.0144	per therm	$798,577	$0.0144	per therm	$798,577	
Interruptible Sales (IS-1)	Therms	16,655	$0.0144	per therm	$240	$0.0144	per therm	$240	
Daily Balancing Service (DBS-1)	Therms	82,437	$0.0000	per therm	$0	$0.0000	per therm	$0	
Interdepartmental with Firm Sales (FS-1)	Therms	104,294	$0.0144	per therm	$1,502	$0.0144	per therm	$1,502	
Revenues - Firm Sales (FS-1)					$14,104,758			$15,230,529	
Revenues - Interruptible Sales (IS-1)					$3,427			$3,765	
Revenues - Daily Balancing Service (DBS-1)					$23,123			$24,796	
Revenues - Interdepartmental Firm Sales (FS-1)					$25,103			$27,220	
Act 141 Fixed Charge					$1,513			$1,513	
Act 141 Credit	Therms	3,549,271	($0.0141)	per therm	($50,045)	($0.0141)	per therm	($50,045)	
TOTAL MARGIN		55,660,089			$14,107,879			$15,237,778	
GAS COST [1]					$21,497,828			$21,168,400	
TOTAL REVENUES					$35,605,707			$36,406,178	2.25%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	
MEDIUM COMMERCIAL AND INDUSTRIAL DISTRIBUTION GSD-2							
CUSTOMER CHARGE							
Firm Sales (FS-1)	Bills	7,918	$3.7196 per bill per day	$895,825	$3.7196 per bill per day	$895,825	
Interruptible Sales (IS-1)	Bills	84	$3.7196 per bill per day	$9,504	$3.7196 per bill per day	$9,504	
Interruptible Sales and Firm Sales Nomination - Firm	Bills	-	$3.7196 per bill per day	$0	$3.7196 per bill per day	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Bills	87	$3.7196 per bill per day	$9,843	$3.7196 per bill per day	$9,843	
Daily Balancing Service (DBS-1)	Bills	1,308	$3.7196 per bill per day	$147,984	$3.7196 per bill per day	$147,984	
Interdepartmental with Firm Sales (FS-1)	Bills	24	$3.7196 per bill per day	$2,715	$3.7196 per bill per day	$2,715	
	Days	365	$113.14 per bill per month		$113.14 per bill per month		
DAILY ADMINISTRATIVE FEES							
DBS-1 Administrative Charge	Bills	1,308	$4.30 per bill per day	$171,076	$4.30 per bill per day	$171,076	
DBS-1 Telemetering Charge	Bills	1,308	$1.50 per bill per day	$59,678	$1.50 per bill per day	$59,678	
Is-1 Interruptible Sales Telemetering Charge	Bills	48	$1.50 per bill per day	$2,190	$1.50 per bill per day	$2,190	
Is-1 Interruptible Sales and Firm Sales Nomination - Interruptible Telemetering Charge	Bills	75	$1.50 per bill per day	$3,422	$1.50 per bill per day	$3,422	
DISTRIBUTION SERVICE CHARGE							
Firm Sales (FS-1)	Therms	30,028,073	$0.1192 per therm	$3,579,346	$0.1320 per therm	$3,963,706	
Interruptible Sales (IS-1)	Therms	563,668	$0.1192 per therm	$67,189	$0.1320 per therm	$74,404	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	172,463	$0.1192 per therm	$20,558	$0.1320 per therm	$22,765	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	370,376	$0.1192 per therm	$44,149	$0.1320 per therm	$48,890	
Daily Balancing Service (DBS-1)	Therms	8,355,678	$0.1192 per therm	$995,997	$0.1320 per therm	$1,102,949	
Interdepartmental with Firm Sales (FS-1)	Therms	66,157	$0.1192 per therm	$7,886	$0.1320 per therm	$8,733	
ADMINISTRATIVE CHARGE							
Firm Sales (FS-1)	Therms	30,028,073	$0.0119 per therm	$357,334	$0.0119 per therm	$357,334	
Interruptible Sales (IS-1)	Therms	563,668	$0.0119 per therm	$6,708	$0.0119 per therm	$6,708	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	172,463	$0.0119 per therm	$2,052	$0.0119 per therm	$2,052	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	370,376	$0.0119 per therm	$4,407	$0.0119 per therm	$4,407	
Daily Balancing Service (DBS-1)	Therms	8,355,678	$0.0000 per therm	$0	$0.0000 per therm	$0	
Interdepartmental with Firm Sales (FS-1)	Therms	66,157	$0.0119 per therm	$787	$0.0119 per therm	$787	
Revenues - Firm Sales (FS-1)				$4,832,505		$5,216,865	
Revenues - Interruptible Sales (IS-1)				$85,591		$92,806	
Revenues - Interruptibles Sales and Firm Sales Nomination - Firm				$22,610		$24,817	
Revenues - Interruptible Sales and Firm Sales Nomination - Interruptible				$61,821		$66,562	
Revenues - Daily Balancing Service (DBS-1)				$1,374,735		$1,481,687	
Revenues - Interdepartmental Firm Sales (FS-1)				$11,388		$12,235	
Act 141 Fixed Charge				$2,065		$2,065	
Act 141 Credit	Therms	7,918,362	($0.0141) per therm	($111,649)	($0.0141) per therm	($111,649)	
TOTAL MARGIN		39,556,415		$6,279,066		$6,785,388	
GAS COST [1]				$10,410,026		$11,739,603	
TOTAL REVENUES				$16,689,092		$18,524,990	11.00%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	
LARGE COMMERCIAL AND INDUSTRIAL DISTRIBUTION GSD-3							
CUSTOMER CHARGE							
Firm Sales (FS-1)	Bills	204	$26.5000 per bill per day	$164,433	$26.5000 per bill per day	$164,433	
Interruptible Sales (IS-1)	Bills	48	$26.5000 per bill per day	$38,690	$26.5000 per bill per day	$38,690	
Interruptible Sales and Firm Sales Nomination - Firm	Bills	-	$26.5000 per bill per day	$0	$26.5000 per bill per day	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Bills	12	$26.5000 per bill per day	$9,673	$26.5000 per bill per day	$9,673	
Daily Balancing Service (DBS-1)	Bills	532	$26.5000 per bill per day	$428,814	$26.5000 per bill per day	$428,814	
	Days	365	$806.04 per bill per month		per bill per month		
DAILY ADMINISTRATIVE FEES							
DBS-1 Administrative Charge	Bills	532	$4.30 per bill per day	$69,581	$4.30 per bill per day	$69,581	
