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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates — 3270-UR-120

FINAL DECISION

This is the Final Decision regarding the application of Madison Gas and Electric Company (MGE) for authority to change electric and natural gas rates on January 1, 2015.

Final overall rate changes authorized consisting of a $15,416,000 annual rate increase for electric utility operations (a 3.76 percent increase) and a $3,788,000 annual rate decrease for natural gas utility operations (a 1.98 percent decrease) for the test year ending December 31, 2015.

Introduction

On April 17, 2014, MGE filed an application with the Commission requesting authority to change its electric and natural gas rates effective January 1, 2015. MGE requested an $11,530,000 increase (2.82 percent increase) for electric operations and a $4,352,000 decrease (2.28 percent decrease) for natural gas operations. These rate changes are based on a 10.2 percent return on common equity.

On June 27, 2014, a prehearing conference was held at the Commission to determine the issues in this docket and to establish a schedule for the hearings. The technical and public hearing sessions were held October 9, 2014. The Commission received over 1,160 comments from members of the public as part of the Commission's public hearing process. Comments were received through the Commission's website, by written comments at the public hearing, or by personal testimony given at the public hearing. The Commission considered this matter at its open meeting on November 26, 2014.

The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission files.

MGE's Filing

MGE's original application proposed a two-year rate case with increases to customer fixed charges. According to MGE, its intent in proposing the changes was to move rate classes closer to their cost-based rates and to more accurately recover revenue from the appropriate billing components. For example, MGE proposed significantly increasing the portion of the rate that would be recovered in fixed charges from $10.44 per month for residential customers to a total of $21.83 per month in 2015 and $48.66 per month for residential customers in 2016.

After its initial application, MGE reached an agreement with Citizens Utility Board (CUB) that narrowed the issues in this docket.[1] Pursuant to that agreement, MGE agreed to reduce the combined monthly fixed electric charge for residential customers to $19.00 per month.[2] In exchange, CUB agreed to not contest MGE's proposed fixed charges for the residential and small commercial customers for the 2015 test year, provided MGE withdrew its rate design proposals for residential and small commercial customers for 2016 and further modified its proposals for 2015. In addition to the agreed-upon fixed charges for 2015, CUB, along with Clean Wisconsin (Clean WI), and MGE agreed to engage in a collaborative[3] to explore electric rate designs that are appropriate for a changing industry characterized by evolving technologies.

[1] The dissent offers a version of the pre-application history of MGE's filing on the electric fixed charges. (Concurrence and Dissent of Commissioner Eric Callisto in this docket, at 2-3.) None of that information is in the record and that version may not accurately reflect reality and some give-and-take between MGE and other interested stakeholders that lead to the initial filing, and the subsequent agreement reached between MGE and CUB.

[2] As part of the agreement, MGE also agreed to reduce the combined monthly fixed charge for small commercial Cg-5 customers to $23.93, $22.28 for small commercial Cg-3 single phase customers, and $30.49 for small commercial three phase customers.

[3] This collaborative described at the June 27, 2014, Prehearing Conference (PSC REF#: 210437, Transcript Vol. 1. Prehearing Conference, 7-8) is distinguished in this Final Decision from the "community-wide conversation"

MGE filed two sets of supplemental direct testimony in this proceeding. The second set, filed August 14, 2014, replaced the first set of supplemental direct testimony in its entirety.[4] In the second set of supplemental direct testimony, MGE changed its two-year rate case proposal to a one-year proposal and made additional changes to the rate design proposal consistent with its agreement with CUB described above. Additionally, MGE provided the Commission with several updates related to cost estimates for the 2015 test year.[5]

MGE's proposed revenue requirement and rate design changed significantly between its filing of the application and Commission staff's direct testimony in this proceeding.

Findings of Fact

1. MGE is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a).

2. Presently authorized rates for MGE's electric utility operations will produce total operating revenues of $415,265,000 for the test year ending December 31, 2015, which results in an adjusted net operating income of $36,608,000 and an annual revenue deficiency of $15,417,000. Presently authorized rates for MGE's natural gas utility operations will produce total operating revenues of $194,415,000 for the test year ending December 31, 2015, which results in an adjusted net operating income of $14,882,000 and an annual revenue excess of ($3,788,000).

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process described by MGE's president in an October 2, 2014, letter to MGE customers (PSC REF#: 222067, Ex.-MGE-Bollum-2).

[4] The first set of supplemental direct testimony was filed on July 18, 2014, informing the Commission of changes in the estimates of MGE's Pension and Other Post-Retirement Benefits obligations (OPRB) and its fuel costs.

[5] In addition to the updates on OPRB and fuel, MGE addressed the 2013 fuel refund to customers, System Support Resource (SSR) costs, and transmission escrow treatment.

3. For the Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $575,845,000 at current rates subject to the Commission's jurisdiction for the test year is 6.36 percent, which is inadequate.

4. For the Wisconsin retail natural gas utility, the estimated rate of return on average net investment rate base of $158,054,000 at current rates subject to the Commission's jurisdiction for the test year is 9.42 percent, which is excessive.

5. A reasonable increase in operating revenue for the test year to produce a 7.96 percent return on MGE's average net investment rate base for Wisconsin retail electric operations is $15,417,000.

6. A reasonable decrease in operating revenue for the test year to produce a 7.98 percent return on MGE's average net investment rate base for natural gas operations is $3,788,000.

7. MGE's filed operating income statements and net investment rate base for the test year, as adjusted for Commission decision, are reasonable.

8. It is reasonable to set a 2015 fuel plan year cost of monitored fuel of $123,014,928, or $35.79 per megawatt-hour (MWh), as shown in Appendix D.

9. It is reasonable to monitor all fuel costs using an annual bandwidth of plus or minus 2.0 percent.

10. It is reasonable to forecast the fuel cost plan year costs of spot coal, natural gas, and heating oil used for electric generation purposes by using the November 17, 2014, New York Mercantile Exchange (NYMEX) futures prices and PJM Northern Illinois Hub futures prices.

11. It is reasonable in 2015 to forecast a 40 percent blend of Powder River Basin (PRB) coal to bituminous coal at each Elm Road Generating Station (ERGS) unit, which is co-owned by MGE.

12. It is reasonable to forecast an additional one and one-half week inspection outage at each ERGs unit during 2015.

13. It is reasonable to reflect the effect of the updated budgets for the American Transmission Company LLC (ATC) Network Service Fees and Midcontinent Independent System Operator, Inc. (MISO) Schedules 26 and 26A charges.

14. It is reasonable that MGE's 2015 revenue requirement should not reflect any costs related to MISO's Presque Isle Power Plant (PIPP) System Support Resource (SSR) agreement. It is reasonable to allow MGE to use escrow accounting treatment for its 2015 MISO SSR costs and for all 2015 other electric transmission costs billed by MISO and ATC.

15. It is reasonable to increase the 2015 monitored fuel forecasts by $4.24 million to reflect the impact of the pending rail contract for delivery of coal to the Columbia Energy Center (Columbia), which is co-owned by MGE.

16. It is reasonable to accept and incorporate all the other Commission staff uncontested fuel adjustments, as adjusted by updates for the NYMEX futures settlement prices.

17. It is reasonable to continue to review the appropriateness of whether to include recovery in rates the costs associated with the Wisconsin Pollutant Discharge Elimination System (WPDES) settlement agreement on a case-by-case basis. It is further reasonable to include $333,200 in the electric revenue requirement for the test year reflecting MGE's annual contribution to the Fund for Lake Michigan (Fund).

18. It is reasonable to include MGE's updated estimate of Pension and Other Post-Retirement Benefit (OPRB) costs relating to the return on pension assets and discount rate assumptions in the electric and natural gas revenue requirements.

19. It is reasonable to reflect in MGE's revenue requirement the Commission staff adjustments and corrections not contested by any party.

20. A long-term range of 55.0 percent to 60.0 percent for MGE's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

21. An appropriate target level for MGE's test-year average common equity measured on a financial basis is 55.0 percent.

22. A reasonable estimate of debt equivalent of MGE's off-balance sheet obligations, imputed into the financial capital structure for the test year, is $69,482,000.

23. A reasonable financial capital structure for the test year consists of 54.99 percent common stock equity, 33.94 percent long-term debt, 2.75 percent short-term debt, and 8.32 percent debt equivalent of off-balance sheet obligations.

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

25. It is reasonable to base MGE's dividend restriction on the financial capital structure in this proceeding and to set the dividend restriction at $43,250,000.

26. It is reasonable to require MGE to submit a ten-year financial forecast in its next rate proceeding.

27. A reasonable utility capital structure for ratemaking for MGE for the test year consists of 58.96 percent common stock equity, 37.96 percent long-term debt, and 3.08 percent short-term debt.

28. A reasonable interest rate for MGE's short-term borrowing through commercial paper is 0.40 percent for the test year.

29. A reasonable embedded cost for long-term debt for MGE is 5.13 percent.

30. A reasonable rate of return on MGE's common equity is 10.2 percent.

31. A reasonable weighted average composite cost of capital is 7.97 percent.

32. It is reasonable to consider the full range of cost-of-service studies (COSS)[6] presented in the record when allocating test-year 2015 electric revenue responsibility.

33. It is not appropriate to specify particular costs as appropriate to consider when setting electric fixed charges. It is reasonable to consider a variety of factors in determining which utility costs should be treated as electric fixed costs, including Commission policies, fairness, and economic efficiency over the short and long term, when setting fixed charge rates for residential and small commercial customers.

34. It is reasonable to authorize monthly fixed electric charges of $19.00 for residential classes, $23.93 for the Cg-5 small commercial class, and $22.28 and $30.49 for single-phase and three-phase Cg-3 small commercial customers, respectively.

35. The overall electric rate design proposed by MGE, as adjusted for the final revenue requirement and the uncontested rate and tariff changes proposed in the testimony of MGE witness Steven James, are reasonable.

[6] Depending upon context, COSS may also be read in the singular to denote one cost-of-service study.

36. It is not reasonable at this time to authorize a new electric low-income rate option as proposed by MGE.

37. It is reasonable to direct MGE to work with Commission staff and other interested parties and stakeholders to further analyze electric low-income rate design options, including alternatives to MGE's current lifeline rate, for potential consideration in MGE's next rate case.

38. It is reasonable to require MGE to maintain the Rg-3 rate for low-income customers to the end of 2015 and to require MGE to work with Commission staff and other stakeholders to consider an alternative to this rate for potential consideration in MGE's next rate case.

39. It is reasonable to authorize the Rg-7, Cg-7, and Cg-8 tariffs proposed by MGE for customers who currently have electric generation facilities on their premises (also known as distributed generation (DG) customers) with the modification to allow qualifying customers to continue to take service under the revised rates until December 31, 2026.

40. The Green Power Tomorrow voluntary renewable rider rate of $0.0244 per kilowatt-hour (kWh) is reasonable.

41. It is reasonable to approve the experimental plug-in electric vehicle tariffs proposed by MGE.

42. It is reasonable to require that the final Sp-3 rate design use the revised demand billing statistics to reflect coincident demands from the University of Wisconsin-Madison's Charter Street facility and to incorporate the correct winter/summer split for energy components.

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

44. It is not necessary to provide formal guidance for MGE's proposed rate design collaborative.

45. It is not necessary to open a statewide investigation to consider utility rate design policy.

46. It is reasonable to rely on the results of multiple natural gas COSS along with other factors, such as bill impacts, as guides for revenue allocation and rate design.

47. It is reasonable to rely upon the natural gas rate design proposed by MGE when determining final rates for natural gas service, except as otherwise modified herein.

48. Presently authorized natural gas rates of MGE are unreasonable because they produce excess natural gas revenues. It is reasonable to authorize rates and rules for natural gas service for MGE as shown in Appendix C.

49. It is reasonable to terminate the RD-2 lifeline rate at year-end 2015 and to require MGE to assist RD-2 customers in taking advantage of the Department of Administration's (DOA) Weatherization Assistance Program.

50. It is not reasonable at this time to authorize a new natural gas low-income rate option as proposed by MGE.

51. It is reasonable to authorize a telemetering rate of a $1.40 per day.

52. It is reasonable to authorize a new seasonal service SD-2 tariff that would be beneficial to seasonal customers having significant seasonal usage of natural gas.

53. It is reasonable to grandfather, for a period not to exceed 10 years, MGE's existing seasonal service SD-1 customers.

54. It is reasonable to authorize Purchased Gas Adjustment (PGA) tariff revisions to provide for true-up period flexibility that will result in a more appropriate cost recovery.

55. It is reasonable to require MGE to conduct a feasibility study and develop an implementation plan in its next natural gas rate case for metered demand charges for its largest volume retail distribution customers.

56. It is reasonable to authorize a transportation administrative charge of $4.30 per day.

57. It is reasonable to lower the availability requirement for Steam and Power Gas Generation Distribution Service (SP-1).

58. It is reasonable to revise MGE’s Natural Gas Curtailment Plan to align the plan’s categories to the Natural Gas Sales Priority of Use Program and the IS-1 gas supply tariff.

59. The reasonable level of expensed conservation costs recoverable in rates for the 2015 test year is $5,188,817 for electric operations and $2,142,148 for natural gas operations. The level for electric utility operations consists of the conservation escrow budget of $4,671,702 and non-escrow conservation and energy efficiency funding for Customer Service Conservation activities of $517,115. The level for natural gas operations consists of the conservation escrow budget of $1,685,112 and non-escrow Customer Service Conservation activity funding of $457,036.

Conclusions of Law

The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.37, 196.374, 196.395, and 196.40, other provisions of Wis. Stat. ch. 196, and Wis. Admin. Code chs. PSC 113, 116, 134, and 185 to enter an order authorizing MGE to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel costs treatment set forth in Appendix D, subject to the conditions specified in this Final Decision. Such rates and rules for electric and natural gas utility service in Appendices B, C, and D are just, reasonable, and appropriate as a matter of law.

Opinion

Applicant 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 143,400 retail customers in Madison and the surrounding area in Dane County. MGE is also engaged in the purchase, transportation, distribution, and sale of natural gas to approximately 146,500 customers in Madison and the surrounding area of Dane County, and in parts of Columbia, Crawford, Iowa, Juneau, Monroe, and Vernon Counties. MGE is an operating subsidiary of MGE Energy, a holding company based in Madison, Wisconsin.

MGE is a co-owner, along with Wisconsin Electric Power Company (WEPCO) and WPPI Energy (WPPI) 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), the Columbia Power Plant located in Columbia County, Wisconsin (Columbia).

Revenue Requirement

The typical revenue requirement issues in a rate case were not substantially contested in this proceeding. In an informal agreement, or “working stipulation,” between MGE and CUB, the revenue requirement issues, which included a proposed reduction to the return on equity, were not contested in exchange for a one-year rate case and a major post-docket stakeholder technical collaborative on rate design questions involving integration of evolving energy technologies into the electric distribution network. Other parties that focused on rate design concerns did not contest this working stipulation. The working stipulation reasonably narrowed the issues to be addressed and aided in the efficient administration of this proceeding. Consequently, this Final Decision resolves without elaborate discussion a number of the issues in the Revenue Requirement section that are fundamentally uncontested, except the issues of the coal blending at ERGS units 1 and 2, rate treatment of the Wisconsin Pollutant Discharge Elimination System Settlement Agreement (WPDES Settlement),[7] and rate treatment of Pension and OPRB for MGE. The Commission reviewed the record and finds that the resolutions that rendered a revenue requirement issue uncontested are reasonable, supported on the record, consistent with past practice and decisions of the Commission, and contribute to the creation of just and reasonable rates as authorized by this Final Decision.

Income Statement

MGE, other parties, and Commission staff presented testimony and exhibits at the hearing concerning estimates of MGE's 2015 electric and natural gas utility operations. Significant issues pertaining to the income statements are addressed separately below.

Electric Fuel Costs

Pursuant to Wis. Admin. Code § PSC 116.03, each of the five major, investor-owned Wisconsin electric utilities must file a proposed fuel cost plan (monitored fuel costs) for the next

[7] The WPDES Settlement was entered into between WEPCO, MGE, WPPI, Clean WI, and Sierra Club in 2008 to resolve a dispute and litigation relating to ERGS.

calendar year. 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.

The Commission finds that monitored fuel costs of $123,014,928 is a reasonable estimate for MGE's 2015 fuel cost plan year. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 3,436,968 MWh results in an average net monitored fuel cost per MWh of $35.79. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

It is reasonable to monitor MGE's fuel costs using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

Powder River Basin (PRB) Coal Blending at ERGS

In 2011, WEPCO started planning to implement its ERGS Fuel Flexibility project with the goal of modifying the necessary equipment at the power plant to allow combustion of a blend of bituminous and PRB coals. ERGS was designed to burn bituminous coal. However, the delivered cost of that coal compared to PRB coal has changed significantly since ERGS was constructed so that having the flexibility to burn PRB coal will result in overall savings for ratepayers. Blending levels may reach 100 percent PRB coal depending on the economics of the cost of the modifications to ERGS and the resulting fuel cost savings.

WEPCO's and MGE's approved 2014 fuel cost plans reflected a 20 percent PRB coal blend rate at ERGS unit 2 and no PRB coal burned at ERGS unit 1. In January 2014, WEPCO fully converted ERGS unit 2 to a 40 percent PRB coal blend rate and started burning a 20 percent PRB coal blend rate at ERGS unit 1. In May 2014, WEPCO increased the PRB blend rate at ERGS unit 2 to 60 percent. During the summer of 2014, WEPCO continued to test both 40 and

60 percent PRB blend rates at ERGS unit 2, although the majority of that testing had been done at reduced loads due to operational issues, including low coal inventory levels.

WEPCO's filed fuel cost plan for 2015 reflected a 40 percent PRB coal blend rate at ERGS unit 2 and no PRB coal burned at ERGS unit 1. During Commission staff's audit in docket 5-UR-107, WEPCO proposed that a 40 percent PRB coal blend rate at ERGS unit 2 and a 20 percent PRB coal blend rate at ERGS unit1 were appropriate for 2015, based on its testing results experienced to-date. MGE's filing also reflected a PRB blend of 20 percent at unit 1 and 40 percent at unit 2. However, MGE agreed with Commission staff that the decision on coal blend at ERGS made in WEPCO's rate case in docket 5-UR-107 should also be used in MGE's case.

Commission staff was concerned that WEPCO had been conservative in its forecasting of attainable PRB coal blend rates at the ERGS units based on the experience of its fuel flexibility project during 2014. Commission staff proposed that a more aggressive 40 percent PRB coal blend rate be forecasted for both ERGS units during 2015.

In docket 5-UR-107, the Commission noted that WEPCO's approved 2014 fuel plan forecast has resulted in fuel cost over-collections during the year due to higher than forecasted PRB coal blend rates. The Commission finds that, consistent with its decision in docket 5-UR-107, it is reasonable that MGE's 2015 fuel plan reflect a 40 percent PRB blend rate for both ERGS units.

WEPCO testified that for any ERGS unit that has a PRB coal blend rate greater than 20 percent, a one- to two-week inspection outage should be scheduled. Commission staff agreed that it made sense for an inspection outage for an ERGS unit burning greater than 20 percent PRB coal and suggested that an additional one and one-half week inspection outage be used.

The Commission also finds that, consistent with its decision in docket 5-UR-107, it is reasonable to forecast that MGE's 2015 fuel plan should reflect an additional inspection outage at each ERGS unit of one and one-half weeks.

Transmission Costs

Update of ATC Network Service Fees and MISO Schedule 26/26A Charges

During the hearing, MGE provided updated estimates for ATC Network Service Fee costs and the costs of MISO's Schedules 26 for network transmission service and 26A for multi-value transmission projects. The update for ATC costs is based on its new budget made available on October 1, 2014. MGE proposed a reduction of $755,000 to Commission staff's forecast. Similarly, MISO has a new fall budget for its Schedule 26 charges, which MGE estimated would reduce Commission staff's forecast by an additional $878,000.

No party objected to the proposed adjustments to Commission staff's forecast of ATC Network Service Fee costs. The Commission finds it reasonable to reflect the effect of the updated budgets for ATC Network Service Fees and MISO Schedules 26 and 26A charges, as the change will result in rates better matched to recover the most accurate cost projections available.

MISO Schedule 43 Charges

On January 31, 2014, MISO filed with the Federal Energy Regulatory Commission (FERC) an SSR agreement with WEPCO with respect to WEPCO's continued operation of its PIPP for grid reliability purposes. The PIPP SSR agreement became effective February 1, 2014, and was set to expire on January 31, 2015. The PIPP SSR agreement had a fixed component, which reimbursed WEPCO for operations and maintenance (O&M) expenses, carrying costs of inventories, and ongoing capital expenditures incurred to keep PIPP operational. The MISO tariff, Schedule 43, allocated the SSR costs to all of the utilities in the ATC footprint based on each utility's load ratio share.

In a July 29, 2014, order, FERC examined the PIPP SSR agreement and found that the proposed allocation of SSR costs was unjust, unreasonable, and unduly discriminatory. FERC thereupon ordered MISO to allocate SSR costs based on MISO's final load-shed study.

Based on FERC's July 29 order, MGE is no longer responsible for any PIPP SSR costs. Parties before FERC have not contested the holding that removes allocation of SSR costs for PIPP according to the load shares of the utilities in the ATC footprint. Though aspects of the case are still pending, FERC's core holding benefits MGE by removing any SSR cost responsibility MGE may have for continued operation of PIPP. MGE proposed to reduce its 2015 revenue requirement by about $3.8 million to reflect the status of the PIPP SSR agreement. It is reasonable, based on the likelihood that FERC's core holding will not change, that MGE's 2015 revenue requirement not reflect any forecasted costs related to MISO's PIPP SSR agreement.

Since the FERC proceeding for the PIPP SSR agreement is far from complete, MGE as a precaution requested escrow accounting treatment for its 2015 SSR costs. In addition, MGE requested authorization to escrow all electric transmission costs from ATC and MISO during 2015 and 2016, based on the levels of such costs authorized for 2015. MGE withdrew its request for a two-year rate case and modified its request for escrow accounting treatment to cover both its 2015 SSR costs and its 2015 costs for ATC and MISO charges as described above.

Commission staff proposed that the Commission allow MGE to escrow all ATC and MISO transmission-related costs, as it believes that those costs are significant, highly volatile, and outside of MGE's control. As the variability of ATC and MISO transmission-related costs could change in the future, Commission staff proposed authorizing that escrow accounting treatment for 2015 only.

Based on the foregoing information and the lack of objection, the Commission finds it is reasonable to allow MGE to use escrow accounting treatment for its 2015 MISO SSR costs and for all other 2015 electric transmission costs from ATC and MISO.

Uncontested Fuel Adjustments

Pending Rail Contract for Columbia

The current rail transportation contract for Columbia expires on December 31, 2014. At the time of the preparation of Commission staff's forecasted 2015 monitored fuel costs, details of the terms for a new rail contract were not available.

At the hearing in this proceeding, the terms of a new rail contract had been approved by the joint owners of Columbia. Commission staff testified that its projected 2015 monitored fuel cost should be increased by $4,241,000 to reflect the estimated impact of the new rail contract. The Commission concludes that it is reasonable to reflect the impact of the pending rail contract for delivery of coal to Columbia because it will enable a rate that is better designed to recover a more accurate projection of test-year costs.

NYMEX Updates

The Commission finds that it is reasonable to increase monitored fuel costs by $1,740,000 to reflect the updated forecasts based on the NYMEX futures settlement prices for spot coal, natural gas, heating oil, and MISO's Northern Illinois Hub as of November 17, 2014. The Commission finds that this timely update enhances the rate design by providing a more accurate projection of costs intended to be recovered in rates designed for test-year 2015.

All Other Uncontested Fuel Adjustments

The Commission finds it reasonable, based on the reasons noted above, to accept and incorporate all other Commission staff's uncontested fuel adjustments, as adjusted by updates for the NYMEX futures settlement prices as of November 17, 2014.

WPDES Settlement

In 2008, MGE and the other co-owners of ERGS entered into a settlement agreement with Clean WI and Sierra Club wherein they agreed, subject to rate recovery, to help fund Lake Michigan improvement projects. MGE requested that the Commission authorize the recovery in rates of MGE's portion of the annual WPDES Settlement payments, totaling $333,200, because it believes the settlement was prudent and in the interest of its customers and, therefore, the cost to implement the settlement should be recovered in rates. Both Clean WI and Friends of the Fund supported MGE's position, stating the settlement saved ratepayers millions of dollars in costs that could have been incurred had the ERGS owners continued the litigation. Moreover, the projects funded by the settlement support the operation of ERGS and produce economic and environmental benefits for MGE's ratepayers.

This Commission continues to find that the 2008 WPDES Settlement was prudent and in the best interest of the ratepayers. However, that does not mean that recovery of all payments made as part of that agreement is a foregone conclusion. The express terms of the WPDES Settlement reserved for the Commission that determination on a case-by-case basis. The

Commission finds it reasonable to continue to review the appropriateness of whether to include rate recovery of the costs associated with the WPDES Settlement on a case-by-case basis.

In its decision in WEPCO's rate case, docket 5-UR-107, the Commission found it reasonable to include WEPCO's annual the payments to the Fund in the test-year revenue requirement. The Commission finds the same treatment is appropriate in this docket. The record in both 5-UR-107 and this proceeding demonstrate that there are sufficient economic and environmental benefits to MGE's ratepayers to justify rate recovery for this test year.

Update of Pension and Benefit Costs

The Commission has historically allowed updates near the time of its open meeting discussion of the record in the proceeding for Pension and OPRB expenses based on revised actuarial forecasts. Pension and OPRB expenses, while still volatile, are not as significant as they were historically. As companies have downsized their Pension and OPRB benefits, the size of the expense and amount of volatility have declined.

The actuarial assumptions provided by MGE's consultant Prudential, following generally accepted accounting principles (GAAP) and the year-end audit by PricewaterhouseCoopers, are related to management, recording, and auditing of the Pension and OPRB funds themselves. It does not address the validity or accuracy of using Prudential's updates of assumptions in a ten-year forecast to predict next year's pension expense. The Commission finds that, although there is not enough evidence in the record at this time to change past practice of using Pension and OPRB actuarial assumptions, there are questions about their continued use in the projection of test-year pension expenses. Because the issue and a potential change in Commission practice affects all utilities, Commission staff shall review their use and the appropriateness of these projections in estimating test-year pension expenses in the next round of rate cases for MGE and all other investor-owned utilities.

While fair questions have been raised in this proceeding about the continued use of updated estimates for Pension and OPRB expenses, the Commission concludes that it is reasonable to include in the electric and natural gas revenue requirement the updated estimate for Pension and OPRB costs relating to the return on pension assets and the discount rate assumption, as reflected in delayed exhibit Ex.-MGE-Johnson-4. This estimate was based on actuarial assumptions that were provided by Prudential, followed GAAP, and are subject to an end-of-year audit by PricewaterhouseCoopers.

Summary of Operating Income Statements at Present Rates

In addition to the specific items discussed above, the Commission finds all other uncontested Commission staff adjustments to the MGE's estimated income statements are reasonable and just. Accordingly, estimates of the test-year 2015 electric and natural gas operations income statements that are considered reasonable for purposes of determining the revenue requirements in this proceeding are as follows:

	Electric (000's)	Natural Gas (000's)
Operating Revenues:		
Sales	$ 410,363	$ 191,145
Sales for Resale	3,487	
Other Operating Revenues	1,415	3,270
Total Operating Revenues	$ 415,265	$ 194,415
Operating Expenses:		
Power Production Expense:		
Fuel and Purchase Power Expense	$148,185	
Other Production Expense	71,419	
Purchased Gas Expense		$121,680
Production		400
Transmission Expense	36,885	
Distribution Expense	15,307	9,163
Customer Accounts Expense	7,114	6,850
Customer Service & Sales Expense	8,207	4,501
Administrative and General Expenses	32,963	18,339
Total Operation and Maintenance Expenses	$ 320,080	$ 160,933
Depreciation & Amortization Expense	30,147	7,276
Taxes Other Than Income Taxes	16,261	3,633
State and Federal Income Taxes	1,904	4,638
Deferred Income Taxes - Net	10,364	3,118
Investment Tax Credit—Restored	(99)	(66)
Total Operating Expenses	$ 378,657	$ 179,533
Net Operating Income	$ 36,608	$ 14,882

Summary of Average Net Investment Rate Bases

The Commission finds that all uncontested Commission staff adjustments to MGE’s filed average net investment rate bases are appropriate.

