

Date Mailed
January 15, 1999

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Madison Gas and Electric Company for Authority to 3270-UR-109
Change Electric and Natural Gas Rates

**FINDINGS OF FACT, CONCLUSION OF LAW,
AND ORDER**

On April 15, 1998, Madison Gas and Electric Company (MGE or the Company) filed an application with the Public Service Commission of Wisconsin (Commission) under Wis. Stat. §§ 196.03, 196.20 and 196.37, for authority to increase rates for electric and natural gas service.

In accordance with procedures established by the Commission, MGE prefiled various exhibits and related testimony pertaining to financial information with its application. The Company proposed to increase electric rates by \$14.6 million (8.9 percent) and natural gas rates by \$4.6 million (4.5 percent). These levels were based on a test year ending December 31, 1999, and a return on common stock equity of 12.5 percent. On May 1, 1998, MGE submitted additional exhibits and related testimony pertaining to electric and gas cost of service and rate design and its gas cost recovery mechanism (GCRM).

Pursuant to due notice, a prehearing conference was held on July 8, 1998, to define the issues, establish a hearing schedule and consider such other matters that would facilitate the hearing process.

Pursuant to due notice, technical hearings were held in Madison on September 21, 22 and October 14, 1998, before Examiner Donna Paske. A hearing for public comment was also held in Madison on September 23, 1998.

The parties for purposes of review under Wis. Stat. § 227.47 are listed in Appendix A of this order. Other persons who appeared are listed in the Commission's files.

A rate increase in the amount of \$8,402,000 annually from present rates is authorized for electric utility operations, a 5.1 percent increase, and an increase in the amount of \$728,000 annually from present rates is authorized for gas utility operations, a .7 percent increase, for the test year ending December 31, 1999.

FINDINGS OF FACT

THE COMMISSION FINDS:

Applicant and Its Business

Madison Gas and Electric Company is an electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a). It is engaged in the production, transmission, distribution, and sale of electrical energy to approximately 123,000 retail customers in Madison and the surrounding area in Dane County, and in the purchase, transportation, distribution and sale of natural gas to approximately 107,000 customers in Madison and the surrounding area in Columbia, Crawford, Dane, Iowa, Juneau, Monroe and Vernon Counties.

MGE's electric energy supply is currently obtained from a fossil-fuel plant located near the City of Portage, Columbia County, and a nuclear generating plant located near the City of Kewaunee, Kewaunee County. Both plants are jointly owned by MGE, Alliant-Wisconsin Power and Light Company, and Wisconsin Public Service Corporation. MGE's energy requirements are also met by a fossil-fuel generating facility at Blount Street, Madison, as well as gas turbine facilities and interconnections for purchase of energy from other utilities.

The Company purchases its supply of natural gas from various producers and marketers throughout the lower United States and Canada. The natural gas is transported, primarily on Northern Natural Gas Company's and ANR Pipeline Company's systems, to MGE's distribution system for distribution and sale to end users. In addition, some customers purchase their own natural gas supplies and have it transported on interstate pipeline systems to MGE's distribution system. MGE then transports the natural gas to the customer's facilities. The interstate transportation rates of the pipeline companies are subject to the regulation of the Federal Energy Regulatory Commission (FERC).

MGE, intervenors, and Commission staff presented testimony and exhibits at the hearings concerning the Company's estimated electric and gas utility operations for the test year ending December 31, 1999. All parties had the opportunity to cross-examine the witnesses. The Commission discussed the record in this proceeding in open meetings on December 8 and 10, 1998. The Commission approved all uncontested issues as articulated by Commission staff in the synopsis, or decision issues list, prepared for the discussion of the record. Significant and contested issues are discussed separately below.

Income Statement

Additional Employee Needs. In supplemental testimony, the Company requested that an additional \$594,646 be included in the electric revenue requirement for additional staff positions resulting from MGE's experience during this past summer of increased capacity factors at the Blount Generating Station (BGS) and increased reliability concerns at the Systems

Operation Center (SOC). The cost associated with eight additional operators at the BGS was estimated at \$351,646 and the cost for one engineer at the BGS and two positions at the SOC was estimated at \$243,000.

The additional staffing information was not provided to staff during the audit. In accordance with the Commission staff's audit policy for late information, staff did not support the inclusion of these costs in rates. Staff referred to a previous Commission order in docket 6630-UR-102 which outlined Commission policy regarding late information. The order stated that, "after the audit is complete . . . unless there are particularly compelling and unusual circumstances, the auditing staff applies a general policy of not changing its revenue requirement." The order also stated that, "an audited income statement is considered to reflect a reasonable level of operations for the test year."

MGE agreed that the Commission staff's audit policy for late information is an effective way to manage rate cases; however, they contended that these additional positions were critical to the Company maintaining the reliability of its system.

The Commission finds that MGE has shown a compelling need for these positions; however, due to conflicting information provided by the Company regarding the additional operators at the BGS, the Commission will allow only the cost for six operators in addition to the one engineer and the two positions at the SOC. The Commission also reaffirms staff's audit policy for late information.

Income Tax Settlements. MGE projected income tax settlements in the amount of \$1,700,000 and reflected the recovery of this level over a two year period. Commission staff proposed a \$356,000 reduction to the Company filed level based on actual tax settlements since MGE's last rate proceeding. Staff proposed that its estimate of \$1,344,000 be recovered over a four year period due to the material amount of the settlements and due to the cost not being a normal reoccurring expenditure for MGE.

The Company agreed with the Commission staff's overall level of tax settlements; however, they contended that they should be allowed to recover this amount over the biennial rate case period, which would be consistent with the Commission's decision in docket 3270-UR-108. The Commission finds that MGE should be allowed to immediately flow-through the costs associated with this past liability. Therefore, recovery of the Commission staff estimate over the biennial rate case period is appropriate for this proceeding.

Conservation Budget and Escrow Adjustment. Based on its review of advertising costs charged against the electric and gas conservation escrow accounts, Commission staff recommended that \$134,000 be disallowed. Included in this disallowance was \$80,000 associated with the Company's "Life Enhancing Energy - Conservation" TV ad which staff determined to be a mixed advertisement that did not meet the standards that permit recovery of

its costs from ratepayers. The Company agreed with Commission staff's adjustments except for the "Life Enhancing Energy - Conservation" ad. MGE contended that the purpose of the ad was to leave an association in customers minds between energy wise use and the Company as their resource. The Commission finds that there is a sufficient conservation message included in this advertisement and the cost should be allowed to be charged against the electric and gas conservation escrow accounts.

