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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-118

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, 2013.

Final overall rate changes are authorized consisting of a $14,888,000 annual rate increase for electric utility operations (a 3.81 percent increase) and a $1,646,000 annual rate increase for natural gas utility operations (a 0.97 percent increase) for the test year ending December 31, 2013.

Introduction

On March 23, 2012, MGE filed an application with the Commission requesting authority to change its electric and natural gas rates on January 1, 2013. MGE requested a $22,451,000 increase (5.82 percent) for electric operations and a $4,308,000 increase (2.59 percent) for natural gas operations.

On May 21, 2012, a prehearing conference was held at the Commission to determine the issues that would be addressed in this docket and to establish a schedule for the hearings. The Commission held hearings for technical issues and for public comment on September 18, 2012.

The Commission considered this matter at its open meeting on November 9, 2012.

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's files.

EXHIBIT 5

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. MGE's estimates of electric sales of 39.25 and 36.76 percent on-peak usage, for the Cg-4a and Cg-4b rate classes, respectively, are reasonable.

3. MGE's forecast of Sp-3 sales, as adjusted by Commission staff's uncontested minor reductions to MGE's forecast level of sales, is reasonable.

4. It is reasonable for MGE to defer to its next rate case any adjustments to cost overruns for the Elm Road Generating Station (ERGS) that result from the Commission's decisions in docket 5-UR-106.

5. It is reasonable to include the one-time cost savings for FAS 106, other post-retirement benefits, in electric and natural gas revenue requirements.

6. It is reasonable to include MGE's updated estimate of pension and benefits costs relating to the return on pension assets and discount rate assumptions in the electric and natural gas revenue requirements.

7. It is reasonable to include MGE's updated estimates of American Transmission Company LLC (ATC) fees and Midwest Independent Transmission System Operator, Inc. (MISO), Schedule 26 fees in electric revenue requirement.

8. It is reasonable to include Commission staff adjustments that were not contested by any party or listed separately for a Commission decision in the final electric and natural gas revenue requirements.

9. A 2013 test-year total fuel cost of $131,560,113 is reasonable.

10. A test-year fuel rule cost of monitored fuel of $106,128,834, or $30.93 per megawatt-hour (MWh), as shown in Appendix D, is reasonable.

11. It is reasonable to monitor all fuel costs using an annual bandwidth of plus or minus 2 percent.

12. It is reasonable to use the 2013 New York Mercantile Exchange (NYMEX) futures Henry Hub natural gas prices from October 10, 2012, as the basis for forecasting test-year cost of electric generation from natural gas.

13. It is reasonable to use the 2013 NYMEX futures prices for Northern Illinois Hub (NI Hub) Locational Marginal Prices (LMP) Swaps for Peak and Off Peak from October 10, 2012, as the basis for forecasting test-year MISO marginal energy prices.

14. It is reasonable to use a regression analysis of the relationships between NI Hub prices and MISO LMPs for the 12-month period ended August 31, 2012, as the basis for forecasting test-year congestion costs and marginal transmission losses on the MISO system.

15. It is reasonable that the test-year fuel costs reflect the forecasted differences between the hourly LMPs for the MGE load zone node and the various MISO nodes where MGE has generation facilities outside of Madison.

16. It is reasonable to forecast test-year LMP differentials based on historical data from the 12-month period ended August 31, 2012.

17. It is reasonable that the test-year electric fuel cost forecasts do not reflect a forecast of MISO Revenue Sufficiency Guarantee (RSG) make-whole payments.

18. It is reasonable to direct Commission staff to review, in future proceedings, MGE's capacity purchasing procedures and the prudence of any decisions with respect to the purchase of any additional required capacity.

19. It is reasonable to require MGE to develop a forecasted Equivalent Forced Outage Rate (EFOR) for the West Campus Cogeneration Facility (WCCF), based on the most recent available historical outage data, in its next rate proceeding.

20. It is reasonable, in future rate proceedings, to require MGE to model its portion of the ERGS unit, on the same basis that the Commission finds appropriate for Wisconsin Electric Power Company's (WEPCO) portion of the ERGS unit, in the current WEPCO rate proceeding in docket 5-UR-106.

21. It is reasonable to authorize MGE to use deferral accounting, with interest to accrue at MGE's cost of short-term debt, for any 2013 Cross-State Air Pollution Rule (CSAPR) compliance costs incurred prior to the vacation of CSAPR by the District of Columbia (D.C.) Circuit Court of Appeals, and address rate recovery of these costs in MGE's next rate proceeding.

22. It is reasonable that the monitored fuel costs authorized in this proceeding be considered the approved fuel cost plan for the 2013 plan year that complies with Wis. Stat. § 196.20(4)(c).

23. It is reasonable to include Commission staff's fuel cost adjustments that were not contested by any party or listed separately for a Commission decision in the final electric and natural gas revenue requirements in this proceeding.

24. It is appropriate to exclude all of MGE's customer service conservation activities budgeted for the test year from the escrow budget. This does not included escrow expenditures for Focus on Energy.

25. A reasonable level of expensed customer service conservation costs recoverable in rates for the test year is $1,932,214 for electric operations and $1,577,236 for natural gas operations. This excludes Focus on Energy funding.

26. 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.

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

28. A reasonable estimate of the debt equivalent of MGE's off-balance sheet obligations, to be imputed into the financial capital structure for the test year, is $68,019,280.

29. A reasonable financial capital structure for the test year consists of 55.00 percent common stock equity, 32.33 percent long-term debt, 4.03 percent short-term debt, and 8.64 percent debt equivalent of off-balance sheet obligations.

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

31. It is reasonable to base MGE's dividend restriction on the financial capital structure in this proceeding and to set the dividend restriction at $0.

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

33. A reasonable utility capital structure for ratemaking for MGE for the test year consists of 59.09 percent common stock equity, 36.37 percent long-term debt, and 4.54 percent short-term debt.

34. A reasonable interest rate for MGE's short-term borrowing through commercial paper is 0.20 percent for the test year.

35. A reasonable interest rate for MGE's new long-term debt issued in the test year is 4.54 percent.

36. A reasonable average embedded cost for MGE's long-term debt is 5.51 percent.

37. The rate of return on common equity of 10.30 percent as established in MGE's last rate case, docket 3270-UR-117, remains in place as it was not an issue addressed in this proceeding.

38. A reasonable weighted average composite cost of capital is 8.10 percent.

39. It is reasonable to rely on the results of one or more electric cost-of-service study (COSS) along with other factors, such as bill impacts, when allocating revenue responsibility.

40. It is reasonable to require analysis of the WCCF station service load as it relates to cost-of-service in MGE's next base rate case.

41. It is reasonable to approve the electric and natural gas rate changes, tariff provision changes, and the test year forecasted customer class revenue increases shown in Appendices B and C.

42. It is reasonable to change MGE's electric Distribution Extension Allowances as shown in Appendix B.

43. It is reasonable to increase electric and natural gas customer charges by 20 percent.

44. It is reasonable to allow the existing Sp-3 rate structure to remain in place, but to increase the generation credit to a rate of $0.46 per kilowatt-day, with the level of other charges revised in a manner that follows the rate design proposed by Commission staff.

45. It is reasonable to replace MGE's current Time-of-Use (TOU) rate structure with one comprised of a base energy rate for all energy used by TOU customers, and adder rates for the on-peak TOU rate periods, as proposed by MGE.

46. It is reasonable to adjust the Rg-3 lifeline rates in a manner that follows the rate design proposed by Commission staff.

47. MGE's plan to implement the remaining demand response initiatives ordered by the Commission in docket 3270-UR-116 is reasonable.

48. MGE's proposed modifications to the Pg-1 parallel generation tariff, revised to address capacity payment and renewable energy attributes in a manner consistent with that proposed by Commission staff, are reasonable.

49. MGE's proposed revisions to the Pg-2 net metering tariff are reasonable. It is reasonable to increase the green pricing premium for the Green Power Tomorrow program to $0.040 per kilowatt-hour (kWh).

50. Commission staff's calculations of 2005 Wisconsin Act 141 costs included in electric and natural gas base rates are reasonable.

51. It is reasonable for the Commission to consider all of the natural gas COSS as guides in determining revenue allocation and rate design.

52. It is reasonable to maintain MGE's current telemetering charge and require MGE to provide a report, in its next rate case, that contains up-to-date cost information about the number and types of telemetering equipment in service.

53. It is reasonable to make changes to the SD-1 Seasonal Off-Peak Distribution Service tariff, as described in this Final Decision.