DBS-1 Telemetering Charge	Bills	532	$1.50 per bill per day	$24,273	$1.50 per bill per day	$24,273	
Is-1 Interruptible Sales Telemetering Charge	Bills	48	$1.50 per bill per day	$2,190	$1.50 per bill per day	$2,190	
Is-1 Interruptible Sales and Firm Sales Nomination - Interruptible Telemetering Charge	Bills	12	$1.50 per bill per day	$548	$1.50 per bill per day	$548	
DISTRIBUTION SERVICE CHARGE							
Firm Sales (FS-1)	Therms	4,473,219	$0.0789 per therm	$352,937	$0.0865 per therm	$386,933	
Interruptible Sales (IS-1)	Therms	1,672,808	$0.0789 per therm	$131,985	$0.0865 per therm	$144,698	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	213,525	$0.0789 per therm	$16,847	$0.0865 per therm	$18,470	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	545,078	$0.0789 per therm	$43,007	$0.0865 per therm	$47,149	
Daily Balancing Service (DBS-1)	Therms	28,416,097	$0.0789 per therm	$2,242,030	$0.0865 per therm	$2,457,992	
ADMINISTRATIVE CHARGE							
Firm Sales (FS-1)	Therms	4,473,219	$0.0094 per therm	$42,048	$0.0094 per therm	$42,048	
Interruptible Sales (IS-1)	Therms	1,672,808	$0.0094 per therm	$15,724	$0.0094 per therm	$15,724	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	213,525	$0.0094 per therm	$2,007	$0.0094 per therm	$2,007	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	545,078	$0.0094 per therm	$5,124	$0.0094 per therm	$5,124	
Daily Balancing Service (DBS-1)	Therms	28,416,097	$0.0000 per therm	$0	$0.0000 per therm	$0	
Revenues - Firm Sales (FS-1)				$559,418		$593,414	
Revenues - Interruptible Sales (IS-1)				$188,589		$201,302	
Revenues - Interruptible Sales and Firm Sales Nomination - Firm				$18,854		$20,477	
Revenues - Interruptible Sales and Firm Sales Nomination - Interruptible				$58,352		$62,494	
Revenues - Daily Balancing Service (DBS-1)				$2,764,698		$2,980,660	
Act 141 Fixed Charge				$1,120		$1,120	
Act 141 Credit	Therms	16,950,617	($0.0141) per therm	($239,004)	($0.0141) per therm	($239,004)	
TOTAL MARGIN		35,320,726		$3,352,027		$3,620,463	
GAS COST [1]				$2,330,147		$2,398,516	
TOTAL REVENUES				$5,682,174		$6,018,979	5.93%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	
LARGE COMMERCIAL AND INDUSTRIAL DEMAND-BASED DISTRIBUTION GSD-3D									
CUSTOMER CHARGE									
Firm Sales (FS-1)	Bills	-	$26.5000	per bill per day	$0	$26.5000	per bill per day	$0	
Interruptible Sales (IS-1)	Bills	-	$26.5000	per bill per day	$0	$26.5000	per bill per day	$0	
Interruptible Sales and Firm Sales Nomination - Firm	Bills	-	$26.5000	per bill per day	$0	$26.5000	per bill per day	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Bills	-	$26.5000	per bill per day	$0	$26.5000	per bill per day	$0	
Daily Balancing Service (DBS-1)	Bills	-	$26.5000	per bill per day	$0	$26.5000	per bill per day	$0	
	Days	-	$0.00	per bill per month			per bill per month		
DAILY ADMINISTRATIVE FEES									
DBS-1 Administrative Charge	Bills	-	$4.30	per bill per day	$0	$4.30	per bill per day	$0	
DBS-1 Telemetering Charge	Bills	-	$1.50	per bill per day	$0	$1.50	per bill per day	$0	
Is-1 Interruptible Sales Telemetering Charge	Bills	-	$1.50	per bill per day	$0	$1.50	per bill per day	$0	
Is-1 Interruptible Sales and Firm Sales Nomination - Interruptible Telemetering Charge	Bills	-	$1.50	per bill per day	$0	$1.50	per bill per day	$0	
DISTRIBUTION SERVICE CHARGE									
Firm Sales (FS-1)	Therms	-	$0.0385	per therm	$0	$0.0422	per therm	$0	
Interruptible Sales (IS-1)	Therms	-	$0.0385	per therm	$0	$0.0422	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	-	$0.0385	per therm	$0	$0.0422	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	-	$0.0385	per therm	$0	$0.0422	per therm	$0	
Daily Balancing Service (DBS-1)	Therms	-	$0.0385	per therm	$0	$0.0422	per therm	$0	
DEMAND-BASED BILLING DETERMINANT									
Firm Sales (FS-1)	Therms	-	$0.0148	per therm	$0	$0.0148	per therm	$0	
Interruptible Sales (IS-1)	Therms	-	$0.0148	per therm	$0	$0.0148	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	-	$0.0148	per therm	$0	$0.0148	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	-	$0.0148	per therm	$0	$0.0148	per therm	$0	
Daily Balancing Service (DBS-1)	Therms	-	$0.0148	per therm	$0	$0.0148	per therm	$0	
ADMINISTRATIVE CHARGE									
Firm Sales (FS-1)	Therms	-	$0.0094	per therm	$0	$0.0094	per therm	$0	
Interruptible Sales (IS-1)	Therms	-	$0.0094	per therm	$0	$0.0094	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Firm	Therms	-	$0.0094	per therm	$0	$0.0094	per therm	$0	
Interruptible Sales and Firm Sales Nomination - Interruptible	Therms	-	$0.0094	per therm	$0	$0.0094	per therm	$0	
Daily Balancing Service (DBS-1)	Therms	-	$0.0000	per therm	$0	$0.0000	per therm	$0	
Revenues - Firm Sales (FS-1)					$0			$0	
Revenues - Interruptible Sales (IS-1)					$0			$0	
Revenues - Interruptible Sales and Firm Sales Nomination - Firm					$0			$0	
Revenues - Interruptible Sales and Firm Sales Nomination - Interruptible					$0			$0	
Revenues - Daily Balancing Service (DBS-1)					$0			$0	
Act 141 Fixed Charge					$0			$0	
Act 141 Credit	Therms	-	($0.0141)	per therm	$0	($0.0141)	per therm	$0	
TOTAL MARGIN		-			$0			$0	
GAS COST					$0			$0	
TOTAL REVENUES					$0			$0	0.00%