The level of expensed conservation costs recoverable in rates for the test year ending December 31, 1999, is \$2,549,324 for electric utility operations and \$2,160,972 for gas utility operations. The level for electric operations consists of the conservation budget of \$2,920,324 less an escrow adjustment of \$371,000, which represents the amortization of the projected underspent escrow balance at December 31, 1998 over a two year period. The level for gas operations consists of the conservation budget of \$1,996,972 plus an escrow adjustment of \$164,000 which represents the amortization of the projected overspent escrow balance at December 31, 1998 over a two year period. The Commission finds it reasonable to require MGE to continue accounting for allowable conservation expenditures on an escrow basis.

In docket 3270-UR-108, the Company's previous rate case, the Commission found it reasonable to allow MGE to discontinue the practice of capitalizing conservation expenditures. Commission staff proposed to amortize the estimated unamortized electric and gas capitalized conservation balances on December 31, 1998, over a four-year period, which is consistent with the amortization periods authorized by the Commission for other utilities. MGE did not object to this proposal. Based on a four-year amortization period, the annual amortization of the remaining capitalized conservation investments is \$1,447,000 for electric operations and \$512,000 for gas operations. These amortizations shall be charged to a non-escrowed customer service expense account in each year of the biennial period.

Advertising. MGE did not include any costs in its electric advertising budget relating to the Company's wind energy project. Based on the Commission staff's review of these costs, staff proposed that \$75,000 be added to MGE's budget for marketing this project. The Commission finds staff's adjustment to be appropriate.

The Company's advertising, as evidenced by the record in this proceeding, with the exception of costs charged against the electric and gas conservation escrow accounts as noted above, produce direct and substantial benefits to ratepayers. Various portions of the advertising demonstrate energy conservation methods, demonstrate methods of reducing ratepayer costs, are required by law, or otherwise directly and substantially benefit ratepayers. Therefore, pursuant to Wis. Stat. § 196.595, the Commission will allow the cost of such advertising to be recovered in rates.

Kewaunee Nuclear Plant Decommissioning Expenses. During the hearings, MGE updated its estimate of nuclear plant decommissioning expenses to coincide with the amounts

included in docket 3270-UR-108 and in docket 05-DE-100, regarding the service life of Kewaunee. The Company's updated estimate included contributions of \$8,091,000 to the trust funds. The Citizens' Utility Board contended that since the Commission authorized the replacement of steam generators at the Kewaunee nuclear power plant (KNPP), which will allow the plant to operate until 2013, the Commission should decelerate MGE's collection of decommissioning funds authorized in docket 05-DE-100 to reflect the expected remaining life of the KNPP.

Based on its review, which considered the results of a recent Kewaunee decommissioning study and current financial factors, Commission staff concluded that a reasonable range of contributions to the trust funds for the 1999 test year was between \$7.5 million and \$9.0 million. The Commission finds that the Company's updated estimate is reasonable for this proceeding.

Based on the above, the test year electric income statement includes nuclear plant decommissioning expenses in the amount of \$11,666,440. Included in this amount are cash payments of \$7,730,000 to a tax qualified external trust fund, cash payments of \$361,000 to a nonqualified trust fund, and net of tax realized earnings of \$3,575,440 on the trust funds. The decommissioning costs collected from ratepayers are considered to be incurred evenly throughout the year and shall be deposited in the external trust funds at least monthly.

Kewaunee Nuclear Power Plant Ownership Change. The Company indicated that there was not enough information available at the time of the hearing to update the electric revenue requirement estimate in this docket to reflect MGE's proposed sale of the Kewaunee Nuclear Power Plant to Wisconsin Public Service Corporation. The Commission finds that it is premature to identify any dollar estimate associated with the proposed sale in this proceeding. As a result, the Commission determined that this docket should be reopened in mid-1999, so that the costs associated with the proposed sale can be considered for rate making purposes.

Columbia Energy Center Test Year Budget. Commission staff originally decreased the level of Columbia expenses included in the test year by \$117,000 based on information provided by Commission staff auditors involved in reviewing Wisconsin Service Corporation's current rate case proceeding, docket 6690-UR-111.

As a result of various revisions submitted by Alliant-Wisconsin Power and Light Company regarding the Columbia budget, MGE and Commission staff subsequently agreed that the budgeted level included in the Company's filing was a reasonable test year estimate to be used in determining the revenue requirement. The Commission finds the agreed-upon level to be reasonable.

Impact of Joint Plant Arbitration Settlement for Columbia and Kewaunee Nuclear Power Plant. The Company and Commission staff have agreed that based on current

information available, a reasonable estimate of the revenue requirement impact of the arbitration settlement will result in \$89,000 of additional expense to MGE. This consists of an increase in MGE's share of Columbia expenses of \$347,000 per year and a decrease in MGE's share of Kewaunee Nuclear Power Plant expenses of \$258,000. The Commission finds the agreed-upon level to be reasonable.

The Company has also agreed that it will not seek recovery of costs associated with the arbitrator's decision relating to 1997 and 1998 issues. The Commission finds MGE's position to be appropriate.

Gas Sales Forecast. In supplemental testimony, the Company contended that one of its Seasonal Distribution (SD-1) customers would switch to its alternative fuel at the expiration of its contract with MGE in June of 1999, based on projected waste oil prices versus natural gas prices. Commission staff disagreed with the Company's assertion, stating that MGE had received no indication from the customer in question that it would not continue to use natural gas throughout the test year. Staff also indicated that even if the customer used its alternative fuel, it was unlikely that it would abandon the use of natural gas completely. The Commission determined that there is inadequate information on which to base this reduction in sales and finds that MGE's filed forecast for SD-1 sales is appropriate.

Commission staff's fuel cost summary included an adjustment to MGE's Blount gas expense; however, due to the timing of information exchange, the gas sales forecast did not reflect this change. The Commission finds that the gas sales forecast should be adjusted to coincide with the fuel costs, which results in a \$44,000 reduction in gas margin revenues.

Natural Gas Sales Promotion. MGE proposed to continue with the same natural gas sales promotion programs that were approved in its last rate case, docket 3270-UR-108. Those programs were part of a two-year plan to complete saturation goals for specific end-uses in residential, multi-family and commercial customer markets. In addition, MGE proposed to promote the use of gas for space heating to new residential customers located on existing mains.