54. MGE's proposed light emitting diode (LED) lighting tariff, as modified by this Final Decision, is reasonable.

55. It is reasonable to require that MGE install equipment that will provide daily usage information for SD-1 customer billing as soon as reasonably practicable, and no later than April 30, 2013.

56. It is reasonable to add language to MGE's natural gas service rules that state that MGE may disconnect a customer's service if a customer refuses to allow authorized utility personnel access to their premises at all reasonable times for purposes related to providing safe and reliable service.

57. It is reasonable to exclude MGE's costs associated with its Compressed Natural Gas (CNG) distribution service from utility plant in service and to recognize this service as a non-utility service.

58. It is reasonable to deny MGE's request to file tariffs for firm natural gas supply service that includes demand discounts for natural gas vehicles (NGV).

59. It is reasonable to allow MGE to continue its CNG retail service to NGVs pursuant to its CNG-1 tariff that is on file with the Commission.

60. It is reasonable to further investigate NGV policies in the first quarter of 2013.

Conclusion of Law

The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40, 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 cost 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 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 141,000 retail customers in Madison and the surrounding area in Dane County, and in the purchase, transportation, distribution, and sale of natural gas to approximately 145,000 customers in Madison and the surrounding area in Dane County, and in Columbia, Crawford, Iowa, Juneau, Monroe, and Vernon Counties. MGE is an operating subsidiary of MGE Energy, a holding company based in Madison, Wisconsin.

Income Statement

MGE, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of MGE's 2013 electric and natural gas utility operations. Significant issues pertaining to the income statements are addressed separately below.

On-Peak Percentages for the Cg-4a and Cg-4b Rate Classes

In docket 3270-UR-116,[1] the Commission found it reasonable for MGE to close its Cg-1a and 1b rate schedules to new customers, and work with Commission staff to develop a plan to transfer all of these customers to TOU rate schedules. In compliance with this directive, MGE closed the Cg-1a and 1b rate classes to new customers in January 2010 and transferred all customers to the Cg-4a and 4b (TOU) rate classes by April 2012.

Commission staff increased MGE's estimate of commercial sales of electricity by $611,000 to reflect its estimates of the proportion of kWh energy usage in the Cg-4a and Cg-4b rate classes that is used during on-peak periods as opposed to off-peak. Commission staff estimated that 39.95 percent and 39.20 percent of kWh energy usage for rate classes Cg-4a and Cg-4b, respectively, will be used during on-peak hours. This was based on an average of load research data for 2009, and April and May 2012 actual on-peak usage data, as adjusted for estimated seasonality and estimated load shifting to off-peak hours in response to TOU rates.

MGE contested this adjustment because Commission staff's on-peak estimates exceed the 2009 load research data. MGE testified that its estimates (39.25 and 36.76 percent on-peak for Cg-4a and Cg-4b, respectively) were more consistent with the Commission's intent in requiring the shift to mandatory TOU rates, by assuming that customers would react to increasing on-peak electric rates and begin shifting some of their energy use to the lower priced off-peak periods.

The Commission finds that MGE's forecast of on-peak percentages for the Cg-4a and Cg-4b rate classes is appropriate for the test year. Commissioner Callisto dissents.

[1] *Final Decision, Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates*, docket 3270-UR-116 (December 22, 2009) at 43 (PSC REF#: 125079).

Sp-3 Sales Forecast

There are three sources of electricity used to supply the total campus load: (1) energy the University of Wisconsin (UW) purchases from MGE under the Sp-3 rate; (2) energy UW receives on a station service basis to serve electric chillers generated and provided directly from WCCF; and (3) energy UW self-generates at the Charter Street Heating Plant (CSHP). Energy purchased under the Sp-3 rate is further segregated into traditional campus loads and energy supplied to the WCCF chillers in lieu of station service when the facility is available, but not operating. The energy used to directly supply the electric chillers when WCCF is operating is treated as station service, and UW pays for this energy on a cost-sharing basis under the operation and maintenance agreement for WCCF. The Sp-3 rate schedule applies exclusively to UW.

MGE testified that it forecasted sales to UW based on an analysis of historic electric usage, considering all three sources of electricity to ensure that the projection for electric use is reasonable across the total campus load. MGE's forecast of total campus electricity use for 2013 reflects a 2.5 percent increase over the 2011 calendar year level. MGE's forecast reflects a substantial increase in the level of CSHP generation between the 2011 actual and the 2013 forecast level due to the CSHP plant going offline and coming back online. This translates into a net decrease in traditional electricity sales to serve campus loads under Sp-3. In addition, MGE forecasts a significant increase in the level of electricity directly supplied to the WCCF chillers through station service, which translates to a decrease in the level of electricity supplied to the WCCF chillers under the Sp-3 rate.

UW testified that MGE's use of 2010 and 2011 data to project sales for 2013 will likely understate sales because UW has increased its need for electricity as a result of the completion of several large construction projects, such as Union South and Discovery Center, and the installation of a new chiller at CSHP replacing steam chiller loads. UW's actual usage for the 12 months ended June 2012 exceeds MGE's proposed test-year figures in all categories of distribution service demand, winter on-peak demand, and summer on-peak demand.

The Commission finds that MGE's forecast of Sp-3 sales, as adjusted by Commission staff's uncontested minor reductions to MGE's forecast level of sales, is appropriate for the test year.

Elm Road Generating Station Adjustments

Commission staff's financial statements included all costs associated with MGE's 8.33 percent ownership in ERGS. However, there were material cost overruns associated with the project. The nature of the overruns is an issue in the WEPCO rate case, docket 5-UR-106. The Commission concludes that it is reasonable that the decisions the Commission makes in docket 5-UR-106, with respect to ERGS cost overruns, also apply to MGE, and for MGE to defer any adjustments to its next rate case.

Post-Retirement Cost Savings

At the hearing, MGE reported that it had identified a one-time cost savings for FAS 106, other post-retirement benefits, of $1,500,000 ($960,000 for electric and $540,000 for gas) as a result of the negotiation process for medical premiums, and requested that this savings be included in its revenue requirement calculation. The Commission finds it reasonable to include this savings in electric and natural gas revenue requirements.

Update of Pension and Benefit Costs

MGE provided an update of pension and benefit costs for the test year prior to the Commission decision showing an increase in pension expense of $2,099,000 ($1,343,000 for electric and $756,000 for gas), based on current market information for the return on pension assets and discount rate assumptions. A forecast of pension and benefit costs was included in Commission staff's revenue requirement, but the actual return on assets and the discount rate are volatile. An update of these costs closer to the time of the Commission decision protects both the ratepayers and shareholders from changes in the pension assumptions. The Commission considers it reasonable to include MGE's updated estimate of pension and benefits costs relating to the return on pension assets and discount rate assumptions in the electric and natural gas revenue requirements.

Update of ATC Network Service Fees and MISO Schedule 26 Fees

MGE provided updated forecasts of ATC network service fees of $881,000, and MISO Schedule 26 fees of $1,085,000. The Commission finds it reasonable to include these updated estimates in test-year electric revenue requirement.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this opinion, all other Commission staff adjustments to MGE's filed operating income statements are reasonable and just. Accordingly, the estimated electric and natural gas utility operating income statements at present rates for the test year that are considered reasonable for the purpose of determining the revenue requirements in this proceeding are as follows:

	Electric (000's)	Gas (000's)
Operating Revenues		
Sales of Electricity	$390,289	$ -
Sales for Resale	2,190	-
Sales of Gas	-	166,419
Other Operating Revenues	1,436	3,144
Total Operating Revenues	$393,915	$169,563
Operating Expenses		
Steam Power Generation Expenses	$118,973	$ -
Other power Generation Expenses	4,434	-
Other Power Supply Expenses	83,965	-
Purchased Gas Expenses	-	101,425
Transmission Expenses	33,855	-
Distribution Expenses	14,520	8,615
Customer Accounts Expenses	7,886	6,582
Customer Service Expenses	8,066	5,751
Administrative & General Expenses	39,946	21,404
Total Operation & Maintenance Expenses	$311,645	$143,777
Depreciation and Amortization Expense	25,926	6,448
Taxes Other Than Income Taxes	15,608	3,070
Deferred Income Taxes	897	2,253
State Income Taxes	2,029	402
Federal Income Taxes	7,474	3,222
Investment Tax Credit	(110)	(103)
Total Operating Expenses	$363,469	$159,069
Net Operating Income	$ 30,446	$ 10,494

Summary of Average Net Investment Rate Bases

Commission staff proposed a number of adjustments to MGE's filed electric and natural gas utility average net investment rate bases. No party opposed these adjustments and the Commission finds them to be reasonable. Accordingly, the estimated electric and natural gas average net investment rate bases for the test year, which the Commission finds are reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Gas (000's)
Utility Plant in Service	$941,118	$345,566
Less Reserve for Depreciation	406,889	182,717
Net Utility Plant	$534,229	$162,848
Add: Fuel Inventory	5,981	
Stored Gas		9,898
Materials and Supplies	13,758	2,336
Less: Accumulated Deferred Income Taxes	135,722	38,154
Customer Advances for Construction	400	802
Average Net Investment Rate Base	$417,846	$136,126

Pro Forma Rate of Return

The estimated net operating income for the test year ending December 31, 2013, results in a rate of return on average net investment rate base of 7.28 percent for electric operations and 7.72 percent for gas operations.

Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is $106,128,834, which reflects the cost of generation, chemicals to control emissions, fuel and ash handling, purchased power (including capacity and energy), transmission, MISO administrative costs, and a baseline level of uneconomic dispatch costs at MGE's WCCF, less revenues from opportunity sales and from the MISO and PJM Interconnection LLC (PJM) Ancillary Services Markets. The test-year fuel cost divided by the test-year estimate of native energy requirements of 3,431,424 MWh results in an average net monitored fuel cost per MWh of $30.93. 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). The level of uncertainty of fuel costs is not expected to be significantly changed, and fuel costs are not expected to be significantly more volatile in the test year than they have been in the recent past. The application of a 2 percent bandwidth is appropriate for these fuel costs.

The fuel cost data in Appendix D shall be used for monitoring MGE's 2013 fuel costs.

Natural Gas Forecasts

In its March 29, 2012, application, MGE used the 2013 NYMEX futures Henry Hub natural gas prices from January 17, 2012, as the basis for its forecast of test-year natural gas prices. Commission staff's estimate of test-year natural gas prices was based on NYMEX futures from May 16, 2012. The updated natural gas prices shown in the delayed exhibit reflect the 2013 NYMEX futures Henry Hub natural gas prices from October 10, 2012.

The Commission finds it is reasonable to use the 2013 NYMEX futures Henry Hub natural gas prices from October 10, 2012, as the basis for forecasting test-year cost of electric generation from natural gas.

Economic Energy Forecasts

An important factor affecting the test year electric fuel forecasts is the forecasted market prices for electricity, that is, the prices at which MGE will purchase its energy requirements from, and sell its generation sources into, the MISO market. These market prices are represented by the LMP at each of the MISO nodes. The hourly LMPs are comprised of three cost components: (1) marginal energy prices; (2) congestion cost, which reflects the extent to which transmission congestion may prevent MISO from dispatching the lowest cost of energy to a particular node; and (3) marginal losses on the MISO system. The sum of congestion costs and marginal losses has been described as the "basis difference" or "basis" between the system's energy price and the LMP for each MISO location.

Marginal Energy Prices

At any given time, the marginal energy price is constant throughout the MISO system, but the basis difference will vary by location. The basis differences are heavily influenced by localized conditions, which change over time. Weather, load, and generation levels by location, transmission outages, and transmission system design primarily affect congestion and losses.

For the test-year fuel forecasts, MGE and Commission staff used the NYMEX futures for NI Hub LMP Swaps (peak and off-peak) as the basis for forecasting test-year marginal energy prices. In its application of March 29, 2012, MGE used the 2012 NYMEX futures from January 17, 2012, and in Commission staff's Ex.-PSC-Hillebrand-1, the 2012 NYMEX futures are from May 16, 2012. The electricity prices updated in the delayed exhibit reflect the 2013 NYMEX futures NI Hub LMP Swaps (peak and off-peak) prices from October 10, 2012.

The Commission finds it is reasonable to use 2013 NYMEX futures prices for NI Hub (peak and off-peak) from October 10, 2012, as the basis for forecasting test-year MISO marginal energy prices.

MGE LMP

MGE filed using a regression analysis of the applicable relationships for the 12-month period ended December 31, 2011. Commission staff used a regression analysis of the applicable relationships for the 12-month period ended August 31, 2012.

The Commission finds it is reasonable to use a regression analysis of the relationships between NI Hub prices and MISO LMPs for the 12-month period ended August 31, 2012, as the basis for forecasting test-year congestion costs and marginal transmission losses on the MISO system.

LMP Differentials

In this proceeding, MGE indicated that due to the operation of the MISO market, MGE is exposed to the differences between the LMP for the MGE load zone node and the various MISO nodes where MGE has generation facilities outside of Madison. When MGE sells its generation from outside Madison to MISO, the hourly LMP for each generation node is often different from the LMP for the energy purchases from MISO to serve MGE load at the same time, which MGE refers to as LMP differentials. If the generation node LMP is less than the MGE LMP, MGE experiences additional fuel costs. Financial Transmission Rights can be used as a financial hedge against these LMP differentials but are not available for all generation sources from MISO and may cause further cost exposure if the protected generation source is not running.

In its filing of March, 29, 2012, MGE forecasted the LMP differentials based on the generation-weighted LMP differences in the Day Ahead MISO market during 2011. Commission staff updated the LMP differentials through August 31, 2012.

The Commission finds it is reasonable that the test-year fuel costs reflect the forecasted differences between the hourly LMPs for the MGE load zone node and the various MISO nodes where MGE has generation facilities outside of Madison. It is reasonable to forecast test-year LMP differentials based on historical data from the 12-month period ended August 31, 2012.

MISO Revenue Sufficiency Guarantee Make-Whole Payments

As part of the MISO energy market, the operating costs of generating units are reflected in the offer price to the MISO market. If the generating unit has not been dispatched by MISO as part of its economic dispatch, the LMP at the generator node will be lower than the generating unit's cost of production. If MISO calls upon a generating unit to be dispatched for reliability purposes, MISO uses RSG make-whole payments to compensate for the difference between the LMP and the unit's operating costs.

Citizens Utility Board (CUB) argued that MGE has historically received revenue from MISO make-whole payments, and it is reasonable to expect that MGE will receive such payment in 2013. CUB argued that MGE has not shown that the additional costs that the make-whole payments are intended to offset are not in the test-year fuel forecasts, and unless such data is provided, the test year fuel costs should be reduced by the MISO make-whole payments.

MGE argued that MGE's test-year fuel forecasts are based on MISO security-constrained economic dispatch. If MISO dispatches units for reliability reasons, which are typically uneconomic, operators are entitled to the MISO make-whole payments to offset the additional dispatch costs not covered by the LMP. MGE argued that since its fuel forecasts do not include these uneconomic dispatch costs, it is not appropriate to include the MISO revenues from the make-whole payments.

The Commission finds that it is reasonable that the test-year electric fuel cost forecasts do not reflect a forecast of MISO RSG make-whole payments.

Cross-State Air Pollution Rule Compliance Costs – Sulfur Dioxide

The U.S. Environmental Protection Agency (EPA) issued a final version of CSAPR on July 6, 2011, and published it as a final rule in the *Federal Register* on August 8, 2011. This rule replaced EPA's 2005 Clean Air Interstate Rule, and was designed to address the transport of air pollution across state boundaries for 27 eastern states. CSAPR established new, more stringent levels of allotted sulfur dioxide emission allowances for the states, including Wisconsin and its utilities. Utilities had several options from which to choose to meet CSAPR emission standards, including retiring older generating plants, changing the dispatch of plants, purchasing power from other utilities, installing pollution-control equipment, and purchasing allowances through a limited trading program. On August 21, 2012, the D.C. Circuit Court of Appeals vacated and remanded CSAPR to EPA.

Because of the uncertainty due to the continuing litigation with respect to CSAPR, and the fact that re-dispatch of plants to comply with CSAPR was cost-prohibitive, MGE developed a compliance plan for 2012 based on a combination of emission allowances, options to purchase allowances, the purchase of allowances with "regulatory out" provisions. For 2013 compliance, MGE followed the principles of its CSAPR compliance plan, but because of the cost of options, and both cost and availability issues with the purchase of allowances with "regulatory out" provisions, chose to purchase emission allowances only. On June 26, 2012, MGE signed a contract to purchase two thousand 2013 vintage CSAPR emission allowances, at a cost of $235 each, for a total of $470,000. This represented the majority, but not all of MGE's estimated 2013 CSAPR emission allowance requirements.

Commission staff proposed that the $470,000 spent by MGE on CSAPR allowances be amortized over the 2013-2014 biennium, with the provision that should MGE recover any value from the sale of these allowances, that it be returned to ratepayers in a subsequent rate proceeding. This issue was uncontested. The Commission, however, finds that a more fully-developed record is required before making a decision on recoverability. Therefore, the Commission finds it reasonable to authorize MGE to use deferral accounting for any 2013 CSAPR compliance costs incurred prior to the vacation of CSAPR by the D.C. Circuit Court of Appeals, with interest to accrue at MGE's cost of short-term debt. Rate recovery of these deferred costs shall be addressed in MGE's next rate proceeding.