For purposes of determining the revenue requirements in this proceeding, reasonable estimates of MGE’s test-year average net investment rate bases for its electric and natural gas operations are as follows:

	Electric (000's)	Natural Gas (000's)
Utility Plant in Service	$1,149,432	$377,166
Less: Accumulated Depreciation	431,996	188,266
Net Utility Plant	$717,436	$188,900
Add: Fuel Inventory	7,677	
Gas in Storage Inventory	---	11,436
LNG Fuel Inventory	---	---
Materials and Supplies	14,526	2,341
Less: Accumulated Deferred Income Taxes	162,805	43,827
Customer Advances for Construction	989	796
Average Net Investment Rate Base	$ 575,845	$ 158,054

Pro Forma Rate of Return

The net operating income for purposes of this proceeding for the test year ending December 31, 2015, results in a rate of return on the average net investment rate base of 6.36 percent for electric utility operations and 9.42 percent for natural gas utility operations.

Energy Efficiency

Customer Service Conservation

MGE's proposed 2015 natural gas and electric residential customer service conservation (CSC) activities provide energy efficiency education, information, and technical assistance to help both single family and multifamily residential customers in both new and existing homes control their energy use. MGE's non-residential CSC activities are intended to help its business customers decrease their energy consumption through increased participation in Focus on Energy. Services include on-site energy assessments, staffing of trade shows, and promotion of customer training. MGE also proposed "General" CSC activities aimed at both residential and non-residential customers. These activities include memberships in organizations, media advertising, and web service and other tools for providing energy efficiency information.

In its Order in docket 5-BU-102, dated July 12, 2012, the Commission provided guidance regarding appropriate CSC activities. The Commission defined CSC activities as "those activities and services that a utility provides to customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus on Energy and federal and state energy programs. Fifty-one percent (51%) of an activity or service must be dedicated to energy efficiency in order to meet the definition of CSC." The Commission finds that MGE's proposed 2015 CSC activities meet the Commission's definition.

Conservation Escrow Budget

MGE's proposed conservation escrow budget consists of its required natural gas and electric contributions for Focus on Energy, plus prior year true ups. The appropriate 2015 conservation escrow budget is $6,356,814, with $4,671,702 allocated to electric ($4,551,111 for 2015 contributions to Focus on Energy and a $120,591 prior year true up) and $1,685,112 allocated to natural gas ($2,030,704 for 2015 contributions minus a $345,592 prior year true-up).

Financial Capital Structure and Dividend Restriction

The long-term range for MGE's common equity ratio, on a financial basis, found reasonable in docket 3270-UR-117, was 55.0 to 60.0 percent common equity. The Commission has not made a change to the long-term range in this case. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing MGE at a given time.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the utility is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital.

Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent is necessary for the Commission to make an independent judgment regarding MGE's financial capital structure. This information is most readily available from MGE and shall be provided as part of its next rate case application. The information shall include, at a minimum, the following information:

1. The minimum annual lease and purchased power agreement (PPA) obligations;
2. The method of calculation, along with the calculated amount of the debt equivalent; and
3. Supporting documentation, including all reports, correspondence, and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent to the extent available, and publicly available documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, it is reasonable to impute $69,482,000 of debt equivalent associated with MGE's off-balance sheet obligations. Incorporating this estimate of off-balance sheet debt equivalents and other Commission determinations, MGE's financial capital structure for the test year consists of 54.99 percent common stock equity, 33.94 percent long-term debt, 2.75 percent short-term debt, and 8.32 percent debt equivalent of off-balance sheet obligations.

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 and natural gas dividend practices as long as MGE is below the estimated test-year common equity ratio.

Under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs in order for ratepayers to be protected. The identification of utility needs goes beyond foreseeable needs. MGE must have flexibility to finance both foreseen and unforeseen capital requirements.

In previous dockets, the Commission has 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. Commission policy has been to set the dividend limit to those included in the test-year forecast. In this docket, no dividends were forecasted. Consequently, MGE may not pay dividends, including pass-through of subsidiary dividends, if its actual average common equity ratio, on a financial basis, is or will fall below the test-year authorized level of 55.0 percent.

Ten-Year Financial Forecast

MGE's ten-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case proceeding, MGE and Commission staff deducted MGE's investment in the common equity of ATC (net of deferred income taxes associated with transmission assets transferred to ATC), along with other non-utility items, from its financial common equity to arrive at the common equity amount for its regulatory capital structure. The Commission agrees that these deductions remain appropriate for ratemaking.

A reasonable utility ratemaking capital structure for purposes of establishing just and reasonable rates for MGE's test year consists of 58.96 percent common stock equity, 37.96 percent long-term debt, and 3.08 percent short-term debt.

Short-Term Debt

MGE's test-year capital structure contains $23,011,000 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate. A reasonable estimate of the average cost of short-term commercial paper for the test year is 0.40 percent. This forecast is based on the average of test-year commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter. This is a reasonable and objective method of determining short-term debt costs.

Long-Term Debt

The embedded cost of long-term debt of 5.13 percent is reasonable for the test year.

Return on Equity

The working stipulation between parties in this proceeding used a 10.20 percent return on equity (ROE) as part of considerations exchanged by MGE and CUB to narrow the issues. The previously authorized return on equity was 10.30 percent.

In reaching its determination as to the appropriate ROE, the Commission must balance the needs of investors with the needs of consumers, with due consideration to economic and financial conditions along with public policy considerations. When making this decision, the Commission exercises its legislative function in setting policy based upon its balancing of these factors. The law recognizes the great degree of discretion exercised by the Commission in making such decisions and affords such decisions great weight deference. The use of this discretion is also necessary because the investors' required return cannot be measured with precision. Because that return cannot be measured precisely, determining the appropriate ROE is often a contested issue in rate case proceedings. Here, the parties agreed to a ROE.

Given the above-mentioned considerations, the Commission finds that the balance is struck most reasonably in this proceeding by accepting the settlement and authorizing an ROE of 10.2. While the dissenting opinion argues that a lower ROE is appropriate based upon the Commission's approval of increased fixed charges, there is not substantial evidence in the record in this cases upon which to make such a determination.[8] Further, absent a showing of a direct, identifiable reduction in an investor's required return based upon an increase in fixed charges, the Commission is also not persuaded that there are sound public policy reasons at this time for setting a lower ROE simply because the Commission has determined an increase in the amount of fixed charges is appropriate.

The Commission determines that a 10.20 percent ROE for MGE is reasonable.

[8] The dissent states as foregone conclusions that the Commission knows "that increasing fixed customer charges reduces a utility's financial risk" and that "there is a direct relationship between increasing fixed charges and financial risk reduction", and cites one statement by Commission staff witness Mr. Singletary. (Concurrence and Dissent of Commissioner Eric Callisto in this docket, at 2.) That is hardly the type of substantial evidence necessary to support the sweeping conclusory statements offered by the dissent.

Commissioner Callisto dissents and writes separately.

Using a 10.20 percent return on equity, the average utility capitalization ratios, annual cost rates, and composite cost of capital rate considered reasonable and just for setting rates for the test year, are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$440,395	58.96%	10.20%	6.01%
Long-Term Debt	$283,500	37.96%	5.13%	1.95%
Short-Term Debt	$23,011	3.08%	0.40%	0.01%
Total Utility Capital	$746,906	100.00%		7.97%

The weighted cost of capital rate of 7.97 percent is reasonable for MGE for the test year. It generates an economic cost of capital of 12.00 percent and a pre-tax interest coverage ratio of 6.12 times on the regulatory capital structure.

Rate of Return on Rate Base

The 7.97 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of MGE's average net investment rate base plus Construction Work in Progress (CWIP) for the test year is 100.46 percent of capital applicable primarily to utility operations plus deferred investment tax credit. The estimate reflects all appropriate Commission adjustments and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to average net investment rate base.

Accordingly, the Commission finds that the 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:

	Electric	Natural Gas
Weighted Cost of Capital	7.97%	7.97%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	100.46%	100.46%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	7.93%	7.93%
Average CWIP Balance (000's)	13,646	1,916
Less: CWIP Earning 100 % AFUDC	8,873	0
Remaining CWIP Earning a Current Return	4,773	1,916
Percentage of Remaining CWIP to Earn a Current Return	50%	50%
Average CWIP Earning a Current Return	2,387	958
Adj. to Adj. Wtd. Cost of Capital to Provide a Current Return on CWIP	0.03%	0.05%
Deferred Amts. That Earn a Return at the STD Rate ERGS	(941)	
MISO Schedule 43	(1,289)	
Environmental Compliance	(281)	
Total Amt. of Deferrals that Earn a STD Return	(2511)	
Adj. to Adj. Wtd. Cost of Capital to Provide a STD Return on Certain Deferred Amounts	0.00%	
Required Return on Net Investment Rate Base	7.96%	7.98%

Revenue Requirement

Based on the findings in this order, a $15,417,000 increase in electric utility revenues and a $3,788,000 decrease in natural gas utility revenues are reasonable for determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	6.36%	9.42%
Required Return on Average net Investment Rate Base	7.96%	7.98%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.60%	(1.43)%
Average Net Investment Rate Base (000's)	$575,845	$158,054
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$ 9,230	$ (2,267)
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$ 15,417	$ (3,788)

Electric COSS and Rates

Electric COSS

MGE, Airgas Merchant Gases (Airgas), the City of Madison, CUB, and Commission staff testified regarding COSS issues and the appropriate methods for allocating the plant and operating expenses that comprise MGE's revenue requirement. MGE prepared three COSS, including its preferred 12CP (coincident peak) "Standard" model. Additionally, MGE prepared a time-of-use (TOU) study and, at the request of a large customer, a 1CP variation of MGE's "Standard" model. Commission staff prepared a Locational COSS based on MGE's TOU study as well as "Capacity" versions of the utility filed studies. Commission staff also prepared a TOU study reflecting its preferred treatment of interruptible capacity. The City of Madison submitted the results of three cost of service studies reflecting modifications to MGE's "Standard" and

TOU studies. Finally, Airgas submitted the results of its preferred COSS reflecting the use of a 4CP production demand allocation method. CUB did not submit the results of its own COSS model. However, CUB testified that, based on its preferred allocation methods, it supported the use of results produced by Commission staff's "Capacity" variants of the "Standard," TOU, and Locational studies.

No consensus was reached by the parties over the course of this proceeding regarding COSS methodologies, with disagreements existing across virtually every cost category, but primarily around the allocation of production plant, production O&M, and distribution costs. As such, the record in this proceeding contains a vigorous and thorough vetting of the COSS methods presented, which are accompanied by extensive quantitative evidence illustrating the effect these different methods have on utility COSS results. This Commission's long standing practice is to consider the results of several COSS for the purposes of allocating test-year revenue responsibility. The evidence in this proceeding supports a continuation of this practice, as no one COSS is capable of reflecting every equitable balance of costs imposed and benefits received for every class of ratepayer. The Commission finds it reasonable to consider the results of all COSS in the record for the purposes of class revenue requirement allocation.

As will be discussed below, MGE requested that the Commission authorize an increase in the fixed charges that was contested by other parties. MGE, the City of Madison, CUB, the Environmental Law and Policy Center (ELPC), Natural Resources Defense Council (NRDC), RENEW Wisconsin (RENEW), and Commission staff all submitted testimony regarding fixed costs and what utility costs are appropriate to consider for the purposes of setting fixed charges.

MGE provided the results of a functionalized cost analysis that suggests that the embedded customer and "grid-connection" related cost for the residential customers to be approximately $21.55 per month, and approximately $25.06 per month for the small commercial classes. Commission staff provided the results of an alternative analysis that considered a narrower range of costs for inclusion in fixed charges. This analysis suggested a customer-related and grid-connection cost of $17.43 per month for residential customers, and $18.97 per month for the small commercial classes. The City of Madison argued that the method MGE used to determine its fixed costs was inappropriate, and that such charges should not be set purely based on COSS determinations, but also upon evaluation of other policy considerations. ELPC, NRDC, and RENEW, similarly suggested that the Commission primarily consider issues such as public policy, fairness, and economic efficiency over the short and long term in order to determine the level of just and reasonable fixed charge rates. Dane County did not submit testimony on this issue, but in its brief objected to MGE's request to create additional categories of costs to be considered for the purposes of setting fixed charge rates. Finally, CUB explained in the record why it was not contesting the overall fixed charge issues in this case. CUB noted that its decision not to contest those issues for the 2015 test year is reflective of the give-and-take between CUB and MGE, does not reflect CUB's position on the reasonableness of those rates, and should not be considered precedential in any proceeding.

While the Commission recognizes that the identification of specific utility costs as the basis for decisions on fixed charges would provide additional clarity in future rate case proceedings, the Commission finds that it is not necessary at this time to do so for electric rates.[9]

[9] In contrast, gas rate COSS have considered whether costs for such things such as meters are fixed in nature because gas rate design has proceeded historically from the concept that gas is a physically deliverable commodity

Identifying specific utility costs for inclusion in fixed rates would require this Commission to choose one COSS, which would be contrary to long standing Commission practice, and inconsistent with its decision regarding COSS as they relate to customer class revenue allocation. Absent substantial evidence supporting a change in Commission practice, this Commission finds it reasonable to instead consider the setting of fixed charges as a policy decision, and to consider state and Commission policies, fairness, and economic efficiency over the short- and long-term when setting fixed charge rates for residential and small commercial customers.

Electric Revenue Allocation

MGE proposed an electric revenue allocation for the 2015 test year that included: (1) increases for the residential and small commercial classes that are below average; (2) an increase for the Cp-1 class that is slightly above average; and (3) above average increases for the medium and large commercial and industrial (C&I), lighting, and miscellaneous classes, the University of Wisconsin-Madison (UW), and Oscar Mayer. Commission staff proposed an alternative electric revenue allocation for the 2015 test year that had a narrower range of increases and decreases. Commission staff's proposal included: (1) increases for the residential and small commercial classes that are slightly below average; and (2) above average increases for all business classes which consist of medium and large C&I, Cp-1, lighting, and miscellaneous classes, UW and Oscar Mayer. The City of Madison proposed an electric revenue allocation that included: (1) a below average increase for the residential class; (2) no increase for the small commercial classes; and (3) above average increases for all business service classes.

capable of being stored and transported via pipelines, mains, and laterals,. Electric service lacks comparable characteristics—it cannot be practically stored, for example. The generation of electricity and the distribution network of wires are more tightly integrated to produce the desired output, that is, to be constantly available as a system to instantaneously provide service upon flicking a switch.

CUB proposed a partial electric revenue allocation for the 2015 test year that included no increase for the residential and small commercial/industrial classes, and above average increases for the lighting, miscellaneous, and all business service classes. Airgas did not propose a full electric revenue allocation but instead proposed that the Cp-1 receive an increase of less than 1 percent.

Consistent with the past practice and the above determination regarding embedded cost of service, the Commission finds that it is useful to take into account the results of a number of different COSS in addition to other factors such as rate stability and bill impacts when making a determination on class revenue allocation in this case. The Commission finds that the electric revenue allocations for 2015 shown in Appendix B are reasonable. The Commission finds that this allocation reflects the cost causation principles argued by MGE and is reasonable considering all of the other factors enumerated in this decision. The Commission finds that this allocation facilitates a gradual approach to rate design shifts, results in relative fairness among customer classes, balances short- and long-term economic efficiency, and has no undesirable effects on economic development. These considerations also guided the Commission in the establishment of the actual rates and charges, as determined in the next section, and are intended to recover the allocated class costs.

Chairperson Montgomery dissents and would have preferred increasing revenues from the Cp-1 class by no more than 1.1 percent which, when compared with the majority's allocation, would have had only a very minor effect on all other customers.

Electric Rate Design

MGE proposed an overall electric rate design that includes increases in fixed charges and decreases in energy charges for the residential and small commercial customers. For the medium and large C&I classes, MGE's proposal included relatively larger increases in demand charges, and lesser increases in energy charges. The Commission staff proposed electric rates that increase the energy charge revenue more than did MGE, relative to the increases in demand charge revenue. The City of Madison proposed an electric rate design intended to mitigate the impact on customer classes with large increases and decreases. Airgas indicated that it supports rate design proposals that recover capacity related costs, particularly capacity that is used infrequently, in the form of a fixed charge.

The Commission finds that the overall electric rate design proposed by MGE is reasonable, in general, except for certain specific details as noted herein. The authorized rates appear in Appendix B.

Commissioner Callisto dissents and would have followed Commission staff's recommendations.

Electric Fixed Charges

MGE's electric rate design proposal included increasing the fixed charge from $10.44 per month to $19 per month for residential customers,[10] and decreasing the variable energy rates for those customers. MGE proposed collecting two different types of electric fixed charges. For residential customers, MGE proposed a customer charge of $14.97 and a grid connection service charge equivalent to $4.03 per month. According to MGE, its intent with these changes is to

[10] As noted previously, *infra* at fn. 2, MGE also proposed increasing the fixed monthly charge for the small commercial, Cg-3 and Cg-5, classes.

send more accurate price signals, reduce subsidies, and to more fairly set rates by better aligning customer charges with the costs customers cause. Commission staff proposed an electric rate design that limited the increase in total fixed charges for residential and small commercial customers to 20 percent. Commission staff's proposed fixed charge increases are inclusive of MGE's proposed grid connection charge. The City of Madison, City of Middleton, Dane County, NRDC, Wind on the Wires, ELPC, and RENEW opposed MGE's proposed increases in fixed charges based on what they argued were customer equity and other policy grounds. Clean WI also opposed MGE's proposed fixed charge increases, arguing that MGE failed to provide sufficient justification for the proposed changes, and that, in addition to potentially undermining customer conservation, efficiency and renewable energy efforts, these changes are contrary to Wisconsin energy policies set forth under Wis. Stat. § 1.12(4). Airgas indicated that it supports rate design proposals that recover capacity related costs, particularly capacity that is used infrequently, in the form of a fixed charge.

MGE's proposed rate realignment would shift the recovery of some of its fixed costs from the variable energy charge to a monthly fixed charge. The fixed charges have a direct relationship to the variable energy charges in classes that have no demand charge.   Residential classes and small commercial classes with demand under 20 kWh do not have any monthly demand charges. Charges for these smaller classes are either per day or per kWh.

Regardless of the level of these fixed and variable charges, the entire rate design must recover the test-year revenue requirement for each class. For every dollar that is recovered via fixed charges, a dollar less needs to be recovered from the energy charge. The converse is also true; if the fixed charge is less, energy rates must be higher to recover the same amount of revenue. While the revenue to be recovered from each class is a separate determination, the increases proposed for the fixed charges are intended to better align the costs to serve individual customers with the revenues received from that customer.

In this proceeding, MGE is asking the Commission to more closely align fixed charges with fixed costs and to fundamentally engage in an exercise to enact reforms to restructure its rate design. Such an exercise goes to the core reason the Wisconsin legislature created this Commission: to bring to bear this agency's expertise and knowledge about rates and the price signals that are sent to customers, and the sort of behavior this Commission wants to foster as a matter of public policy.[11] In designing rates, the Commission exercises a legislative function that reflects the changing nature of the utility industry, which includes the emergence of increased customer interest in distributed generation. Each of the parties recognized this basic principle when they asked the Commission to consider various public policy objectives in setting the fixed charges. Wisconsin courts have long held that the Commission has wide discretion in determining the factors upon which it may base its rate decisions. Further, the Commission is not bound to any single regulatory formula; it is permitted to make the pragmatic adjustments, which may be called for by particular circumstances, unless its statutory authority plainly precludes this. To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence, and specialized knowledge

[11] The dissent draws a narrow and incorrect conclusion about this Commission's expertise. Indeed, this Commission does have the technical and policy expertise to set rates. However, the dissent chooses to focus on the technical knowledge of this agency and its staff, and fails to acknowledge that the Commission also functions in a quasi-legislative manner when setting rates and, thus, the policy and technical expertise of the agency are utilized when setting rates. Under the dissent's interpretation, the Commission would never have to make decisions, but rely only on the advice of Commission staff. This, of course, is incorrect and contrary to this Commission's statutory mandate to weigh the evidence of all parties in rate setting and make decisions based on the entire record.

to identify a reasonable result, bearing in mind the various public policies that may be impacted by various ratemaking decisions. Wis. Stat. §§ 227.57 (6), (8), and (10).

MGE urged the Commission to align the fixed charge more closely with the fixed costs of the utility, such as hooking up to the grid, meter costs, billing, and other costs that do not vary with usage. In rates designed without demand charges, there are two services conceptually provided by a utility.

First, state law requires that utilities provide reliable and adequate electric service. Wis. Stat. § 196.03(1). MGE must build an infrastructure that allows it to provide electricity instantaneously matched to whatever demands a customer places on the system. Theoretically, if a customer requires no electricity for 364 of the 365 days of a year, MGE nevertheless must build an electric system to provide service to this customer for the one day a year this customer requires power. There is no dispute that there are certain fixed costs incurred from simply connecting to the system and that MGE is obligated to make its system available regardless of the frequency that system will be relied upon by certain customers. MGE urged the Commission to consider fixed charges as the portion of the customer bill that pays for, at least in part, this service offered by MGE. For customers with very low usage, this service is sometimes referred to as "backup service."

The second category of service provided by a utility is the provision of electricity itself. The variable energy charge conceptually represents that cost. Where a particular rate design collects a significant portion of the utility's fixed costs through the variable energy charge, this results in higher-use customers subsidizing lower-use customers regardless of the reasons those customers may have lower use. To the extent a customer reduces usage via energy efficiency, conservation or renewable generation, the customer reduces his or her contribution to the utility's fixed costs and these costs must be picked up from other customers.

This is the general framework in which the Commission must determine what the fixed charges and variable energy charges should be within a class.

In this case, the Commission agrees with MGE that an appropriate fixed charge should better align the charge with the fixed costs of providing service, regardless of the amount of energy used or demand placed on the system by the customer. The regulated utility ratemaking process is intended to simulate a free market for monopoly utilities. When rates are properly designed, the rate structure signals to customers the actual cost of providing both backup service and electricity to each class. If the fixed charge is too low, the customer will receive an incorrect price signal that the cost to provide access to the electric system is lower than it actually is to the utility. They will also receive an incorrect signal that the variable cost to provide energy is higher than it actually is to the utility. Setting price signals correctly is important because those signals influence customer behavior, which in turn influences how the utility incurs costs.

As discussed further below, MGE provides a compelling case that its fixed charges are insufficient to recover its fixed costs. As a result, the variable energy charge is correspondingly too high. The result is a price signal that tells customers that the economic benefit of conservation is higher than it actually is. To the customer, the economic benefit is whatever savings they realize on their bill by implementing savings or installing renewable energy. But the economic benefit to the system is less than the economic benefit received by individual customers. In other words, if the fixed costs are in part recovered in the variable energy charge, a customer may save $10 per month by conserving electricity, but the utility may only save

$6 per month as a result of that customer using less energy. That $4 must then be recovered by other ratepayers the next time rates are adjusted.

The question then becomes how to determine what those fixed costs actually are. Here, the Commission relies upon its long standing experience and approach to COSS. COSS attempt to classify every type of utility cost to provide information about what causes that cost and how it should be allocated. The Commission has traditionally declined to adopt specific COSS as its preferred approach, and similarly declines here to select one party's proposed definition of "fixed cost" over another. As discussed more specifically below, the evidence in this record establishes that MGE's fixed costs far exceed the proposed increase in its fixed charges. Thus, it is sufficient in this case to recognize that MGE's proposal moves fixed charges closer to its fixed costs. It is not pragmatic or necessary at this time to further define fixed costs.

Certain parties requested that the Commission mitigate the proposed increase in fixed charges for public policy reasons. Clean WI, RENEW, and ELPC argue that the Commission should maintain lower fixed charges without regard to MGE's fixed costs in order to support the development of renewable energy and energy efficiency measures. It may be true that raising the fixed charge could have an incidental effect upon the payback period of certain energy efficiency measures and renewable energy resources. However, even under MGE's proposal, 79 percent of a typical customer's bill will remain variable. Thus, the Commission finds that the parties' concerns are overstated.

More importantly, however, the purpose of rate design is not to subsidize the payback of energy efficiency measures or renewable energy. The purpose of rate design is, fundamentally, to connect the rates that customers pay to the costs the utility incurs. Such an approach appropriately encourages efficient utility scale planning.

As Wisconsin courts have long recognized, rate design is a quintessential legislative function firmly left to the discretion of the Commission. Other substantial state and federal programs are designed specifically to support the development and implementation of conservation and renewable energy resources. The Commission is not required to use rate design as a hidden subsidy for these resources. This Commission continues to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want, or who cannot afford, to own generation to make sure these customers are not subsidizing the costs for those who choose to do so.

Clean WI, ELPC, and RENEW argue that lowering the energy charge will violate the Energy Priorities Law (EPL), Wis. Stat. § 1.12. They argue that the law would be violated because the proposed rate design would: (1) encourage customers to consume more energy; (2) render many energy efficiency measures uneconomic; and (3) have a negative impact on Focus on Energy. The Commission is not persuaded that the EPL requires the Commission to disconnect fixed charges from fixed costs. Further, if the Commission accepted these parties' arguments, then any Commission action that lowered the variable cost of energy would violate the law. In times of falling fuel prices, the Commission regularly requires utilities to give variable credits based on energy use to its customers. Under the theory of Clean WI, RENEW, and ELPC, such a credit would be illegal because it lowers the economic benefit of renewable energy by saving customers money on their energy usage. Such a construction of the law would also, if taken to its logical conclusion, prohibit the imposition of any fixed customer charge. This is not a reasonable construction of the statute.[12]

According to the Supreme Court of Wisconsin, the Commission must interpret the EPL in the context its other statutory obligations. See *Clean Wisconsin, Inc. v. Pub. Serv. Comm'n of Wisconsin*, 2005 WI 93, 282 Wis. 2d 250, 700 N.W.2d 768. With respect to the setting of utility rates, the Commission's fundamental obligation is to set just and reasonable rates that ensure the adequate provision of utility service. Wis. Stat. §§ 196.03, 196.20, and 196.37. Nothing in the EPL changes that responsibility. Nor does EPL require the Commission to favor one group of customers over another.

The text of the law clearly shows that the Commission is not bound to support renewable energy development at the cost of all other ratemaking principles or public policy goals. The law requires the Commission to prioritize the development of renewable energy resources that are "cost effective." Wis. Stat. § 1.12(3)(b) and (4), and Wis. Stat. § 196.025(1)(ar). Thus, the law specifically sets forth a state policy that the cost effectiveness be a significant consideration in the development of these resources. The law does not require the Commission to artificially inflate, to any degree, the cost effectiveness of renewable energy resources when it sets utility rates.

The Commission supports energy efficiency and renewable energy in many ways. It supports and regulates the Focus on Energy program that provides direct financial incentives for energy efficiency and renewable energy development. The Commission also allows utilities to

[12] The dissent argues that the Final Decision "fails to coherently apply our Energy Priorities Law", but fails to explain what, in its view, coherently applying that law might look like. (Concurrence and Dissent of Commissioner Eric Callisto in this docket, at 9.) If the law were applied as certain intervenors suggest, any vote to increase the fixed customer charge would violate it.

implement voluntary energy efficiency programs. Finally, the Commission is charged by state law to ensure that the state's utilities comply with the renewable portfolio standard. Rate design is neither the only, nor necessarily the most appropriate, tool for policy makers to encourage energy conservation and renewable energy.

Further, the Commission also must consider the effect of adopting Clean WI, ELPC, and RENEW's policy choice on customers that cannot implement energy efficiency or renewable measures. To the extent fixed costs are recovered through the variable energy charge, more fixed costs are paid by higher energy users within a class. The Commission finds that the most equitable result is to better align fixed charges with the fixed costs to serve a customer so that, as best as can be determined in a reasonable regulatory environment, members in a class pay for their fair share of the cost of service.

Parties opposed to MGE's proposal argued that the effect of this rate design change will fall disproportionately upon low-income users. MGE, however, provided substantial evidence that established that low-income users are not all low-energy users. (Direct-MGE-Bollum-14r-15r.) Ratepayers will be affected differently based upon how much energy they use, not by their income status. A substantial portion of low-income users will realize savings with this rate design. Furthermore, the total dollar bill impact of these changes to those customers who will see bill increases is relatively small. While the fixed charge for small residential customers will be increased, the variable energy charge will be decreased. The Commission finds that the parties' concerns are largely overstated and do not warrant deviation from basic rate design principles.