Commission staff proposed that MGE's gas sales promotion budget be eliminated because the established goals will likely be met, an incentive for gas space heating is already provided in its extension tariff and the elimination of gas sales promotion incentives is consistent with the elimination of conservation rebates. MGE provided no compelling reason to continue with its proposed programs.

The Commission finds that it is reasonable to eliminate MGE's natural gas sales promotion budget for the 1999 and 2000 biennial period.

Deferred Accounting Treatment for Power Control Program. In supplemental testimony, MGE requested deferred accounting treatment for its Power Control Program for the biennial rate case period. The Company indicated that without such a recovery mechanism, it viewed the program as fiscally irresponsible to operate.

Staff recommended that MGE be allowed to defer the costs of utilizing its Power Control Program for the summers of 1999 and 2000. Staff also recommended that the Company be required to defer any revenues it receives from selling the additional energy or capacity available on its system resulting from the use of the program. The Commission finds staff's recommendations to be reasonable.

Electric Fuel Costs

Under Wis. Admin. Code § PSC 116.04, the Commission must establish monthly and annual ranges for monitoring the test year fuel forecasts. The Commission finds that the following variance ranges are reasonable for the applicant's fuel costs: 1) for the annual range, plus or minus 3 percent; 2) for the monthly range, plus or minus 10 percent; and 3) for the cumulative range, plus or minus 10 percent for the first month of the test year, plus or minus 6 percent for the second month of the test year and plus or minus 3 percent for the remaining months of the test year. It is reasonable that the definition of fuel costs and the method of application of those ranges, established in prior Commission decisions for MGE and in docket 1-AC-143, continue to be utilized. It is appropriate to use the data in Appendix D for monitoring these ranges.

The Commission determined that a reasonable 1999 test year level of net fuel costs is \$42,682,961. This total is based on producing 2,976,043 MWh of energy. Of this total, \$42,509,681 will be monitored under the fuel rules. The remaining \$173,280 is an amortization of a deferral over the biennial rate case period.

Summary of Monitored Fuel Costs. MGE's filing included 2,976,043 MWh and \$44,293,270 of net costs to be monitored under the fuel rules. The Commission's adjustments to this filing reduced the fuel costs by approximately \$1,784,000 to a level of \$42,509,681. The adjustments consisted of uncontested net reductions of \$1,365,000 and a contested reduction of \$419,000. The Commission finds that the following uncontested adjustments to MGE's filed fuel cost estimates are reasonable:

1. MGE reduced its test year fuel costs by \$584,000 in updating its forecast data.
2. An amortization expense in the amount of \$60,000 relating to generation replacement costs for the 1998 Kewaunee nuclear outage was eliminated. It was the Company's second request for these costs.

3. Summarized totals in the filing were adjusted to reflect information in supporting schedules. Wheeling costs were decreased \$27,000 and revenues from sales for resale were increased \$10,000.

4. Electric utility fuel costs for natural gas were decreased by \$168,000 to reflect the unit cost adjustment from the gas utility audit.

5. Shifting economy purchases to parallel generation increased test year fuel costs by \$44,000.

6. Forecasted wheeling costs were decreased by \$359,000 to reflect filing corrections and a historical level of total purchased costs.

7. Capacity costs were increased by \$354,000 to reflect inflation adjustments and additional purchases.

8. Calculation corrections decreased nuclear fuel costs by \$491,000.

9. Nuclear generation increased by 2,000 MWh to reflect the restart date after Kewaunee's maintenance outage and by 2,500 MWh to reflect efficiency and capacity assumptions. These adjustments decreased net fuel costs by \$29,000 and \$35,000, respectively.

The contested adjustment was the forced outage rate for MGE's share of the Kewaunee plant. MGE used a 5 percent rate based on an "unavailability rate" it developed in a 6-year study of the operating results of the Kewaunee plant. Commission staff's first option used a rate of 1.33 percent, based on the assumptions of Wisconsin Public Service Corporation (WPS) in its current rate case. WPS is the operating partner of the Kewaunee plant. The WPS assumption was based on a recent historical average of forced outage rates at Kewaunee. Commission staff's second option used a forced outage rate of 2.4 percent, consistent with the Commission's decision in the Kewaunee steam generator replacement docket, 6690-CE-151. The decision in that docket relied on calculations of the forced outage rate for the entire history of the Kewaunee plant.

The Commission determined that a reasonable forced outage rate assumption is 1.33 percent. The method of its determination from a review of actual data is consistent with the application of the rate to the test year assumptions. The rate is consistent with that used in determining Kewaunee generation in the current WPS rate case. Kewaunee generation is increased by 35,504 MWh over MGE's forecast to reflect the appropriate rate. This generation adjustment decreases the net fuel cost forecast by \$419,000.

Summary of Unmonitored Fuel Costs. MGE's filing of fuel costs included \$1,664,282 for certain deferrals and for known and significant costs that would not be monitored under the fuel rules. The Commission authorized \$173,280 of these requests. MGE's request of \$1,339,242 for known and significant costs occurring in calendar year 2000 was eliminated by the Commission's decision to reopen this docket during 1999 to consider changes in calendar year 2000 fuel costs for ratemaking purposes. MGE's fuel cost forecast for calendar year 2000 should be completed by mid-1999, when the status of Kewaunee and MGE's ownership interests in the plant is better known. The Commission denied MGE's request for deferral of replacement generation costs for the 1997 and 1998 Kewaunee outages of \$33,333 and \$118,427 respectively.

The Commission notes that an estimate of these costs was included in the Kewaunee surcharge in MGE's last rate case. If that estimate was insufficient to cover the costs, MGE had the right to request recovery under the fuel rules in that docket. Recovery in the current docket is not appropriate.

The Commission authorized MGE's request for a two year amortization of \$173,280 for Federal Department of Energy Decontamination and Decommissioning (D&D) uncollected in MGE's rates during 1997 and 1998. This amount represents the deferred D&D assessment from 1997 and 1998 for which MGE received no rate recovery. In MGE's last rate case, the Commission agreed to hold MGE harmless if the Appeals court overturned the decision in Yankee Atomic Electric Company vs. the United States.