WEPCO Capacity Purchased Power Agreement

MGE currently purchases capacity from WEPCO via a Purchased Power Agreement (PPA) signed in 2007. Since then, the market value of capacity has declined as has MGE's capacity requirements. Under this PPA, MGE can nominate to purchase several blocks of capacity from WEPCO. MGE currently purchases only the first block of capacity, the minimum required under the PPA, and monitors the markets for the lowest cost capacity for future needs.

In this proceeding, CUB requested that the Commission require MGE to pursue lower-priced capacity through a competitive process rather than purchasing additional capacity under the WEPCO PPA.

Because the Commission finds that MGE is not currently purchasing any additional capacity (beyond the first block it must purchase under the terms of the PPA), the Commission declines to adopt CUB's approach. Instead, the Commission directs Commission staff to monitor and review MGE's future capacity purchasing procedures and decisions and make this information available to the Commission in future proceedings.

Planned Outage Schedule

CUB had concerns that, for the 2013 test year, MGE was scheduling too many planned outages in the month of September, when replacement power costs were cheaper in October. CUB was also concerned that by scheduling so many planned outages in one month, MGE could artificially cause a need to purchase additional capacity.

MGE demonstrated that LMPs were actually forecasted to be higher in the month of October, as compared to September, and that it has surplus capacity in those months.

As MGE already files support for its proposed planned outage schedule in its fuel plans and rate proceedings that Commission staff auditors routinely review, the Commission finds it unnecessary to order MGE to file any additional support for its planned outage schedules.

West Campus Equivalent Forced Outage Rate

CUB requested that MGE be required to develop an EFOR for WCCF, based on historical outage data, as MGE could not provide any data to support the 5.0 percent EFOR MGE has used for the WCCF for the last several years. CUB also provided its estimated EFOR of 0.6 percent based on the last 5 years actual data.

MGE responded that CUB understated the EFOR it had developed, and that, for the WCCF, the assumed EFOR has little impact on fuel costs as it is frequently dispatched for reasons unrelated to the utility's economic requirements.

Even if the impact on fuel costs is minimal, the Commission concludes it is reasonable to require MGE to develop an EFOR for the WCCF, based on historical outage data, as it can provide no support for the EFOR currently used.

Elm Road Generating Station Modeling

MGE has purchased a portion of WEPCO's ERGS. MGE models its portion of ERGS on a "must run" basis as opposed to an "economic" basis. CUB takes the position that MGE should model its portion of ERGS on an economic basis in order to maximize revenue from the unit. MGE performed a modeling run with its portion of ERGS modeled as an economic unit. MGE's share of the additional revenues from that unit was approximately $16,000. MGE noted that the impact of modeling as an economic unit would change with each run, but the overall impact of CUB's proposed change is likely to be immaterial.

This issue is also being addressed in the current WEPCO rate proceeding, docket 5-UR-106. Going forward, it is reasonable to require MGE to model its portion of the ERGS unit on the same basis that the Commission decides is appropriate for WEPCO in docket 5-UR-106.

Surplus Capacity Marketing Strategy

Like many Midwestern utilities today, MGE has a surplus of capacity. Because there is so much surplus capacity on the market, capacity is not easy to sell today and when it is sold, the price is usually very low. CUB takes the position that the Commission should require MGE to develop a strategy to utilize MISO's capacity market and any other means available in order to offset the cost of its surplus capacity.

MGE noted that it already actively monitors the bilateral market and the monthly capacity auction for opportunities to market its surplus capacity, and will continue to do so in the future, in order to take advantage of any opportunities that may arise. For this reason, the Commission finds it reasonable to not require MGE to develop a strategy to maximize revenues from its surplus capacity. Commissioner Callisto dissents.

Customer Service Conservation Escrow and Budget Adjustment

MGE proposed a conservation budget, excluding Focus on Energy funding, of $4,679,267 for customer service conservation (CSC) activities. Docket 5-BU-102 eliminated minimum spending requirements for CSC activities, established a definition of CSC, and provided direction to utilities and Commission staff in evaluating CSC activities and spending. Commission staff proposed that all budgeted CSC activities be excluded from escrow treatment. MGE did not object to this proposal, requesting only that those expenses excluded from the conservation escrow be treated as regular customer service expenditures in this case. The Commission finds it reasonable to exclude all CSC activities budgeted by MGE for the test year from the conservation escrow and to treat these expenses as regular customer service expenditures.

The Commission concludes that the record in this proceeding is inadequate to support inclusion in rates of the full amount of the requested CSC budget. At the open meeting of November 9, 2012, the Commission took official notice, pursuant to Wis. Stat. § 227.45, of the following documents filed on the Commission's Electronic Regulatory Filing system: PSC REF#: 170027, PSC REF#: 170552, and PSC REF#: 171418.[2] These documents indicate that MGE currently spends a significantly greater amount on CSC activities than utilities with larger, more dispersed territories. This high level of customer service conservation spending indicates that it is reasonable to expect MGE to find ways to deliver these services more cost effectively. There are also unresolved questions regarding whether the activities funded by these expenditures are duplicative of those funded through the statewide Focus on Energy program.

The Commission finds it is reasonable to reduce MGE's conservation budget, excluding Focus on Energy funding by 25 percent, to $1,932,214 for electric operations and $1,577,236 for natural gas operations.

[2] The Commission provided notice to the parties of its taking of official notice of the referenced documents and parties were afforded an opportunity to rebut, offer countervailing evidence, or contest the validity of the official notice (PSC REF #: 176342). MGE provided comments, objecting to the official notice taken and providing three primary options to address the Commission's concerns raised in this proceeding regarding MGE's CSC spending (PSC REF#: 176760). The Commission appreciates MGE's comments, but declines to adopt any of its proposed alternatives.

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 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 $68,109,280 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 55.00 percent common stock equity, 32.33 percent long-term debt, 4.03 percent short-term debt, and 8.64 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 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 docket, MGE and Commission staff deducted MGE's investment in 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 with these deductions.

A reasonable utility ratemaking capital structure for purposes of establishing just and reasonable rates for MGE's test year consists of 59.09 percent common stock equity, 36.37 percent long-term debt, and 4.54 percent short-term debt.

Short-Term Debt

MGE's test-year capital structure contains $31,761,449 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 0.20 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 5.51 percent is reasonable for the test year. This estimate includes a new debt issuance, at a rate of 4.54 percent.

Common Equity

The Commission previously determined, in docket 3270-UR-117, a 10.30 percent return on utility common equity to be reasonable. As rate of return on common equity was not an issue addressed in this proceeding, the Commission determines that this return on equity shall remain in place until addressed in a subsequent rate case proceeding. Using a 10.30 percent return on equity, the average utility capitalization ratios, annual cost rates, and the 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	$413,664	59.09%	10.30%	6.09%
Long-Term Debt	$254,654	36.37%	5.51%	2.00%
Short-Term Debt	$31,761	4.54%	0.20%	0.01%
Total Utility Capital	$700,080	100.00%		8.10%

The weighted cost of capital rate of 8.10 percent is reasonable for MGE for the test year. It generates an economic cost of capital of 12.18 percent and a pre-tax interest coverage ratio of 6.06 times on the regulatory capital structure.

Rate of Return on Rate Base

The 8.11 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 be 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 98.76 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 the average net investment rate base.

To allow a current return on the average test-year CWIP balance, an adjustment must be added to the return on net investment rate base. Given MGE's financing and cash flow requirements in the test year and the forecasted amount of construction activity, it is reasonable to allow a current return on 50 percent of CWIP for the test year. In addition, an adjustment is necessary to include a return on the unamortized ERGS regulatory assets at the short-term interest rate approved in this proceeding.