The opponents of MGE's proposal also noted that the current cost of the subsidy created by recovering some of MGE's fixed costs with variable energy charges is small compared to the total revenue of MGE. They ask the Commission to ignore that subsidy as immaterial compared to their favored policy objectives. The Commission, however, agrees with MGE that over time, this disconnect may grow exponentially. Each year, renewable energy resources become cheaper and more attractive to utility ratepayers who can afford them. The use of distributed generation is expected to continue to grow, requiring more and more fixed costs to be paid for by non-participating customers. Further, the intra-class subsidy is not just limited to renewable energy owners. Every low energy use customer pays less than their proportionate share of the fixed cost to provide access to the electric system when fixed costs are recovered in the energy charge. Thus, the magnitude of the subsidy is much greater than argued by RENEW. In any event, the Commission prefers to correctly align costs now, when the relative impacts are small, rather than waiting until the effect of such an adjustment could be shocking to the ratepayers.

With these policies in mind, the Commission now turns to the specific record evidence offered in this proceeding that support implementation of the Commission's stated policy directives.

MGE defined fixed costs as follows:

> Fixed costs describe the category of expenses that the Company incurs to provide service that remain the same for a customer of the short and medium term regardless of the amount of energy the customer consumes.
>
> From an accounting perspective, [all fixed costs are the same.] But from a traditional utility resource planning and rate design perspective, fixed costs are often further separated into those costs that change over the long term based on the number of customers (basic customer costs) and on the demands a customer puts on the physical capacity of the distribution, transmission and generation infrastructure of the utility system (demand-related costs).

(Direct-MGE-Bollom-2.)

MGE witness John Krueger specifically identified these categories of costs and calculated the per customer share of those costs. His analysis showed that the total fixed cost to serve the average residential customer is $69.17 per month, $37.32 of which is exclusive of generation and transmission. MGE then proposed raising the total residential fixed charges to $19.00 per month. Mr. Krueger provided similar evidence to support MGE's proposed fixed charge increase for small commercial customers.

MGE did not request that the fixed charges be set at a level that would recover all of its fixed costs, but rather that the fixed charges be moved closer to the total fixed costs. Specifically, for residential customers, it requested a total fixed charge level of $19.00 per month. Mr. Krueger also presented testimony that the variable cost of energy is also significantly lower than the energy charge to date, with an approximate value of $0.03884/kWh. Thus, MGE's analysis shows a significant disconnect between the way costs are incurred by the utility (in a fixed fashion, or variable) and how the customers pay for it. Because the revenue requirement is the same within each class, this disconnect means that low energy users pay for less of the fixed costs to connect than they cause MGE to incur. As MGE witness Gregory Bollom explained:

> MGE's current rate structure is the result of cost allocation and rate design patterns that are in some cases decades old. MGE's rates today reflect how the Commission has balanced concerns about the accessibility, affordability, and policy goals of natural gas and electricity service over time. The cumulative result of those policy choices is a rate design where some percentage of the company's fixed costs are recovered through fixed rate elements and the remaining percentage is recovered through variable rate elements. The company's variable costs are also recovered through the variable rate elements. While the Commission did authorize an adjustment to the level of fixed charges for some classes in MGE's last full rate

> case, there is still a significant mismatch between the way costs of service are actually incurred and the way they are currently recovered through different rate design elements....

(Direct-MGE-Bollom-2-3.)

While certain parties urge different results for public policy reasons, there is substantial evidence in the record to support the fixed charges set by this Final Decision.

The Commission is not persuaded with the arguments that an increase in fixed charges to the levels proposed by MGE will have a detrimental impact on energy efficiency, conservation, or the development of renewables.[13] Under MGE's proposal, the effect on customers' decisions to implement energy efficiency, conservation, or renewable measures is likely to be very small. Indeed, MGE recognized that its proposed rate changes could slightly reduce customer disincentives to invest in energy efficiency, conservation, and distributed generation. Mr. Bollom noted in his direct testimony:

> Customer conservation in recent years has highlighted the fact that the current relationship between rates and costs often creates confusion for customers that take energy efficiency measures to help manage their utility bills.

(Direct-MGE-Bollom-12.)

> There is an inherent inconsistency in how MGE's rates are structured today. MGE's local electricity and natural gas distribution service is a largely fixed-cost business. Yet historically, different stakeholders have advocated, and the PSCW has adopted, rate designs that recover a significant portion of these fixed costs of service through charges that vary with the quantity of electricity and natural gas consumed. The argument has been that higher kWh and therm charges provide a better incentive for customers to conserve energy. While this may be the case in the short term, it creates confusion for customers over time and can discourage customers from taking actions to reduce their usage. Customers expect that as they reduce their electricity and natural gas use their monthly bill will go down. What customers do not expect, though, is that the rates they pay in the future will

[13] The dissent is critical of the Commission's determination and, for "illustrative purposes" impermissibly resorts to non-record evidence in an attempt to demonstrate that increasing fixed charges may impact energy efficiency. (Concurrence and Dissent of Commissioner Eric Callisto in this docket, at 7, fn. 18.)

> increase as a result of their conservation. This is exactly what happens with MGE's current rate structure. The fixed costs that are recovered through charges that vary with the level kWh and therm usage must be reallocated into higher rates as customers reduce their energy usage. This is counterintuitive to customers…
>
> Customers often express frustration at what appears at times to be a "Whack-A-Mole" game. Customers reduce their usage to reduce their bills. MGE under-recovers its fixed costs and is forced to request a rate increase in its next rate case. The PSCW grants a rate increase for the prudently incurred fixed costs. Customers' bills go back up, offsetting a portion of the savings they experienced when they took the conservation action in the first place. Because the future savings expected when the customer made the decision to conserve are not fully realized, it can appear to customers as a never-ending cycle and tends to discourage further conservation over time…
>
> If rates are designed to recover costs in a manner that matches how costs are incurred, the mixed signals are effectively eliminated for customers. If fixed costs are recovered through fixed charges and costs that only vary by the level of energy consumed, either kWh or therm, are recovered through variable kWh or therm charges, then MGE's costs and revenue recovery move in tandem and there is no under-recovery of fixed costs when customers reduce their energy usage through conservation measures. Consequently, there is no need for MGE to seek higher rates in the next case simply due to the under-recovery of fixed costs associated with customer conservation.

(Direct-MGE-Bollom-14-15.)

Further, whether or not the shifting of costs between fixed charges and energy charges is material in the context of renewable energy payback, the Commission must consider the impact of rate design on all customers. The Commission is concerned that the failure of low-usage customers to pay for their share of fixed costs will cause costs to go up for other customers. Mr. Bollom explained how the inclusion of fixed costs in energy charges subsidizes customers who can afford to implement renewable energy measures at the expense of those who cannot:

> MGE currently has more than 300 customers with installed or accepted applications for customer-owned and sited distributed generation (DG) projects. While there are many factors that influence a customer's decision to pursue DG, savings they realize on their utility bill are a big part of the economic calculation they evaluate when considering whether to install their own on-site generation.

> When the cost of electricity from distributed generation, solar, wind or other fuel source is equal to or less than the customer's retail electricity rate from MGE; it is generally in the customer's interest to consider installing its own generation. However, the retail electricity rate recovers much more than just the variable costs of energy the customer's own generation displaces. As I testified earlier, a significant portion of MGE's fixed costs of service are recovered from charges that vary with the level of kWh usage. Therefore, a significant share of the savings customers currently see in their electricity bills as a result of installing DG represent payments toward the fixed costs of service. Allowing these customers to avoid paying the costs of the infrastructure necessary to take service from, and often put energy onto, the distribution grid unfairly shifts costs to other customers. Depending upon the size of the customer's DG system, a customer can avoid paying anything at all for its use of the distribution, transmission and generation infrastructure. The costs associated with the DG customer's use of the system are paid entirely by other customers of MGE. Over time, as more distributed generation of all types is added to MGE's system, the level of costs inappropriately borne by other customers will grow, increasing the utility bills for residential and small business customers that either cannot or choose not to pursue their own on-site distributed generation.

(Direct-MGE-Bollom-20.)

Finally, while all parties urged different results for policy reasons, there is no debate that utilities incur basic costs to provide backup service or access to the grid. Ultimately, the Commission must weigh the views of the parties and the testimony presented, and then proceed in its decision to balance the various statutory goals of rate design and public policy.

In order to prevent intra-class subsidies, to provide appropriate price signals to ratepayers, and encourage efficient utility scale planning, the Commission determines that the fixed charges should be increased to more closely reflect the utility's fixed costs to provide basic service to a customer. The Commission determines that it is reasonable, after weighing the testimony and policy arguments presented by the parties, to set the fixed charge to $19/month for residential classes, $23.93/month for the Cg-5 small commercial class, and $22.28 and $30.49 for single-phase and three-phase Cg-3 small commercial customers, respectively.

Commissioner Callisto dissents and writes separately.

As part of its overall rate design, MGE also proposed the institution of a new, monthly fixed "grid connection charge" of $4.03, to be assessed uniformly to customers in all customer classes except for the lighting, Cp-1, Sp-3, and most miscellaneous classes. This grid connection charge would be assessed in addition to any existing customer charges. Commission staff did not take a position on the establishment of a new grid connection charge, but noted that the imposition of an additional fixed charge may prove confusing to customers and suggested that the Commission consider the total of all monthly fixed charges when setting rates. The City of Madison, Clean WI, Dane County, ELPC, RENEW, NRDC, and Wind on the Wires all objected to the proposed grid connection charge.

The Commission understands MGE's desire to unbundle the grid connection charge from other fixed costs in order to more clearly identify the underlying reasons for these fixed charges. Nonetheless, the Commission believes that establishing a separate grid connection charge on the customer bill may be confusing for customers and is unnecessary to achieve the stated goals of the rate restructuring. Rather than create a separate line item on the customer bill, the Commission finds it reasonable to require that all of the fixed charges be reflected in a single, fixed, customer charge. MGE may continue to unbundle grid connection costs for cost allocation purposes, but to better convey to customers what utility costs are recovered through this fixed charge, MGE shall rename the customer charge a "Grid Connection and Customer Service" charge.

Commissioner Callisto dissents and writes separately.

Tariffs for Distributed Generation Customers

As part of its overall rate design, MGE proposed to institute three new tariffs that would be available to any customer who has installed distributed generation (DG) facilities before June 1, 2014. These Rg-7, Cg-7, and Cg-8 tariffs would provide a fixed/variable charge rate structure consistent with MGE's currently existing rate design. These new rates are intended to provide a grandfathering mechanism for current DG customers by preserving the relative value of any consumption offset by self-generation. MGE proposed customers who enrolled in the Rg-7, Cg-7, and Cg-8 rates shall be allowed to continue to take service under these tariffs until December 31, 2029.

As noted above, the Commission does not believe that the fixed charges for residential and small commercial customers will inappropriately discourage customer investment in distributed generation in the future. However, the Commission recognizes that the increase in fixed charges will affect the economics of customers who have already installed DG systems within MGE's service territory. Therefore, the Commission, finds it reasonable to recognize the good-faith investment these customers made in DG under the existing tariff structure and to allow qualifying customers to continue to take service under these rates until December 31, 2026. The proposed Rg-7, Cg-7, and Cg-8 tariffs are approved.

Commissioner Nowak dissents.

Low Income and Lifeline Rates

MGE also proposed a new Rg-6 tariff that offers a low-income rate option for residential customers. This rate would be an optional service and would be available to customers who qualify for the federally funded Low Income Home Energy Assistance Program, and/or

Wisconsin's Public Benefits Energy Assistance Program. Once a customer qualifies for either of these programs, the customer would be eligible to remain on the Rg-6 tariff for 24 months. Proof of continued eligibility would be required for continuation under this rate for each subsequent 24-month term. MGE stated that this rate is intended to provide a rate relief mechanism for low-income residential customers who would be adversely affected by the company's proposal to increase fixed charges. NRDC indicated that, should the Commission approve MGE's proposed fixed charges, a low-income rate might be appropriate. However, NRDC argued that the proposed Rg-6 tariff would not sufficiently address the inequities in MGE's fixed charge increases for low-income customers. ELPC and RENEW did not support the creation of a low-income rate as they did not support the fixed charge increases proposed by MGE. The City of Madison recognized the impact that MGE's proposal may have on low-income customers, but did not take a position on the proposed Rg-6 tariff.

As noted above, the Commission has determined that the proposed fixed charge increase for residential customers will not disproportionately disadvantage lower-income groups to a significant extent. (Direct-MGE-Bollum-15r.) As such, the Commission does not find it reasonable to approve a new low-income rate option in this proceeding. However, the Commission finds some merit in the concerns raised in this proceeding regarding rate impacts on low-income customers generally. To that end, MGE shall work with Commission staff and other interested parties and stakeholders to analyze further low-income rate design options for potential consideration in MGE's next rate case.

Commissioner Callisto dissents and writes separately.

MGE’s rate design proposal included the elimination of the Rg-3 residential lifeline tariff. The lifeline tariff provides, to a qualifying customer, a discounted customer charge and an inclining block rate with the first 300 kW billed at a lower rate than the standard residential energy charge. This rate schedule is optional for residential customers living in an individually metered residential unit who satisfy the eligibility requirements. MGE’s residential lifeline tariff has been closed to new customers since July 30, 1985, and currently has 12 customers enrolled. Over the past few rate cases, the Commission has gradually adjusted the Rg-3 rates to more closely align with the standard Rg-1 residential rates, with a stated desire to eventually eliminate the rate. MGE is the only Wisconsin investor-owned utility that still has a lifeline rate in place. Commission staff did not have any strong objection to MGE’s proposal to cancel the Rg-3 lifeline tariff in this proceeding, noting that it has been the Commission’s intent to phase out MGE’s lifeline rate and transition those customers to a standard rate offering over the course of a number of proceedings. Commission staff noted that, absent an alternative low-income rate option, closing the Rg-3 tariff and transferring all current customers to the standard Rg-1 tariff would produce, on average, a 62 percent increase in rates for these customers.

The Commission recognizes that customers taking service under Rg-3 would experience significant rate increases if this tariff were cancelled immediately. However, the Commission continues to believe that it is appropriate to phase out MGE’s legacy lifeline rate. Thus, the Commission finds that it is reasonable to allow the existing customers to continue to take service under this tariff until December 31, 2015. In addition, the Commission directs MGE, in conjunction with its discussion of the proposed Rg-6 low-income rate, to work with Commission staff and other interested parties to consider alternatives for potential consideration in MGE's next rate case.

Commissioner Callisto dissents and writes separately.

Plug-in Electric Vehicles

MGE included in its rate design a proposal to implement two experimental tariffs relating to plug-in electric vehicles (PEV). Both programs are intended to provide MGE with more information on how individuals with PEVs use MGE's system and how best to integrate the use of PEVs into MGE's operations. MGE proposed an experimental pilot rider (EV-1 rider) that will involve a limited number of customers who charge their electric vehicles at home. Under the EV-1 rider, MGE will install and operate Level 2 charging equipment at the customers' homes. Customers will be billed per day for the use of the equipment, and will pay rates under the Rg-1, Rg-2, or Rg-3 schedule, whichever applies to the particular customer. MGE also proposed an experimental tariff (Schedule EV-2) associated with the use of MGE's 26 public charging stations. Currently, all public charging stations are available at no cost. In exchange, MGE receives information from the PEV drivers about their vehicles and their driving, and charging patterns and preferences. Under the proposed EV-2, drivers will be billed based on the amount of time they are connected to the stations. Further, MGE proposed to reduce charges for drivers who share information about themselves, their vehicles, their driving patterns, and their PEV charging decision-making and sessions. The proposed experimental PEV rate programs were uncontested.

The Commission finds that it is reasonable to approve the proposed EV-1 and EV-2 rates on an experimental basis. The creation of tariffed rates for PEV charging service and equipment will allow MGE to collect additional information regarding the charging behavior of PEV users that will be instructive in developing future rates for PEVs. Moreover, the EV-1 rate will provide customers an additional option for obtaining Level-2 PEV home charging equipment. Finally, the new PEV-2 rate will send users of MGE's public charging stations a more appropriate price signal, which will encourage more economically-efficient consumer decision making regarding PEVs and PEV adoption.

Revised Sp-3 Billing Determinants

MGE developed a forecast of anticipated 2015 energy usage and demand levels by UW for purposes of the Sp-3 tariff. This tariff provides a special rate designed to serve the unique characteristics of UW. Since the original filing in this case, MGE had the opportunity to meet with UW staff to review and discuss the forecast. Based on those discussions, MGE indicated that it believes the demand billing statistics used to develop the Sp-3 demand charges are too low. MGE provided revised Sp-3 billing statistics and requested that the Commission to use the revised billing statistics when setting the final rate levels for the Sp-3 rate.

As UW's Sp-3 rate class represents a large proportion of MGE's overall electric sales revenue, the Commission finds it is reasonable to use these uncontested, revised billing units for final rate design purposes. The use of the revised Sp-3 billing units produces an additional $844,584 in test-year revenue under present rates. This revision shall be reflected in the final revenue deficiency and revenue allocation.

Green Power Tomorrow Voluntary Renewable Energy Rider

MGE's voluntary renewable energy riders, collectively marketed as Green Power Tomorrow (GPT), provide an option for customers who wish to have all or some of their energy supplied by renewable resources. GPT customers are charged a per-kWh rate for energy purchased under the rider that is in addition to the customer's base energy rate for energy consumed. The GPT rate is intended to cover the incremental costs of providing renewable energy, recognizing the fact that renewable energy is more expensive than MGE's embedded cost of energy production. If the GPT rate is too low, non-participating customers subsidize the renewable energy purchases of participating customers. Conversely, if the GPT rate is too high, participating customers pay for utility costs unrelated to the renewable energy provided under the rider. The GPT rate is examined in each rate case to ensure that it accurately reflects the cost differential between the utility's standard cost of energy and the cost of energy provided under the GPT program. In this case, Commission staff analyzed the incremental cost of GPT energy using the calculation methodology approved by the Commission in docket 4220-UR-118. Commission staff's analysis showed that the incremental cost of GPT is $0.0244 per kWh. Commission staff proposed to lower the GPT from $0.0400 per kWh to $0.0244 per kWh. MGE reviewed Commission staff's calculations, and noted that while its approach differs from Commission staff, it did not object to the proposed rate.

As previously discussed, the Commission generally attempts to align rates with costs. Nonetheless, the Commission finds that further investigation into the manner in which this rate is calculated is warranted. MGE, shall work with Commission staff and other interested stakeholders to continue to monitor this rate and provide a more detailed analysis of the methodology used to calculate this rate in its next rate case.

Chairperson Montgomery dissents.

New Rate Classes

Airgas provided testimony regarding the appropriateness of MGE's current rate class structure and whether or not those rate classes appropriately reflect differences in customer consumption patterns. Airgas requested that the Commission direct MGE to develop new customer class breakouts that group customers with similar load profiles in the same customer class. MGE indicated that it is not necessary at this time for the Commission to direct it to develop new rate classes. NRDC indicated that, should the Commission accept Airgas' proposal, such a process should be undertaken with the input of all parties in this docket, or in a separate statewide proceeding on utility rate design. The Commission finds there to be insufficient evidence in this proceeding to justify ordering MGE to develop new customer classes. However, it is reasonable for MGE to continue to evaluate possible development of new customer class breakouts that reflect similar load profiles among customers within a given classes. Though not required to propose new customer classes, MGE shall report in its next rate case on the status of its evaluation.

Separate Rate Investigation and Collaborative

Several parties to this proceeding suggested that a separate investigation into statewide utility rates and rate design issues could assist the Commission in future rate design policy decisions.

While the Commission recognizes the parties' interest in further study of rate design issues, the Commission finds that there is sufficient evidence in the record upon which to base its decisions in this proceeding. Additionally, as is evidenced by the volume of testimony in this proceeding, the Commission continues to believe that individual utility rate proceedings provide for a sufficient and robust examination of rate design issues. Therefore, the Commission does not find it necessary to open a separate investigation into these issues. Similarly, while looking forward to the results of the rate design collaborative and the community-wide conversation to which MGE has committed itself, the Commission does not find it necessary at this time to provide specific guidance to either process.

Commissioner Callisto dissents and writes separately.

Natural Gas COSS and Rate Design

Natural Gas COSS

MGE prepared a single customer-oriented COSS. In order to establish a range of reasonableness, Commission staff prepared both a customer-oriented COSS (COSS A) and a commodity-oriented study (COSS B). MGE's study and Commission staff's COSS A allocate costs based on the number of customers, average usage, and peak demand. Commission staff's COSS B allocates gas main-related costs on commodity and customer demands, not on the number of customers. Customer-oriented studies generally result in higher costs to low-volume service rate classes and lower costs to large-volume service rate classes, when compared to the results of commodity-oriented COSS.

Similar to its approach to electric COSS, the Commission has not endorsed a particular natural gas COSS methodology in the past. Instead, it has relied on the results of all of the available COSS to provide a range of reasonableness for revenue allocation and rate design. This continues to be an appropriate policy to use in this docket.

Natural Gas Rates

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for MGE in Appendix C of this Final Decision will provide a 7.98 percent rate of return on the average gas net investment rate base. This represents a decrease of 5.24 percent in margin rates and a 1.95 percent decrease in total natural gas sales revenues. Margin rates exclude natural gas commodity costs.

As shown in Appendix C, the natural gas COSS results in a relatively wide range of changes in charges to the various service rate classes. The authorized rates as set forth in Appendix C are based on the cost of supplying natural gas service to the various service rate classes and other rate-setting goals. A summary of the revenue rate impacts on a service rate class is shown in Appendix C. The percentage rate change to any individual customer will not necessarily equal the overall percentage change to the associated service rate class, but will depend on the specific usage level of the customer.

Appendix C also shows some typical natural gas bills for residential service, comparing existing rates with new rates including the cost of natural gas.

Fixed General Service Rates Monthly Charges for Residential Customers and the Smallest Volume Commercial Service Rate Class

MGE proposed increasing the fixed charges for residential customers from $12.17 a month to $21.87 a month. This increase includes an increase in the Basic Customer Charge to $13.42 a month and the implementation of a new charge, the System Connection Service Charge, of $8.45 a month. MGE also proposed increasing the fixed charges for the GDS-1, small commercial customers, from $21.07 per month to $24.16 per month. This proposal included a decrease in the Basic Customer Charge from $21.07 a month to $13.38 a month and implementing a System Connection Charge Service Charge of $10.95 per month.

The fixed rates proposed by MGE are reasonable. The authorized fixed charges for residential customers and the small commercial customers are designed to recover all of the customer-related costs, including meter reading, billing and collection expenses, and the depreciation and return associated with meters and service laterals. In addition, the authorized fixed service charges are also designed to recover a portion of MGE's fixed costs, including capital costs related to mains. MGE incurs fixed costs regardless of the volume of gas used by its customers, so it is more appropriate to recover such costs through fixed service charges than through volumetric charges. The Commission finds that MGE's proposed fixed service charges will not recover all fixed costs.[14] The price of natural gas, which is recovered entirely through volumetric rates, comprises about two-thirds of the total cost to provide natural gas service to customers. The Commission therefore finds that even with increased fixed charges, customers continue to have a strong incentive to invest in energy efficiency.

For residential and small commercial customers, the authorized general service rates result in a greater percentage increase, or smaller percentage decrease, to lower energy use customers in the service rate class, than for higher-energy users within the same service class. The lowest-energy use customers within a rate class will experience the highest percentage increases, or smallest decreases, in rates because their bills are comprised of proportionately more of the fixed daily distribution service charge than the volume charges when compared to

[14] To avoid customer confusion given the Commission's determination to have electric fixed charges appear on the customer's bill as "bundled" and referred to as "Grid Connection and Customer Service Charge", the Commission concludes it is reasonable for MGE to similarly bundle the gas fixed charges, and have those charges appear on the customer's bill for natural gas as "System Connection and Customer Service Charge."

customers in the class with higher-energy use users. Given that strong distinction in gas service between the commodity and its transport, the shift towards fixed charges better aligns fixed transport costs with a fixed charge, and highlights to the consumer the cost of particular levels of commodity consumption.

Some typical gas bills for residential customers were computed to compare existing rates with authorized rates. The comparisons are set forth in Appendix C.

Commissioner Callisto dissents and writes separately.

Low-Income Residential Rates

MGE proposed to eliminate its Residential Lifeline Distribution Service (RD-2) tariff for low-income customers. This tariff has been closed to new customers since of July 30, 1985, and there currently are eight existing customers served by this tariff. At the time the tariff was closed to new customers, the existing customers were placed on a priority list to receive weatherization services. When energy efficiency measures were installed in their dwellings, they were moved to the regular residential rates. Any Lifeline customers who received weatherization services prior to July 30, 1985, could remain on the rate until they no longer met the income or other qualification guidelines established for the program. If an existing Lifeline customer moved from one residence to another, it is considered a termination of service at the former residence and commencement of a new service under regular residential rates at the subsequent location.

In addition to eliminating the RD-2 tariff, MGE also proposed a new tariff, Residential Low Income (RLI-1), to mitigate the customer rate impacts resulting from increased fixed charges to low-volume, low-income residential service customers. MGE proposed moving any qualifying RD-2 customers to the RLI-1 service tariff.

The Commission determines that avenues other than the proposed RLI-1 tariff may be better suited to address the needs of all low-income customers. The MGE-proposed community-wide conversation, discussed in the Electric Rates section, may identify reasonable alternatives. It is therefore not appropriate to approve the RLI-1 tariff at this time. The Commission finds it is reasonable to terminate the RD-2 lifeline rate on December 31, 2015. A one-year delay in terminating this tariff allows existing customers to take advantage of the DOA's Weatherization Assistance Program, with assistance from MGE, if they have not already done so. A one-year delay also avoids the undesirable possibility of affected low-income customers being subject to three different rate treatments in three consecutive years.

Commissioner Callisto dissents and writes separately.

Seasonal Service

MGE proposed changes to its existing Seasonal Off-Peak Distribution Service (SD-1). MGE proposed to close this rate to new customers on January 1, 2015. MGE also proposed to increase the customer charge for SD-1 from $31.31 a month to $38.00 a month and increase the per-therm volumetric distribution charge of from $.0831 to $0.1016. The Commission concludes it is reasonable to grandfather any current SD-1 customers wishing to continue service under SD-1 for a period no greater than ten years.

MGE's proposed new seasonal tariff, SD-2, would have a customer charge of $130.42 per-month and a per-therm volumetric distribution charge of $0.0776. At an energy usage of 50,000 therms per year, the lower SD-2 volume charges will be sufficient to offset the higher SD-2 service charges. However, the customer consumption patterns observed by Commission staff suggest that customers with energy use substantially less than 50,000 therms per year would see a large increase under the SD-2 rate. Commission staff suggested a potential for additional customer class(es) for seasonal customers with usage less than 50,000 therms per year. The Commission finds it reasonable to direct MGE, in conjunction with Commission staff and other interested stakeholders, to further evaluate in MGE's next rate case whether MGE should either: (1) continue to make SD-1 available to seasonal customers with usage less than 50,000 therms per year; or (2) consider whether such seasonal customers should be a particular service type within their distribution service classes or made into a new class of customer.

Purchased Gas Adjustment

Currently, MGE's PGA tariff contains a monthly gas cost reconciliation provision that requires it to use the remaining PGA year or heating season when truing up the cost recovery from system sales customers. Allowing the true-up period to flex can help result in more appropriate and reasonable cost recovery for ratepayers. The Commission finds this approach reasonable because it provides for a better match of rate and cost recovery periods.

Metered Demand Rates

Metered Demand Charges are designed to generate revenues based on maximum daily demands for the purpose of recovering costs associated with the investment and operation of facilities to meet demands in excess of average loads. Several state gas utilities have metered demand charges on file with this Commission for service to their largest-volume customers. Currently, MGE recovers these costs through fixed charges and volumetric usage rates.

Typically, a customer's metered demand charge is based on the customer's peak gas day use of the most recent 12-month billing history. Given similar customer volumes, metered demand charges result in customers with higher peak day usage paying more for service than customers with lower peak days. This cannot be accomplished by merely revising monthly service charges or volumetric distribution charges. Because the cost to provide natural gas service on peak days is higher than other days, metered demand charges are a means of recovering demand costs in a more equitable manner within a rate class. Therefore, the Commission finds it appropriate to require MGE to conduct a feasibility study and, in its next rate case, provide an implementation plan for of metered demand charges for its largest volume customers.

Steam and Power Gas Generation Distribution Service (SP-1)

MGE's current SP-1 tariff is available to steam and power gas generation facilities that use at least 25 million therms per year. However, unpredictable weather conditions greatly impact the need to run these power generation facilities. In a year with significantly lower than normal customer heating and cooling demands, even large-volume steam and power gas generation facilities may use less than 25 million therms in a year. The Commission determines it appropriate to lower the usage requirement for SP-1 customers to 17 million therms. This will reduce the movement of these customers between rate classes due to weather-related demand.