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	
INTERRUPTIBLE GENERATION DISTRIBUTION SERVICE IGD-1							
CUSTOMER CHARGE							
Interruptible Generation with IS-2 Sales	Bills	72	$150.0000 per bill per day	$328,500	$150.0000 per bill per day	$328,500	
Interruptible Generation with Daily Balancing Service	Bills	24	$150.0000 per bill per day	$109,500	$150.0000 per bill per day	$109,500	
Interruptible Generation with LS-1 Sales	Bills	-	$150.0000 per bill per day	$0	$150.0000 per bill per day	$0	
	Days	365	$4,562.50 per bill per month		per bill per month		
DAILY ADMINISTRATIVE FEES							
IS-2 Interruptible Generation Administrative Charge	Bills	72	$50.00 per bill per day	$109,500	$50.00 per bill per day	$109,500	
IS-2 Interruptible Generation Telemetering Charge	Bills	72	$1.50 per bill per day	$3,285	$1.50 per bill per day	$3,285	
DBS-1 Administrative Charge	Bills	24	$4.30 per bill per day	$3,139	$4.30 per bill per day	$3,139	
DBS-1 Telemetering Charge	Bills	24	$1.50 per bill per day	$1,095	$1.50 per bill per day	$1,095	
LS-1 Interruptible Generation Administrative Charge	Bills	-	$80.00 per bill per day	$0	$80.00 per bill per day	$0	
LS-1 Interruptible Generation Telemetering Charge	Bills	-	$1.50 per bill per day	$0	$1.50 per bill per day	$0	
DISTRIBUTION SERVICE CHARGE							
Interruptible Generation with IS-2 Sales	Therms	813,595	$0.0338 per therm	$27,500	0.0377 per therm	$30,673	
Interruptible Generation with Daily Balancing Service	Therms	37,792,641	$0.0338 per therm	$1,277,391	0.0377 per therm	$1,424,783	
Interruptible Generation with LS-1 Sales	Therms	-	$0.0338 per therm	$0	0.0377 per therm	$0	
Revenues - Interruptible Generation with IS-2 Sales				$468,785		$471,958	
Revenues - Interruptible Generation with Daily Balancing Service				$1,391,125		$1,538,517	
Revenues - Interruptible Generation with LS-1 Sales				$0		$0	
Act 141 Fixed Charge				$9,269		$9,269	
TOTAL MARGIN		38,606,236		$1,869,179		$2,019,744	
GAS COST [1]				$234,053		$220,917	
TOTAL REVENUES				$2,103,232		$2,240,661	6.53%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES	PRESENT REVENUES	2021 PROPOSED RATES	2021 PROPOSED REVENUES	
STEAM AND POWER GENERATION GAS DISTRIBUTION SP-1							
CUSTOMER CHARGE	Bills	12	$2,500.00 per bill per day	$912,500	$2,500.00 per bill per day	$912,500	
	Days	365	$76,041.67 per bill per month		per bill per month		
DAILY ADMINISTRATIVE FEES							
Administrative Charge	Bills	12	$80.00 per bill per day	$29,200	$80.00 per bill per day	$29,200	
Telemetering Charge	Bills	12	$1.50 per bill per day	$548	$1.50 per bill per day	$548	
DISTRIBUTION SERVICE CHARGE							
Large Annual Use Gas Sales (LS-1)	Therms	21,257,397	$0.0369 per therm	$784,398	$0.0434 per therm	$922,571	
Act 141 Fixed Charge				$8,112		$8,112	
TOTAL MARGIN		21,257,397		$1,734,758		$1,872,931	
GAS COST [1]				$8,394,040		$6,276,892	
TOTAL REVENUES				$10,128,798		$8,149,823	-19.54%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