Accordingly, the rate of return on average electric and natural gas utility net investment rate bases that are reasonable for the purposes of determining just and reasonable rates are as follows:

	Electric	Gas
Weighted Cost of Capital	8.11%	8.11%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	98.76%	98.76%
Percent Return Requirement Applicable to Net Investment Rate Base	8.21%	8.21%
Adjustment to Return Requirement to Provide Current Return on 50% of CWIP	1.20%	0.23%
Adjustment to Return Requirement for ERGS Earning at Short-Term Debt Rate	0.01%	-
Adjusted Percent Return Requirement on Average Net Investment Rate Base	9.41%	8.44%

Revenue Requirement

Based on the findings in this Final Decision, a \$14,888,000 increase in electric utility revenues and a \$1,646,000 increase in natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates and are computed as follows:

	Electric	Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	7.28%	7.72%
Required Return on Average Net Investment Rate Base	9.41%	8.44%
Earning Deficiency as a Percent of Average Net Investment Rate Base	2.13%	0.72%
Average Net Investment Rate Base (000's)	$417,846	$136,126
Amount of Earning Deficiency on Average Net Investment Rate Base (000's)	$ 8,913	$ 985
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$ 14,888	$ 1,646

Electric Cost of Service

MGE, Airgas Merchant Gasses, LLC (Airgas), CUB, UW, and Commission staff testified regarding COSS issues and the appropriate allocation methods for plant and operation and maintenance (O&M) expenses. MGE, Airgas, CUB and Commission staff disagreed on the appropriate allocators for plant and O&M expenses for production, distribution, transmission, and purchased power. UW also expressed concern regarding the inclusion of WCCF operations in MGE's COSS. The current Commission practice of relying on a variety of COSS, as well as other factors, when allocating revenue responsibility is supported by this discussion. The Commission believes that it is reasonable to continue to rely on the results of one or more COSS along with other factors, such as bill impacts, when allocating revenue responsibility. MGE shall work with Commission staff and provide an analysis of the WCCF station service load as it relates to the cost-of-service in MGE'S next base rate case.

Electric Revenue Allocation

An allocation of the electric revenue increase that results in an approximate 4.67 percent increase for the residential customer classes, an approximate 2.68 percent increase for the small commercial and industrial customer classes, an approximate 3.79 percent increase for the large commercial and industrial customer classes, and an approximate 2.34 percent increase for the contract services customer classes is reasonable. A 0.00 percent electric increase for the Cp-1 rate class that is included in the large commercial and industrial customer group is reasonable. A 2.40 percent electric increase for the Sp-3 rate class and a 2.00 percent electric increase for the Sp-4 rate class that are included in the large contract services customer group are also reasonable. The authorized customer class electric revenue increases are shown in Appendix B. Commissioner Callisto dissents.

Electric Rate Design

MGE requested the Commission determine that, as a matter of principle, it is appropriate and necessary for MGE to move to rate designs that recover certain fixed costs through fixed rather than variable charges. CUB and Commission staff objected to this proposal, citing concerns over bill impact, price incentives for conservation and efficiency, and a lack of clarity over what costs would be recovered through fixed charges. The Commission declines to make a formal declaration as requested by MGE.

As an initial step towards a rate design structure that recovers certain fixed costs through fixed rather than variable charges, MGE proposed to increase all customer charges by 40 percent over present rates. The Commission finds it reasonable to increase customer charges by 20 percent. Commissioner Callisto dissents.

The authorized electric rate design reflects Commission staff's proposed rate design adjusted so as to reflect the increase in customer charges and the final revenue requirement. The authorized rate increases are distributed among the customer charges, electricity service demand charges for demand-billed rates, and electricity service energy rates. Rg-3 lifeline service rates are increased so as to reduce the differential between Rg-3 and Rg-1 rates. All TOU classes, excluding Sp-3 and Sp-4 contract service classes, are transitioned to a three-period TOU structure consistent with that proposed by MGE. Commission staff and MGE shall track customer satisfaction with the base-plus-adder approach associated with this TOU structure to see if it appropriately addresses the billing and accounting issues raised by MGE in this proceeding. New, optional three-period TOU offerings with critical peak pricing are authorized under new Cg-2A and Cg-6A tariffs. All of the authorized electric rate design changes, which are shown in Appendix B, are reasonable.

Sp-3 Rate Structure

MGE provides electric service to UW on the Sp-3 rate schedule, which is available exclusively to UW. In docket 3270-UR-116, the Commission approved the current generation credit approach that had been proposed by MGE. Under this rate structure, a demand charge is assessed against UW's peak monthly load. A generation credit of $0.12329 per kilowatt per day (kW-day) is then applied to output from UW's 8 megawatts of generating capacity at CSHP. On-peak and off-peak energy charges are based on hourly LMPs.

The UW proposed that the generation credit be replaced with a standby rate, arguing that the current Sp-3 rate design is inappropriate as it was based on a plan to increase CSHP generation capacity that was ultimately cancelled by the state of Wisconsin. UW also argues that the Sp-3 generation credit is too low and should be adjusted to reflect a longer-term cost of capacity. The Commission finds it reasonable to allow the existing Sp-3 rate structure to remain in place, but to increase the generation credit to a rate of $0.46 per kW-day, with the level of other charges revised in a manner that follows the rate design proposed by Commission staff. The Commission recognizes that it has left unresolved in this proceeding whether UW's WCCF station service load should be included in determining Sp-3 cost of service. To the extent resolution of that issue should require modification of the Commission's determination in this proceeding to allow the existing Sp-3 rate structure to remain in place, but to increase the generation credit, this issue can be re-examined in a subsequent rate case proceeding.

Commissioner Callisto dissents.

UW requested that MGE be required to meet with UW within 90 days of the Commission's order in this docket to discuss the potential for restructuring the Sp-3 energy charges to be a direct measure of actual MISO LMPs, and if agreement is reached, to present the proposal to the Commission for consideration. MGE indicated a willingness to commit to continued discussions with UW. Accordingly, the Commission finds it unnecessary to address UW's request at this time.

LED Lighting

MGE proposed to introduce the first LED outdoor lighting tariff in the state under its OL-1, Outdoor Overhead Lighting rate schedule. Existing OL-1 metal halide outdoor security lighting options (renamed to outdoor overhead lighting) would be closed and replaced with LED service options. Clean Wisconsin (Clean WI) objected to MGE's proposed OL-1 LED rate design, stating that the proposed tariff fails to account for the unique attributes of LED lighting and does not accommodate the features of LED lighting that make it appealing to customers. Clean WI also argued that the proposed LED rates overestimate the costs associated with LED lighting. Clean WI presented two alternative rate design proposals for the unmetered OL-1 class and requested that MGE be required to introduce LED rate options for the SL-1, SL-2, and SL-3 street light rates, as well as the "Dusk-To-Dawn Yard Lighting" rate schedule.

The Commission finds MGE's proposed OL-1 LED lighting rate design for outdoor overhead lighting service, coupled with retaining MGE's existing metal halide outdoor overhead lighting rate design, is reasonable. Commission staff shall monitor customer uptake under OL-1, and MGE, Clean WI and Commission staff shall continue to work on LED rate design options for presentation in MGE's next full rate case.

Demand Response Plan

On September 1, 2010, MGE filed a demand response plan based on the Commission's *Final Decision* in docket 3270-UR-116. Of the four demand response initiatives not yet implemented, MGE proposed the implementation of three in this proceeding:

- Split the current TOU pricing periods into additional pricing periods;
- Bid interruptible load into the MISO market as price sensitive load; and
- Develop a critical peak pricing option for Cg-2 and Cg-6 customers.

MGE indicated that the fourth initiative outstanding from its demand response plan, bidding a direct load control program into the MISO energy market as price sensitive load, is uneconomic at this time based on customer research. The Commission finds MGE's plan to implement the remaining demand response initiatives ordered by the Commission in docket 3270-UR-116 is reasonable. MGE and Commission staff shall clarify and work on permitting MGE to bid load into the MISO market.

Customer Owned Generation

MGE proposed modifying the Pg-1 parallel generation energy rates in a manner similar to the approach adopted in Wisconsin Public Service Corporation's 2011 rate case, docket 6690-UR-120. The Pg-1 energy rates for each year would be based on MGE's Day-Ahead load zone LMPs for the previous 12 months ending in October. Commission staff requested that clarifying language be added to the Pg-1 tariff that would establish Pg-1 capacity payments based off of the MISO capacity market, clarifying that customers would retain all renewable attributes (credits) associated with energy sold to MGE, unless the company chooses to buy the credits from the customer. The Commission finds MGE's proposed changes to the Pg-1 tariff, as modified to address capacity payments and energy credits per Commission staff's recommendations, reasonable.

MGE also requested approval to add new language to the Pg-2 net metering tariff to clarify that, with respect to any energy for which the customer receives a net energy credit on its monthly bill, that customer retains any renewable energy credits and benefits, emissions allowances, or other renewable energy, air emissions, or environmental benefits for which the customer's generation project qualifies. The Commission finds this change to be reasonable as it reflects MGE's current practices and will avoid possible confusion.

Green Pricing Program

MGE has a green pricing program that is marketed under the name Green Power Tomorrow. In MGE's previous rate case, the Commission approved an increase in the green pricing rate to 2.50¢ per kWh as a phased-in approach to move the premium toward the incremental cost of acquiring renewable energy.