Effective Date

The Commission finds it reasonable for the authorized electric and natural gas rate increases and all tariff provisions that restrict the terms of service to take effect no sooner than January 1, 2015, provided that these rates and tariff provisions are filed with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code §§ PSC 113.0406(1)(a) and 134.13(1)(b). If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, it is reasonable to require that they take effect one day after the date they are filed with the Commission and made available to the public.

The Commission finds it reasonable for the authorized electric and natural gas rate decreases and all tariff provisions that restrict the terms of service to take effect no sooner than January 1, 2015. It is also reasonable to require the utility to file these rates decreases and tariff provisions with the Commission and make them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code §§ PSC 113.0406(1)(a) and 134.13(1)(b) by that date.

Order

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

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2015, 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 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the

public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

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

4. The authorized rate decreases and tariff provisions that expand the terms of service shall take effect January 1. 2015. MGE shall file these rate decreases and tariff provision with the Commission and make them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date.

5. By January 1, 2015, MGE shall revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices B and C or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

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

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

8. The appropriateness of whether to include recovery in rates of the costs associated with WPDES Settlement shall continue to be determined on a case-by-case basis.

9. Commission staff shall review the issue of inclusion of pension and benefits updates and their prediction record in the next round of rate cases for all investor-owned utilities.

10. The 2015 approved fuel cost plan for MGE shall reflect a forecast of 40 percent blend of Powder River Basin coal to bituminous coal at both Elm Road Generating units 1 and 2.

11. The electric fuel costs in Appendix D shall be used for monitoring of MGE’s 2015 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

12. All 2015 fuel costs shall be monitored using a plus or minus 2.0 percent tolerance band.

13. MGE shall to use escrow accounting treatment for its 2015 MISO SSR costs and for all other electric transmission costs from ATC and MISO.

14. MGE shall submit a ten-year financial forecast in its next rate proceeding.

15. MGE shall not pay dividends, including pass-through of subsidiary dividends, in excess of $43,250,000 if its actual average common equity ratio, on a financial basis, is or will fall below the test-year authorized level of 55.0 percent.

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

17. MGE shall record annual conservation accrual amounts of $5,188,817 for electric utility operations and $2,141,148 for natural gas utility operations. The level for electric utility operations consists of the conservation escrow budget of $4,671,702 ($4,551,111 for 2015 contributions and a $120,591 prior year true up) and $517,115 for non-escrow Customer Service Conservation activities. The level for natural gas utility operations consists of the conservation escrow budget of $1,685,112 ($2,030,704 for 2015 contributions minus a $345,592 prior year true up) and non-escrow Customer Service Conservation activity funding of $457,036.

18. MGE shall work with Commission staff and other interested parties and stakeholders to analyze further low-income rate design options, including alternatives to MGE's current lifeline rate, for potential consideration in MGE's next rate case.

19. If MGE elects to discuss or proposes new electric customer class breakouts, it shall report to the Commission with its evaluation in its next rate case.

20. MGE shall terminate service under it Residential Lifeline Distribution Service (RD-2) tariff at the end of 2015 and assist current customers subscribing to this tariff in taking advantage of the DOA's Weatherization Assistance Program. Furthermore, MGE should discuss the need for low-volume, low-income tariffs during the community conversations.

21. MGE shall grandfather any current SD-1 customers wishing to continue service under SD-1 for a period not greater than ten years. MGE shall evaluate in its next gas rate proceeding service options for seasonal customers with usage less than 50,000 therms per year.

22. MGE shall submit a feasibility study and implementation plan of metered demand charges for its largest-volume customers in its next natural gas rate application.

23. Jurisdiction is retained.

Docket 3270-UR-120

Concurrence and Dissent

Commissioner Callisto concurs in part, dissents, and writes separately (see attached).

Dated at Madison, Wisconsin, this 23rd day of December, 2014.

By the Commission:

Sandra J. Paske
Secretary to the Commission

SJP:JJB:cmk:DL: 00952156

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney 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.[15] 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

[15] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

APPENDIX A

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates — 3270-UR-120

CONTACT LIST FOR SERVICE BY PARTIES

AIRGAS MERCHANT GASES, LLC
Steven A. Heinzen
Heinzen Law SC
Two East Mifflin Street, Suite 402
Madison, WI 53703
Ph. 608-209-7468
Steve.heinzen@heinzenlaw.com

Additional Contact:
Ken Lyons
Airgas Merchant Gases, LLC
6990A Snowdrift Road
Allentown, PA 18106
Phone: 866.437.4250, x4163
ken.lyons@airgas.com

BOARD OF REGENTS OF THE UW SYSTEM
Andrew Norman, University Legal Counsel
361 Bascom Hall, 500 Lincoln Drive
Madison, WI 53706
Ph. 608-263-7400
anorman@vc.wisc.edu

CITIZENS UTILITY BOARD
Kira E. Loehr
James B. Woywod
Dennis Dums
16 North Carroll Street, Suite 640
Madison, WI 53703
Ph. 608-251-3322
loehr@wiscub.org; woywod@wiscub.org; dums@wiscub.org

Docket 3270-UR-120

CITY OF MADISON
Doran Viste
Assistant City Attorney
Office of the City Attorney
210 Martin Luther King Jr. Blvd, Rm. 401
Madison, WI 53703-3345
Ph.: 608-266-4511
Fax: 608-267-8715
dviste@cityofmadison.com

> Additional Contact:
> Jeanne Hoffman
> Facilities and Sustainability Manager
> 210 Martin Luther King Jr. Blvd, Rm. 115
> Madison, WI 53703
> Phone: (608) 266-4091
> Fax: (608) 264-9275
> jhoffman@cityofmadison.com

CITY OF MIDDLETON
Lawrence E. Bechler
Murphy Desmond S.C.
33 East Main Street, Suite 500
P.O. Box 2038
Madison, WI 53701-2038
Phone No.: 608-257-7181
Fax No.: 608-257-4333
lbechler@murphydesmond.com

> Additional Contact:
> Abby Attoun, AICP
> Assistant Director of Community Development
> City of Middleton
> 7426 Hubbard Avenue
> Middleton, WI 53562
> Ph.: (608) 821-8343
> Fax.: (608) 827-1080
> aattoun@ci.middleton.wi.us

Docket 3270-UR-120

CITY OF MONONA
William S. Cole
Monona City Attorney
2945 Triverton Pike Drive, Suite 101
Madison, WI 53711-7508
Phone: (608) 221-0079
Fax: (608) 221-7335
wcole@execpc.com

Additional contact:
Patrick Marsh
Monona City Administrator
5211 Schluter Road
Monona, WI 53716
Ph.: (608) 222-2525
Fax: (608) 222-9225
pmarsh@ci.monona.wi.us

CLEAN WISCONSIN
Katie Nekola
Pamela M. Ritger
634 Main St. Ste 300
Madison WI 53703-2687
Ph.: 608-251-7020 x14 or x18
knekola@cleanwisconsin.org; pritger@cleanwisconsin.org

DANE COUNTY
Marcia A. MacKenzie
Dane County Corporation Counsel
210 Martin Luther King, Jr. Blvd, Room 419
Madison, WI 53703
MacKenzie.marcia@countyofdane.com

Additional contact:
Carlos A. Pabellon
Dane County Corporation Counsel
210 Martin Luther King, Jr. Blvd, Room 419
Madison, WI 53703
pabellon@countyofdane.com

Docket 3270-UR-120

ENVIRONMENTAL LAW & POLICY CENTER
Bradley D. Klein
Howard A. Learner
Stephanie K. Chase
222 S. Hamilton Street, Suite 14
Madison, Wisconsin 53703
Ph.: (608) 204-9735
bklein@elpc.org
hlearner@elpc.org
schase@elpc.org

MADISON GAS AND ELECTRIC
Edwin J. Hughes
Stafford Rosenbaum LLP
222 West Washington Avenue, Suite 900
Madison, WI 53701-1784
Ph. 608-259-2658
ehughes@staffordlaw.com

NATURAL RESOURCES DEFENSE COUNCIL
Samantha Williams
20 N Wacker Drive, Suite 1600
Chicago, IL 60606
Ph.:312-651-7930
swilliams@nrdc.org

PUBLIC SERVICE COMMISSION OF WISCONSIN (not a party but must be served)
Michael Varda
Jodee Bartels
610 North Whitney Way
PO Box 7854
Madison, WI 53707-7854
Michael.varda@wisconsin.gov; Jodee.bartels@wisconsin.gov

RENEW WISCONSIN
Bradley D. Klein
Stephanie K. Chase
Environmental Law & Policy Center
222 S. Hamilton Street, Suite 14
Madison, Wisconsin 53703
Ph. 608-204-9735
bklein@elpc.org
schase@elpc.org

Docket 3270-UR-120

Additional contact:

    Michael Vickerman
    Program and Policy Director
    RENEW Wisconsin
    222 S. Hamilton Street
    Madison, WI 53703
    Ph.: 608-255-4044
    mvickerman@renewwisconsin.org

WIND ON THE WIRES
Susan M. Crawford
Jeffrey L. Vercauteren
Cullen, Weston, Pines & Bach, LLP
122 West Washington Avenue, Suite 900
Madison, Wisconsin 53703
Ph. 608-251-0101
crawford@cwpb.com; vercauteren@cwpb.com

WISCONSIN INDUSTRIAL ENERGY GROUP, INC.
Steven A. Heinzen
Heinzen Law SC
Two East Mifflin Street, Suite 402
Madison, WI 53703
Ph. 608-209-7468
Steve.heinzen@heinzenlaw.com

    Additional contact:
    Todd Stuart
    Executive Director
    Wisconsin Industrial Energy Group, Inc.
    10 E. Doty Street, Ste. 800
    Madison, WI 53703
    Phone: 608.441.5740
    Fax: 608.441.5741
    tstuart@wieg.org

Madison Gas & Electric Company
Summary of Present and Authorized Electric Class Revenues
For the Test Year 2015

	RATE CLASS	KWH	PRESENT REVENUES	2015 AUTHORIZED REVENUES	AUTHORIZED DOLLAR INCREASE	AUTHORIZED PERCENT INCREASE
Rg-1	Residential	793,322,701	$130,262,024	$134,948,112	$4,686,088	3.60%
Rg-2	Residential Time-of-Use	12,656,391	$1,776,968	$1,840,867	$63,899	3.60%
Rw-1	Residential Controlled Water Heating	86,950	$9,745	$10,067	$322	3.30%
Rg-3	Residential Lifeline (CLOSED)	68,805	$9,524	$9,865	$341	3.58%
Rg-6	Residential Low Income		$0	$0	$0	
Rg-7	Residential Distributed Generation		$35,198	$36,466	$1,268	3.60%
	TOTAL RESIDENTIAL REVENUE	806,134,847	$132,093,460	$136,845,377	$4,751,918	3.60%
Cg-5	Small C&I Lighting and Power (<20 kW)	200,735,955	$30,739,256	$30,774,728	$35,472	0.12%
Cg-3	Small C&I Optional Time-of-Use (<20 kW)	7,245,930	$948,379	$949,318	$939	0.10%
	TOTAL SMALL COMMERCIAL & INDUSTRIAL REVENUE	207,981,885	$31,687,635	$31,724,046	$36,411	0.11%
Cg-4	C&I Time-of-Use (20-200 kW)	629,129,578	$78,786,427	$82,418,360	$3,631,933	4.61%
Cg-2/6	C&I Lighting and Power Time-of-Use (>200 kW)	1,074,291,653	$110,959,590	$116,474,628	$5,515,039	4.97%
Cp-1	C&I High Load Factor Direct Control Interruptible - Transmission Volt.	98,859,953	$5,031,132	$5,189,433	$158,301	3.15%
Sp-3	University of Wisconsin Time-of-Use	423,277,181	$38,436,610	$40,359,746	$1,923,135	5.00%
Sp-4	Oscar Mayer Foods Corporation Time-of-Use	68,131,917	$5,964,737	$6,259,197	$294,460	4.94%
	TOTAL LARGE COMMERCIAL & INDUSTRIAL REVENUE	2,293,690,282	$239,178,496	$250,701,364	$11,522,868	4.82%
	Primary Voltage Discount (kW)		($56,903)	($56,903)	$0	0.00%
	Primary Voltage Discount (kWh)		($223,724)	($223,724)	$0	0.00%
	Transformer Equipment Discount (kW)		($17,493)	($17,493)	$0	0.00%
	TOTAL DISCOUNTS [1]		($298,120)	($298,120)	$0	0.00%
Is-3	Interruptible Service Rider		($555,726)	($555,726)	$0	0.00%
Is-4	Direct Control Interruptible Service Rider		($448,227)	($448,227)	$0	0.00%
SCS	Summer Curtailable Service		$0	$0	$0	0.00%
	TOTAL INTERRUPTIBLE CREDITS [1]		($1,003,953)	($1,003,953)	$0	0.00%
Gf-1	General Flat Rate	5,731,920	$683,642	$727,666	$44,024	6.44%
Mg-2	Secondary Service for Municipal Defense Sirens	0	$3,366	$3,524	$158	4.69%
MLS	Athletic Field Lighting	462,633	$64,834	$68,236	$3,402	5.25%
OL-1	Outdoor Overhead Lighting Service - Private Unmetered	1,913,952	$575,260	$614,534	$39,274	6.83%
EV-1	Home Electric Vehicle Charging Stations		$0	$0	$0	0.00%
EV-2	Electric Vehicle Public Charging Pilot Rider		$0	$12,750	$12,750	0.00%
	TOTAL MISCELLANEOUS AND LIGHTING	8,108,505	$1,327,102	$1,426,710	$99,608	7.51%
SL-1	Streetlighting Service - Company-Owned and Company-Maintained	1,814,472	$225,838	$229,263	$3,425	1.52%
SL-2	Streetlighting Service - Customer-Owned and Customer-Maintained	4,093,700	$480,116	$529,832	$49,717	10.36%
SL-3	Streetlighting Service - Customer-Owned and Company-Maintained	4,689,888	$765,842	$811,284	$45,442	5.93%
	TOTAL STREETLIGHTING SERVICE	10,598,060	$1,471,796	$1,570,379	$98,583	6.70%
RWE-1	Residential Wind Energy Program		$2,120,000	$1,293,200	($826,800)	-39.00%
BWE-1	Business Wind Energy Program		$1,090,802	$821,389	($269,413)	-24.70%
BGS	Backup Generation Service		$954,020	$954,020	$0	0.00%
AGS	Alternative Generation Schedule		$0	$0	$0	0.00%
TOTAL ELECTRIC RETAIL REVENUE		3,326,513,579	$409,923,309	$425,336,485	$15,413,176	3.76%
	Interdepartmental*	3,247,422	$388,312	$418,078	$29,766	7.67%
TOTAL ELECTRIC RETAIL REVENUE W/ INTERDEPART.		3,329,761,001	**$410,311,621**	**$425,754,563**	**$15,442,942**	3.76%

Notes

[1] Discounts and interruptible credits are listed here for reference. They are already subtracted from the appropriate Commercial and Industrial Class revenue totals.

Madison Gas & Electric Company
Summary of Present and Authorized Electric Rates
For the Test Year 2015

TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
RESIDENTIAL SERVICE Rg-1						
Grid Connection & Customer Service Charge	$10.44	$0.34308	per bill per day	$0.62466	per bill per day	$19.00
Distribution Charge		$0.03000	per kWh	$0.03425	per kWh	
Electricity Charge						
Winter Electricity		$0.10992	per kWh	$0.09581	per kWh	
Summer Electricity		$0.12222	per kWh	$0.10708	per kWh	
RESIDENTIAL TIME-OF-USE Rg-2						
Grid Connection & Customer Service Charge	$10.44	$0.34308	per bill per day	$0.62466	per bill per day	$19.00
Distribution Charge		$0.03000	per kWh	$0.03425	per kWh	
Electricity Charge						
On-Peak Periods 1 & 3 Adder - Winter		$0.16650	per kWh	$0.16021	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.19500	per kWh	$0.18763	per kWh	
On-Peak Periods 2 Adder - Winter		$0.16650	per kWh	$0.16021	per kWh	
On-Peak Periods 2 Adder - Summer		$0.21812	per kWh	$0.20988	per kWh	
Base Energy Electricity - Winter		$0.04289	per kWh	$0.04127	per kWh	
Base Energy Electricity - Summer		$0.04289	per kWh	$0.04127	per kWh	
RESIDENTIAL CONTROLLED WATER HEATING Rw-1						
Grid Connection & Customer Service Charge	$4.08	$0.13428	per bill per day	$0.28000	per bill per day	$8.52
Distribution Charge		$0.03000	per kWh	$0.03000	per kWh	
Electricity Charge						
Winter Electricity		$0.05608	per kWh	$0.03454	per kWh	
Summer Electricity		$0.06401	per kWh	$0.04097	per kWh	
RESIDENTIAL LIFELINE Rg-3						
Grid Connection & Customer Service Charge	$7.62	$0.25051	per day per bill	$0.25051	per day per bill	$7.62
Distribution Charge		$0.03000	per kWh	$0.03000	per kWh	
Electricity Charge						
Winter First 300 kWh per month		$0.07164	per kWh	$0.07549	per kWh	
Winter Over 300 kWh per month		$0.03828	per kWh	$0.04034	per kWh	
Summer First 300 kWh per month		$0.08054	per kWh	$0.08487	per kWh	
Summer Over 300 kWh per month		$0.04168	per kWh	$0.04392	per kWh	
RESIDENTIAL DISTRIBUTED GENERATION Rg-7 (New Offering)						
Grid Connection & Customer Service Charge		N/A		$0.35512	per day per bill	$10.80
Distribution Charge		N/A		$0.03100	per kWh	
Electricity Charge						
Winter Electricity		N/A		$0.11890	per kWh	
Summer Electricity		N/A		$0.13221	per kWh	
SMALL C/I LIGHTING AND POWER Cg-5 (0-20 kW)						
Grid Connection & Customer Service Charge	$10.44	$0.34308	per day per bill	$0.78669	per day per bill	$23.93
Distribution Charge		$0.03000	per kWh	$0.02473	per kWh	
Electricity Charge						
Winter Electricity		$0.10992	per kWh	$0.10332	per kWh	
Summer Electricity		$0.12222	per kWh	$0.11672	per kWh	
SMALL C/I TIME-OF-USE Cg-3 (<20 kW)						
Grid Connection & Customer Service Charge						
Single Phase	$10.44	$0.34308	per day per bill	$0.73249	per day per bill	$22.28
Three Phase	$18.70	$0.61480	per day per bill	$1.00249	per day per bill	$30.49
Distribution Charge		$0.03000	per kWh	$0.02473	per kWh	
Electricity Charge						
On-Peak Periods 1 & 3 Adder - Winter		$0.16650	per kWh	$0.16650	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.19500	per kWh	$0.19500	per kWh	
On-Peak Periods 2 Adder - Winter		$0.16650	per kWh	$0.16650	per kWh	
On-Peak Periods 2 Adder - Summer		$0.21812	per kWh	$0.21812	per kWh	
Base Energy Electricity - Winter		$0.04289	per kWh	$0.04289	per kWh	
Base Energy Electricity - Summer		$0.04289	per kWh	$0.04289	per kWh	

Madison Gas & Electric Company
Summary of Present and Authorized Electric Rates
For the Test Year 2015

TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
C/I LIGHTING AND POWER TIME-OF-USE Cg-4 LEVEL A (20-75 kW)						
Grid Connection & Customer Service Charge						
Single Phase	$48.00	$1.57824	per day per bill	$6.19251	per kWh	$188.36
Three Phase	$51.70	$1.69960	per day per bill	$6.32048	per kWh	$192.25
Distribution Charge						
Customer Maximum Demand	$2.50	$0.08219	per kW per day	$0.08480	per kWh	$2.58
Electricity Charges						
Maximum Monthly Demand: Winter	$10.20	$0.33520	per kW per day	$0.34530	per kW per day	$10.50
Summer	$12.50	$0.41100	per kW per day	$0.42300	per kW per day	$12.87
On-Peak Periods 1 & 3 Adder - Winter		$0.05770	per kWh	$0.05487	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.06903	per kWh	$0.06558	per kWh	
On-Peak Periods 2 Adder - Winter		$0.05770	per kWh	$0.05487	per kWh	
On-Peak Periods 2 Adder - Summer		$0.07455	per kWh	$0.07306	per kWh	
Base Energy Electricity - Winter		$0.05337	per kWh	$0.04975	per kWh	
Base Energy Electricity - Summer		$0.05337	per kWh	$0.04975	per kWh	
C/I LIGHTING AND POWER TIME-OF-USE Cg-4 LEVEL B (76-200 kW)						
Grid Connection & Customer Service Charge						
Single Phase	$48.00	$1.57824	per day per bill	$6.19251	per day per bill	$188.36
Three Phase	$51.70	$1.69960	per day per bill	$6.32048	per day per bill	$192.25
Distribution Charge						
Customer Maximum Demand	$2.50	$0.08219	per kW per day	$0.08480	per kW per day	$2.58
Electricity Charges						
Maximum Monthly Demand: Winter	$10.20	$0.33520	per kW per day	$0.34530	per kW per day	$10.50
Summer	$12.50	$0.41100	per kW per day	$0.42300	per kW per day	$12.87
On-Peak Periods 1 & 3 Adder - Winter		$0.05770	per kWh	$0.05487	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.06903	per kWh	$0.06558	per kWh	
On-Peak Periods 2 Adder - Winter		$0.05770	per kWh	$0.05487	per kWh	
On-Peak Periods 2 Adder - Summer		$0.07455	per kWh	$0.07306	per kWh	
Base Energy Electricity - Winter		$0.05337	per kWh	$0.04975	per kWh	
Base Energy Electricity - Summer		$0.05337	per kWh	$0.04975	per kWh	
C/I LIGHTING AND POWER TIME-OF-USE CG-2 (OVER 200 kW)						
Grid Connection & Customer Service Charge	$190.80	$6.27288	per day per bill	$8.93449	per day per bill	$271.76
Distribution Charge						
Customer Maximum Demand	$3.00	$0.09863	per kW per day	$0.10600	per kW per day	$3.22
Electricity Charges						
Maximum Monthly Demand: Winter	$10.54	$0.34652	per kW per day	$0.37100	per kW per day	$11.28
Summer	$12.88	$0.42350	per kW per day	$0.45100	per kW per day	$13.72
On-Peak Periods 1 & 3 Adder - Winter		$0.03724	per kWh	$0.03843	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.04537	per kWh	$0.04682	per kWh	
On-Peak Periods 2 Adder - Winter		$0.03724	per kWh	$0.03843	per kWh	
On-Peak Periods 2 Adder - Summer		$0.05354	per kWh	$0.05622	per kWh	
Base Energy Electricity - Winter		$0.05500	per kWh	$0.05668	per kWh	
Base Energy Electricity - Summer		$0.05500	per kWh	$0.05668	per kWh	
C/I LIGHTING AND POWER CRITICAL PEAK PRICING CG-2A (OVER 200 kW)						
Grid Connection & Customer Service Charge	$159.00	$5.22740	per kW	$8.93449	per kW	$271.76
Distribution Charge						
Customer Maximum Demand	$3.00	$0.09863	per bill per day	$0.10600	per bill per day	$3.22
Electricity Charges						
Maximum Monthly Demand: Winter	$10.54	$0.34652	$0.00000	$0.37100	$0.00000	$11.28
Summer	$12.88	$0.42350	$0.00000	$0.45100	$0.00000	$13.72
On-Peak Periods 1 & 3 Adder - Winter		$0.03724	per kWh	$0.03843	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.04537	per kWh	$0.04682	per kWh	
On-Peak Periods 2 Adder - Winter		$0.03724	per kWh	$0.03843	per kWh	
On-Peak Periods 2 Adder - Summer		$0.04537	per kWh	$0.04682	per kWh	
Base Energy Electricity - Winter		$0.05500	per kWh	$0.05668	per kWh	
Base Energy Electricity - Summer		$0.05500	per kWh	$0.05668	per kWh	
Critical Peak Pricing Adder		$0.22600	per kWh	$0.22432	per kWh	

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TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
C/I LIGHTING AND POWER TIME-OF-USE HLF CG-6 (OVER 1,000 kW)						
Grid Connection & Customer Service Charge	$190.80	$6.27288	per day per bill	$8.93449	per day per bill	$271.76
Distribution Charge						
Customer Maximum Demand	$3.00	$0.09863	per kW per day	$0.10600	per kW per day	$3.22
Electricity Charges						
Maximum Monthly Demand: Winter	$10.54	$0.34652	per kW per day	$0.37100	per kW per day	$11.28
Summer	$12.88	$0.42350	per kW per day	$0.45100	per kW per day	$13.72
On-Peak Periods 1 & 3 Adder - Winter		$0.02817	per kWh	$0.02944	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.03494	per kWh	$0.03669	per kWh	
On-Peak Periods 2 Adder - Winter		$0.02817	per kWh	$0.02944	per kWh	
On-Peak Periods 2 Adder - Summer		$0.04110	per kWh	$0.04398	per kWh	
Base Energy Electricity - Winter		$0.05323	per kWh	$0.05579	per kWh	
Base Energy Electricity - Summer		$0.05323	per kWh	$0.05579	per kWh	
C/I LIGHTING AND POWER HLF CRITICAL PEAK PRICING CG-6A (OVER 1,000 kW)						
Grid Connection & Customer Service Charge	$190.80	$6.27288	per day per bill	$8.93449	per day per bill	$271.76
Distribution Charge						
Customer Maximum Demand	$3.00	$0.09863	per kW per day	$0.10600	per kW per day	$3.22
Electricity Charges						
Maximum Monthly Demand: Winter	$10.54	$0.34652	per kW per day	$0.37100	per kW per day	$11.28
Summer	$12.88	$0.42350	per kW per day	$0.45100	per kW per day	$13.72
On-Peak Periods 1 & 3 Adder - Winter		$0.02817	per kWh	$0.02944	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.03494	per kWh	$0.03669	per kWh	
On-Peak Periods 2 Adder - Winter		$0.02817	per kWh	$0.02944	per kWh	
On-Peak Periods 2 Adder - Summer		$0.03494	per kWh	$0.03669	per kWh	
Base Energy Electricity - Winter		$0.05323	per kWh	$0.05579	per kWh	
Base Energy Electricity - Summer		$0.05323	per kWh	$0.05579	per kWh	
Critical Peak Pricing Adder		$0.22777	per kWh	$0.22521	per kWh	
COMMERCIAL DISTRIBUTED GENERATION (0-20 kW) Cg-7						
Grid Connection & Customer Service Charge		N/A		$0.34308	per day per bill	$10.44
Distribution Charge		N/A		$0.02473	per kWh	
Electricity Charge						
Winter Electricity		N/A		$0.11520	per kWh	
Summer Electricity		N/A		$0.12809	per kWh	
COMMERCIAL DISTRIBUTED GENERATION (20-200 kW) Cg-8						
Grid Connection & Customer Service Charge						
Single Phase		N/A		$1.63742	per day per bill	$49.80
Three Phase		N/A		$1.76215	per day per bill	$53.60
Distribution Charge						
Customer Maximum Demand		N/A		$0.08533	per kW per day	$2.60
Electricity Charges						
Maximum Monthly Demand: Winter		N/A		$0.34861	per kW per day	$10.60
Summer		N/A		$0.42744	per kW per day	$13.00
On-Peak Periods 1 & 3 Adder - Winter		N/A		$0.06100	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		N/A		$0.07300	per kWh	
On-Peak Periods 2 Adder - Winter		N/A		$0.06100	per kWh	
On-Peak Periods 2 Adder - Summer		N/A		$0.07950	per kWh	
Base Energy Electricity - Winter		N/A		$0.05583	per kWh	
Base Energy Electricity - Summer		N/A		$0.05583	per kWh	