Type of Service	BILLING UNITS	NUMBER OF BILLING UNITS	PRESENT RATES		PRESENT REVENUES	2021 PROPOSED RATES		2021 PROPOSED REVENUES	
SEASONAL USE DISTRIBUTION SUDS-1									
CUSTOMER CHARGE									
Interruptible Sales (IS-1)	Bills	840	$1.50	per bill per day	$38,325	$1.50	per bill per day	$38,325	
Daily Balancing Service (DBS-1)	Bills	60	$1.50	per bill per day	$2,738	$1.50	per bill per day	$2,738	
	Days	365		per bill per month			per bill per month		
DAILY ADMINISTRATIVE FEES									
DBS-1 Administrative Charge	Bills	60	$4.30	per bill per day	$7,848	$4.30	per bill per day	$7,848	
DBS-1 Telemetering Charge	Bills	60	$1.50	per bill per day	$2,738	$1.50	per bill per day	$2,738	
IS-1 Interruptible Sales Administrative Charge	Bills	-	$50.00	per bill per day	$0	$50.00	per bill per day	$0	
IS-1 Interruptible Sales Telemetering Charge	Bills	-	$1.50	per bill per day	$0	$1.50	per bill per day	$0	
DISTRIBUTION SERVICE CHARGE									
IS-1 Interruptible Sales (first 2,000) therms	Therms	82,093	$0.1242	per therm	$10,196				
IS-1 Interruptible Sales (next 18,000) therms	Therms	336,614	$0.1140	per therm	$38,374				
IS-1 Interruptible Sales (all therms > 20,000 therms)	Therms	2,871,423	$0.1071	per therm	$307,529				
DBS-1 Daily Balancing (first 2,000) therms	Therms	29,364	$0.1242	per therm	$3,647				
DBS-1 Daily Balancing (next 18,000) therms	Therms	224,916	$0.1140	per therm	$25,640				
DBS-1 Daily Balancing (all therms > 20,000 therms)	Therms	297,560	$0.1071	per therm	$31,869				
Is-1 On-Peak	Therms	48,432	$0.5000	per therm	$24,216	$0.1000	per therm	$4,843	
DBS On-Peak	Therms	24,794	$0.5000	per therm	$12,397	$0.1000	per therm	$2,479	
IS-1 Interruptible Sales (first 5,000) therms	Therms	129,921				$0.1544	per therm	$20,060	
IS-1 Interruptible Sales (all therms > 5,000 therms)	Therms	3,160,209				$0.1394	per therm	$440,533	
DBS-1 Daily Balancing (first 5,000) therms	Therms	31,373				$0.1544	per therm	$4,844	
DBS-1 Daily Balancing (all therms > 5,000 therms)	Therms	520,467				$0.1394	per therm	$72,553	
ADMINISTRATIVE CHARGE									
Interruptible Sales (IS-1)	Therms	3,290,130	$0.0144	per therm	$47,378		per therm		
Daily Balancing Service (DBS-1)	Therms	551,840	$0.0000	per therm	$0		per therm		
Revenues - Interruptible Sales (IS-1)					$466,018			$503,761	
Revenues - Daily Balancing Service (DBS-1)					$86,877			$93,200	
Act 141 Fixed Charge					$67			$67	
Act 141 Credit	Therms	265,993	($0.0141)	per therm	($3,751)	($0.0141)	per therm	($3,751)	
TOTAL MARGIN		3,841,970			$549,211			$593,277	
GAS COST [1]					$784,064			$951,897	
TOTAL REVENUES					$1,333,275			$1,545,174	15.89%