The Commission is aware of cost mitigation efforts for the spent fuel disposal fee. Like the recovery of deferred D&D costs, spent fuel disposal fee changes are also supported by the Commission's general practice of granting true-ups for past nuclear fuel costs and credits reflecting changes in federal tax rates and tax-like assessments. If those efforts result in a cost reduction for MGE in the future, the effect should also be deferred.

Compliance With Four Times Rule

The Commission finds that the amount budgeted for proceedings before the Commission is less than four times the amount budgeted to be assessed to MGE in the test year for Commission expenses under Wis. Stat. § 196.85.

Estimated Operating Income Statements at Present Rates

Based on the foregoing findings, the Commission finds that the estimated electric and gas utility operating income statements at present rates for the test year ending December 31, 1999, which are reasonable for the purpose of determining just and reasonable rates in this proceeding are as follows:

	Electric <u>(000's)</u>	Gas <u>(000's)</u>
<u>Operating Revenues</u>		
Sales of Electricity	\$ 164,626	\$ --
Sales to Other Utilities	436	--
Sales of Gas	--	99,005
Transportation Sales	--	2,773
Other Operating Revenues	984	265
Total Operating Revenues	<u>\$ 166,046</u>	<u>\$ 102,043</u>
<u>Operating Expenses</u>		
Fuel	\$ 29,702	\$ --
Purchased Power	12,000	--
Other Production Expenses	24,083	--
Manufactured Gas Production Exp.	--	31
Purchased Gas Expenses	--	63,054
Transmission Expenses	3,116	
Distribution Expenses	8,017	5,154
Customer Accounts Expenses	4,458	3,226
Customer Service Expenses	4,786	3,457
Sales Promotion Expenses	--	--
Administrative and General Expenses	16,933	8,757
Total Oper. & Maint. Exp.	<u>\$ 103,095</u>	<u>\$ 83,679</u>
Depreciation and Amortization	29,963	5,679
Taxes Other than Income Taxes	7,529	1,919
Deferred Income Taxes	(2,761)	(139)
State Income Taxes	1,916	546
Federal Income Taxes	7,774	2,397
Investment Tax Credit	(574)	(173)
Total Operating Expenses	<u>\$ 146,942</u>	<u>\$ 93,908</u>
Net Operating Income	\$ 19,104	\$ 8,135
Interest Income Earned on Nuclear Decommissioning Trust Funds	<u>3,575</u>	<u>--</u>
Adjusted Net Operating Income	<u>\$ 22,679</u>	<u>\$ 8,135</u>

Average Net Investment Rate Base

Marinette 83-MW Gas Combustion Turbine Project. In supplemental testimony, the Company indicated that it had entered into an agreement to have an 83-MW gas combustion turbine (CT) built at an estimated cost of \$31.4 million with a targeted date of operation being June 1, 2000. MGE acknowledged that there would be no increase to the 1999 test year electric rate base for this project. However, due to the size of the project, the Company requested that a representative test year amount be included in the electric revenue requirement. MGE proposed that an adder adjustment to the overall return on electric net investment rate base be included to reflect the capital expenditure impact. In addition, MGE requested that a representative test year level of operation and maintenance expenses be included in revenue requirement.

Prior to the Commission decision in this proceeding, the Commission approved the combustion turbine project in docket 3270-CE-121. Based on the approved cost of \$33.4 million and incorporating the Commission-approved adjusted weighted cost of capital and average electric net investment rate base in this proceeding, the revenue requirement impact associated with the return adder is approximately \$1,730,000. The Commission finds that it is reasonable to include representative test year levels for MGE's capital expenditures and operation and maintenance costs associated with this project in this proceeding.

Gas Supply Main Expansion Project. In supplemental testimony, MGE indicated that it had filed an application with the Commission (docket 3270-CG-112) for authority to construct and place in operation a 12-inch high-pressure supply main to interconnect its South Gate and North Gate Stations. The Company requested that the revenue requirement impact of approximately \$950,000 associated with the project cost be incorporated into the test year.

Shortly before the Commission decision in this proceeding, MGE withdrew its application in docket 3270-CE-112 and submitted another construction application (docket 3270-CG-115) relating to the purchase of two high-pressure supply laterals from ANR Pipeline Company and the construction of a high-pressure supply main to interconnect the two laterals.

The Commission finds that no record has been established in this proceeding relating to docket 3270-CG-115. Therefore, inclusion of costs associated with this project and the issue of how the Company should recover the revenue requirement impact are moot points. However, if MGE moves to reopen this case at a later date, the Commission would be willing to review the revenue requirement impact at that time.

Wind Turbine Project. The Company included capital expenditures and operation and maintenance costs (except for advertising) in their filing. Staff also included these costs on the assumption that the project would be approved prior to the hearings in this proceeding.

Subsequent to the hearing but prior to the Commission decision in this proceeding, the Commission approved MGE’s wind turbine project in docket 3270-CE-120. The Commission therefore finds it appropriate to include the costs associated with this project in the electric revenue requirement.

Wilton/Norwalk Gas Extension Project. Prior to the hearings in this proceeding, MGE and Commission staff agreed to reduce gas utility plant in service and associated depreciation expense by \$225,000 and \$8,000 respectively. These adjustments reflect the disallowance of costs incurred by MGE relating to the gas extension project.

Electric Inventory Adjustments. The Commission finds reasonable a \$3,509,000 increase to MGE’s filed electric net investment rate base, due to nuclear fuel stock increases and coal inventory updates.

Accordingly, the Commission finds that the estimated electric and gas utility average net investment rate bases for the test year ending December 31, 1999, which are actually used and useful for the convenience of the public and which are considered reasonable for the purpose of setting just and reasonable rates in this proceeding are as follows:

	Electric (000’s)	Gas (000’s)
Utility Plant in Service	\$621,432	\$188,573
Less: Reserve for Depreciation	<u>344,226</u>	<u>101,522</u>
Net Utility Plant	\$277,206	\$ 87,051
Add: Nuclear Fuel Investment – Net	10,188	--
Fuel Inventory	2,950	--
Stored Gas Inventory	--	6,782
Materials and Supplies	5,175	443
Less: Deferred Income Taxes	47,851	16,133
Customer Advances for Construction	<u>1,099</u>	<u>295</u>
Average Net Investment Rate Base	<u>\$246,569</u>	<u>\$ 77,848</u>

Pro Forma Rate of Return

The adjusted net operating income for purposes of this proceeding for the test year ending December 31, 1999, results in a rate of return on average investment rate base of 9.20 percent for electric utility operations and 10.45 percent for gas utility operations.