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C/I HIGH LOAD FACTOR CONTROL INTERRUPTIBLE SERVICE TRANS. VOLTAGE CP-1						
Grid Connection & Customer Service Charge	$780.01	$25.64400	per day per bill	$31.82000	per day per bill	$967.86
Distribution Charge		None		None		
Electricity Charges						
Maximum Monthly Demand: Winter	$3.88	$0.12759	per kW per day	$0.13300	per kW per day	$4.05
Summer	$4.56	$0.14989	per kW per day	$0.15600	per kW per day	$4.75
On-Peak Periods 1 & 3 Adder - Winter		$0.01704	per kWh	$0.01755	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.02573	per kWh	$0.02655	per kWh	
On-Peak Periods 2 Adder - Winter		$0.01704	per kWh	$0.01755	per kWh	
On-Peak Periods 2 Adder - Summer		$0.03199	per kWh	$0.03391	per kWh	
Base Energy Electricity - Winter		$0.03839	per kWh	$0.03948	per kWh	
Base Energy Electricity - Summer		$0.03839	per kWh	$0.03948	per kWh	
UNIVERSITY OF WISCONSIN TIME-OF-USE SP-3						
Grid Connection & Customer Service Charge		$3,500.00	per bill	$3,500.00	per bill	
Distribution Charge						
Customer Maximum Demand	$2.50	$0.08219	per kW per day	$0.09534	per kW per day	$2.90
Electricity Charges						
Maximum Monthly Demand						
Winter	$29.73	$0.97737	per kW per day	$1.00767	per kW per day	$30.65
Summer	$34.23	$1.12540	per kW per day	$1.16017	per kW per day	$35.29
Generation Credit		($0.46000)	per kW per day	($0.46000)	per kW per day	
On-Peak Energy						
Winter		$0.03300	per kWh	$0.03710	per kWh	
Summer		$0.03600	per kWh	$0.03860	per kWh	
Off-Peak Energy						
Winter		$0.02393	per kWh	$0.02500	per kWh	
Summer		$0.02393	per kWh	$0.02500	per kWh	
OSCAR MAYER TIME-OF-USE SP-4						
Grid Connection & Customer Service Charge	$286.80	$9.42912	per day per bill	$24.95249	per day per bill	$758.97
Distribution Charge						
Customer Maximum Demand	$2.50	$0.08219	per kW per day	$0.09000	per kW per day	$2.74
Electricity Charges						
Firm Contract Demand: Winter	$10.54	$0.34652	per kW per day	$0.38800	per kW per day	$11.80
Summer	$12.88	$0.42350	per kW per day	$0.46900	per kW per day	$14.27
On-Peak Periods 1 & 3 Adder - Winter		$0.02840	per kWh	$0.03000	per kWh	
On-Peak Periods 1 & 3 Adder - Summer		$0.03240	per kWh	$0.03400	per kWh	
On-Peak Periods 2 Adder - Winter		$0.02840	per kWh	$0.03000	per kWh	
On-Peak Periods 2 Adder - Summer		$0.03858	per kWh	$0.04000	per kWh	
Base Energy Electricity - Winter		$0.05054	per kWh	$0.05140	per kWh	
Base Energy Electricity - Summer		$0.05054	per kWh	$0.05140	per kWh	
Supplemental Energy						
Periods 1 & 3 Adder - Winter		$0.02840	per kWh	$0.03000	per kWh	
Periods 1 & 3 Adder - Summer		$0.03240	per kWh	$0.03400	per kWh	
Periods 2 Adder - Winter		$0.02840	per kWh	$0.03000	per kWh	
Periods 2 Adder - Summer		$0.03858	per kWh	$0.04000	per kWh	
SUMMER CURTAILABLE SERVICE (SCS)						
Cg-1 Summer Interruptible kW	$0.00	$0.00000	per kW per day	$0.00000	per kW per day	$0.00
Cg-4 Summer Interruptible kW	$0.00	$0.00000	per kW per day	$0.00000	per kW per day	$0.00
Cg-2 Summer Interruptible kW	$0.00	$0.00000	per kW per day	$0.00000	per kW per day	$0.00
Cg-6 Summer Interruptible kW	$0.00	$0.00000	per kW per day	$0.00000	per kW per day	$0.00
Sp-3 Summer Interruptible kW	$0.00	$0.00000	per kW per day	$0.00000	per kW per day	$0.00
INTERRUPTIBLE SERVICE RIDER Is-3						
Cg-2 Winter Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Cg-2 Summer Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Cg-6 Winter Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
Cg-6 Summer Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
SP-3 Winter Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)
SP-3 Summer Interruptible kW	($3.75)	($0.12329)	per kW per day	($0.12329)	per kW per day	($3.75)

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DIRECT CONTROL INTERRUPTIBLE SERVICE RIDER Is-4						
Variable Pricing						
Cg-4 Winter Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-4 Summer Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-2 Winter Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-2 Summer Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-6 Winter Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Cg-6 Summer Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Sp-3 Winter Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
Sp-3 Summer Interruptible kW	($4.00)	($0.13151)	per kW per day	($0.13151)	per kW per day	($4.00)
MISCELLANEOUS FLAT RATE SERVICE GF-1						
LEVEL II CATV Amplifiers		$72.50	each per bill	$76.50	each per bill	
LEVEL III Unmetered Service						
Grid Connection & Customer Service Charge	$10.44	$0.34308	per bill per day	$0.65420	per bill per day	$19.90
Distribution Service		$0.03000	per kWh	$0.03000	per kWh	
Electricity Service		$0.08942	per kWh	$0.09600	per kWh	
SECONDARY SERVICE FOR MUNICIPAL DEFENSE SIRENS Mg-2						
Motor Driven Sirens		$3.86	each per bill	$4.05	each per bill	
Electronic Sirens		$5.60	each per bill	$5.86	each per bill	
ATHLETIC FIELD LIGHTING MLS						
Grid Connection & Customer Service Charge	$10.44	$0.34308	per day per bill	$0.78669	per day per bill	$23.93
Distribution Service		$0.03000	per kWh	$0.03000	per kWh	
Electricity Service		$0.10413	per kWh	$0.10250	per kWh	
OUTDOOR OVERHEAD LIGHTING SERVICE --OL-1 (PRIVATE UNMETERED)						
DUSK-TO-DAWN YARD LIGHTING						
150 WATT HPS LAMPS		$15.00	per lamp per bill	$16.15	per lamp per bill	
100 WATT HPS LAMPS		$13.40	" " " "	$14.25	" " " "	
70 WATT HPS LAMPS		$12.50	" " " "	$13.15	" " " "	
400 WATT MV LAMPS (CLOSED)		$22.00	" " " "	$22.15	" " " "	
250 WATT MV LAMPS (CLOSED)		$18.00	" " " "	$17.85	" " " "	
175 WATT MV LAMPS (CLOSED)		$15.60	" " " "	$15.85	" " " "	
SECURITY FLOOD LIGHTING						
400 WATT HPS LAMPS		$25.70	per lamp per bill	$25.95	per lamp per bill	
250 WATT HPS LAMPS		$21.10	" " " "	$21.55	" " " "	
150 WATT HPS LAMPS		$17.10	" " " "	$18.45	" " " "	
70 WATT HPS LAMPS		$13.80	" " " "	$15.05	" " " "	
400 WATT MH LAMPS		$25.70	" " " "	$25.35	" " " "	
250 WATT MH LAMPS		$21.10	" " " "	$21.25	" " " "	
150 WATT MH LAMPS		$17.10	" " " "	$18.35	" " " "	
70 WATT MH LAMPS		$13.80	" " " "	$15.85	" " " "	
400 WATT EQUIVALENT LED LAMPS		$23.90	" " " "	$24.15	" " " "	
250 WATT EQUIVALENT LED LAMPS		$19.20	" " " "	$19.35	" " " "	
150 WATT EQUIVALENT LED LAMPS		$15.50	" " " "	$16.75	" " " "	
70 WATT EQUIVALENT LED LAMPS		$13.70	" " " "	$16.15	" " " "	
POLES: WOOD		$7.70	" " " "	$8.85	" " " "	
NONWOOD		$13.70	" " " "	$14.25	" " " "	

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TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
STREET LIGHTING SERVICE -- SL-1 (COMPANY OWNED AND COMPANY MAINTAINED)						
Distribution Service Charge		$3.00	per lamp ber bill	$3.20	per lamp ber bill	
Electricity Service Unit Charge		$0.06957	per kWh	$0.07859	per kWh	
OVERHEAD SERVICE FACILITIES CHARGE						
ALL NIGHT EVERY NIGHT						
400 WATT MV		$9.40	per lamp per bill	$8.40	per lamp per bill	
250 WATT MV		$7.70	" " " "	$8.00	" " " "	
175 WATT MV		$7.60	" " " "	$7.90	" " " "	
250 WATT HPS		$8.20	" " " "	$8.40	" " " "	
200 WATT HPS		$7.50	" " " "	$7.80	" " " "	
150 WATT HPS		$6.50	" " " "	$7.60	" " " "	
100 WATT HPS		$5.80	" " " "	$7.60	" " " "	
70 WATT HPS		$5.70	" " " "	$7.60	" " " "	
300 WATT INC		$7.90	" " " "	$7.70	" " " "	
250 WATT EQUIVALENT LED (LARGE)		N/A	" " " "	$16.60	" " " "	
150 WATT EQUIVALENT LED (MEDIUM)		N/A	" " " "	$14.40	" " " "	
100 WATT EQUIVALENT LED (SMALL)		N/A	" " " "	$12.50	" " " "	
MIDNIGHT						
400 WATT MV MN		$9.40	per lamp per bill	$8.40	per lamp per bill	
UNDERGROUND SERVICE FACILITIES CHARGE						
250 WATT HPS ANEN		$18.40	per lamp per bill	$13.40	per lamp per bill	
200 WATT HPS ANEN		$17.60	" " " "	$13.00	" " " "	
150 WATT HPS ANEN		$17.40	" " " "	$12.70	" " " "	
100 WATT HPS ANEN		$17.20	" " " "	$12.60	" " " "	
70 WATT HPS ANEN		$17.10	" " " "	$12.50	" " " "	
250 WATT EQUIVALENT LED (LARGE)		N/A	" " " "	$21.00	" " " "	
150 WATT EQUIVALENT LED (MEDIUM)		N/A	" " " "	$18.70	" " " "	
100 WATT EQUIVALENT LED (SMALL)		N/A	" " " "	$16.90	" " " "	
STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED AND CUSTOMER MAINTAINED)						
Distribution Service Charge		$3.00	per lamp ber bill	$3.20	per lamp ber bill	
Electricity Service Unit Charge		$0.06957	per kWh	$0.07859	per kWh	
ALL NIGHT (Below are the monthly charges/lamp resulting from the Distribution Service & Electricity Service Charges, above)						
400-WATT MV ANEN		$13.57	" " " "	$15.15	" " " "	
250-WATT MV ANEN		$9.61	" " " "	$10.67	" " " "	
175-WATT MV ANEN		$7.73	" " " "	$8.54	" " " "	
100-WATT MV ANEN		$5.71	" " " "	$6.27	" " " "	
400-WATT HPS ANEN		$13.23	per lamp per bill	$14.75	per lamp per bill	
250-WATT HPS ANEN		$9.61	" " " "	$10.67	" " " "	
200-WATT HPS ANEN		$8.22	" " " "	$9.09	" " " "	
150-WATT HPS ANEN		$6.97	" " " "	$7.68	" " " "	
100-WATT HPS ANEN		$5.71	" " " "	$6.27	" " " "	
70-WATT HPS ANEN		$4.95	" " " "	$5.40	" " " "	
90-WATT LPS ANEN		$5.43	per lamp per bill	$5.95	per lamp per bill	
55-WATT LPS ANEN		$4.46	" " " "	$4.85	" " " "	
35-WATT LPS ANEN		$3.97	" " " "	$4.30	" " " "	
175-WATT MH ANEN		$9.61	" " " "	$10.67	" " " "	
100-WATT MH ANEN		$5.71	" " " "	$6.27	" " " "	
70-WATT MH ANEN		$4.95	" " " "	$5.40	" " " "	
MIDNIGHT SCHEDULE						
400-WATT MV MN		$8.29	per lamp per bill	$9.17	per lamp per bill	
250-WATT MV MN		$6.34	" " " "	$6.97	" " " "	
400-WATT HPS MN		$8.08	per lamp per bill	$8.94	per lamp per bill	
250-WATT HPS MN		$6.34	" " " "	$6.97	" " " "	
200-WATT HPS MN		$5.64	" " " "	$6.19	" " " "	
150-WATT HPS MN		$5.02	" " " "	$5.48	" " " "	
100-WATT HPS MN		$4.39	" " " "	$4.77	" " " "	
70-WATT HPS MN		$3.97	" " " "	$4.30	" " " "	

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STREET LIGHTING SERVICE -- SL-2 (CUSTOMER OWNED AND CUSTOMER MAINTAINED) -- Continued						
90-WATT LPS MN		$4.25	per lamp per bill	$4.61	per lamp per bill	
55-WATT LPS MN		$3.77	" " " "	$4.06	" " " "	
35-WATT LPS MN		$3.49	" " " "	$3.75	" " " "	
175-WATT MH MN		$5.30	" " " "	$5.79	" " " "	
100-WATT MH MN		$4.39	" " " "	$4.77	" " " "	
70-WATT MH MN		$3.97	" " " "	$4.30	" " " "	
10:30 PM SCHEDULE						
400-WATT MV 10:30 (CLOSED)		$6.83	per lamp per bill	$7.52	per lamp per bill	
400-WATT HPS 10:30		$6.69	" " " "	$7.37	" " " "	
250-WATT HPS 10:30		$5.37	" " " "	$5.87	" " " "	
200-WATT HPS 10:30		$4.88	" " " "	$5.32	" " " "	
150-WATT HPS 10:30		$4.46	" " " "	$4.85	" " " "	
100-WATT HPS 10:30		$3.97	" " " "	$4.30	" " " "	
70-WATT HPS 10:30		$3.70	" " " "	$3.99	" " " "	
3:00 A.M. SCHEDULE						
100-WATT MV 3AM (CLOSED)		$5.02	per lamp per bill	$5.48	per lamp per bill	
400-WATT HPS 3AM		$10.65	" " " "	$11.84	" " " "	
250-WATT HPS 3AM		$7.94	" " " "	$8.78	" " " "	
200-WATT HPS 3AM		$6.97	" " " "	$7.68	" " " "	
150-WATT HPS 3AM		$5.99	" " " "	$6.58	" " " "	
100-WATT HPS 3AM		$5.02	" " " "	$5.48	" " " "	
70-WATT HPS 3AM		$4.46	" " " "	$4.85	" " " "	
175-WATT MH 3AM		$6.48	" " " "	$7.13	" " " "	
100-WATT MH 3AM		$5.02	" " " "	$5.48	" " " "	
70-WATT MH 3AM		$4.46	" " " "	$4.85	" " " "	
STREET LIGHTING SERVICE -- SL-3 (CUSTOMER OWNED AND COMPANY MAINTAINED)						
Distribution Service Charge		$3.00	per lamp ber bill	$3.20	per lamp ber bill	
Electricity Service Unit Charge		$0.06957	per kWh	$0.07859	per kWh	
OVERHEAD SERVICE						
ALL NIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT HPS ANEN Maintenance Charge		$1.57	per lamp per bill	$1.00	per lamp per bill	
200 WATT HPS ANEN Maintenance Charge		$1.57	" " " "	$1.00	" " " "	
150 WATT HPS ANEN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	
100 WATT HPS ANEN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	
70 WATT HPS ANEN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	
MIDNIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT HPS MN Maintenance Charge		$1.57	per lamp per bill	$1.00	per lamp per bill	
200 WATT HPS MN Maintenance Charge		$1.27	" " " "	$1.00	" " " "	
150 WATT HPS MN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	
100 WATT HPS MN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	
150 WATT HPS MN Maintenance Charge		$1.15	" " " "	$1.00	" " " "	

Madison Gas & Electric Company
Summary of Present and Authorized Electric Rates
For the Test Year 2015

TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
STREET LIGHTING SERVICE -- SL-3 (CUSTOMER OWNED AND COMPANY MAINTAINED) -- Continued						
ALL NIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT MH ANEN Maintenance Charge		$1.50	per lamp per bill	$1.00	per lamp per bill	
150 WATT MH ANEN Maintenance Charge		$1.25	" " " "	$1.00	" " " "	
70 WATT MH ANEN Maintenance Charge		$1.25	" " " "	$1.00	" " " "	
MIDNIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT MH MN Maintenance Charge		$1.50	per lamp per bill	$1.00	per lamp per bill	
150 WATT MH MN Maintenance Charge		$1.25	" " " "	$1.00	" " " "	
70 WATT MH MN Maintenance Charge		$1.25	" " " "	$1.00	" " " "	
UNDERGROUND SERVICE						
ALL NIGHT SCHEDULE MAINTENANCE CHARGE						
175 WATT MV ANEN		$1.15	per lamp per bill	$1.00	per lamp per bill	
250 WATT MV ANEN		$1.57	" " " "	$1.00	" " " "	
250 WATT HPS ANEN		$1.57	" " " "	$1.00	" " " "	
200 WATT HPS ANEN		$1.57	" " " "	$1.00	" " " "	
150 WATT HPS ANEN		$1.15	" " " "	$1.00	" " " "	
100 WATT HPS ANEN		$1.15	" " " "	$1.00	" " " "	
70 WATT HPS ANEN		$1.15	" " " "	$1.00	" " " "	
MIDNIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT HPS MN		$1.57	per lamp per bill	$1.00	per lamp per bill	
150 WATT HPS MN		$1.15	" " " "	$1.00	" " " "	
100 WATT HPS MN		$1.15	" " " "	$1.00	" " " "	
ALL NIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT MH ANEN		$1.50	per lamp per bill	$1.00	per lamp per bill	
150 WATT MH ANEN		$1.25	" " " "	$1.00	" " " "	
70 WATT MH ANEN		$1.25	" " " "	$1.00	" " " "	
MIDNIGHT SCHEDULE MAINTENANCE CHARGE						
250 WATT MH MN		$1.50	per lamp per bill	$1.00	per lamp per bill	
150 WATT MH MN		$1.25	" " " "	$1.00	" " " "	
70 WATT MH MN		$1.25	" " " "	$1.00	" " " "	
ALTERNATIVE GENERATION SCHEDULE - AGS						
SUMMER						
Firm Standby						
Maximum Monthly Demand		$0.42350	per kW per day	$0.45100	per kW per day	
On-Peak 2 Energy Adder		$0.05354	per kWh	$0.05622	per kWh	
On-Peak 1 and 3 Energy Adder		$0.04537	per kWh	$0.04682	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	
Interruptible Standby Charge						
Maximum Monthly Demand		$0.29199	per kW per day	$0.31949	per kW per day	
On-Peak 2 Energy Adder		$0.05354	per kWh	$0.05622	per kWh	
On-Peak 1 and 3 Energy Adder		$0.04537	per kWh	$0.04682	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	
WINTER						
Firm Standby						
Maximum Monthly Demand		$0.34652	per kW per day	$0.37100	per kW per day	
On-Peak 2 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
On-Peak 1 and 3 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	

Madison Gas & Electric Company
Summary of Present and Authorized Electric Rates
For the Test Year 2015

TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
ALTERNATIVE GENERATION SCHEDULE - AGS -- Continued						
Interruptible Standby Charge						
Maximum Monthly Demand		$0.21501	per kW per day	$0.23949	per kW per day	
On-Peak 2 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
On-Peak 1 and 3 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	
Firm Maintenance - Winter Only						
Maximum Monthly Demand		$0.34652	per kW per day	$0.37100	per kW per day	
On-Peak 2 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
On-Peak 1 and 3 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	
Interruptible Maintenance - Winter Only						
Maximum Monthly Demand		$0.21501	per kW per day	$0.23949	per kW per day	
On-Peak 2 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
On-Peak 1 and 3 Energy Adder		$0.03724	per kWh	$0.03843	per kWh	
Base Energy		$0.05500	per kWh	$0.05668	per kWh	
BACKUP GENERATION SERVICE (BGS)						
DIESEL GENERATORS						
Continuing Contract	$1.50	$0.04932	per kW per day	$0.04932	per kW per day	$1.50
Renewed Contracts Prior to 1/1/2010	$2.00	$0.06575	per kW per day	$0.06575	per kW per day	$2.00
Renewed Contracts On or After 1/1/2010	$3.00	$0.09863	per kW per day	$0.09863	per kW per day	$3.00
NATURAL GAS GENERATORS						
Natural Gas Generators - New Contract	$5.00	$0.16438	per kW per day	$0.16438	per kW per day	$5.00
HOME ELECTRIC VEHICLE CHARGING RIDER: EV-1						
Grid Connection & Customer Service Charge		NA		$0.64145	per bill per day	$19.51
ELECTRIC VEHICLE PUBLIC CHARGING PILOT RIDER: EV-2						
Level 1 and 2 Charging						
Subscribers		NA		$0.01670	per Minute	
Non-Subscribers		NA		$0.03330	per Minute	
DC Fast Charging						
Subscribers		NA		$0.04150	per Minute	
Non-Subscribers		NA		$0.08300	per Minute	
RESIDENTIAL WIND ENERGY (RWE-1)						
Incremental Charge for Wind Energy		$0.04000	per kWh	$0.02440	per kWh	
BUSINESS WIND ENERGY (BWE-1)						
Incremental Charge for Wind Energy - kWh Block		$0.04000	per kWh	$0.02440	per kWh	
Incremental Charge for Wind Energy - Fixed		$0.01000	per kWh	$0.01000	per kWh	

Madison Gas & Electric Company
Summary of Present and Authorized Electric Rates
For the Test Year 2015

TYPE OF SERVICE	Monthly Equivalent	PRESENT RATES		AUTHORIZED RATES		Monthly Equivalent
PARALLEL GENERATION (Pg-1)						
Grid Connection & Customer Service Charge						
Single Phase	$9.80	$0.32210	per bill per day	$0.32210	per bill per day	$9.80
Three Phase	$11.62	$0.38210	per bill per day	$0.38210	per bill per day	$11.62
*Pg-1 credit rates are updated automatically pursuant to the currently authorized tariff. The rates below are consistent with the company's filing in Docket 3270-TE-100 for calendar year 2015 and are provided for informational purposes only.						
ENERGY PAYMENT TO CUSTOMER						
Electric Credit						
Primary Service, On-Peak		$0.04041	per kWh	$0.05320	per kWh	
Primary Service, Off-Peak		$0.02949	per kWh	$0.03781	per kWh	
Secondary Service, On-Peak		$0.03997	per kWh	$0.05262	per kWh	
Secondary Service, Off-Peak		$0.02924	per kWh	$0.03748	per kWh	
Capacity Credit, On-Peak		$0.00010		$0.00152		
PARALLEL GENERATION (Pg-3) EXPERIMENTAL						
Grid Connection & Customer Service Charge						
Single Phase	$10.75	$0.35340	per bill per day	$0.35340	per bill per day	$10.75
Three Phase	$16.75	$0.55070	per bill per day	$0.55070	per bill per day	$16.75
ENERGY PAYMENT TO CUSTOMER		$0.06100	per kWh	$0.06100	per kWh	
PRIMARY & TRANSFORMER DISCOUNTS (Applicable to certain C/I customer classes)						
Primary Voltage Energy Discount		(0.00100)	per kWh	($0.00100)	per kWh	
Primary Voltage Demand Discount	($0.10)	(0.00328)	per kW per day	($0.00328)	per kW per day	($0.10)
Transformer Demand Discount	($0.10)	(0.00328)	per kW per day	($0.00328)	per kW per day	($0.10)

Revenue Impact of Authorized Rates including Cost of Gas

New Margin Rate Classes Distribution Classes and Admin Cost Categories	Volumes	Current Margin & Admin Revs Per Dist. Class	+ Cost of Gas Revenues	= Rebundled Service Revs by Dist. Class	+ Authorized Margin Rev. Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change w/COG	Percent Change w/o COG
Residential Distribution (RD-1, RD-2)								
Residential with Firm Sales	95,325,731	$ 48,308,800	$ 48,590,287	$ 96,899,087	$ (3,133,118)	$ 93,765,969	(3.23)%	(6.49)%
Residential Low Income	4,574	$ 95,122	$ 2,332	$ 97,453	$ 8,659	$ 106,113	8.89%	9.10%
Act 141 Charge		$ (597)		$ (597)	$ 146	$ (451)	(24.47)%	(24.47)%
Subtotal	95,330,305	$ 48,403,325	$ 48,592,619	$ 96,995,944	$ (3,124,313)	$ 93,871,631	(3.22)%	(6.45)%
Small Commercial / Industrial Distribution (GSD-1)								
GSD-1 with Firm Sales (FS-1)	53,501,517	$ 12,809,418	$ 27,231,915	$ 40,041,333	$ (771,505)	$ 39,269,829	(1.93)%	(6.02)%
Interdepartmental (with FS-1)	144,718	$ 31,225	$ 74,217	$ 105,442	$ (2,618)	$ 102,825	(2.48)%	(8.38)%
GSD-1 with Interruptible Sales and FS-1 nomination - Firm	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
GSD-1 with Interruptible Sales and FS-1 nomination - Int.	-	$ -	$ -	$ -	$ -	$ -	0.00%	0.00%
GSD-1 with Interruptible Sales	17,324	$ 3,113	$ 7,463	$ 10,576	$ (384)	$ 10,193	(3.63)%	(12.32)%
GSD-1 with Daily Balancing Service (DBS-1)	102,118	$ 27,052	$ -	$ 27,052	$ 114	$ 27,167	0.42%	0.42%
Act 141 Charge		$ (58,452)		$ (58,452)	$ 16,004	$ (42,448)	(27.38)%	(27.38)%
Subtotal	53,765,677	$ 12,812,356	$ 27,313,596	$ 40,125,952	$ (758,387)	$ 39,367,565	(1.89)%	(5.92)%
Medium Commercial / Industrial Distribution (GSD-2)								
GSD-2 with Firm Sales (FS-1)	26,765,986	$ 4,123,937	$ 13,581,056	$ 17,704,993	$ (398,870)	$ 17,306,124	(2.25)%	(9.67)%
GSD-2 with Interruptible Sales and FS-1 nomination - Firm	219,030	$ 28,102	$ 109,083	$ 137,184	$ (3,329)	$ 133,855	(2.43)%	(11.85)%
GSD-2 with Interruptible Sales and FS-1 nomination - Int.	898,747	$ 136,729	$ 387,186	$ 523,915	$ (13,035)	$ 510,880	(2.49)%	(9.53)%
GSD-2 with Interruptible Sales (IS-1)	757,078	$ 113,080	$ 326,154	$ 439,235	$ (8,792)	$ 430,442	(2.00)%	(7.78)%
GSD-2 Inter Departmental	99,008	$ 14,045	$ 51,083	$ 65,128	$ (1,489)	$ 63,638	(2.29)%	(10.60)%
GSD-2 with Daily Balancing Service (DBS-1)	5,745,108	$ 843,396	$ -	$ 843,396	$ 21,625	$ 865,021	2.56%	2.56%
Act 141 Charge		$ (106,396)		$ (106,396)	$ 28,867	$ (77,528)	(27.13)%	(27.13)%
Subtotal	34,484,957	$ 5,152,893	$ 14,454,563	$ 19,607,456	$ (375,023)	$ 19,232,433	(1.91)%	(7.28)%
Large Commercial / Industrial Distribution (GSD-3)								
GSD-3 with Firm Sales (FS-1)	4,007,889	$ 472,730	$ 2,022,510	$ 2,495,239	$ (52,876)	$ 2,442,364	(2.12)%	(11.19)%
GSD-3 with Interruptible Sales and FS-1 nomination - Firm	219,000	$ 20,805	$ 108,519	$ 129,324	$ (2,650)	$ 126,674	(2.05)%	(12.74)%
GSD-3 with Interruptible Sales and FS-1 nomination - Int.	232,710	$ 29,505	$ 100,253	$ 129,758	$ (2,984)	$ 126,774	(2.30)%	(10.11)%
GSD-3 with Interruptible Sales (IS-1)	817,217	$ 91,200	$ 352,063	$ 443,263	$ (9,874)	$ 433,389	(2.23)%	(10.83)%
GSD-3 with Daily Balancing Service (DBS-1)	23,911,394	$ 1,879,348	$ -	$ 1,879,348	$ 146,862	$ 2,026,211	7.81%	7.81%
Act 141 Charge		$ (258,389)		$ (258,389)	$ 69,371	$ (189,017)	(26.85)%	(26.85)%
Subtotal	29,188,210	$ 2,235,199	$ 2,583,344	$ 4,818,544	$ 147,850	$ 4,966,394	3.07%	6.61%
Interruptible Generation Distribution (IGD)								
Interruptible Generation with (IS-2)	792,785	$ 82,418	$ 334,036	$ 416,454	$ (871)	$ 415,583.29	(0.21)%	(1.06)%
Interruptible Generation with Daily Balancing (DBS-1)	5,290,118	$ 274,577	$ -	$ 274,577	$ (2,807)	$ 271,770	(1.02)%	(1.02)%
Interruptible Generation with Interdepartmental Sales (LS-1)	44,944,730	$ 1,635,032	$ 18,937,237	$ 20,572,269	$ (25,533)	$ 20,546,736.05	(0.12)%	(1.56)%
Act 141 Charge		$ 8,669		$ 8,669	$ 127	$ 8,796	1.46%	1.46%
Subtotal	51,027,633	$ 2,000,696	$ 19,271,273	$ 21,271,969	$ (29,084)	$ 21,242,885	(0.14)%	(1.45)%
Steam and Power Generation Gas Distribution (SP-1)								
SP-1 with Large Annual Use Gas Sales (LS-1)	17,783,524	$ 1,299,456	$ 8,242,999	$ 9,542,455	$ 316,721	$9,859,176	3.32%	24.37%
Act 141 Charge		$ 7,500		$ 7,500	$ 110	$ 7,610	1.47%	1.47%
Subtotal	17,783,524	$ 1,306,956	$8,242,999	$ 9,549,955	$ 316,831	$9,866,786	3.32%	24.24%
Seasonal Distribution (SD-1)								
SD-1 with Interruptible Sales (IS-1)	2,829,559	$ 334,556	$ 1,218,994	$ 1,553,550	$ 22,197	$ 1,575,747	1.43%	6.63%
SD-1 with Daily Balancing (DBS-1)	423,464	$ 37,464	$ -	$ 37,464	$ 8,097	$ 45,561	21.61%	21.61%
Act 141 Charge		$ (18,280)		$ (18,280)	$ 4,981	$ (13,299)	(27.25)%	(27.25)%
Subtotal	3,253,023	$ 353,740	$ 1,218,994	$ 1,572,734	$ 35,275	$ 1,608,008	2.24%	9.97%
Compressed Natural Gas Sales Service (CNG-1)	4,685	$ 2,490	$ 2,018	$ 4,508	$ (41)	$ 4,468	(0.90)%	(1.64)%
Compressed Natural Gas Sales Service Inter Departmental	2,516	$ 1,337	$ 1,084	$ 2,421	$ (22)	$ 2,399		(1.64)%
Compressed Natural Gas Electric Compression Charge		$ 1,080		$ 1,080	$ 720	$ 1,800		66.67%
Act 141 Charge		$ (62)		$ (62)	$ 17	$ (45)	(27.20)%	(27.20)%
Subtotal	7,201	$ 4,845	$ 3,102	$ 7,948	$ 674	$ 8,622	8.49%	13.92%
Company Use Volume	231,410							
Total	285,071,940	$ 72,270,012	$ 121,680,489	$ 193,950,500	$ (3,786,177)	$ 190,164,323	(1.95)%	(5.24)%
Revenue Totals:	Total Rate Revenue at Current Rates:			$ 193,950,500		$ 190,164,323		
	plus Other Non-gas Operating Revenue			$466,573		$466,573		
	Total Gas Utility Revenues			$ 194,417,073		$ 190,630,896	(1.95)%	