[1] Gas Cost under Present Revenues reflects the authorized Cost of Gas from the Commission Final Decision in 3270-UR-122 for Test Year 2020.

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS COST OF GAS REVENUES AND BASE RATES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

All Territories

	FS-1	IS-1	IS-2 , LS-1	DBS-1	Total
Annual D-1	$ 11,730,492	$ -	$ -	$ -	$ 11,730,492
Seasonal D-1	$ 7,340,155	$ -	$ -	$ -	$ 7,340,155
Balancing Costs	$ 2,042,678	$ 67,033	$ -	$ -	$ 2,109,711
Interruptible Market Reservation - IMR	$ -	$ 82,833	$ -	$ -	$ 82,833
75% IMR			$ 70,932		$ 70,932
LS-1 Reservation Costs	$ -	$ -	$ 430,700	$ -	$ 430,700
Commodity Cost of Gas	$ 53,883,324	$ 1,718,762	$ 5,996,177	$ -	$ 61,598,264
Total by Supply/Balancing Option	$ 74,996,649	$ 1,868,628	$ 6,497,809	$ -	$ 83,363,086
Relevant Volumes	197,057,893	6,458,714	22,070,992	75,198,694	300,786,293
Total for Sales Classes:	$ 83,363,086				

Base Rates - Cost of Gas	Annual D-1	Seasonal D-1	Balancing	LS-1 Reservation	Commodity
	$0.0596	$0.0513	$0.0104	$0.0236	$0.2734

MADISON GAS AND ELECTRIC COMPANY
DOCKET 3270-UR-123
NATURAL GAS BILLING STATISTICS AND REVENUES
FOR THE YEAR JANUARY 1 - DECEMBER 31, 2021