Capital Structure and Cost of Capital

A reasonable utility capital structure for the purpose of establishing just and reasonable rates for the test year consists of 53.35 percent common equity, 40.68 percent long-term debt and 5.97 percent short-term debt.

The long-term range for the utility's common equity ratio found reasonable in the last rate case was 50 to 55 percent common equity. The Commission believes that as the energy industry moves towards deregulation, the Company's common equity ratio will need to increase. Consequently, the Commission finds that the Company should be moving the percent of equity in its capital structure towards a long-term range of 55 to 60 percent. The utility's ten-year financial forecast, filed in the Company's next rate case, should incorporate the higher equity range.

Short-Term Debt. MGE's test year capital structure contains approximately \$21.3 million of short-term debt, of which \$16 million is linked to fixed rates with a composite rate of 6.29 percent for the test year. A reasonable estimate of the average cost of short-term debt in excess of \$16 million for the test year is 4.58 percent. This forecast is based on the average of test year estimates provided by the Blue Chip Financial Forecasts newsletter. This is a reasonable and objective method of determining the short-term debt cost.

Long-Term Debt. MGE's test year estimate of long-term debt included a proposed issuance of \$30 million. Commission staff recommended that the Commission use the actual issuance rate for this debt, when known. The debt was issued in September 1998, at an interest rate of 6.02 percent. The Commission finds that the resulting embedded cost of long-term debt of 7.42 percent is reasonable for the test year.

Return on Common Equity. The Company requested a 12.50 percent return on common stock equity and provided expert testimony to support its request. Commission staff testified at the hearing that it would be reasonable to set the allowed return on equity in the range from 10.80 to 11.70 percent, given economic conditions at that time and the investment risk profile of MGE. Staff recommended a point estimate of 11.70 percent and that the most recent

information should be utilized at the time of the Commission decision in projecting capital costs for the test year.

In its determination of a fair return on common stock equity, the Commission must strike a balance between the interests of investors and those of consumers. It would be undesirable to allow a return on equity so high as to be excessive, just as it would be undesirable to allow a return so low as to discourage investors. The return on common stock equity should be adequate to provide compensation for the risk assumed by stock owners. The authorized return on common stock equity should be commensurate with earnings of other business enterprises that have similar risks, maintain the financial integrity of the utility, attract and hold capital at reasonable costs, and protect the interests of utility customers.

In view of the above considerations, the Commission considers a 12.20 percent return on utility common stock equity to be reasonable in this proceeding for the purpose of establishing just and reasonable rates. The Commission finds that the authorized rate should enable MGE to meet the Commission’s increased equity ratio guidelines.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable for setting just and reasonable rates for the test year are as follows:

	<u>Amount</u> <u>(000’s)</u>	<u>Percent</u>		<u>Annual Cost</u> <u>Rate</u>		<u>Weighted</u> <u>Cost</u>	
Utility Common Equity	\$ 190,064	53.35	%	12.20	%	6.51	%
Long-Term Debt	144,944	40.68		7.42		3.02	
Short-Term Debt – Fixed	16,000	4.49		6.29		0.28	
Short-Term Debt – Variable	<u>5,268</u>	<u>1.48</u>		4.58		<u>0.07</u>	
 Total Utility Capital	 \$ <u>356,276</u>	 <u>100.00</u>	 %			 <u>9.88</u>	 %

The resulting weighted cost of capital of 9.88 percent is reasonable for MGE in the test year and generates an economic cost of capital of 14.24 percent, and a pre-tax coverage ratio of 4.23 times.

Rate of Return on Rate Base

It is necessary that the 9.88 percent composite cost of capital be translated into a rate of return which can be applied to the average net investment rate base and used to compute the overall return requirement in dollars.

Commission staff's estimate of the Company's average net investment rate base plus construction work in progress (CWIP) and conservation investments for the test year is 93.90 percent of capital applicable primarily to utility operations plus deferred investment tax credit. The Commission finds that this estimate reflects all appropriate staff and Commission adjustments and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to average net investment rate base.

Construction Work in Progress. The Company requested a current return on 100 percent of forecasted test year CWIP. The Commission has previously granted MGE a current return on 50 percent of its CWIP. Given that the level of forecasted CWIP approximates the level of CWIP forecasted in the last test year, the Commission finds that it is reasonable to continue its current policy of allowing a current return on 50 percent of CWIP. The average CWIP balance which does not earn a current return will accrue an allowance for funds used during construction (AFUDC) return at the adjusted weighted cost of capital of 10.52 percent.

In supplemental testimony, MGE requested that it be allowed to earn a current return on 100 percent of the CWIP associated with the Company's proposed gas main expansion project, docket 3270-CG-112. Because MGE withdrew its application in docket 3270-CG-112 and no record has been established for a subsequent gas main expansion project, docket 3270-CG-115, the Commission finds the Company's request to be moot at this time.

The Company also requested an adder adjustment to the overall return on electric rate base associated with the Company's proposed combustion turbine project as a method of including a representative test year amount in revenue requirement for the capital cost impact. Commission staff concurred with an adder adjustment and recommended that the Company's calculation be updated to reflect the return and construction project information available at the time of the Commission's decision. The Commission finds that inclusion of a 0.42 percent return on the electric rate base is reasonable.

In addition to the CWIP and combustion turbine adjustments, an adjustment to the return on net investment rate base is needed to provide the Company with a return on conservation investments. A further adjustment is required to reflect the tax savings of MGE's Industrial Development Revenue Bonds entirely in the electric revenue requirement.