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Margin	Authorized Margin
Residential, RD-1		
Basic Customer Charge (per day)	$ 0.4000	$ 0.4419
System Connection Charge (per day)	N/A	$ 0.2776
Distribution Margin (per therm)	$ 0.2739	$ 0.0916
(Winter per therm)	(Same Margin Rates)	
Act 141 Charge	$ 0.0111	$ 0.0085
Residential, RD-2		
Basic Customer Charge (per day)	$ 0.4000	$ 0.4419
System Connection Charge (per day)	N/A	$ 0.2776
Distribution Margin (per therm)	$ 0.2739	$ 0.0916
(Winter per therm)	$0.2539	$0.0716
Act 141 Charge	$ 0.0111	$ 0.0085
Small Commercial & Indust., GSD-1		
Basic Customer Charge (per day)	$ 0.6930	$ 0.4400
System Connection Charge (per day)	N/A	$ 0.3600
Distribution Margin (per therm)	$ 0.1386	$ 0.1267
(Winter per therm)	(Same Margin Rates)	
Act 141 Charge	$ 0.0172	$ 0.0126
Medium Commercial & Indust., GSD-2		
Basic Customer Charge (per day)	$ 3.6771	$ 0.6413
System Connection Charge (per day)	N/A	$ 3.0783
Distribution Margin (per therm)	$ 0.0983	$ 0.0991
(Winter per therm)	(Same Margin Rates)	
Act 141 Charge	$ 0.0172	$ 0.0126
Large Commercial & Indust., GSD-3		
Basic Customer Charge (per day)	$ 21.0116	$ 1.2500
System Connection Charge (per day)	N/A	$ 18.7500
Distribution Margin (per therm)	$ 0.0650	$ 0.0714
(Winter per therm)	(Same Margin Rates)	
Act 141 Charge	$ 0.0172	$ 0.0126
Interruptible Generation, IGD-1		
Customer Charge (per day)	$ 117.30	$ 117.30
Distribution Margin (per therm)	$ 0.0350	$ 0.0344
Act 141 Charge	$ -	$ -

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Margin	Authorized Margin
Steam and Power Generation Gas Distribution (SP-1)		
Customer Charge (per day)	$ 1,592.88	$ 1,950.00
Distribution Margin (per therm)	$ 0.0393	$ 0.0497
Act 141 Charge	$ -	$ -
Seasonal Off-Peak Distribution, SD-1		
Customer Charge (per day)	$ 1.0300	$ 1.2500
Distribution Margin (per therm)	$ 0.0831	$ 0.1016
Act 141 Charge	$ 0.0172	$ 0.0126
Seasonal Off-Peak Distribution, SD-2		
Customer Charge (per day)	$ -	$ 4.2900
Distribution Margin (per therm)	$ -	$ 0.0776
Act 141 Charge	$ -	$ 0.0126
Compressed Natural Gas CNG-1		
Customer Charge (per day)	$ -	$ -
Distribution Margin (per therm)	$ 0.5050	$ 0.5063
Elec Comp Chrg	$ 0.1500	$ 0.2500
Act 141 Charge	$ 0.0172	$ 0.0126

Gas Rate Comparison
Present and Authorized Gas Rates

	Present Margin	Authorized Margin
Administrative Charges for Supply Options:		
IS-1 Administrative Charge for RD-1, RD-2, GSD-1, SD-1, SD-2 and CNG-1 (per therm)	$ 0.0265	$ 0.0140
Added Margin for Firm RD-1 and GSD-1 Sales (per therm)	$ 0.0035	$ 0.0025
Total FS-1 Admin. Charge for RD-1 and GSD-1(per therm)	$ 0.0300	$ 0.0165
IS-1 Administrative Charge for GSD-2 (per therm)	N/A	$ 0.0115
Added Margin for Firm GSD-2 Sales (per therm)	N/A	$ 0.0025
Total FS-1 Admin. Charge for GSD-2 (per therm)	$ -	$ 0.0140
	$ -	$ -
IS-1 Administrative Charge for GSD-3 (per therm)	N/A	$ 0.0090
Added Margin for Firm GSD-3 Sales (per therm)	N/A	$ 0.0025
Total FS-1 Admin. Charge for GSD-3 (per therm)	$ -	$ 0.0115
IS-2 Service Charge (per cust. per day)	$ 31.00	$ 30.00
LS-1 Service Charge (per cust. Per day)	$ 51.00	$ 55.00
Telemetering Charge (per cust. per day)	$ 1.50	$ 1.40
DBS Admin. Charge (per cust. per day)	$ 3.70	$ 4.30
Cost of Gas Rate Factors:		
Base Average Annual Demand (D-1 Annual)	$ 0.0518	$ 0.0463
Base Average Seasonal Demand (D-1 Winter)	$ 0.0456	$ 0.0444
Base Average GRI Demand	$ -	$ -
Base Average Commodity	$ 0.3562	$ 0.4213
Base Average Balancing Reservation	$ 0.0102	$ 0.0095
LS-1 Firm Reservation of contracted demand per day	$ 0.0199	$ 0.0206

Monthly Residential Bill Impact Analysis

Gas Costs	Summer	Winter
Firm Service	0.4771	0.5216

Summer Monthly Use Therms		Current Customer Charge	Current Admin. & Distribut'n Charges	Total Monthly Non-Gas Costs Before Rate Change	Gas Costs	Total Costs	Authorized Admin. & Customer Charges	Authorized Admin. & Distribut'n Charges	Total Monthly Non-Gas Costs After Rate Change	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
RD-1 / FS-1: Residential Distribution with Firm Sales													
5		$ 12.17	$ 1.52	$ 13.69	$ 2.39	$ 16.07	$ 21.88	$ 0.54	$ 22.43	$ 2.39	$ 24.81	$0.73	54.38%
15		$ 12.17	$ 4.56	$ 16.73	$ 7.16	$ 23.88	$ 21.88	$ 1.62	$ 23.51	$ 7.16	$ 30.66	$0.57	28.39%
27	avg	$ 12.17	$ 8.21	$ 20.37	$ 12.88	$ 33.25	$ 21.88	$ 2.92	$ 24.80	$ 12.88	$ 37.69	$0.37	13.33%
35		$ 12.17	$ 10.64	$ 22.80	$ 16.70	$ 39.50	$ 21.88	$ 3.78	$ 25.67	$ 16.70	$ 42.37	$0.24	7.25%
50		$ 12.17	$ 15.20	$ 27.36	$ 23.86	$ 51.22	$ 21.88	$ 5.41	$ 27.29	$ 23.86	$ 51.15	($0.01)	(0.14)%
75		$ 12.17	$ 22.79	$ 34.96	$ 35.79	$ 70.74	$ 21.88	$ 8.11	$ 29.99	$ 35.79	$ 65.78	($0.41)	(7.02)%
105		$ 12.17	$ 31.91	$ 44.08	$ 50.10	$ 94.18	$ 21.88	$ 11.35	$ 33.24	$ 50.10	$ 83.34	($0.90)	(11.51)%
105		$ 12.17	$ 31.91	$ 44.08	$ 50.10	$ 94.18	$ 21.88	$ 11.35	$ 33.24	$ 50.10	$ 83.34	($0.90)	(11.51)%
150		$ 12.17	$ 45.59	$ 57.75	$ 71.57	$ 129.32	$ 21.88	$ 16.22	$ 38.10	$ 71.57	$ 109.67	($1.64)	(15.20)%
200		$ 12.17	$ 60.78	$ 72.95	$ 95.43	$ 168.38	$ 21.88	$ 21.62	$ 43.50	$ 95.43	$ 138.93	($2.45)	(17.49)%
300		$ 12.17	$ 91.17	$ 103.34	$ 143.14	$ 246.48	$ 21.88	$ 32.43	$ 54.31	$ 143.14	$ 197.46	($4.09)	(19.89)%

Winter Monthly Use Therms		Current Customer Charge	Current Admin. & Distribut'n Charges	Total Monthly Non-Gas Costs Before Rate Change	Gas Costs	Total Costs	Authorized Admin. & Customer Charges	Authorized Admin. & Distribut'n Charges	Total Monthly Non-Gas Costs After Rate Change	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
RD-1 / FS-1: Residential Distribution with Firm Sales													
5		$ 12.17	$ 1.52	$ 13.69	$ 2.61	$ 16.29	$ 21.88	$ 0.54	$ 22.43	$ 2.61	$ 25.03	$0.73	53.63%
15		$ 12.17	$ 4.56	$ 16.73	$ 7.82	$ 24.55	$ 21.88	$ 1.62	$ 23.51	$ 7.82	$ 31.33	$0.57	27.62%
27		$ 12.17	$ 8.21	$ 20.37	$ 14.08	$ 34.45	$ 21.88	$ 2.92	$ 24.80	$ 14.08	$ 38.89	$0.37	12.86%
35		$ 12.17	$ 10.64	$ 22.80	$ 18.25	$ 41.06	$ 21.88	$ 3.78	$ 25.67	$ 18.25	$ 43.92	$0.24	6.98%
50		$ 12.17	$ 15.20	$ 27.36	$ 26.08	$ 53.44	$ 21.88	$ 5.41	$ 27.29	$ 26.08	$ 53.37	($0.01)	(0.13)%
75		$ 12.17	$ 22.79	$ 34.96	$ 39.12	$ 74.08	$ 21.88	$ 8.11	$ 29.99	$ 39.12	$ 69.11	($0.41)	(6.71)%
105	avg	$ 12.17	$ 31.91	$ 44.08	$ 54.76	$ 98.84	$ 21.88	$ 11.35	$ 33.24	$ 54.76	$ 88.00	($0.90)	(10.97)%
105		$ 12.17	$ 31.91	$ 44.08	$ 54.76	$ 98.84	$ 21.88	$ 11.35	$ 33.24	$ 54.76	$ 88.00	($0.90)	(10.97)%
150		$ 12.17	$ 45.59	$ 57.75	$ 78.23	$ 135.99	$ 21.88	$ 16.22	$ 38.10	$ 78.23	$ 116.33	($1.64)	(14.45)%
200		$ 12.17	$ 60.78	$ 72.95	$ 104.31	$ 177.26	$ 21.88	$ 21.62	$ 43.50	$ 104.31	$ 147.82	($2.45)	(16.61)%
300		$ 12.17	$ 91.17	$ 103.34	$ 156.47	$ 259.81	$ 21.88	$ 32.43	$ 54.31	$ 156.47	$ 210.78	($4.09)	(18.87)%
Avg. Annual Residential Billing													
714		$ 146.00	$ 216.98	$ 362.98	$ 364.00	$ 726.99	$ 262.62	$ 77.18	$ 339.80	$ 364.00	$ 703.80	($1.93)	(3.19)%

Residential Lifeline Distribution Service

SPECIAL TERMS AND PROVISIONS

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

2. Any customer who misinforms the Company about total household income will be subject to back billing for the difference between what the customer would have paid under the Residential Distribution Service (Rate Schedule RD-1) and what the customer actually paid under this rate schedule.

3. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

4. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

5. The Residential Lifeline Distribution Service (RD-2) tariff will be closed effective January 1, 2016, after which all customers will transfer to the appropriate RD-1 rate and service schedule.

~~5~~6. 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.

(Next Sheet is G-20)

Interruptible Generation Distribution Service

AVAILABILITY

Available to any customer who was receiving service under the Company's Rate Schedules IGT-1 or IGS-1 as of October 15, 1996, and who:

1. Uses natural gas as a fuel for the generation of electricity or steam.
2. Will curtail or interrupt service upon request of the Company.
3. Will provide and maintain suitable and adequate alternate fuel standby facilities or will discontinue use, during an interruption, of any equipment for which alternate fuel facilities are not maintained. ~~Alternate fuel is an energy source other than natural gas.~~

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 total service charge will be the same as though one meter was installed.

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 an interruptible basis only, and the Company will have the right to interrupt or curtail deliveries of gas hereunder, whenever and to the extent necessary such interruption or curtailment, in the sole judgment of the Company, may be required.

RATE

Customer charge per day [1] ....
Distribution service per therm............

[1] The customer charge will be applied in any billing period the customer is classified as receiving service under this rate schedule.

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 Large Boiler Gas Sales Service (Rate Schedule IS-2) unless customer contracts with the Company for service under Daily Balancing Service (Rate Schedule DBS-1).

~~PENALTY~~ UNAUTHORIZED USE CLAUSE

The customer will be required to pay a ~~penalty~~ charge of $2.50 per therm for all unauthorized use of gas during any interruption or curtailment of service ordered by the Company. ~~If customer continues to use unauthorized gas, the Company may physically disconnect service to the customer.~~

(Continued on Sheet G-25.1)

UNAUTHORIZED USE CLAUSE (continued)

The availability of this charge does not preclude the Company from physically controlling the customer's gas supply upon the customer's failure to curtail or interrupt their gas consumption as instructed by the Company.

SPECIAL TERMS AND PROVISIONS

1. When interruption of deliveries hereunder is required, the customer will interrupt the use of gas at the time and to the extent requested by the Company. The Company will notify the customer as far in advance as is feasible, and the customer will discontinue or interrupt the use of gas under this rate schedule as ordered by the Company.

   In addition, the Company reserves the right to test the interruptibility of any customer on this rate schedule for any period of at least four hours that the Company requests. The Company has the option of requesting this test interruption of service at least one time each year. The Company reserves the right to move any customer who fails three interruptions, either actual or test, to the appropriate commercial and industrial gas distribution service for which they would otherwise qualify, provided that the Company has the capacity to serve the customer under the appropriate commercial and industrial gas distribution service.

2. Service under this rate schedule will commence following approval of the customer's application for service by the Company.

3. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

4. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

5. If special equipment, such as motor-operated valves, metering bypass, 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 telemetering equipment necessary for service under the Company's Rate Schedules IS-1, IS-2, or DBS-1. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

6. 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.

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

(Next Sheet is G-26)

Seasonal Off-Peak Distribution Service

AVAILABILITY

Service under this rate schedule is available to commercial and industrial customers. SD-1 service is designed for customers that use the vast majority of their natural gas during the off-peak period of April 1 through December 31. While SD-1 service is available year-round, incentive pricing is in place to encourage off-peak consumption. The distribution rate for service during the April through December off-peak period is significantly lower than the distribution rate for the January through March on-peak period.

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 total service charge will be the same as though one meter was installed.

APPLICABILITY AND CHARACTER OF SERVICE

The Company will provide distribution service for the delivery of gas supply through the Company's facilities for eligible customers.

Distribution service by the Company under this rate schedule will be on a firm basis.

RATE

Customer charge per day[(1)] ....
Distribution service per therm (April 1 through December 31) ....
Distribution service per therm (January 1 through March 31) ....

[(1)] The daily customer 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 SD-1 meter must be equipped with a data-logging Encoder Receiver Transmitter (ERT) which allows for accurate billing of both on-peak and off-peak consumptions.

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 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 with the Company for service under Daily Balancing Service (Rate Schedule DBS-1).

UNAUTHORIZED USE CLAUSE

The customer will be required to pay a charge of $2.50 per therm for all unauthorized use of gas during any interruption or curtailment of service ordered by the Company.

The availability of this charge does not preclude the Company from physically controlling the customer's gas supply upon the customer's failure to curtail or interrupt their gas consumption as instructed by the Company.

(Continued on Sheet G-26.1)

Seasonal Off-Peak Distribution Service

M **SPECIAL TERMS AND PROVISIONS**

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

2. Service under this rate schedule will commence following approval of the customer's application for service by the Company.

3. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

4. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

5. If special equipment, such as motor-operated valves, metering bypass, 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 telemetering equipment necessary for service under the Company's Rate Schedules IS-1, IS-2, or DBS-1. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

6. The Seasonal Off-Peak Distribution Service (SD-1) tariff will be closed to new customers effective January 1, 2015. Existing customers have the option to continue taking service under the SD-1 rate and service schedule for a period of 10 years from the January 1, 2015, closure date. Once a customer transfers from the SD-1 service tariff to another service tariff, they will no longer be eligible to receive service under the SD-1 rate and service tariff.

7~~6~~. 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.

R (Next Sheet is G-27)

Steam and Power Generation Gas Distribution Service

AVAILABILITY

Available to large distribution service customers on a firm basis who:

1. Use at least ~~25~~17 million therms per year on this Rate Schedule.

2. Contract for service under this Rate Schedule with the Company for a term of five years with one-year automatic renewals thereafter unless terminated with a six-month written notice to the Company prior to the end of the initial term or the end of a given renewal term thereafter.

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

Customer charge per day [(1)] ....
Distribution service per therm............

[(1)] The customer charge will be applied in any billing period the customer is classified as receiving service under this rate schedule.

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 Large Annual Use Gas Sales Service (Rate Schedule LS-1) unless the customer contracts with the Company for service under Daily Balancing Service (Rate Schedule DBS-1).

(Continued on Sheet G-27.1)

Steam and Power Generation Gas Distribution Service

SPECIAL TERMS AND PROVISIONS

1. Service under this rate schedule will commence following approval of the customer's application for service by the Company.

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 telemetering equipment necessary for service under the Company's Rate Schedules LS-1 or DBS-1. 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 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 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. Customers who have their meters turned off and back on within a 12-month period will pay the customer charge applicable to the customer for the period while service was not being used.

(Next Sheet is G-28)

Compressed Natural Gas Distribution Service

AVAILABILITY

This rate schedule is available to customers for purchase of compressed natural gas generally ~~for~~ used as a motor fuel at Company-owned fueling station facilities. The customer must agree to curtail or interrupt service upon request by the Company.

APPLICABILITY AND CHARACTER OF SERVICE

This rate schedule applies to compressed natural gas generally distributed as available to customers for use as a motor fuel.

RATE

Distribution service per therm....................
Administrative charge per therm:
GSD-1..
GSD-2..
GSD-3..
Electric compression charge per therm......
Natural gas service (1) ....

(1) Subject to adjustment for cost of purchased gas. See sheet G-38 for purchased gas adjustment clause and refund provision and sheet G-3.1 for current effective rates. The purchased gas adjustment will include an interruptible market reservation component determined on a monthly basis.

PAYMENT

The customer will be required to pay the distribution service, administrative charge, electric compression charge, and natural gas service on all therms. Payment is due no~~t~~ 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.

SPECIAL TERMS AND PROVISIONS

1. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

2. Service under this rate schedule is subject to ~~adjustment for applicable~~ additional road-use taxes.

3. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

(Next Sheet is G-30)

Interruptible Gas Sales Service

AVAILABILITY

Available to commercial and industrial customers who receive distribution service under the Company's Rate Schedules GSD-2, GSD-3, or SD-1; to Elroy-area customers who were interruptible customers prior to August 20, 1997, and are served under the Company's Rate Schedule GSD-1; and to Viroqua-area customers who are served under the Company's Rate Schedule GSD-1. This gas service is for annual gas service supplied at a single point of delivery and may be taken in conjunction with the Company's Firm Gas Sales Service rate schedule. Furthermore, the customer will:

1. Contract for service under this rate schedule with the Company for a term of one year with one-year automatic renewals thereafter unless terminated with a six-month written notice to the Company prior to November 1 of the year of termination.

2. Interrupt service upon request of the Company.

3. Provide and maintain suitable and adequate alternate fuel standby facilities or will discontinue use, during an interruption, of any equipment for which alternate fuel facilities are not maintained. ~~Alternate fuel is an energy source other than natural gas.~~

APPLICABILITY AND CHARACTER OF SERVICE

Gas supply provided by the Company to any customer under this rate schedule will be on an interruptible basis only and the Company will have the right to interrupt deliveries of gas supply hereunder, whenever and to the extent necessary such interruption, in the sole judgment of the Company, may be required.

Telemetering equipment must be installed by the Company before service will be provided on this rate schedule. The customer must provide a business-grade telephone line to allow the Company continuous access at any time for meter reading purposes and connection to existing electrical facilities as necessary for operation of the telemetering equipment. Once telemetering is installed, the Company, at its option, may bill the customer based on telemetered consumption, provided that actual meter readings are taken no less often than once every six months to verify the telemetered consumption.

When the Company, in its sole discretion, determines an interruption of gas service is necessary in an area or areas of its service territory, customers receiving service under this rate schedule in any affected area will be interrupted in the following order:

1. The first customers to be interrupted will be customers receiving distribution service on Rate Schedule SD-1 in the interruption area.

2. The next group to be interrupted will be customers in Rate Schedule GSD-3 in the interruption area.

3. If further interruption is necessary after all GSD-3 customers in the interruption area are interrupted, then GSD-2 customers will be interrupted.

4. If further interruption is necessary after all GSD-2 customers in the interruption area are interrupted, then GSD-1 customers will be interrupted.

(Continued on Sheet G-31.1)

Interruptible Gas Sales Service

RATE

Administrative charge per therm:
GSD-1..
GSD-2..
GSD-3..
Telemetering charge per day [(1)]..........
Natural gas service per therm [(2)] ....

(1) This charge only applies to customers receiving distribution service under the Company's Rate Schedules GSD-1, GSD-2, and GSD-3 and only to Viroqua-area customers if installed.

(2) Subject to adjustment for cost of purchased gas. See sheet G-38 for purchased gas adjustment clause and refund provision and sheet G-3.1 for current purchased gas adjustment amounts and effective rates. The purchased gas adjustment will include an interruptible market reservation component determined on a monthly basis.

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.

~~PENALTY~~ UNAUTHORIZED USE CLAUSE

Customers are responsible for an additional charge for unauthorized use upon failure to curtail or interrupt natural gas requirements when notified by Company. Availability of this charge does not preclude the Company from physically controlling customer's gas supply upon customer's failure to curtail or interrupt. The additional charge for unauthorized use will be assessed as follows:

1. During a curtailment or interruption when interstate pipeline capacity is not limited, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $2.50 per therm for gas used in excess of the maximum quantity level requested by the Company.

2. During a curtailment or interruption due to capacity limitations on interstate pipelines, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $10.00 per therm for gas used in excess of the maximum quantity level requested by the Company.

Incremental cost, as referenced above, will include any interstate pipeline penalties incurred as a result of customers' failure to curtail or interrupt, as well as the total cost of incremental interstate pipeline capacity and/or gas commodity purchased to serve customers' load on the day(s) of curtailment or interruption.

(Continued on Sheet G-31.2)

Interruptible Gas Sales Service

SPECIAL TERMS AND PROVISIONS

1. When interruption of deliveries hereunder is required, the customer will interrupt the use of gas at the time and to the extent requested by the Company. The Company will notify the customer as far in advance as is feasible, and the customer will discontinue or interrupt the use of gas under this rate schedule as ordered by the Company. In addition, the Company reserves the right to test the interruptibility of any customer on this rate schedule for any period of at least four hours that the Company requests. The Company has the option of requesting this test interruption of service at least one time each year. The Company reserves the right to move any customer who fails three interruptions, either actual or test, to the firm rate schedule for which they would otherwise qualify, provided that the Company has the capacity to serve the customer under the firm rate schedule.

2. If, during an interruption, a customer finds it necessary to use some natural gas on an emergency basis, such gas may be requested from the Company under the Backup Sales Service (Rate Schedule BU-1) subject to the terms and conditions of that rate schedule. The customer will nominate the volume of gas to be purchased under the Backup Sales Service rate schedule and the Company must approve it prior to purchase. The approved Backup Sales Service nomination will be considered first gas through the meter, after any FS-1 gas supply, for billing purposes. Should the customer use gas in excess of the Backup Sales Service nomination approved by the Company during an interruption period, the customer will be subject to the ~~penalty~~ unauthorized use clause of this rate schedule.

3. Gas that may be required for the operation of standby fuel equipment only (pilot lights) will be available during periods of interruption under this rate schedule.

4. Gas obtained hereunder will not be resold.

5. If special equipment, such as motor-operated valves, metering bypass, and remote control is required to monitor gas service, such special equipment will be installed by the Company at the customer's expense. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

6. Any customer receiving service under this rate schedule that wishes to discontinue the service and have the same load served under one of the Company's other system supply sales services will apply for that service in writing. Availability of the requested service will be determined by the Company and the customer will be treated as a new customer in determining the availability of gas.

7. The Company will file a report with the Public Service Commission of Wisconsin after each curtailment. The report will be filed by the Company within 45 days following the event.

~~7~~8. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

~~8~~9. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

RESERVED RIGHT TO LIMITATION OF ADDITIONAL CONTRACTS

Service under this rate schedule is predicated on the availability to the Company of a sufficient natural gas supply to enable service thereunder to be made available during a major portion of each year without impairment of service to other customers. The Company, therefore, reserves the right to decline acceptance of any additional contracts for service hereunder at such time as, in the Company's sole judgment, the volumes of service already contracted for equal the gas supply available for this class of service.

(Next Sheet is G-32)

Interruptible Large Boiler Gas Sales Service

AVAILABILITY

Available to commercial and industrial customers who receive distribution service under the Company's Rate Schedule IGD-1. This gas service is for annual gas service supplied at a single point of delivery. Furthermore, the customer will:

1. Contract for service under this rate schedule with the Company for a term of one year with one-year automatic renewals thereafter unless terminated with a six-month written notice to the Company prior to November 1 of the year of termination.

2. Interrupt service upon request of the Company.

3. Provide and maintain suitable and adequate alternate fuel standby facilities or will discontinue use, during an interruption, of any equipment for which alternate fuel facilities are not maintained. Alternate fuel is an energy source other than natural gas.

APPLICABILITY AND CHARACTER OF SERVICE

Gas supply provided by the Company to any customer under this rate schedule will be on an interruptible basis only, and the Company will have the right to interrupt deliveries of gas supply hereunder, whenever and to the extent necessary such interruption, in the sole judgment of the Company, may be required.

Telemetering equipment must be installed by the Company before service will be provided on this rate schedule. The customer must provide a business-grade telephone line and connection to existing electrical facilities as necessary for operation of the telemetering equipment. Once telemetering is installed, the Company, at its option, may bill the customer based on telemetered consumption, provided that actual meter readings are taken no less often than once every six months to verify the telemetered consumption.