	Rate Class	Volumes Therms	2021 Proposed COG Revenues	Present Margin Revenues	TOTAL Revenues	2021 Proposed COG Revenues	2021 Proposed Margin Revenues	2021 Proposed TOTAL Revenues	Proposed Dollar Adjustment	[1] Proposed Percentage Adjustment
RD-1	Residential Distribution - Firm Sales	106,300,022		$55,370,605			$59,770,871		$4,400,266	7.95%
	TOTAL RESIDENTIAL DISTRIBUTION REVENUE	**106,300,022**	**$40,606,862**	**$55,370,050**	**$95,976,912**	**$40,606,862**	**$59,770,871**	**$100,377,733**	**$4,400,821**	**4.59%**
GSD-1	Firm Sales (FS-1)	55,456,703		$14,104,758			$15,230,529		$1,125,771	7.98%
GSD-1	Interruptible Sales (IS-1)	16,655		$3,427			$3,765		$338	9.86%
GSD-1	Daily Balancing Service (DBS-1)	82,437		$23,123			$24,796		$1,673	7.24%
GSD-1	Interdepartmental with Firm Sales (FS-1)	104,294		$25,103			$27,220		$2,117	8.43%
	Act 141 - Fixed Amount			$1,513			$1,513			
	Act 141 - Credit Amount			-$50,045			-$50,045			
	TOTAL SMALL COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**55,660,089**	**$21,168,400**	**$14,107,879**	**$35,276,279**	**$21,168,400**	**$15,237,778**	**$36,406,178**	**$1,129,899**	**3.20%**
GSD-2	Firm Sales (FS-1)	30,028,073		$4,832,505			$5,216,865		$384,360	7.95%
GSD-2	Interruptible Sales (IS-1)	563,668		$85,591			$92,806		$7,215	8.43%
GSD-2	Interruptible Sales and Firm Sales Nomination - Firm	172,463		$22,610			$24,817		$2,207	9.76%
GSD-2	Interruptible Sales and Firm Sales Nomination - Interruptible	370,376		$61,821			$66,562		$4,741	7.67%
GSD-2	Daily Balancing Service (DBS-1)	8,355,678		$1,374,735			$1,481,687		$106,952	7.78%
GSD-2	Interdepartmental with Firm Sales (FS-1)	66,157		$11,388			$12,235		$847	7.44%
	Act 141 - Fixed Amount			$2,065			$2,065			
	Act 141 - Credit Amount			-$111,649			-$111,649			
	TOTAL MEDIUM COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**39,556,415**	**$11,739,603**	**$6,279,066**	**$18,018,668**	**$11,739,603**	**$6,785,388**	**$18,524,990**	**$506,322**	**2.81%**
GSD-3	Firm Sales (FS-1)	4,473,219		$559,418			$593,414		$33,996	6.08%
GSD-3	Interruptible Sales (IS-1)	1,672,808		$188,589			$201,302		$12,713	6.74%
GSD-3	Interruptible Sales and Firm Sales Nomination - Firm	213,525		$18,854			$20,477		$1,623	8.61%
GSD-3	Interruptible Sales and Firm Sales Nomination - Interruptible	545,078		$58,352			$62,494		$4,142	7.10%
GSD-3	Daily Balancing Service (DBS-1)	28,416,097		$2,764,698			$2,980,660		$215,962	7.81%
	Act 141 - Fixed Amount			$1,120			$1,120			
	Act 141 - Credit Amount			-$239,004			-$239,004			
	TOTAL LARGE COMMERICAL & INDUSTRIAL DISTRIBUTION REVENUE	**35,320,726**	**$2,398,516**	**$3,352,027**	**$5,750,543**	**$2,398,516**	**$3,620,463**	**$6,018,979**	**$268,436**	**4.67%**
GSD-3D	Firm Sales (FS-1)	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales (IS-1)	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales and Firm Sales Nomination - Firm	-		$0			$0		$0	0.00%
GSD-3D	Interruptible Sales and Firm Sales Nomination - Interruptible	-		$0			$0		$0	0.00%
GSD-3D	Daily Balancing Service (DBS-1)	-		$0			$0		$0	0.00%
	Act 141 - Fixed Amount			$0			$0			
	Act 141 - Credit Amount			$0			$0			
	TOTAL LARGE COMMERICAL & INDUSTRIAL DEMAND DISTRIBUTION REVENUE	**-**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**0.00%**
IGD-1	Interruptible Generation with IS-2 Sales	813,595		$468,785			$471,958		$3,173	0.68%
IGD-1	Interruptible Generation with Daily Balancing Service	37,792,641		$1,391,125			$1,538,517		$147,392	10.60%
IGD-1	Interruptible Generation with LS-1 Sales	-		$0			$0		$0	0.00%
	Act 141 Charge			$9,269			$9,269			
	TOTAL INTERRUPTIBLE GENERATION DISTRIBUTION REVENUE	**38,606,236**	**$220,917**	**$1,869,179**	**$2,090,096**	**$220,917**	**$2,019,744**	**$2,240,661**	**$150,565**	**7.20%**
SP-1	Large Annual Use Gas Sales (LS-1)	21,257,397		$1,726,646			$1,864,819		$138,173	8.00%
	Act 141 Charge			$8,112			$8,112			
	TOTAL STEAM AND POWER GENERATION GAS DISTIBUTION REVENUE	**21,257,397**	**$6,276,892**	**$1,734,758**	**$8,011,650**	**$6,276,892**	**$1,872,931**	**$8,149,823**	**$138,173**	**1.72%**
SUDS-1	Interruptible Sales (IS-1)	82,093		$466,018			$508,696		$42,678	9.16%
SUDS-1	Daily Balancing Service (DBS-1)	29,364		$86,877			$86,081		-$796	-0.92%
	Act 141 - Fixed Amount			$67			$67			
	Act 141 - Credit Amount			-$3,751			-$3,751			
	TOTAL SEASONAL USE DISTRIBUTION REVENUES	**3,841,970**	**$951,897**	**$549,211**	**$1,501,108**	**$951,897**	**$591,093**	**$1,542,990**	**$41,882**	**2.79%**
	Company Use	243,437								
TOTAL VOLUMES AND REVENUES		**300,786,293**	**$83,363,086**	**$83,262,170**	**$166,625,256**	**$83,363,086**	**$89,898,268**	**$173,261,354**	**$6,636,098**	**3.98%**

[1] The proposed percentage adjustment for individual rate class categories does not include Act 141 fixed or credit amounts. The percentage adjustment also excludes cost of gas revenues.
The total class level revenues does include Act 141 fixed and credit amounts and cost of gas revenues.