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

	<u>Electric</u>	<u>Gas</u>
Cost of Capital	9.88%	9.88%
Average Percent of Utility Net Investment Rate Base Plus CWIP and Conservation Investments to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	93.90	93.90
Percent Return Requirement Applicable to Net Investment Rate Base	10.52	10.52
Adjustment to Return Requirement to Provide Current Return on CWIP	.24	.11
Adjustment to Return Requirement to Provide a Return on Combustion Turbine	.42	--
Adjustment to Return Requirement to Provide a Return on Conservation Investments	.13	.15
Adjustment to Reflect Tax Savings on Industrial Development Revenue Bonds	(.07)	.23
Adjusted Percent Return Requirement on Net Investment Rate Base	<u>11.24%</u>	<u>11.01%</u>

Revenue Requirement

On the basis of the above findings, the Commission finds that an increase in electric utility revenues of \$8,402,000 and an increase in gas utility revenues of \$728,000 are reasonable for purposes of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	9.20%	10.45%
Required Return on Average Net Investment Rate Base	11.24%	11.01%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	2.04%	.56%
Average Net Investment Rate Base (000's)	\$246,569	\$ 77,848
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	\$ 5,030	\$ 436
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	\$ 8,402	\$ 728

Demand-Side Management

Electric Demand-Side Management Goals. The Commission finds it reasonable to approve electric demand-side management (DSM) goals similar to previous years. MGE shall achieve 27 GWh across all sectors with at least 10 GWh in the residential sector in both 1999 and 2000. Some portion of the electric DSM goals can be met through programs that induce measurable changes in the conservation marketplace. It is appropriate for Commission staff and the Company to continue using an informal process to determine how much of the approved electric goals can be met by engaging in this type of staff-approved market preparation activity.

Natural Gas Demand-Side Management Goals. Over the past three years, Commission natural gas DSM staff has been developing a regulatory model for negotiating trade-offs between the establishment and achievement of quantitative energy savings goals and qualitative market preparation goals with natural gas utilities in Wisconsin. Utilities have received credit for market preparation activity by having their energy savings goals reduced on a percentage basis. In return for a certain level of effort and rigor in implementing and evaluating programs, Commission staff and utilities hope to accomplish the primary objective of creating market effects which can lead to permanent changes in the competitive delivery of energy efficiency services. Commission natural gas DSM staff developed a set of guidelines outlining

the objectives and requirements for development and evaluation of market preparation programs and achievement. MGE and Commission staff have come to an agreement on the credit it should receive for its energy savings goals. MGE has proposed, and the Commission has found reasonable, five market preparation goals and an evaluation plan to measure achievement as a trade-off for 50 percent of its residential/rental gas energy savings goal for the 1999 and 2000 biennial period.

Energy Savings Goals. The Commission finds that the following gas energy savings goals and minimum sector targets are reasonable for the 1999 and 2000 biennial period:

<u>Sector</u>	<u>Therm Target</u>	<u>Therm Goal</u>
Residential/Rental	277,125	369,500
Comm./Ind.	723,000	964,000
Low-Income	165,000	165,000
Any Sector	<u>333,375</u>	<u>--</u>
Total	1,498,500	1,498,500

The acceptance of these energy savings goals by the Commission is contingent on MGE following through on its commitment to implement its market preparation programs, to work toward the achievement of its market preparation goals and to complete its evaluation plan. Otherwise, MGE's gas energy savings goals will revert back to pre-1998 levels.

Market Preparation Goals. MGE and Commission staff have negotiated a 50 percent credit on the achievement of its energy savings goals in return for agreeing to design and implement market preparation programs that create and sustain a viable competitive market for whole house or home performance services. Whole house services provide a different and more comprehensive approach to solving health, comfort, safety and energy efficiency problems for residential customers. The building, its equipment and its occupants are viewed as an integrative and interactive unit, as changing one component of the building's performance may affect other components, sometimes adversely. For example, installing a high efficiency furnace to save energy without assessing its impact on the overall building and the health and safety of its occupants can lead to serious problems with increased infiltration of cold air, moisture damage and customer discomfort.

Whole house services are an emerging market that needs the stimulus of utility market preparation programs. By inducing market effects that potentially result in greater demand for this service and that provide educational and training opportunities for new and existing businesses, MGE and Commission staff hope to prepare the residential market for Public

Benefits¹ efforts. If successful, MGE's programs show promise for creating momentum in residential markets for infrastructure development and permanent changes in the ability of the private sector in MGE's service territory to deliver whole building services. Eventually, the market for these services should be self-sustaining.

The Commission finds it reasonable for MGE to establish the following market preparation goals for the 1999 and 2000 biennial period:

1. Establish performance standards for contractors for the marketing and delivery of comprehensive, whole house services.
2. Integrate whole house energy assessment and treatment into the home real estate and lending market.
3. Establish a high level of awareness of the importance of whole house energy efficiency and a demand for high performance housing among homeowners.
4. Work with secondary schools to incorporate whole house energy efficiency principles in home design and construction training curriculum.
5. Establish the Environmental Protection Agency Energy Star® criteria as minimum standards for appliances, equipment and new construction in the whole house market.

The Commission finds it reasonable for MGE to perform an evaluation of its market preparation programs as described in its evaluation plan and to measure achievement of its goals in comparison to specific established performance standards for the development of the whole house market.

Low-Income Energy Efficiency Services. In response to Commission concerns with the current level of funding, energy savings achievement and comprehensive services provided by utilities to their low-income customers, Commission staff proposed a set of funding and delivery guidelines. These guidelines would apply to all utilities and would govern funding and delivery of energy efficiency services to these customers until some other Public Benefits entity can take over responsibility for providing these services.

The Commission finds it reasonable to require MGE to follow these guidelines:

¹ Public Benefits refers to the funding and delivery of low-income energy services, energy efficiency, renewable energy and environmental research and development programs as described in the Commission's Enunciations of Policy and Principles, docket 05-BU-100.

Funding

1. All Wisconsin utilities will maintain and/or increase their level of overall funding for low-income energy efficiency programs if necessary to meet their energy savings goals and provide comprehensive services.
2. All Wisconsin utilities will pay up to 100 percent of the costs of delivering and installing energy conservation measures for all eligible low-income customers, if necessary, to complete the work determined to be cost-effective by the state energy audit. Coordination and cost sharing with state weatherization operators should not result in utilities not meeting their energy savings goals or paying less than their share of total program costs.
3. All utility payments for contracted services will be based on dollars per kWh and therms saved. The dollar amount per kWh and therm will be determined, at minimum, by covering 50 percent or more of the contractor's cost of administering and delivering energy efficiency services at the program level.
4. All Wisconsin utilities shall establish a goal of holding their internal administrative costs to 15 percent or less of total program costs.

Delivery

1. All Wisconsin utilities will deliver or pay for the delivery of comprehensive energy efficiency services to all eligible low-income customers when determined to be cost-effective by the state energy audit. Comprehensiveness includes non-energy savings benefits like improvements to or maintenance of the health, comfort and safety of the treated building.
2. All Wisconsin utilities will consider contracting with other providers if state weatherization operators cannot deliver and install measures sufficient to achieve energy savings goals and deliver comprehensive services to all eligible low-income customers.