In this case, MGE proposed to increase the rate to 3.00¢ per kWh in order to recover more of the program's incremental costs, which MGE estimates to be 5.26¢ per kWh. While Commission staff raised concerns regarding the method MGE used to estimate the green pricing premium in this proceeding, staff agreed that the rate proposed by MGE is an appropriate step towards aligning the green pricing rate with incremental cost, estimating the program's incremental costs to be 4.13¢ based on an alternate method. Given the voluntary nature of MGE's green pricing program, and in light of the fact that incremental program costs not recovered through the green pricing premium must be recovered by non-participating customers, the Commission finds it reasonable to increase the green pricing rates under MGE's RWE-1 and BWE-1 to 4.00¢ per kWh in order to more closely align the premium rate with incremental cost. Commissioner Callisto dissents.

Natural Gas COSS and Rate Design

MGE prepared an embedded COSS for this proceeding, and Commission staff prepared two embedded COSSs, titled COSS A and COSS B. MGE's COSS and COSS A allocate the costs associated with mains and certain other plant investments, overheads, and operating expenses to the customer classes based, in part, on the number of customers in each class. COSS B allocates these costs to the classes based, in part, on the throughput of each class. Notable allocation differences between MGE's COSS and Commission staff's two COSSs include the allocators used for Focus on Energy expense, uncollectibles, and income taxes. The Commission recognizes that any COSS is not a precise reflection of cost causality and believes that it is reasonable to consider the results of all of the COSSs when determining revenue allocation and rate design.

The Commission approves Commission staff's revenue allocation, adjusted for the final revenue requirement. Residential class distribution revenue is increased by 2.3 percent. Small, medium, and large commercial distribution revenues are increased by 2.9, 1.4, and 3.9 percent, respectively. IGD-1 Interruptible Generation distribution revenue is increased by 3.3 percent, while SP-1 Steam and Power Generation distribution revenue is increased by 2.9 percent. SD-1 Seasonal Off-Peak distribution revenue is increased by 2.4 percent. CNG-1 Compressed Natural Gas distribution revenue is increased by 176.2 percent.

MGE proposed to increase the customer charges of the residential class, the three commercial classes, the IGD-1 class, and SD-1 class, based on a customer cost analysis derived from its COSS. MGE stated that the proposed increases are appropriate because collecting a larger portion of the costs it identified as fixed customer costs through the customer charge more closely aligns costs with cost causation. Additionally, a higher customer charge provides more bill stability for the customer, while still allowing for an ample price signal to encourage conservation and energy efficiency. Commission staff supported all of MGE's proposed customer charge increases, except the increases for the residential and small commercial classes. Commission staff testified that MGE's residential and small commercial customer charges are currently set at the highest level currently authorized by the Commission for Wisconsin investor-owned natural gas utilities. Additionally, Commission staff expressed concern that increasing the residential and small commercial customer charges would significantly reduce the incentive for customers to conserve energy and install energy efficiency measures by decreasing the savings customers could experience due to using less gas.

The Commission approves MGE's proposed customer charge increases, including those for the residential and small commercial classes. The residential customer charge is increased from $0.3370 per day ($10.25 per month) to $0.4000 per day ($12.17 per month), a 19 percent increase. The small commercial customer charge is increased from $0.6600 per day ($20.08 per month) to $0.6930 per day ($21.08 per month), a 5 percent increase. Commissioner Callisto dissents regarding the residential and small commercial customer charge increases.

The authorized rate design decreases the IS-1 interruptible administrative charge from $0.0295 to $0.0265 per therm and the FS-1 administrative charge from $0.0330 to $0.0300, based on the COSS results. The IS-1 administrative charge is paid by all system sales customers that use interruptible gas, while the FS-1 administrative charge is paid by all system sales customers that use firm gas. These charges collect costs related to gas supply purchasing personnel, gross receipts tax on gas sales revenue, and the return on stored gas. The FS-1 charge also collects costs related to MGE's peaking plant. The present charges were set in January 2008. In recent years, the return on stored gas and gross receipts tax on gas sales revenues have decreased considerably due to natural gas price decreases.

The authorized revenue allocation and rates are shown in Appendix C.

Telemetering Charge

MGE proposed to increase the telemetering charge from $1.50 to $1.75 per day, based on its COSS results. However, during this proceeding, it came to light that the telemetering equipment that is currently being installed is much less expensive than the equipment that was previously installed. Until up to date information regarding telemetering costs can be obtained, it is appropriate to retain the present telemetering charge. The Commission directs that MGE, in its next rate case, provide information about the number and types of telemetering equipment in service, the cost of each type of equipment, and the cost of maintaining this equipment.

CNG-1 Compressed Natural Gas Distribution Service

The CNG-1 tariff contains rates for usage at MGE's CNG fueling station. This CNG facility is located on utility property and has been owned and operated by MGE for many years. It is utilized mostly to fuel MGE's fleet of CNG vehicles, although it is also utilized occasionally by third parties.

The CNG-1 distribution charge is increased from $0.2202 to $0.5050 per therm. Additionally, a $0.1500 per therm electric compression charge is added to collect expenses associated with the cost of the electricity used for compressing the natural gas. These rate changes increase CNG-1 distribution revenues by 176.2 percent and put CNG-1 prices on a more equal footing with CNG market prices, which is important at this time when the CNG industry is showing signs of expansion.

SD-1 Seasonal Off-Peak Distribution Service

SD-1 service is available to customers, such as agricultural crop dryers and asphalt companies that use their gas between May and November of each year. Under the current tariff, MGE has the ability to extend this period to include all or parts of April or December, if requested by a customer. The SD-1 customer charge is billed in May through November of each year as well as in any other month that usage occurs. If usage occurs during the months of December through April, a $0.50 per therm penalty is also applied, unless the customer has received authorization from MGE to use gas during this period. The current rate structure requires MGE to manually process any charges that require billing outside of the months of May through November. In order to eliminate manual billing and its potential for billing errors, MGE proposed to make several changes to the SD-1 tariff. These changes were supported by Commission staff, and the Commission finds they are appropriate.

Under the revised SD-1 tariff, customers no longer need to ask permission to burn gas in any month of the year. The customer charge will be billed during all 12 months, but will collect about the same amount of annual revenue as the present customer charge collects during seven months. The distribution charge for usage during the months of April through December is set at $0.0831 per therm, while the distribution charge for usage during January through March is set at a much higher rate of $0.4000 per therm. The higher distribution charge during January, February, and March should deter customers from using much gas during these months.

SD-1 customer usage is not currently being measured on a daily basis. This makes it impossible to determine how much usage during a billing period occurred in the previous month and how much occurred in the current month. This is an important distinction when the lower or higher distribution charge should be applied in one of these months. MGE indicated that it plans to install equipment that would provide daily usage readings sometime in the near future. However, because daily usage information is critical to billing under the revised SD-1 tariff, the Commission directs that MGE install this equipment as soon as reasonably practicable and no later than April 1, 2013.

Change in Service Rules

The Commission finds that it is appropriate for MGE to add language to its natural gas service rules stating that MGE may disconnect a customer's service if a customer refuses to allow authorized utility personnel access to their premises at all reasonable times for purposes related to providing safe and reliable service. This service rule change is in line with current natural gas administrative rule provisions that allow for disconnection of service when customers do not provide reasonable access to utility equipment on their premises. Additionally, this added provision mirrors a provision that is currently contained in MGE's electric service rules.

CNG Distribution Service and Supply Service for NGVs[3]

MGE's proposed filing for service to NGVs includes two tariffs: (1) a distribution service tariff for refueling NGVs (Distribution Service for Natural Gas Vehicles–NGV); and (2) a gas supply sales service tariff for gas sales to NGVs (Firm Gas Sales Service for Natural Gas Vehicles–FS-3).

The first tariff proposal focuses on the delivery of high-pressure gas to its distribution customers and left the fueling of vehicles to other parties already in the market for providing that service. The second tariff proposal offers a firm natural gas supply service that included a discount from the standard firm natural gas supply service to customers filling NGVs.

The Commission excludes MGE's costs associated with its CNG distribution service from utility plant in service, acknowledging that these services could be provided by private capital investments. Allowing a utility to invest in these services could create an unfair anticompetitive environment and presents the potential for cross-subsidization from other regulated utility services. Therefore, it is reasonable to exclude MGE's costs associated with its CNG distribution service from utility plant in service and deny the request to file tariffs that would provide for either a distribution service or supply service for the refueling NGVs.

[3] The Commission granted MGE's request to disregard the comments to the Briefing Memorandum filed on behalf of Kwik Trip, Inc., in this proceeding. Commissioner Callisto dissents.