Madison Gas and Electric Company
Present and 2021 Authorized Natural Gas Rates

Rate Schedule	Present Rates	Authorized Rates	Units	Present Monthly Equivalent	Authorized Monthly Equivalent
Residential Distribution Service RD-1					
System Connection and Customer Service Charge	$ 0.7195	$ 0.7195	per day	$ 21.88	$ 21.88
Distribution Service	$ 0.1382	$ 0.1796	per therm		
Small Commercial Distribution Service GSD-1					
System Connection and Customer Service Charge	$ 0.8000	$ 0.8000	per day	$ 24.33	$ 24.33
Distribution Service	$ 0.1563	$ 0.0177	per therm		
Medium Commercial Distribution Service GSD-2					
System Connection and Customer Service Charge	$ 3.7196	$ 3.7196	per day	$ 113.14	$ 113.14
Distribution Service	$ 0.1192	$ 0.1320	per therm		
Large Commercial Distribution Service GSD-3					
System Connection and Customer Service Charge	$ 26.50	$ 26.50	per day	$ 806.04	$ 806.04
Distribution Service	$ 0.0789	$ 0.0865	per therm		
Interruptible Generation Distribution Service IGD-1					
System Connection and Customer Service Charge	$ 150.00	$ 150.00	per day	$ 4,562.50	$ 4,562.50
Distribution Service	$ 0.0338	$ 0.0377	per therm		
Steam Power Generation Gas Distribution Service SP-1					
System Connection and Customer Service Charge	$ 2,500.00	$ 2,500.00	per day	$ 76,041.67	$ 76,041.67
Distribution Service	$ 0.0369	$ 0.0434	per therm		
Seasonal Off-Peak Distribution Service (SUDS-1)					
System Connection and Customer Service Charge	$ 1.50	$ 1.50	per day	$ 45.63	$ 45.63
Distribution Service Rates per Cycle Bill					
Distribution Service (first 2,000 therms)	$ 0.1242	N/A	per therm		
Distribution Service (next 18,0000 therms)	$ 0.1140	N/A	per therm		
Distribution Service (all therms > 20,000 therms)	$ 0.1071	N/A	per therm		
Distribution Service (first 5,000 therms)	N/A	$ 0.1415	per therm		
Distribution Service (all therms > 5,000 therms)	N/A	$ 0.1265	per therm		
On-Peak Distribution	$ 0.5000	$ 0.1000	per therm		
Large Commercial and Industrial Distribution with Demand (GSD-3D)					
System Connection and Customer Service Charge	$ 26.50	$ 26.50	per day	$ 806.04	$ 806.04
Distribution Service	$ 0.0385	$ 0.0422	per therm		
Demand Charge	$ 0.0148	$ 0.0148	per therm per day		
Firm Gas Sales (FS-1)					
Therm Administrative Charge					
RD-1, GSD-1	$ 0.0144	$ 0.0144	per therm		
GSD-2	$ 0.0119	$ 0.0119	per therm		
GSD-3	$ 0.0094	$ 0.0094	per therm		
Interruptible Gas Sales Service (IS-1)					
Therm Administrative Charge					
GSD-1	$ 0.0144	$ 0.0144	per therm		
GSD-2	$ 0.0119	$ 0.0119	per therm		
GSD-3	$ 0.0094	$ 0.0094	per therm		
Telemetering Charge					
GSD-1	$ 1.50	$ 1.50	per day	$ 45.63	$ 45.63
GSD-2	$ 1.50	$ 1.50	per day	$ 45.63	$ 45.63
GSD-3	$ 1.50	$ 1.50	per day	$ 45.63	$ 45.63

Interruptible Large Boiler Sales Service (IS-2)								
Daily Administrative Charge	$	50.00	$	50.00	per day	$	1,520.83	$	1,520.83
Telemetering Charge	$	1.50	$	1.50	per day	$	45.63	$	45.63
Large Annual Use Gas Sales Service (LS-1)									
Daily Administrative Charge	$	80.00	$	80.00	per day	$	2,433.33	$	2,433.33
Telemetering Charge	$	1.50	$	1.50	per day	$	45.63	$	45.63
Daily Balancing Service (DBS-1)									
Daily Administrative Charge	$	4.30	$	4.30	per day	$	130.79	$	130.79
Telemetering Charge	$	1.50	$	1.50	per day	$	45.63	$	45.63
Backup Sales Service (BU-1)									
Administrative Charge									
GSD-1	$	0.0144	$	0.0144	per therm				
GSD-2	$	0.0119	$	0.0119	per therm				
GSD-3	$	0.0094	$	0.0094	per therm				
Base Average Cost of Gas									
Commodity Rate Charge (Commodity)	$	0.2879	$	0.2734	per therm				
Annual Demand Charge (D-1 Annual)	$	0.0583	$	0.0596	per therm				
Seasonal Demand Charge (D-1 Winter)	$	0.0526	$	0.0513	per therm				
Balancing Reservation Charge (Balancing)	$	0.0110	$	0.0104	per therm				
LS-1 Firm Reservation Charge	$	0.0233	$	0.0236	per therm of contracted demand per day				
Act 141 Distribution Rate*									
Residential	$	0.0094	$	0.0094	per therm				
Non-Residential	$	0.0141	$	0.0141	per therm				