When the Company, in its sole discretion, determines an interruption of gas service is necessary, all customers receiving distribution service under Rate Schedule IGD-1 in conjunction with this rate schedule will be interrupted before any customers receiving service under GSD-3 are interrupted.

RATE

Administrative charge per day............
Telemetering charge per day.............
Natural gas service per therm (1) ....

(1) Subject to adjustment for purchased gas. See sheet G-38 for purchased gas adjustment clause and refund provision and sheet G-3.1 for current cost of gas. The cost of gas includes the interruptible market reservation component (75 percent of the IS-1 Market Reservation Component). Customers will be charged any and all penalties assessed to the Company by the interstate pipelines that are related to the customer's service.

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.

(Continued on Sheet G-32.1)

~~PENALTY~~ UNAUTHORIZED USE CLAUSE

Customers are responsible for an additional charge for unauthorized use upon failure to curtail or interrupt natural gas requirements when notified by Company. Availability of this charge does not preclude Company from physically controlling customer's gas supply upon customer's failure to curtail or interrupt. The additional charge for unauthorized use will be assessed as follows:

1. During a curtailment or interruption due to capacity limitations on interstate pipelines, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $10.00 per therm for gas used in excess of the maximum quantity level requested by the Company.

2. During a curtailment or interruption when interstate pipeline capacity is not limited, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $2.50 per therm for gas used in excess of the maximum quantity level requested by the Company.

Incremental cost, as referenced above, will include any interstate pipeline penalties incurred as a result of customers' failure to curtail or interrupt, as well as the total cost of incremental interstate pipeline capacity and/or gas commodity purchased to serve customers' load on the day(s) of curtailment or interruption.

SPECIAL TERMS AND PROVISIONS

1. When interruption of deliveries hereunder is required, the customer will interrupt the use of gas at the time and to the extent requested by the Company. The Company will notify the customer as far in advance as is feasible, and the customer will discontinue or interrupt the use of gas under this rate schedule as ordered by the Company. In addition, the Company reserves the right to test the interruptibility of any customer on this rate schedule for any period of at least four hours that the Company requests. The Company has the option of requesting this test interruption of service at least one time each year. The Company reserves the right to move any customer who fails three interruptions, either actual or test, to the firm rate schedule for which they would otherwise qualify, provided that the Company has the capacity to serve the customer under the firm rate schedule.

2. If, during an interruption, a customer finds it necessary to use some natural gas on an emergency basis, such gas may be requested from the Company under the Backup Sales Service (Rate Schedule BU-1) subject to the terms and conditions of that rate schedule. The customer will nominate the volume of gas to be purchased under the Backup Sales Service rate schedule and the Company must approve it prior to purchase. The approved Backup Sales Service nomination will be considered first gas through the meter for billing purposes. Should the customer use gas in excess of the Backup Sales Service nomination approved by the Company during an interruption period, the customer will be subject to the ~~penalty~~ unauthorized use clause of this rate schedule.

3. The Company will file a report with the Public Service Commission of Wisconsin after each curtailment. The report will be filed by the Company within 45 days following the event.

~~3~~4. Gas that may be required for the operation of standby fuel equipment only (pilot lights) will be available during periods of interruption under this rate schedule.

(Continued on Sheet G-32.2)

Interruptible Large Boiler Gas Sales Service

SPECIAL TERMS AND PROVISIONS (continued)

~~4~~5. Gas obtained hereunder will not be resold

~~5~~6. If special equipment, such as motor-operated valves, metering bypass, and remote control is required to monitor gas service, such special equipment will be installed by the Company at the customer's expense. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

~~6~~7. Any customer receiving service under this rate schedule that wishes to discontinue the service and have the same load served under one of the Company's other system supply sales services will apply for that service in writing. Availability of the requested service will be determined by the Company, and the customer will be treated as a new customer in determining the availability of gas.

~~7~~8. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

~~8~~9. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

RESERVED RIGHT TO LIMITATION OF ADDITIONAL CONTRACTS

Service under ~~T~~this gas rate schedule is predicated on the availability to the Company of a sufficient natural gas supply to enable service thereunder to be made available during a major portion of each year without impairment of service to other customers. The Company, therefore, reserves the right to decline acceptance of any additional contracts for service hereunder at such time as, in the Company's judgment, the volumes of service already contracted for equal the gas supply available for this class of service.

(Next Sheet is G-33)

Large Annual Use Gas Sales Service

AVAILABILITY

Available to large annual use customers who receive distribution service under the Company's Rate Schedule SP-1. This gas service is for annual gas service supplied at a single point of delivery with a minimum annual usage of ~~25~~17 million therms. Customers served on the Company's IGD-1 Interruptible Generation Distribution Service are also eligible for this rate schedule, without the minimum annual usage requirement. Furthermore, the customer will:

1. Contract for service under this rate schedule with the Company for an initial term of five years with one-year automatic renewals thereafter unless terminated. Service can begin at any time the Company is able to provide the service; however, the initial contract year will begin the following November 1 and continue through October 31 of the following year. Notice of termination must be provided to the Company in writing by May 1 of a given year with a one-year termination notice period to begin no earlier than November 1 of that same year.

2. Interrupt the interruptible portion of this service upon request of the Company.

3. Provide and maintain suitable and adequate alternate fuel standby facilities or will discontinue use, during an interruption, of any equipment for which alternate fuel facilities are not maintained down to the level of nominated firm sales service provided hereunder. Alternate fuel is an energy source other than natural gas.

APPLICABILITY AND CHARACTER OF SERVICE

A contracted daily level of gas, subject to availability as determined by the Company, will be provided on a firm basis as first through the meter for customers on this rate schedule. The customer may choose zero therms per day of firm service, but if the customer wishes to contract for firm service, a minimum of 50,000 therms per day will be required. The contracted firm service will remain in effect on a rolling three-year period. Reductions in the contracted firm service will take effect three years after notification from the customer. Increases are subject to availability of firm service from the Company and will take effect when approved by the Company.

Gas used above the contracted firm gas supply will be provided by the Company on an interruptible basis, and the Company will have the right to interrupt deliveries of gas supply hereunder, whenever and to the extent necessary such interruption, in the sole judgment of the Company, may be required.

Telemetering equipment or other electronic devices to remotely read the meter must be installed by the Company before service will be provided on this rate schedule. The customer may be required to provide a business-grade telephone line and connection to existing electrical facilities as necessary for operation of these devices. Once the remote metering equipment is installed, the Company, at its option, may bill the customer based on the electronically read consumption, provided that actual meter readings are periodically taken to verify the electronically read consumption.

When the Company, in its sole discretion, determines an interruption of gas service is necessary, the interruptible portion of service provided hereunder will be interrupted before any customers receiving service under Rate Schedule IS-1 are interrupted.

(Continued on Sheet G-33.1)

Large Annual Use Gas Sales Service

RATE

Administrative charge per day..........................
Electronic metering charge per day..................
Natural gas service: (1)
Firm reservation rate per therm of
contracted firm demand (therms per day)..
Volumetric rate... See Pricing Formula below.

(1) Subject to adjustment for purchased gas. See sheet G-38 for purchased gas adjustment clause and refund provision and sheet G-3.1 for the current cost of gas. The cost of gas includes interruptible market reservation component (75 percent of the IS-1 Market Reservation Component) for the interruptible portion of gas delivered. The interruptible portion of gas delivered will be total billing period therms less the product of the number of therms of contracted firm sales volume times the number of days in the billing period. The interruptible portion will not be less than zero. Customers will be charged any and all penalties assessed to the Company by the interstate pipelines that are related to the customer's service.

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.

USAGE ESTIMATES

Customers will, by February 28 of each year, provide the Company with estimates of annual natural gas needs by month for the twelve-month period beginning November 1 of the current year through October 31 of the following year. This will include estimated daily swing volume ranges for each month.

By the 15th of each month, customers receiving service under this rate schedule will provide an estimate of expected gas usage for the next month, including preliminary estimates of daily usage. The usage will be broken down into three pricing categories: System Priced Supply, Fixed Priced Supply, and Daily Priced Supply. Daily volumes will be estimates and can be changed, but only in accordance with the Nominations process described below. Fluctuations of actual volumes when compared to estimate may result in pricing differences as described in Pricing Formula below. On a best-efforts basis, and avoiding harm to other system supply customers, the Company may allow a customer to modify their monthly estimate within the month to acquire additional or dispose of excess monthly supply. The Company reserves the right to reject the estimate or limit the amount of daily swing supply available to the customer if the Company's contracted interstate pipeline capacity is not expected to be available for the service.

(Continued on Sheet G-33.2)

Large Annual Use Gas Sales Service

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.

~~PENALTY~~ UNAUTHORIZED USE CLAUSE

Customers are responsible for an additional charge for unauthorized use upon failure to curtail or interrupt natural gas requirements down to the nominated firm sales volume when notified by Company. Availability of this charge does not preclude Company from physically controlling customer's gas supply upon customer's failure to curtail or interrupt. The additional charge for unauthorized use will be assessed as follows:

1. During a curtailment or interruption when interstate pipeline capacity is not limited, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt or $2.50 per therm for gas used in excess of the maximum quantity level requested by the Company.

2. During a curtailment or interruption due to capacity limitations on interstate pipelines, the additional charge will be the greater of the incremental cost to the Company that results from a failure to curtail or interrupt or $10.00 per therm for the gas used in excess of the maximum quantity level requested by the Company.

Incremental cost, as referenced above, will include any interstate pipeline penalties incurred as a result of customers' failure to curtail or interrupt, as well as the total cost of incremental interstate pipeline capacity and/or gas commodity purchased to serve customers' load on the day(s) of curtailment or interruption.

(Continued on Sheet G-33.5)

Large Annual Use Gas Sales Service

SPECIAL TERMS AND PROVISIONS

1. When interruption of deliveries hereunder is required, the customer will interrupt the use of gas at the time and to the extent requested by the Company down to the contracted firm daily quantity. Interruptions or curtailments can be called at any time during the day and can be called for daily and hourly flow reasons. When an interruption is called for part of a gas day, the contracted firm daily quantity will be prorated over the gas day on a 24-hour basis to determine the available firm gas supply for the portion of the gas day that the interruption is required. The Company will notify the customer as far in advance as is feasible, and the customer will discontinue or interrupt the use of gas under this rate schedule as ordered by the Company.

   In addition, the Company reserves the right to test the interruptibility of any customer on this rate schedule for any period of at least four hours that the Company requests. The Company has the option of requesting this test interruption of service at least one time each year. The Company reserves the right to move any customer who fails three interruptions, either actual or test, to the appropriate firm gas sales rate schedule for which they would otherwise qualify, provided the Company has the capacity to serve the customer under the firm gas sales service rate schedule.

2. Gas obtained hereunder will not be resold.

3. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

4. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

5. If special equipment, such as motor-operated valves, metering bypass, 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 telemetering equipment necessary for service under this rate schedule or the Company's DBS-1 rate schedule. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

6. Any customer receiving service under this rate schedule that wishes to discontinue the service and have the same load serv~~ic~~ed under one of the Company's other system supply sales services or through a third party under Daily Balancing Service, will apply for that service in writing. Availability of the requested service will be determined by the Company. If the customer is requesting one of the Company's gas sales services, the customer will be treated as a new customer in determining the availability of gas.

7. The Company will file a report with the Public Service Commission of Wisconsin after each curtailment. The report will be filed by the Company within 45 days following the event.

RESERVED RIGHT TO LIMITATION OF ADDITIONAL CONTRACTS

Service under ~~T~~this gas rate schedule is predicated on the availability to the Company of a sufficient natural gas supply to enable service thereunder to be made available during a major portion of each year without impairment of service to other customers. The Company, therefore, reserves the right to decline acceptance of any additional contracts for service hereunder at such time as, in the Company's judgment, the volumes of service already contracted for equal the gas supply available for this class of service.

(Next Sheet is G-34)

Daily Balancing Service

AVAILABILITY

The Daily Balancing Service (DBS) is available to customers served under Rate Schedules GSD-1, GSD-2, GSD-3, IGD-1, SP-1, or SD-1 and is required for customers delivering Third-Party Natural Gas Supplies to the Company for distribution on the above schedules. This rate schedule applies to balancing service provided 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 total administrative charge and telemetering charge will be the same as though one meter was installed.

The customer must have an effective Daily Balancing Service Contract prior to the commencement of service under this rate schedule. Service under this rate schedule will start on the first gas day of the month and terminate on the last gas day of the month.

APPLICABILITY AND CHARACTER OF SERVICE

Customers under this rate schedule will be responsible for arranging for the purchase and delivery of Third-Party Natural Gas Supplies to the Company's facilities for the term of service under this rate schedule. Deliveries of Third-Party Natural Gas Supplies to the Company must be nominated on a daily basis in accordance with the terms and provisions of this rate schedule. Daily imbalances between nominated Third-Party Natural Gas Supplies and customer usage must also be dealt with in accordance with the terms and provisions of this rate schedule. In calculating daily imbalances, customers will receive the benefit of pooling positive and negative imbalances with other customers by being a member of a Third-Party Balancing Pool or a Company-Administered Balancing Pool. Balancing Service is available to customers to resolve daily imbalances and cash out accumulated monthly commodity imbalances. Customers in the Viroqua service territory may form Third-Party Balancing Pools. Deliveries in the Viroqua service territory must be nominated and balanced separately from deliveries to other areas of the Company.

Telemetering equipment must be installed by the Company before service will be provided on this rate schedule. The customer must provide a business-grade telephone line and connection to existing electrical facilities as necessary for operation of the telemetering equipment. Customers must maintain continuous phone and electric service to the telemetering equipment to continue on this service. Once telemetering is installed, the Company, at its option, may bill the customer based on telemetered consumption, provided that actual meter readings are taken no less often than once every six months to verify the telemetered consumption.

BALANCING ADMINISTRATIVE RATES

The following charges will apply to each individual customer any month the customer is classified as receiving service under this rate schedule. The administrative charge recovers the incremental cost of administering Third-Party Natural Gas Supply deliveries. The telemetering charge recovers costs associated with equipment necessary to telemeter the customer's consumption to the Company's offices.

Administrative charge per day............
Telemetering charge per day..............

In addition to the Balancing Administration Rates above, Balancing Service Charges and Commodity Cashout Charges/Credits, as described below, will apply to the Pooling Agents of Third-Party Balancing Pools and to individual customers in the Company-Administered Balancing Pool.

(Continued on Sheet G-34.1)

Daily Balancing Service

BALANCING SERVICE CHARGES (continued)

Nonconstraint Day

First tier rates for Imbalance Volumes that are either overnominations or undernominations between 0% and 25%:

	Maximum Rate per Therm	Effective Rate per Therm	Minimum Rate per Therm
DBS charge		(1)	

(1) The Effective Rate is discountable between the Maximum and Minimum Rates. See sheet G-3.1 for the current Effective First Tier Rate.

Second tier rates for Imbalance Volumes that are either overnominations or undernominations greater that 25%:

	Maximum Rate per Therm	Effective Rate per Therm	Minimum Rate per Therm
DBS charge		(1)	(2)

(1) The Effective Rate is discountable between the Maximum and Minimum Rates. See sheet G-3.1 for the current Effective First Tier Rate.

(2) The higher of this rate or the Effective First Tier Rate.

Any over-run or under-run charges or penalties assessed by pipelines will be prorated among those customers in a Company-Administered Pool and/or Third-Party Pools that contributed to the cause of the ~~penalties~~costs. The daily balancing revenues received from balancing charges at rates higher than the Effective First-Tier Rate will be netted against these pipeline charges or penalties assessed on the same day on each month's Balancing Service bill for affected customers or Third-Party Pools.

(Continued on Sheet G-34.5)

BALANCING SERVICE CHARGES (continued)

High-Flow Constraint Condition

A High-Flow Constraint Condition is one in which the Company expects natural gas demand in an area or areas of its service territory to exceed the available delivered supply of gas. The condition can result from, but will not be limited to, economic factors, extremely cold weather, pipeline regulator or compressor failure, main breaks, and other emergency situations.

When the Company determines that a High-Flow Constraint Condition exists, the Company will declare a High-Flow Constraint Period in the affected area(s). During this period, the Company will: (1) require customers using Third-Party natural gas supplies to use no more than their daily confirmed, scheduled, and Company-accepted pipeline deliveries and (2) to the extent necessary, interrupt interruptible customers. One or both of these actions may be necessary to (a) avoid incurring pipeline penalties, (b) assure adequate supplies are available for firm sales service needs, and (c) to preserve system integrity. Separate nominations will be required for deliveries to pool member customers in individual constrained areas, and these areas may be balanced separately and individually as is deemed necessary by the Company. Company personnel will give Pooling Agents and/or customers as much advance notice of a High-Flow Constraint Condition as possible, normally not less than two hours. Notice of a High-Flow Constraint Condition may also be given after the start of a gas day.

Imbalance Volumes for over-nominations (undertakes) will be subject to the Nonconstraint Day First Tier and Second Tier Balancing Service Charges. To the extent that the Company requests customers or Pooling Agents to curtail usage, or requires customers on interruptible distribution service schedules to interrupt usage, during a High-Flow Constraint Day, the Company may waive the over-nomination imbalance charges above.

Imbalance volumes for undernominations (overtakes) will be subject to an unauthorized-use charge. Availability of this charge does not preclude Company from physically controlling customer's gas supply upon customer's failure to curtail to confirmed, scheduled, and Company-accepted pipeline delivery volume. The additional charge for unauthorized use will be assessed as follows:

1. During a curtailment or interruption when interstate pipeline capacity is not limited, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $2.50 per therm for gas used in excess of the maximum quantity level allowed by the Company.

2. During a curtailment or interruption due to capacity limitations on interstate pipelines, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $10.00 per therm for gas used in excess of the maximum quantity level allowed by the Company.

3. The Company will file a report with the Public Service Commission of Wisconsin after each constraint. The report will be filed by the Company within 45 days following the event.

Incremental cost, as referenced above, will include any interstate pipeline penalties incurred as a result of customers' failure to curtail or interrupt, as well as the total cost of incremental interstate pipeline capacity and/or gas commodity purchased to serve customers' load on the day(s) of curtailment or interruption. To the extent that gas commodity charges are assessed through this provision, the volume assessed charges in this mechanism will not be subject to cash out in the cashout mechanism.

(Continued on Sheet G-34.6)

Backup Sales Service

~~PENALTY~~ UNAUTHORIZED USE CLAUSE

Customers are responsible for an additional charge for unauthorized use upon failure to curtail or interrupt natural gas requirements when notified by Company. Availability of this charge does not preclude Company from physically controlling customer's gas supply upon customer's failure to curtail or interrupt. The additional charge for unauthorized use will be assessed as follows:

1. During a curtailment or interruption when interstate pipeline capacity is not limited, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $2.50 per therm for gas used in excess of the maximum quantity level requested by the Company.

2. During a curtailment or interruption due to capacity limitations on interstate pipelines, the additional charge will be the greater of incremental cost to the Company that results from a failure to curtail or interrupt, or $10.00 per therm for gas used in excess of the maximum quantity level requested by the Company.

Incremental cost, as referenced above, will include any interstate pipeline penalties incurred as a result of customers' failure to curtail or interrupt, as well as the total cost of incremental interstate pipeline capacity and/or gas commodity purchased to serve customers' load on the day(s) of curtailment or interruption.

PAYMENT

Payment is due no later than the due date shown on the bill issued by the Company to the customer. 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.

(Continued on Sheet G-36.2)

Purchased Gas Adjustment and Refund Provision

BASE AVERAGE GAS COST RATE COMPONENTS (continued)

The supply area benchmark index price for gas supply purchased under a contract for the Carlton sourcing obligation, containing a demand charge, reservation fee, and/or premium/discounts will be the actual price of gas as listed on the contract. ~~The benchmark index price will be the index price of gas as listed on the contract.~~ The demand charge, reservation fee and premium/discounts will be treated in the same manner as the Pipeline Capacity Costs, FERC-Approved/Mandated Rates and Charges and Gas Supply Costs. The fuel, FERC-Approved/Mandated variable rates and charges, and variable pipeline transportation costs will be allowed to change any time the change has been filed with the FERC or the PSCW.

The commodity cost of gas for LS-1 service excludes the cost of storage gas and storage-related cost and benefit included in the PGA. The LS-1 Daily Priced Supply or physical Fixed Price Supply difference between the actual price of gas plus fuel, FERC-Approved/Mandated variable rates and charges, and variable transportation costs and the appropriate index price, fuel, FERC-Approved/Mandated variable rates and charges, and variable transportation costs and any financial instruments will be treated in the same manner as the Pipeline Capacity Costs, FERC-Approved/ Mandated Rates and Charges, and Gas Supply Costs and will be collected or refunded in a future PGA filing.

The individual supply area benchmark costs will be added together to determine the total beginning-of-the-month commodity benchmark costs. This commodity benchmark cost will be added to the gas supply costs for the PGA commodity rate calculation.

Storage

Injection period. Gas will be injected into storage at the WACOG for the entire MGE system at the time of injection. In addition to the WACOG, the cost of gas injected into storage will be increased to reflect any additional fuel, variable pipeline transportation costs, FERC-Approved/Mandated variable rates and charges, injection costs, inventory costs or any other cost applicable to the storage injection.

If there is a net withdrawal during an injection month, the gas withdrawn from storage will be valued at the beginning of the month WACOG in storage. The adder will apply to storage as well as the withdrawal costs, fuel, FERC-Approved/Mandated variable rates and charges, and variable pipeline transportation costs to MGE gate stations.

Withdrawal period. The gas will be withdrawn from storage at the WACOG in storage at the beginning of the withdrawal month. The adder will apply to storage as well as the withdrawal costs, fuel, FERC-Approved/Mandated variable rates and charges, and the variable pipeline transportation costs to MGE gate stations.

If there is a net injection during a withdrawal month, the net amount of gas injected into storage during a withdrawal month will be valued at the first-of-the-month benchmark unit cost for all gas during the month of injection. In addition, the cost of gas injection into storage will be increased to reflect any additional fuel, variable pipeline transportation costs, injection costs, inventory costs, FERC-Approved/Mandated variable rates and charges, or any other cost applicable to the storage injection. This will be included in the cost of gas in storage and a new cost of gas in storage will be calculated for the following month. Any difference in the actual cost compared to the benchmark cost will be reflected in the current month. No adjustment will be made to the cost of gas in storage for the difference between benchmark costs and actual costs when gas is injected into storage during the withdrawal season.

The actual cost of gas in storage may increase or decrease during the withdrawal season due to No-Notice Service activity, any overrun activity, net injections made into storage accounts, inventory costs, or any other costs applicable to storage injection or carrying activities.

(Continued on Sheet G-38.3)

Purchased Gas Adjustment and Refund Provision

BASE AVERAGE GAS COST RATE COMPONENTS (continued)

Gas Supply Adder

A single adder of 2 percent will be added to all costs and volumes~~.~~ in each supply area.

Estimate of Benchmark

Since the first-of-the-month index prices are not known prior to the beginning of the month, an estimate of the commodity benchmark costs will be calculated using estimated index prices. The estimate of the commodity benchmark costs will be included in the PGA for collection from customers. When commodity benchmark costs and actual volumes are known, the estimate of the commodity benchmark costs will be reconciled with the commodity benchmark costs at actual volumes. This difference, as well as any difference in the gas supply costs, will be collected or refunded in a future PGA filing.

Comparison of Benchmark to Actual

After the month has ended and actual volumes and dollars are known, the commodity benchmark costs will be updated and compared to the actual commodity costs on a unit cost basis. To do this, the commodity benchmark unit cost as calculated for the beginning of the month will be compared to the actual commodity unit cost, excluding the gas supply costs. To arrive at the actual commodity unit cost, the appropriate actual commodity costs will be divided by actual volumes. When the actual commodity unit cost is less than the commodity benchmark unit cost, the difference in actual costs and benchmark costs will be collected or refunded in a future PGA filing. If actual unit cost is greater than the benchmark unit cost, the product of the actual volume and commodity benchmark unit cost will be collected in a future PGA filing. The excess difference will be filed with the PSCW with an explanation of the key drivers for exceeding the commodity benchmark unit cost of gas. Upon review, and written approval, the excess difference will be collected in a future PGA filing.

Exclusions

Any costs and volumes associated with any opportunity sales or sales to customers served under the BU-1 rate schedule that are made at the actual cost of gas incurred to serve those customers, as well as any costs and volumes associated with transportation and LS-1 customer imbalances and cashouts will be removed from the actual costs and volumes.

(Continued on Sheet G-38.4)

RATE COMPONENT CALCULATION

The **Annual Demand** gas cost rate component will include pipeline reservation costs, enhanced storage reservation costs, and reservation-based FERC-Approved/Mandated rates and charges for the contracted capacity not specifically assigned to Seasonal Demand and/or Balancing Reservation components below. The Annual Demand cost of gas will be adjusted by any Capacity Release/Opportunity Sales values related to annual demand; any Interruptible Market Reservation collected from IS-1, IS-2, or LS-1 rate schedules; or any LS-1 Firm Reservation collected. The Annual Demand gas cost rate will be calculated by dividing the Annual Demand costs by the total estimated therms of firm sales volume, excluding the firm portion of LS-1 sales, for the PGA ~~year~~month.

The **Seasonal Demand** gas cost rate component will include pipeline reservation costs, seasonal storage reservation costs, and reservation-based FERC-Approved/Mandated rates and charges for the contracted capacity associated with Northern Natural Gas TF5 service and ANR Pipeline's Firm Seasonal storage service with the associated transportation contracts for injection and withdrawal storage activities. The Seasonal Demand cost of gas will be adjusted by any Capacity Release/Opportunity Sales values related to seasonal demand. The Seasonal Demand gas cost rate will be calculated by dividing the Seasonal Demand costs by the total estimated therms of firm sales volume, excluding the firm portion of LS-1 sales, for the seasonal period, November through March, for the PGA year's winter season.

The **Commodity** gas cost rate component will include the benchmark-related commodity cost of gas including purchase price, fuel, variable pipeline transportation costs, variable storage costs, variable FERC-Approved/Mandated rates and charges, second pipeline costs and any and all other commodity and/or variable costs not associated with specific gas supply cost categories, plus the gas supply costs including certain financial instruments and the cost and benefits of hedging activity under the Company's approved Natural Gas Risk Management Plan, premiums/discounts associated with LS-1 special purchases/sales, Carlton premiums/discounts, and variable balancing charges. The Commodity gas cost rate component will be adjusted for the Cashout Mechanism of the DBS-1 and LS-1 rate schedules and any Opportunity Sales values related to commodity. The Commodity gas cost rate will be calculated by dividing the Commodity costs by the total estimated therms of commodity sales volume for the PGA ~~year~~month.

The **Balancing Reservation** gas cost rate component will include storage reservation costs, pipeline reservation costs, No-Notice Service reservation costs, and reservation-based FERC-Approved/Mandated rates and charges for the contracted capacity associated with ANR's No-Notice service entitlement, the associated Firm Enhanced Storage service with the associated transportation contracts for injection and withdrawal storage activity entitlement levels. The Balancing Reservation cost of gas will be adjusted by any values associated with Balancing Service Charges, except for penalties, collected under the DBS-1 rate schedule. The Balancing Reservation gas cost rate will be calculated by dividing the Balancing Reservation costs by the total estimated therms of commodity sales volume, excluding IS-2 and LS-1 sales, for the PGA ~~year~~month.

(Continued on Sheet G-38.5)

Purchased Gas Adjustment and Refund Provision

MONTHLY GAS COST RECONCILIATION

At the conclusion of each month, the actual cost of gas determined in accordance with this schedule will be compared to the cost of gas actually recovered from customers. The amount of the difference will be recovered from or returned to customers through an adjustment that is added to or subtracted from each gas cost component's estimated gas costs for the ~~remainder of the PGA year or heating season.~~ time periods as described below.

For the ~~a~~Annual ~~d~~Demand gas cost rate component, the monthly reconciliation adjustment will be calculated based on the total month-end over or under collection divided by the estimated firm sales volume, excluding the firm portion of LS-1 sales, within a defined time period. The defined time period used will be determined by the Company on a monthly basis and will never be less than one month or greater than the remaining months in a given ~~for the remainder of the~~ PGA year.

For the ~~s~~Seasonal ~~d~~Demand gas cost rate component, the monthly reconciliation adjustment will be calculated based on the total month-end over or under collection divided by the estimated firm sales volumes, excluding the firm portion of LS-1 sales, within a defined time period. The defined time period used will be determined by the Company on a monthly basis and will never be less than one month or greater than the remaining months of the seasonal recovery, November through March, in a given PGA year.~~,~~ ~~excluding the firm portion of LS-1 sales.~~

For the Balancing Reservation ~~d~~Demand gas cost rate components, the monthly reconciliation adjustment will be calculated based on the month-end total over or under collection divided by the estimated commodity sales volumes, excluding the IS-2 and LS-1 sales, within a defined time period. The defined time period used will be determined by the Company on a monthly basis and will never be less than one month or greater than the remaining months in a given ~~IS-2 and LS-1 sales, for the remainder of the~~ PGA year.