Presently, MGE has a slow-fill natural gas facility to serve its NGVs that is capable of providing CNG service at pressures up to 3,000 pounds per square inch. The Commission finds that using these facilities as backup to other public facilities is reasonable and that such service can continue as service pursuant to its current tariff, CNG-1.

With regard to NGVs, the Commission believes that the record was not fully developed and did not explore all other possibilities. The Commission has an interest in pursuing other alternatives and directs Commission staff to investigate this matter further. Such an investigation includes meeting with other interested parties in the first quarter of next year to more fully discuss this issues. Depending upon the results of that investigation, the Commission recognizes there may be a need to reconsider tariffs similar to MGE's proposed tariffs.

Order

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

2. The authorized rate increases and tariff provisions that restrict the terms of service shall take effect on January 1, 2013, provided that MGE files these rates and tariff provisions with the Commission and places them in all of the MGE offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they shall take effect on the date they are filed with the Commission and placed in all offices and pay stations.

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

4. MGE will prepare bill inserts that properly identify the rates authorized in this Final Decision. MGE shall distribute the inserts to customers with the first billing containing these rates and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

5. MGE shall defer to its next rate case any adjustments to cost overruns for ERGS that result from Commission decisions in docket 5-UR-106.

6. MGE shall include the one-time cost savings for FAS 106, other post-retirement benefits, in electric and natural gas revenue requirements.

7. The fuel costs in Appendix D shall be used for monitoring of MGE's 2013 fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).

8. All fuel costs for 2013 shall be monitored using a plus or minus 2 percent tolerance band.

9. MGE shall develop a forecasted EFOR for WCCF, based on the most recent available historical outage data, in its next rate proceeding.

10. In future rate proceedings, MGE shall model its portion of the ERGS unit on the same basis that the Commission finds appropriate for WEPCO's portion of the ERGS unit in the current WEPCO rate proceeding, docket 5-UR-106.

11. MGE shall use deferral accounting, with interest to accrue at MGE's cost of short-term debt, for any 2013 CSAPR compliance costs incurred prior to the vacation of CSAPR by the D.C. Circuit Court of Appeals. Rate recovery of these deferred costs shall be addressed in MGE's next rate proceeding.

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

13. MGE shall 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.

14. 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 purchased power agreement 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.

15. MGE shall work with Commission staff and provide an analysis of the WCCF station service load as it relates to the cost-of-service in MGE'S next base rate case.

16. Commission staff and MGE shall track customer satisfaction with the base-plus-adder approach associated with MGE's TOU structure to see if it appropriately addresses the billing and accounting issues raised by MGE in this proceeding.

17. MGE shall monitor customer uptake under OL-1, and MGE, Clean WI, and Commission staff shall continue to work on LED rate design options for presentation in MGE's next full rate case.

18. MGE shall implement the remaining demand response initiatives ordered by the Commission in docket 3270-UR-116. MGE and Commission staff shall clarify and work on permitting MGE to bid load into the MISO market.

19. MGE shall provide a report, in its next rate case, that includes information about the number and types of telemetering equipment currently in service, the cost of each type of equipment, and the cost of maintaining this equipment.

20. MGE shall install equipment that will provide daily usage information for SD-1 customers as soon as reasonably practicable and no later than April 1, 2013.

21. MGE shall exclude costs associated with its CNG distribution service from utility plant in service.

22. MGE shall continue to provide CNG service as backup to other public facilities pursuant to its tariff, Schedule CNG-1, that is on file with this Commission.

23. The two tariffs, Distribution Service for Natural Gas Vehicles–NGV and Firm Gas Sales Service for Natural Gas Vehicles–FS-3, accepted by the Commission on a conditional pilot basis per its letter dated May 23, 2012, shall sunset on December 31, 2012.

24. Jurisdiction is retained.

Dissent and Concurrence

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

Dated at Madison, Wisconsin, this 14th day of December, 2012.

By the Commission:

Sandra J. Paske

Sandra J. Paske
Secretary to the Commission

SJP:AEP:cmk:DL: 00606242

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 mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing 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 mailing 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 mailing 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 mailed its original decision.[4] 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: December 17, 2008

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

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates

3270-UR-118

DISSENT AND CONCURRENCE OF COMMISSIONER ERIC CALLISTO

I dissent from the following portions of the Commission's *Final Decision*: (a) the forecasts of on-peak percentages for the Cg-4a and Cg-4b rate classes; (b) the lack of any required revenue maximization from the utility's surplus capacity; (c) the electric revenue allocation; (d) the increase in the utility's Green Power Tomorrow rates; (e) the increase in the customer charge; and (f) the Sp-3 rate design.

I also write separately in concurrence, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.

On-Peak Forecasts for Cg-4a and Cg-4b Rate Classes

Commission staff had the better analysis here, making a $611,000 adjustment to forecasted on-peak electric sales for the Cg-4a and Cg-4b rate classes. Madison Gas and Electric Company (MGE) relied too heavily on three year old sales research data, ignoring the actual on-peak percentages for the Cg-4 customers in 2010, 2011, and part of 2012. Taking into account the more recent and more complete sales data supports the Commission staff adjustment and would have decreased the overall revenue requirement by $611,000.

Docket 3270-UR-118

Surplus Capacity / Revenue Maximization

I would have supported a requirement that MGE develop a strategy to maximize revenue from its surplus capacity. Wisconsin utilities' surplus capacity has received plenty of attention in recent years, and the Commission spends considerable time and effort evaluating how best to use it, including specific efforts aimed at moving some of Wisconsin's capacity across Regional Transmission Organization (RTO) seams. It would have been appropriate to require a more focused effort from MGE to come up with a strategy for generating more revenue from the extra capacity it has. And if we agree that it is the job of the utility to maximize the economic value of its capacity, then we should not be shy about affirming that obligation through our rate orders.

Electric Revenue Allocation/Green Power Tomorrow Increase

The *Final Decision* approves an overall electric rate increase of 3.81 percent. The increase for different classes of customers varies considerably. Customers who sign up for MGE's Green Power Tomorrow program will see an increase of 60 percent. Yet the one industrial customer under the Cp-1 tariff will have no change in rates. I dissent from the *Final Decision*'s allocation because by insisting on a rate freeze for the Cp-1 class, the Commission unfairly forces other customers, especially those who elect green pricing options, to pay more than they should.

MGE already has very high electric rates. Its rates are the highest for large investor-owned utilities in Wisconsin and among the highest in the country. And even before the Commission's decision on electric revenue allocation, its green pricing rates were also the highest among Wisconsin's large investor-owned utilities. Now, stacking a 60 percent rate increase on top of that, puts MGE in truly rarefied territory. Its Green Power Tomorrow rate will be between 67 percent and 200 percent higher than the green pricing programs offered by all of the other investor-owned utilities in this state.

The Commission's stated rationale for moving the rate for MGE's green pricing customers up so steeply is because such an increase is necessary to reflect the "full cost" of renewable energy. Assuming that the underlying cost analysis is sound, I agree that green pricing rates should reflect the cost of procuring the energy necessary to support them. But responsible utility regulation should encompass a gradualist approach to modifying rates. My colleagues on the Commission appear to agree, at least for Wisconsin Power and Light (WP&L) customers that voluntarily elect to sell energy back to the utility under WP&L's parallel generation rate.[1] In the case of WP&L's parallel generation rate, this Commission has plainly and very recently acknowledged that the tariff in its current form is a subsidy, one that's been around since 2007, and one that pays customers for energy they generate at a price that well exceeds WP&L's avoided costs.[2] Yet, for WP&L, the Commission chose to continue that subsidy into 2013 and will only end it in 2017, after a five-year phase-in, justified on the basis of gradualism. It is unclear to me how parallel generation customers in WP&L's service territory are deserving of this Commission's gentle gradualism, but MGE green pricing customers are not.

The Commission's electric revenue requirement analysis under its adopted allocation is also flawed. Part of the way the Commission gets the Cp-1 class to a zero percent increase is by assuming that $866,000 in additional electric revenue will be generated by increasing the green pricing class by 60 percent. That "extra" $866,000 from the green pricing class then offsets the

[1] *See Final Decision* in docket 6680-FR-105 (Commissioner Callisto, dissenting; Chairperson Montgomery, concurring).
[2] *See id.*

need for revenue from other classes. The problem with the Commission's approach is that the extra $866,000 rests on the assumption that a 60 percent rate increase for a voluntary program will translate into only 10.6 percent total attrition across Green Power Tomorrow offerings, and no attrition for those residential and business customers taking green energy on a percentage basis.[3] How the Commission arrived there is unclear to me, but that assumption appears to dramatically understate what the attrition will actually be following the 60 percent rate increase.