Electric Rates and Rules

The Commission finds that the current electric rates are unreasonable because they will produce inadequate revenues. Authorized final rates, shown in Appendix B, will provide an increase in revenues for the test year of \$8,402,000, a 5.1 percent increase.

Cost-of-Service Studies and Revenue Allocation. The Company presented one embedded cost-of-service study and one marginal cost-of-service study. Unbundled cost-of-service information was also presented. MGE's embedded cost-of-service study allocated all

generation and transmission plant costs based on coincident peak and allocated all distribution costs on a combination of noncoincident peak demands and a customer component. MGE proposed a revenue allocation for the customer classes based on this cost study.

Staff presented three embedded cost-of-service studies, an embedded adjusted company study, and unbundled cost-of-service information. The embedded adjusted company study uses MGE's basic allocation approach, but reflects Commission staff's adjustments to plant, expenses, and revenues. The first of the other three studies, the Capacity method, allocates a portion of the steam plant and generation expenses on an energy basis. This allocation procedure recognizes that steam plants are built to take advantage of lower operating costs, not simply to meet capacity needs. Commission staff's second study, the Time-of-Day method, reflects the fact that energy-related costs vary by time-of-day. Staff's third cost-of-service study, the Location method, allocates all distribution costs based on noncoincident peak demands.

Commission staff used the cost ranges resulting from all of the cost studies as a guide for class revenue allocation. Staff also took into consideration the competitive aspect with other utilities and the bill impacts on all customer classes in determining the appropriate rate class revenue responsibility.

The Commission recognizes that cost-of-service studies are not precise reflections of cost causality, but rather depend heavily on the accuracy of data used and the many judgments and assumptions of the analyst performing the study. The Commission does not consider any single study to be accurate enough to establish the precise cost of providing service to any class, although all have some value. Therefore, the Commission does not adopt any single method or set of assumptions, but rather considers it appropriate that all of the cost studies presented in this proceeding be used in determining class cost responsibility. The Commission finds that consideration of all cost studies presents a balanced guideline to be used in allocating revenue responsibility to the various customer classes.

Selection of final class revenue targets, using the cost-of-service studies as a guideline and adhering to the general principles of ratemaking, is largely a matter of judgment. The Commission has exercised its judgment and allocated revenues based on the record in this proceeding, adopting the method proposed by Commission staff, with adjustments to reflect the final authorized revenue requirement. The total electric revenue increase from base rates of 5.1 percent will result in an average customer class increase or decrease as shown in Appendix B.

Both the Company and Commission staff submitted electric rate designs in this proceeding. Both Commission staff's and MGE's cost-of-service studies have been used as guides to develop rates which reflect cost components within customer classes and provide an accurate price signal to customers. In order to attain rate continuity and achieve the goals of customer understanding and acceptance of rates, the Commission has considered all cost-of-service studies as well as customer bill impacts in the rate design authorized in this order.

The Commission adopts Commission staff's electric rate design structure with adjustments to meet the final authorized revenue requirement. The energy charges for the "energy only" rate classes (i.e., classes without demand charges) and the demand and energy charges for the "demand/energy" rate classes are adjusted to reflect costs and to recover the revenue responsibility allocated to these classes. Other rates are changed to recover the appropriate revenue. All these changes are made while considering customer bill impacts.

The Commission reaffirms its position that flat energy charges are appropriate to promote conservation and that time-differentiated energy charges should be related to marginal costs to provide the proper price signal. The rates authorized by the Commission, as shown in Appendix B, include changes in the rate structure of some rate classes and adjustments to meet the revenue requirement. The Commission finds the electric rate and rule changes described below to be just and reasonable.

Residential and Commercial Non-Demand Rates. The Commission increased the distribution charge for the residential rate classes Rg-1, Rg-2, Rw-1 and Rg-3, and for the small commercial and industrial classes, Cg-5 and Cg-3, from its present level of \$0.0168/kWh to \$0.0208/kWh. The Commission also increased the daily fixed customer charges for the residential Rw-1 class (\$0.0493/day) and the commercial, non-demand rate class Cg-3 (\$0.2466/day) to \$0.0658/day and \$0.3288/day, respectively. Daily fixed customer charges for the remaining energy only classes, Rg-1, Rg-2, Rg-3, and Cg-5 were not increased, as the Company had requested. Maintaining low, fixed customer charges sends customers an appropriate energy conservation signal and avoids the disproportionate rate impacts for low use customers that higher fixed charges would cause. Electric energy charges were generally increased to collect the revenue responsibility allocated to each class.

Small Commercial and Industrial Customers (Demand/Energy Rates). Rate classes Cg-1(A) (20-75 kW) and Cg-1(B) (75-200 kW) are non time-of-use rates while the Cg-4(A) and Cg-4(B) include the same size customers but are optional time-of-use rates. The Commission increased the daily fixed charges for each of the four classes to better reflect customer-related costs. The daily charge for the Cg-1(A) class was increased from \$0.3288/day to \$0.6575/day. The daily charge for the Cg-1(B) class was increased from \$0.4932/day to \$0.9863/day. The daily charge for the Cg-4(A) and Cg-4(B) classes were increased from \$0.6575/day to \$0.9370/day.

Winter electricity demand charges for these classes were increased from \$3.80/kW to \$4.60/kW and summer charges from \$4.80/kW to \$5.60/kW. Existing customer maximum demand charges of \$1.60/kW for the Cg-1(A) and Cg-1(B) classes and \$2.25/kW for the Cg-4(A) and Cg-4(B) classes were increased to \$2.75/kW for the Cg-1 classes and to \$2.80/kW for the Cg-4 classes.

Electricity energy charges for all four classes were decreased to collect the revenue responsibility allocated to each class.

The Commission eliminated the energy cost limiter mechanism in the Cg-1 class, effective January 1, 2000. This rate impact mitigating transition mechanism, which began 16 years ago, has served its purpose and is no longer needed.