For the ~~c~~Commodity gas cost rate component, the monthly reconciliation adjustment will be calculated based on total month-end over or under collection divided by the estimated commodity sales volumes within a defined time period. The defined time period used will be determined by the Company on a monthly basis and will never be less than one month or greater than the remaining months in a given ~~for the remainder of the~~ PGA year.

The monthly commodity reconciliation adjustment will include the difference between actual commodity gas costs and the benchmark unit costs as determined in the Comparison of Benchmark to Actual section above plus gas supply actual costs.

Any over or under collection of gas costs remaining at the end of each PGA year or heating season will become a beginning balance brought forward for the new PGA year.

REFUND PROVISION

Natural gas cost-related refunds received by the Company from its wholesale suppliers resulting from actions taken by the FERC (wholesale refunds) will be refunded to customers by means of the ongoing PGA and true-up mechanism. All refunds received by the Company will be placed in a refund account, and the Company will manage the refund account balance to return outstanding balances to customers as soon as practicable, while allowing for considerations such as those listed below.

(Continued on Sheet G-38.7)

Natural Gas Sales Priority Use Program

The purpose of this program is to provide a mechanism to allocate gas supplies contracted for by the Company to serve new requests for system sales service.

The Company purchases system natural gas supplies to serve those customers who have requested Company system sales service. For those customers, the Company maintains an obligation to provide natural gas service consistent with the availability, terms, and provisions contained in the Firm Gas Sales Service (FS-1).

For interruptible sales customers, the Company purchases open-market gas supplies on a reasonable efforts basis. Interruptible sales customers wishing to transfer to firm system natural gas supplies will be provided firm sales service as the Company is able to secure the firm system natural gas supply for these customers.

Daily Balancing Service (DBS-1) customers wishing to transfer to system natural gas supplies will be provided interruptible open-market purchases on a reasonable efforts basis until such time as the Company is able to secure system natural gas supply for these customers. DBS-1 customers will apply for service under the Company's BU-1 Rate Schedule until such time system sales service is made available. The customer will be treated as a new customer in determining the availability of gas and for the purpose of deposit considerations.

DEFINITIONS

The following definitions will apply to this program:

1. **Existing system sales customer.** An existing system sales service customer is defined as any customer currently served on one of the following rate schedules for which the Company has contracted for natural gas supplies: Firm Gas Sales Service (FS-1), Interruptible Gas Sales Service (IS-1), Interruptible Large Boiler Gas Sales Service (IS-2), Large Annual Use Sales Service (LS-1), or Compressed Natural Gas Distribution Service (CNG-1).

2. **New system sales customers.** Except as defined above, a new system sales customer is defined as any future customer not currently receiving service under any of the Company's available rate schedules who would qualify for one of the following rate schedules: FS-1, IS-1, IS-2, LS-1, and CNG-1.

3. **System supply.** The natural gas planned for and purchased by the Company to meet the needs of those customers having previously requested system sales service. Normal system sales growth as forecast by the Company is included in purchase decisions for future system supply. Those customers classified as either nonsystem sales or transportation service customers are not included in the Company's system supply and will be provided service consistent with the purpose of the gas sales priority use program and the terms and conditions of the rate schedules under which they are currently served.

4. **Customer.** A consumer of natural gas at one location. An entity using gas at separate locations is considered a separate customer at each location.

(Continued on Sheet G-39.1)

Natural Gas Sales Priority Use Program

DEFINITIONS (continued)

5. **Residential service.** A service to customers for all residential purposes in a single-family dwelling, an individually metered apartment, or an apartment building where four or less residential units are served on a single meter.

6. **Commercial service.** A service to customers who are primarily engaged in wholesale or retail trade, agriculture, forestry, fisheries, transportation, communications, sanitary services, finance, insurance, real estate, personal services, government, five or more residential units on a single meter, and service that does not fall directly within one of the other classifications.

7. **Industrial service.** A service to customers who are primarily engaged in a process which creates or changes raw or unfinished materials into another form or product. This includes mining and manufacturing.

8. **Reasonable efforts.** A reasonable effort on the part of the Company to secure gas when it is available on an economical basis as determined by the customer and the Company. The Company need not use any extraordinary effort to secure gas supplies under this tariff.

Service will be provided to existing and new customers based on the level or type of service requested and the available natural gas supplies and the following priorities. Highest priority customers are served first. It is possible that customer classes requiring only annual gas supplies could be served before customer classes in a higher priority requiring peak-day supplies if the peak-day supplies are not available.

PRIORITIES

Priority 1: Use of natural gas for a residential service. Contained in this priority category are existing customers receiving service or new customers requesting service under rate schedules RD-1 and RLI-1.

Priority 2: Use of natural gas by a firm commercial or industrial customer for any purpose when the total use does not exceed 25,000 therms per year. Contained in this priority category are existing customers receiving service or new customers requesting service under rate schedules GSD-1 who elect service under Rate Schedule FS-1.

Priority 3: Use of natural gas for any purpose by any firm commercial or industrial customer over 25,000 therms per year. Contained in this priority category are existing customers receiving system sales service or new customers requesting system sales service under Rate Schedules GSD-2 and GSD-3 who elect service under Rate Schedule FS-1.

Priority 4: Use of natural gas for any purpose by any existing or new customer requesting interruptible commercial or industrial system sales service on Rate Schedules IS-1. ~~or CNG-1.~~

Priority 5: Use of natural gas for any purpose by any existing or new customer requesting interruptible commercial or industrial system sales service on the IS-2 and LS-1 rate schedules.

Priority 6: Use of natural gas for any purpose by existing customers receiving or new customers requesting Company transportation service in the following transportation rate schedules: DBS-1.

(Continued on Sheet G-39.2)

Natural Gas Curtailment Plan

CURTAILMENT PRIORITY CATEGORIES

1. Requirements for boiler fuel use having a maximum day requirement of 30,000 therms or more.

2. Requirements for boiler fuel use having a maximum day requirement of 15,000 to 30,000 therms.

3. Requirements for boiler fuel use having a maximum day requirement of 3,000 to 15,000 therms.

4. All requirements not specified in 1, 2, 3, 5, 6, or 7.

5. Commercial and industrial requirements having a maximum day requirement of less than 3,000 therms and all industrial requirements for feedstock and process needs.

6. Essential agricultural requirements of essential agricultural users as designated by the Secretary of Agriculture and calculated in accordance with 7 C.F.R. 2900, et seq., less any volumes of natural gas which the FERC determines, in accordance with Section 401(b) of the Natural Gas Policy Act of 1978, that essential agricultural users have alternate fuel capability. All such requirements to be calculated in accordance with the provisions of Part 281 of the FERC's regulations.

7. Residential, small commercial requirements having a maximum day requirement of less than 500 therms, firm service for schools, hospitals, sanitation facilities, correctional facilities, police and fire protection facilities, and company use except for power generation.

Curtailment of gas service within each priority category will be done as follows:

1. Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedule IGD-1 and the interruptible portion of SP-1.

2. Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedule SD-1.

~~2~~3. Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedule GSD-3.

~~3~~4. Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedule GSD-2.

~~4~~5. Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedule GSD-1.

5. ~~Interruptible sales service pro rata, for customers receiving their distribution service under Rate Schedules CNG-1 and SD-1.~~

6. Firm service, except for essential Company use, under Rate Schedules RD-1, ~~RD-2~~ RLI-1, GSD-1, GSD-2, and GSD-3 by size, with service to customers having the largest maximum-day requirement for use in such priority category being curtailed first.

(Next Sheet is G-41)

(New Tariff) Seasonal Distribution Service

AVAILABILITY

Service under this rate schedule is available to commercial and industrial customers. SD-2 service is designed for customers that use the vast majority of their natural gas during the off-peak period of April 1 through December 31. While SD-2 service is available year-round, incentive pricing is in place to encourage off-peak consumption. The distribution rate for service during the April through December off-peak period is significantly lower than the distribution rate for the January through March on-peak period.

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 total service charge will be the same as though one meter was installed.

APPLICABILITY AND CHARACTER OF SERVICE

The Company will provide distribution service for the delivery of gas supply through the Company's facilities for eligible customers.

Distribution service by the Company under this rate schedule will be on a firm basis.

RATE

Customer charge per day(1) ....
Distribution service per therm (April 1 through December 31) ....
Distribution service per therm (January 1 through March 31) ....

(1) The daily customer 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 SD-2 meter must be equipped with a data-logging Encoder Receiver Transmitter (ERT) which allows for accurate billing of both on-peak and off-peak consumptions.

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 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 with the Company for service under Daily Balancing Service (Rate Schedule DBS-1).

(Continued on Sheet G-42.1)

(New Tariff) Seasonal Distribution Service

SPECIAL TERMS AND PROVISIONS

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

2. Service under this rate schedule will commence following approval of the customer's application for service by the Company.

3. The rates and character of service under this rate schedule are subject to review and change by the Public Service Commission of Wisconsin.

4. This service is subject to the conditions of delivery set forth herein and to the Company's rules and regulations for gas service.

5. If special equipment, such as motor-operated valves, metering bypass, 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 telemetering equipment necessary for service under the Company's Rate Schedules IS-1, IS-2, or DBS-1. The ownership, installation, operation, and maintenance of all such equipment will be under the exclusive control of the Company.

6. 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.

(Next Sheet is G-45)

Appendix D

Madison Gas and Electric Company
3270-UR-120 2015 Fuel Cost Plan
Electric Fuel Costs per Wis. Admin. Code § PSC 116.02

Month	Fuel Cost	kWh	Fuel Cost per kWh	Cumulative Fuel Cost per kWh
January	$ 10,801,245	285,585,048	$ 0.03782	$ 0.03782
February	10,997,506	267,079,878	0.04118	0.03944
March	10,612,088	269,505,872	0.03938	0.03942
April	10,116,530	256,787,716	0.03940	0.03942
May	9,696,689	264,059,997	0.03672	0.03889
June	9,795,563	299,008,863	0.03276	0.03777
July	11,190,805	337,326,664	0.03317	0.03699
August	10,702,501	333,436,117	0.03210	0.03628
September	10,009,492	301,765,117	0.03317	0.03592
October	9,667,466	278,104,065	0.03476	0.03581
November	9,603,222	259,854,975	0.03696	0.03591
December	9,821,821	284,453,609	0.03453	0.03579
Total	$ 123,014,928	3,436,967,921	$ 0.03579	

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates	3270-UR-120

CONCURRENCE AND DISSENT OF COMMISSIONER ERIC CALLISTO

While I concur with the agreed upon revenue requirement, I dissent from the Final Decision on several issues: return on common equity; overall rate design; fixed charge increases; and the timeline for phasing out Madison Gas and Electric Company's (MGE) lifeline rate. I write separately here to explain my dissenting positions.

Return on Common Equity

I dissent from the 10.20 percent return on equity (ROE) set by the Commission. My first preference was to support that ROE, contingent upon no change in the fixed customer charges and the opening up of a generic investigation on distributed generation and related rate design issues. Recognizing that there was a desire to increase the fixed customer charge, my second choice was to support a reduced ROE of 10.00 percent provided that the fixed charges increased by no more than the Commission staff suggested 20 percent and the generic investigation was opened. Neither of those two options garnered a second vote. I note that in recent years I have voted in favor of modest increases in fixed customer charges, while not making a concomitant suggestion of a reduction in ROE. I have rethought that position, particularly in light of MGE's request to increase its fixed charges by such a large amount.

We know that ROEs are set in part based on the financial risk profile of a utility. We also know that increasing fixed customer charges reduces a utility's financial risk.[1] That there is a direct relationship between increasing fixed charges and financial risk reduction is not in question, and I would have preferred that the Commission's ROE decision take that into account.[2]

Fixed Charges & Generic Investigation on Rate Design

I disagree with the Commission's decision to increase fixed facilities charges on MGE's residential and small commercial electric customers. I disagree for many of the same reasons that I opposed the fixed charge increases for Wisconsin Public Service Corporation (WPSC), in docket 6690-UR-123, and for Wisconsin Electric Power Company (WEPCO), in docket 5-UR-107.[3] It is poor regulatory policy. It is unfair. And it is being accomplished piecemeal, in separate rate case proceedings, over the sound and well-reasoned objections of Commission technical staff, and in the face of overwhelming public and stakeholder opposition. Issues this important, this divisive, and this impactful for customers, deserve more comprehensive investigation and should be dealt with as part of a statewide effort.

Before I address the Commission's Final Decision on electric fixed charges, I want to note some history specific to MGE and its pursuit, in recent years, of restructuring its rate design. Two years ago, in docket 3270-UR-118, the Commission took up MGE's proposal to increase its

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[1] *See* Direct-PSC-Singletary-20 ("Increasing the fixed charges then is a means by which to decrease the utility's exposure to risk from decreased sales.")

[2] This is consistent with my position in both the WPSC and WEPCO rate cases this year. *See* Final Decision in docket 6690-UR-123, Commissioner Callisto Concurrence and Dissent; Final Decision in docket 5-UR-107, Commissioner Callisto Dissent.

[3] *See* Final Decision in docket 6690-UR-123, at 2-11 of Commissioner Callisto's Concurrence and Dissent; Final Decision in docket 5-UR-107, at 5-14 of Commissioner Callisto's Dissent.

electric fixed customer charge by 40 percent, a request that was trimmed back to 20 percent by my colleagues.[4] I did not support the increase then, and I was especially critical of MGE's request, as I thought it regressive, unfair to low income and low usage customers, and undermining of the customer benefits of energy efficiency and conservation.

Earlier this year, before MGE filed its application in 3270-UR-120, it became clear that MGE wanted to realign how its costs were recovered, and that it was evaluating the possibility of implementing variable demand components for residential and small commercial customers – something that would require the availability and deployment of demand meters for the small customer classes. MGE's preference, as I understood it, was to address its concerns about fixed cost recovery, but to not at the same time frustrate the customer benefits of energy efficiency and conservation. It was described as customer empowerment, a laudable and worthy goal, and one that should be something every utility seeks to pursue. This all was to be done in a way that would ensure that the customer impacts of the realignment were not regressive or unduly burdensome for low-income customers. There was also the impression that whatever was proposed by MGE would be coupled with a specific commitment and plan to develop a utility-side alternative for customers interested in supporting distributed renewable generation.

As it happened, MGE abandoned most of those ideas in favor of a more simplistic, yet dramatic, electric fixed charge increase over two years.[5] MGE did not follow through with a rate design that included variable demand components. It did not propose a real plan for widespread demand meter rollout. And it was essentially silent on what it would commit to on distributed, renewable generation. I cover that background because I want to reiterate my support for MGE,

[4] *See* Final Decision in docket 3270-UR-118, at 31.
[5] *See* Final Decision in this docket, at 2.

and others, to continue thinking creatively and looking for alternatives to what has become the industry default these days–a big, fixed customer charge increase.

The Final Decision's ordered fixed customer charge increases for MGE are steep. For electric residential customers, fixed charges will immediately go up 82 percent.[6] The increase will be as much as a 130 percent for the small commercial class.[7] The fixed charge increases are similar on the gas side.[8] These increases will hit low and below average use customers the hardest. They will discourage the adoption of customer-sited, distributed generation. They will undermine the economics of energy efficiency and conservation. And they will restrict how much control customers have over how much they pay, making it harder for customers to pay less by using less.

The Commission characterizes its decision to increase fixed customer charges by between 82 and 130 percent as a simple move to "better align" the charges and costs of utility service.[9] The Commission's rationale is that allowing the recovery of a certain amount of fixed or demand-related costs in a variable energy charge is inefficient and unfair to certain customers, particularly those who use more energy and who do not generate their own electricity. And I have acknowledged the theoretical appeal underlying the fixed facilities charge proposal.[10] But setting and designing utility rates is about more than theory. It is about more than cost-of-service

[6] The dollar increase is from $10.44 to $19.00. *See* Final Decision in this docket, at 2.
[7] The dollar increase is from $10.44 to $23.98. *See* Final Decision in this docket, at 2.
[8] My position on the electric fixed charge increases also applies to MGE's gas fixed charge increase.
[9] *See* Final Decision in this docket, at 43.
[10] *See* Final Decision in docket 6690-UR-123, at 3 of Commissioner Callisto's Concurrence and Dissent; Final Decision in docket 5-UR-107, at 6 of Commissioner Callisto's Dissent.

engineering. And it should involve much more than simply endorsing what a utility puts in its application.[11]

There is a curious hypocrisy to the Commission's Final Decision on fixed charge increases. It begins by trumpeting the specialized knowledge and technical competence of the Commission:

> In this proceeding, MGE is asking the Commission to more strongly align fixed charges with fixed costs and, to fundamentally, engage in an exercise to enact reforms in rate design and re-structuring. Such an exercise goes to the core reason why Wisconsin created this Commission: to bring to bear this agency's expertise and knowledge about rates, how they are designed, and the kind of price signals to be sent to customers, and the sort of behavior this Commission wants to incent as a matter of sound public policy . . . To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence and specialized knowledge to identify a reasonable result, bearing in mind the various public policies that may be impacted by various rate making decisions.[12]

Our agency's "technical competence and specialized knowledge" is an odd thing for the Commission to rely on in a decision that plainly ignores the recommendations of Commission technical staff regarding rate design, efficient price signals, and what sound public policy is in the context of this rate proceeding.

The reality is that the "technical competence and specialized knowledge" of this Commission advised *against* endorsing MGE's proposed fixed charge increases. Two Commission staff witnesses, an Assistant Administrator in the Gas and Energy Division and an Energy Policy Analyst, offered testimony on the fixed charge proposal. Commission staff's

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[11] The Commission's wholesale approval of MGE's fixed charge increase is especially out of balance when viewed against the breadth and scope of opposition to the proposal. The governments of Dane County, the City of Madison, the City of Middleton, and the City of Monona all opposed the fixed charge increases, as did the Natural Resources Defense Council, Wind on the Wires, Environmental Law and Policy Center, Clean Wisconsin, and RENEW Wisconsin.

[12] *See* Final Decision in this docket, at 37.

recommendations were not adopted by the Commission, and their input was largely ignored. Commission staff witness Mr. Singletary recommended that the fixed charge increase be limited to 20 percent for residential and small commercial customers, explaining:

> For these customer classes, fixed charges such as the customer charge make up a larger percent of the class revenue than is the case for larger customer classes. As such, increases in fixed charges for the residential, small commercial, and Cg-4 customer classes would have a disproportionately larger effect on lower energy use customers within each class. In MGE's last full rate case, docket 3270-UR-118, the Commission limited increases in fixed charges to 20 percent. Using that as guidance, I similarly limited the increase in this proceeding to 20 percent for the residential, small commercial, and Cg-4 customer classes.[13]

Mr. Singletary further testified:

> A common rate design principle is that of gradualism and a desire to avoid rate shock when adjusting utility rates. I believe that the percentage increases I have proposed for residential and small commercial fixed charges allows for a more gradual approach, while still allowing for more deliberate movement towards a desired fixed charge level.[14]

Mr. Singletary's "gradual" increase of 20 percent was not adopted. The Commission instead is ordering an increase of between 82 percent and 130 percent.

Commission staff witness Mr. Singletary also submitted testimony specifically addressing the supposed necessity of increasing fixed charges in furtherance of financial risk mitigation:

> When one considers the fact that Wisconsin utilities receive the benefit of a number of risk mitigation measures, including forward looking test years, opportunities for biennial (if not annual) base rate cases, cost of fuel adjustments, and a variety of escrow treatments, this trend in sales hardly seems to present a great deal of risk to the utility's ability to recover its costs while still having a reasonable opportunity to return on its investments. In fact, assuming test-year

[13] *See* Direct-PSC-Singletary-19.
[14] *See id*.

> sales forecasts are, on average, reasonably accurate, MGE is really only exposed to sales risk in the second year the utility is out between cases. This of course assumes that the utility does not come in each year.[15]

Mr. Singletary stated that "there does not appear to be an urgent need to dramatically change MGE's rate design over only one or two rate cases," concluding "I do not believe the company has presented adequate evidence to suggest that haste is in order."[16]

Commission staff also testified regarding the impact increasing fixed charges will have on customer energy efficiency and conservation. Commission staff witness Ms. Stemrich stated:

> MGE's proposal to increase fixed customer charges will reduce the benefit customers receive from installing energy efficiency measures. This decrease in customer benefits does not impact the amount of cost-effective energy efficiency available, as that is determined by the Total Resource Cost Test. However, because customer benefits are reduced, the cost-effectiveness of energy efficiency to the customer is reduced, thereby potentially suppressing or reducing achievable energy efficiency in MGE's footprint.[17]

I note in contrast the Commission's conclusory observation that "raising the fixed charge could have an incidental effect upon the payback period of certain energy efficiency measures," and that increasing the fixed portion of customer bills somehow "encourages efficiency utility scale planning."[18]

[15] *See* Direct-PSC-Singletary-21.
[16] *See id.*
[17] *See* Direct-PSC-Stemrich-4-5.
[18] *See* Final Decision in this docket, at 40. I also note for illustrative purposes that the Program Administrator responsible for running Wisconsin's Focus on Energy program, our statewide energy efficiency and renewable resource program, has cautioned Commission staff that the implications of substantially increasing fixed customer charges "are profound," that doing so "would require Focus on Energy incentives to increase in order to sustain participation," and that such rate design changes would increase "the cost per delivered unit of energy savings" and ultimately decrease the achievable energy savings. *See* Memorandum from Focus on Energy staff Chad Bulman and Tamara Sondgeroth, to Commission staff Carol Stemrich, Jolene Sheil, Preston Schutt, and Joe Fontaine, dated October 9, 2014, at 4-5. I understand that this memorandum is not part of the record in this proceeding, but it is relevant, and the Commission is free to take administrative notice of it under Wis. Stat. § 227.45(3) or reopen the administrative record and allow it into evidence.

I agree that we should rely on the specialized expertise of this agency. But let's be honest about what that expertise advises. The recommendations and analytical conclusions which reflect Commission staff's "technical competence and specialized knowledge" about "rates and the price signals that are sent to customers, and the sort of behavior this Commission wants to foster as a matter of sound public policy,"[19] include the following:

- A fixed customer charge increase of no more than 20 percent for residential and small commercial customers;
- A recognition that steep fixed customer charge increases unfairly impact low usage customers;
- An understanding of utility financial risk that is cognizant of the numerous risk mitigation features already present in Wisconsin's regulatory framework; and
- A recognition that steep fixed customer charge increases will negatively impact customer energy efficiency and conservation.

The Commission either ignored or disagreed with all of this. I agree with the idea that we exist as a regulatory body in part to "bring to bear" our agency's "expertise and knowledge." But there is no support in this Final Decision for the suggestion that is what the Commission is doing here.

The Commission's Final Decision on fixed charges has other problems. It finds "that it is not necessary at this time" to specify what specific costs are appropriate to consider when

[19] *See* Final Decision in this docket, at 37.

setting fixed electric charge rates,[20] yet concludes "that the fixed customer charges should be increased to more closely reflect the utility's fixed costs to provide basic service to a customer."[21] It ignores record evidence showing that it is more likely that low income residents in MGE's service territory are low usage customers, and thus those customers will be disproportionately harmed by the fixed charge increase.[22] It relies heavily on the existence of supposed "subsidies" in current rate design, yet never identifies the extent of these subsidies, nor attempts to quantify them in dollars or as a percentage of utility revenue. It also fails to coherently apply our Energy Priorities Law, Wis. Stat. §§ 196.025(1)(ar) and 1.12(4), to a rate-setting decision that will make energy efficiency, conservation, and renewable energy less cost-effective for MGE's residential and small commercial customers. The Final Decision throws a lot at the wall, but very little of it holds up.

I agree that public utility regulation "is intended to simulate a free market process for monopoly utilities."[23] We are meant to stand in as a proxy for the free market–for competition–because where none exists, the consuming public is otherwise captive and without recourse in the face of a monopoly provider of essential utility service. Today's decision does not protect the consuming public or advance the public interest.

Here is what it does do. If you use less energy than an average user, you are going to pay more on your utility bill. The lower your use, the more you will pay, relative to the current bill structure. You will also have less control over how much you pay. Folks who live in the

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[20] *See id*., at 32-33.
[21] *See id.*, at 48.
[22] *See* Direct-City of Madison-Marcus-17-18 (citing Bureau of Labor Statistics, "lower income people use less electricity," further noting that MGE's claims about income "contradict both national and regional income data as well as MGE's own data on other usage drivers related to the housing stock.")
[23] *See* Final Decision in this docket, at 39.

smallest dwellings–those in apartments, multi-unit housing, often individuals on fixed incomes, will be hit the hardest. About 75 percent of MGE residential customers will have a bill increase as a result of the Final Decision because of the fixed charge increase.[24] For 20,000 of MGE's residential customers, the increase will be greater than 10 percent.[25] For customers who use on average of about 300 kilowatt-hours per month, their annual increase will be roughly $66.00, as a result of the fixed charge increase.[26] For those who use 200 kilowatt-hours per month, the annual increase will be about $79.00.[27] We also know that low usage customers are more likely to be low income customers.[28] So the effect of increasing fixed customer charges will disproportionately impact low income populations.[29] Today's decision will undermine the cost-effectiveness of energy efficiency and conservation measures and discourage the adoption of distributed generation technologies going forward.

It is time to take a measured look at the issues raised by the utility industry's nationwide push to "realign" rate structures. I think we should slow down, approve no fixed charge increase in this case, and open up a generic investigation. I would support a timeline that would ensure completion before the rate case season for test year 2017, and would involve a broad range of interested stakeholders and Commission staff. In addition to rate re-design and the specific issue

[24] *See* Surrebuttal-NRDC-Morgan-4.
[25] *See id.*
[26] *See* Surrebuttal-NRDC-Morgan-5-Table 1.
[27] *See* Surrebuttal-NRDC-Morgan-5-Table 1. I reference these numbers in response to the Commission's continuing effort to downplay the impact these changes will have on utility customers. *Cf.* Final Decision in this docket, at 43 ("the total dollar bill impact of these changes to those customers who will see bill increases is relatively small."). An extra $80.00 each year for utility service is real money, and it will hit those who use the least amount of energy, those least able to respond to it, the hardest.
[28] *See* Direct-City of Madison-Marcus-17-18.
[29] There is good news for the very few MGE residential customers who use more than 2000 kilowatt-hours every month: they will have a 4 percent bill *decrease* in 2015, as a result of the Commission's fixed charge changes. *See* Surrebuttal-NRDC-Morgan-5.

of fixed charges, a more comprehensive investigation would evaluate placing a fair and transparent value on distributed generation, and at least start down the discussion path of the role of regulated utilities in a future with flat load growth, increased distributed generation and more robust consumer involvement in energy choices. Other states are way ahead of Wisconsin in this regard. The solution provided by MGE here, and other regulated companies in this state, is not holistic, not forward thinking, and largely self-serving. It is our job–as regulators–to push and guide where that works, and to lead when others will not.

I would have kept the fixed customer charges where they are now, or limited the increases to 20 percent provided that such an increase would be accompanied by a 20 basis point reduction in ROE and the opening of a generic investigation as I have described.

Low Income and Lifeline Rates

While I do not support the fixed charge increase, I do think that, at a minimum, the Commission should have approved MGE's proposed Rg-6 tariff for low-income customers, in recognition of the impact that increasing fixed charges will have on low-income, low energy customers in MGE's service territory. The Final Decision's rationale here is at odds with itself. On the one hand, it concludes "that the proposed fixed charge increase for residential customers will not disproportionately disadvantage lower-income groups to a significant extent."[30] Yet on the other, it "finds some merit in the concerns raised in this proceeding regarding rate impacts on

[30] *See* Final Decision in this docket, at 51. One is left to wonder what the Commission would consider "significant" disproportionate impact in the context of low-income populations.

low-income customers generally."[31] The Commission should have erred on the side of customers here and approved MGE's low-income rate proposal.[32]

Regarding MGE's proposed elimination of its Rg-3 residential lifeline rate, I agree that it should be phased out. But rather than end the lifeline tariff a year from now, I would have allowed it to phase out over a longer, more gradual period.

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[31] *See id.*

[32] The Commission should be examining this question in other service territories, as well, insofar as it "finds some merit" in the notion that raising fixed charges disproportionately impacts low-income customers.