On revenue allocation, I would have supported something more in line with Commission staff's proposed allocation, which encompassed a much tighter range of impact across customer classes. It also embodied a more gradualist approach for green pricing customers. Commission staff's proposal included a total range of about 2.5 percent: a high-end 4.32 percent increase for the Cp-1 class and low-end 1.89 percent increase for the Sp-3 class, assuming an overall electric increase of 3.32 percent. Applying a similar range to the Commission's agreed upon 3.81 percent increase would have kept the impact across classes more condensed, comparably balanced, and obviated the need for the 60 percent increase on Green Power Tomorrow subscribers.

Customer Charge Increase

The Commission's approved 20 percent increase in the utility's electric customer charge for all customer classes is unnecessary. The more that customers pay in fixed charges versus variable charges, the less of a price signal there is for peak load and energy reduction, both

[3] Green Power Tomorrow subscriptions are either on a block basis or percentage basis. The Commission's revenue allocation assumes attrition rates across the program of 37.5 percent for block sales to residential and business customers, zero percent for sales taken on a percentage basis to residential and business customers, and zero percent for Green Power Tomorrow sales to the state of Wisconsin. Green Power Tomorrow sales to the state of Wisconsin are not subject to the Commission's 60 percent rate increase.

long-accepted goals of sound utility ratemaking. MGE argues that because of energy conservation, the utility is losing margin between rate cases, and so fixed charges should be substantially increased as a guard against revenue erosion. Thus, the utility argues for the increase as a way to reduce its risk. I may have been more persuaded if it weren't for the fact that this utility comes to the Commission nearly every year for a rate increase or if its financial health shows some threat of decline.

MGE financials are in exceptionally good shape. Its stock increased over 24 percent this past year, soundly outperforming the Dow Jones (up 9 percent) and the Dow Jones Utility index (up 1.61 percent) over the same period. Since 2000, the company's stock has increased more than 165 percent. It has the highest bond rating of any combined utility in the country. MGE's argument that customer charge increases are necessary to reduce risk is simply not supportable. The Commission's changes to the customer charge will hit the lowest use customers the hardest, and is regressive.[4]

Sp-3 Rate Design

This issue is a close call, but I think the University of Wisconsin (UW) had the better argument. The Sp-3 rate structure approved today is the direct outgrowth of UW's recent, but now abandoned, plan to substantially increase its generation capacity at Charter Street Heating Plant (CSHP). That plan was the cause of legitimate concern for both MGE and the Commission in that the utility could be forced to confront substantially reduced sales to UW, potentially creating a revenue deficiency for other customers to pick up. But those circumstances are no longer present. UW's generation expansion at CSHP isn't happening, and MGE concedes that it

[4] For the same reasons articulated in this section, I dissent on the increase to the customer charge for residential and small commercial gas customers.

has not incurred additional capacity costs to serve UW. As a result, it is appropriate for the Sp-3 structure to return to a net-of-generation rate, with a standby charge, more firmly rooted in generally accepted principles of cost causation.

Act 141 Large Energy Customer Contributions

I write separately here in concurrence, as I did in the recent rate decision for Superior Water, Light and Power Company, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.[5]

Energy efficiency programs in Wisconsin are governed by 2005 Wisconsin Act 141 (Act 141). Among other things, Act 141 requires the state's utilities to collectively establish and fund a statewide energy efficiency program (Focus on Energy), establishes priorities for the expenditure of those funds, and creates a system of joint oversight, involving the state's utilities, the Commission, and the third party contractor that administers the program. *See generally* Wis. Stat. § 196.374.

Focus on Energy is funded through ratepayer dollars, at an amount equal to 1.2 percent of utility revenues. Wis. Stat. §§ 196.374(3)(b)2. and (5)a. However, each individual ratepayer's contribution to Focus on Energy is not equal to 1.2 percent of their utility bills. While the Commission has determined that the rate classes should generally pay an amount equal to the amount of Focus on Energy incentives distributed to their class, a limited number of large customers pay much less. That disparity and the subsidy that it necessitates is the result of a

[5] *See Final Decision* in docket 5820-UR-113 (Commissioner Callisto, concurring).

section of Act 141 which specifically directs that certain "Large Energy Customers"[6] (LECs) pay into Focus on Energy the amount they paid towards similar programs in 2005, rather than the amount determined by the Commission. Wis. Stat. § 196.374(5)(b)1. and 2005 Wisconsin Act 141, § 102(8)(c). There are currently 869 LECs in Wisconsin, and specifically 51 LECs in the service territory of MGE.

Most LECs pay less into Focus on Energy than they otherwise would in the absence of the statutory exemption. Some LECs pay no money into Focus on Energy because they were paying no money to similar programs in 2005. Regardless of how much they pay into the program, all LECs remain eligible to receive the benefits of Focus on Energy, at an undiminished level.

In the MGE rate case we approve today, LECs are paying about $1.2 million less than they would if all customers were required to pay proportionally equal amounts. The amount last year was $1.3 million less.[7] Accounting for the state's six largest utilities, in 2010, the most recent year for which full data is available, LECs paid $16.2 million less than they would have if the statutory exemption didn't exist.[8] Because the utilities are required to fund the program at 1.2 percent of revenues, that missing LEC money must come from somewhere else, and indeed it does. Those costs are allocated to other non-residential customers. In this case, all of MGE's

[6] A "large energy customer" is a customer that has a demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and, in a month, is billed at least $60,000 for electric service, natural gas service, or both. Wis. Stat. § 196.374(1)(em).
[7] On average, the MGE LECs enjoy a 99 percent discount on the electric rate they pay for Act 141 programs. Under the approved rates, LECs will pay $0.000020 per kilowatt-hour (kWh) for Act 141 program contributions, while non-LECs will pay $0.002005 per kWh. Under present rates, the disparity is $0.000019 per kWh versus $0.002286 per kWh.
[8] *See* Wisconsin Legislative Audit Bureau Report 11-13, Evaluation of the Focus on Energy Program, pp. 21–22 (December 2011).

commercial, industrial, and lighting customers that do not meet the LEC threshold are required to pick up these extra amounts, and essentially subsidize the rate break enjoyed by 51 LECs.

And while, generally, under-collection from LECs is the result of the Act 141 exemption, some LECs in Wisconsin have actually paid more than their proportional share of utility revenues because of the operation of the exemption.[9] Either way, the result is inequitable.

Furthermore, the LEC exemption creates perverse incentives that may not be readily apparent. If a LEC is close to the cutoff line for retaining this designation (*i.e.,* its monthly energy use and/or bill amounts are dropping close to the statutory thresholds), it may not choose to pursue energy efficiency because the energy savings may have a value less than the likely "full" Focus on Energy payment it would be required to make as a non-LEC. Conversely, those customers falling just short of the LEC threshold may have an incentive to use more energy–even when they don't need it–if they believe getting the LEC designation (and the resulting lower Focus on Energy payment) will be more valuable than the energy costs incurred to get to the threshold. It cannot be that Act 141 was intended to create economic incentives for inefficient and wasteful energy usage, which is precisely what the LEC exemption promotes.

Freezing the LEC contributions to Focus on Energy at 2005 levels was meant to be temporary.[10] Act 141 required the Commission, by no later than the end of 2008, to provide the Legislature with a recommendation for equitable cost recovery from all rate classes. Wis. Stat. § 196.374(5)(bm)1. While the Commission did submit a proposal recommending a 3-year

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[9] *See id.* at p. 22, Table 7 (illustrating how Wisconsin Power & Light's LECs pay $616,000 more that they would without Act 141's exemption).

[10] *See id.* at p. 20 ("Legislative documents describe [the Act 141 LEC exemption] as a 'first step' . . . .").

phase-in to proportionally equal funding for LECs, no legislative action was undertaken.[11] As a result, most LECs continue to enjoy proportionally lower contributions to Focus on Energy than other customers in their own rate classes, and in other non-residential customer classes.[12] And those rate breaks for the LECs continue to be subsidized by other commercial and industrial customers.

Not every inequity created by the statutes warrants the Commission's attention. However, where the Legislature empowered the Commission to make a recommendation to resolve an acknowledged disparity in the initial statutory scheme, where that recommendation was not acted on, and where the inequity persists, it is reasonable to make a run at it again. I encourage the Legislature to resolve this issue in the next legislative session.

[11] The Commission's 2008 recommendation can be found at PSC REF#: 106987.

[12] LEC contributions to Focus on Energy are subject to annual adjustments equal to the lesser of the percentage increase in the host utility's operating revenues in the preceding year or the increase in the consumer price index. Wis. Stat. § 196.374(5)(bm)2.