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

Madison Gas and Electric Company

Comparison of Monthly Bills at Present and 2021 Authorized Rates

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

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Authorized Rates	Amount Change	Percent Change
0	$ 21.88	$ 21.88	$ -	0.00%
10	$ 26.98	$ 27.26	$ 0.28	1.02%
20	$ 32.08	$ 32.63	$ 0.55	1.72%
30	$ 37.18	$ 38.01	$ 0.83	2.23%
40	$ 42.28	$ 43.38	$ 1.10	2.61%
50	$ 47.37	$ 48.75	$ 1.38	2.91%
75	$ 60.12	$ 62.19	$ 2.07	3.44%
100	$ 72.86	$ 75.62	$ 2.76	3.79%
200	$ 123.84	$ 129.36	$ 5.52	4.46%
300	$ 174.82	$ 183.10	$ 8.28	4.74%
500	$ 276.78	$ 290.58	$ 13.80	4.99%

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

Monthly Therm Use	Monthly Bill Present Rates	Monthly Bill Authorized Rates	Amount Change	Percent Change
0	$ 21.88	$ 21.88	$ -	0.00%
10	$ 27.51	$ 27.77	$ 0.26	0.96%
20	$ 33.13	$ 33.66	$ 0.53	1.59%
30	$ 38.76	$ 39.55	$ 0.79	2.04%
40	$ 44.38	$ 45.43	$ 1.05	2.37%
50	$ 50.00	$ 51.32	$ 1.32	2.63%
75	$ 64.06	$ 66.04	$ 1.97	3.08%
100	$ 78.12	$ 80.75	$ 2.63	3.37%
200	$ 134.36	$ 139.62	$ 5.26	3.91%
300	$ 190.60	$ 198.49	$ 7.89	4.14%
500	$ 303.08	$ 316.23	$ 13.15	4.34%

Madison Gas and Electric Company
Monitored Fuel Ranges for 2021

Month	Fuel Costs	MWh	Fuel Cost / MWh	Cumulative Fuel Cost / MWh
January	$5,436,311	273,017	$ 19.91	$ 19.91
February	4,915,997	241,696	$ 20.34	$ 20.11
March	5,388,909	256,939	$ 20.97	$ 20.40
April	4,911,140	240,072	$ 20.46	$ 20.41
May	4,790,189	254,230	$ 18.84	$ 20.10
June	5,533,389	284,181	$ 19.47	$ 19.98
July	6,531,591	316,786	$ 20.62	$ 20.09
August	6,131,142	305,816	$ 20.05	$ 20.08
September	5,658,618	283,854	$ 19.93	$ 20.07
October	4,907,652	249,369	$ 19.68	$ 20.03
November	4,665,329	243,342	$ 19.17	$ 19.96
December	5,272,368	262,358	$ 20.10	$ 19.97
	$64,142,635	3,211,660	$ 19.97	

Madison Gas and Electric Company
Amortization Schedule
3270-UR-123

	PSCW Escrow Authorization	Notes	Amortization Period	Test Year 2021 Amortization Amount Electric	Gas	Estimated Balance at 12/31/2021 Deferral Balance (Gross of Tax) Electric	Gas
ERGS	3270-GF-110	1	2021	30,245,644	-	(1)	-
Transmission	Various	1	2021	35,784,442	-	1	-
Conservation Escrow (Focus on Energy)	Various	1	2021	4,836,719	1,974,257	(1)	-
Columbia Agreement	05-BS-214	1	2021	(2,315)	-	-	-
Columbia Percentage Ownership	3270-UR-121	1	2021	(433,367)	-	(1)	-
Combustion Turbine	Requesting		2021 - 2024	298,512	-	895,536	-
Forward Wind Farm	5-BS-226	1	2021	41,765	-	-	-
Pension and OPEB Costs	3270-AF-101 & Requesting		2021	5,777,847	(746,694)	3,652,128	6,341,531
Public Health Emergency - Credit Card Convenience Fees	5-AF-105 & Requesting	2	2021	245,000	255,000	-	-
Public Health Emergency - Bad Debt Expenses	5-AF-105 & Requesting	2	2021	1,175,650	375,000	-	-
Public Health Emergency - Late Payments	5-AF-105	2		-	-	-	-
Public Health Emergency - Other	5-AF-105	2		-	-	-	-
Excess Deferred Taxes - Estimated Protected (Tax Reform)	5-AF-101		2021	(4,874,291)	(436,839)	(75,057,563)	(28,438,803)
Excess Deferred Taxes - Estimated Unprotected (Tax Reform)	5-AF-101	3	2021	(18,195,254)	-	-	4,188,050
2019 Fuel Rules Deferral	3270-FR-2019		2021	(1,866,160)	-	-	-
Miscellaneous Liability	Various		2021	(464,055)	(53,387)	-	-
Totals				$ 52,570,136	$1,367,338	$ (70,509,901)	$ (17,909,222)

(1) MGE true-ups the prior year balance each rate case.
(2) 2020 amounts are currently accruing and not included in the 2021 ending balance.
(3) MGE is proposing to recover the gas unprotected excess deferred taxes in a future rate case.

Negative = Regulatory Liability
Positive = Regulatory Asset

Negative = Reduction of expense
Positive = Addition of expense