Large Commercial and Industrial Rates. The Commission made adjustments to the large commercial and industrial time-of-use rates: Cg-2, Cg-6, Sp-3, Sp-4 and Sp-5. Daily customer charges and customer demand charges were increased for the Cg-2, Cg-6, Sp-3, Sp-4 and Sp-5 classes. Electricity demand charges were increased for the Cg-2, Cg-6, Sp-3 and Sp-4 classes from \$3.80/kW (winter) and \$4.80/kW (summer) to \$4.60/kW (winter) and \$5.60/kW (summer). Electricity demand charges were increased for the Sp-5 class from \$5.50/kW (winter) and \$6.50/kW (summer) to \$5.75/kW (winter) and \$6.75/kW (summer). All interruptible and curtailable credits were left unchanged.

Summer Curtailable Service (SCS), an experimental offering approved by the Commission on an annual basis in 1997 and 1998, has been made a permanent service offering.

The all-energy distribution charges in the Cg-2, Cg-6, Sp-3, Sp-4 and Sp-5 classes were eliminated and base energy rates increased. The result is a decrease in all net per kWh charges except for the Sp-4 class, where net per kWh rates remain unchanged. Existing price differentials between on-peak and off-peak energy rates and between summer and winter energy rates have been maintained where possible.

The Commission maintained all rate components of the transmission Cp-1 rate schedule at their current level.

Street Lighting Rates. The Commission restructured charges in the streetlighting classes SL-1, SL-2 and SL-3. The existing flat monthly rate for lamps under the SL-1 schedule was separated into three charges: distribution service, electricity service, and facilities. For the SL-2 schedule, the flat fee was separated into two charges: distribution and electricity. For the SL-3 schedule, it was separated into three charges: distribution service, electricity service, and maintenance. The sum of the separate charges, in most cases, adds up to the same monthly cost.

Wind Energy Rate. Commission staff included revenues from a new wind energy rate (RWE-2) in its electric rate design and revenue allocation as a “placeholder” for a rate that was anticipated to be proposed and supported by MGE before the close of hearings. No rate was proposed and no support for a rate was given in the hearing. The Commission approves a “placeholder” rate for revenue requirement purposes, but requires that the actual rate, if and when proposed, be subject to staff review and Commission approval, at that time.

Winter Construction. The Commission changed the dates of the electric winter construction charge period from December 10 through March 16, to December 1 through March 31, the same period as for natural gas winter construction charges.

Minimum Bill Language. The Commission finds it reasonable to change the tariff language on minimum bill descriptions to match the definition of customer maximum demand. This change affects the Cg-1, Cg-2, Cg-4, Cg-6, Sp-3 and Sp-4 rate schedules.

Enhanced Services. MGE proposed to begin five experimental service offerings with a deferred implementation date of January 1, 2000. The first four of these offerings are: 1) providing hardcopy of 15-minute detailed consumption data; 2) providing electronic copy of 15-minute detailed consumption data; 3) allowing customers to specify their own meter reading cycle dates; and 4) allowing combined billing (one bill) to customers with multiple locations, after the customer chooses a single meter reading cycle for all locations. The Commission approved each of these new enhanced service offerings, as detailed in Appendix B.

A fifth enhanced service offering proposed by MGE, totalized demand billing, was to allow customers to totalize demand across all their accounts and be billed for on-peak electricity service demand based on the coincident maximum on-peak demand of all their meters. This service is detailed in Appendix B. Commission staff expressed three concerns about MGE's proposed totalized demand offering during the hearings. Those concerns were: 1) the potential for under-collection of distribution related costs if charges are not fully unbundled; 2) the potential for revenue-shifting due to lower revenue from participating customers; and 3) the potential for numerous similar requests from utilities which have not appropriately unbundled charges.

Intervenor WPS Energy Services proposed a different approach to customer bill totalization, which it called "conjunctive billing services." This proposed service would allow customers with multiple facilities located throughout the MGE service territory, whether contiguous or not, to aggregate multiple meters and metering points for cost-of-service, rate design, rate eligibility, and billing. The proposed service would also allow customers to net out customer generation within the combined billing rate structure, allowing customer generation at one facility to offset energy purchases from the utility at another facility.

The Commission finds MGE's proposal for totalized demand billing to be reasonable. The Commission, however, is sensitive to Commission staff concerns about this type of service. The Commission's acceptance of this service is predicated on the Commission's judgement that MGE has appropriately unbundled its relevant rate schedules prior to proposing this service. The Commission is unlikely to approve similar offerings by other utilities unless the Commission finds that a utility has also unbundled rate components.

The Commission finds that the conjunctive billing service proposed by WPS Energy Services is not appropriate at this time. In making this finding, the Commission recognizes the concerns of MGE and Commission staff that such a service could be construed as “retail wheeling” and that the proposal raises issues more appropriately considered in other electric industry restructuring proceedings.

Buy-Back Rates. The Commission finds it reasonable to adjust MGE’s parallel generation buy-back rates to better reflect the utility’s marginal costs of energy. The Commission increased the 1-phase customer charge and decreased the 3-phase customer charge. The on-peak primary rate was decreased from \$0.0388/kWh to \$0.0371/kWh. The on-peak secondary rate was decreased from \$0.0397/kWh to \$0.0376/kWh. The off-peak primary rate was increased from \$0.0167/kWh to \$0.0173/kWh. The off-peak secondary rate was increased from \$0.0171/kWh to \$0.0175/kWh.

Natural Gas Cost-of-Service Studies

Commission staff submitted two fully embedded cost-of-service studies. The Commission finds that a cost-of-service study that considers the used and usefulness of the Company's investment and its cost of operations is a reasonable basis to recover from each class a fair apportionment of the total cost of providing service in a nondiscriminatory manner. In this proceeding, the costs are those anticipated for the test year. Staff's cost-of-service study A (COSS A) is a demand-customer oriented study under which major plant accounts and expense accounts are allocated between demand and customer components. Staff's COSS A is based on studies which have been conducted for various utilities to determine what portion of these accounts varies with the number of customers, regardless of how much gas is distributed, and what portion varies with a customer's demand for gas. Staff's cost-of-service study B is a demand/commodity-oriented study whereby major plant and expense accounts are allocated between demand and commodity components. The Commission has found in numerous rate cases that one objectively “correct” standard does not exist for the overhead or common cost allocation.

The Company submitted one fully embedded cost-of-service study that equates to Commission staff's COSS A. MGE testified to a rate design proposal based on the results of its study.

The studies evolved from a method recognized by the American Gas Association that is described in detail in "Gas Rates Fundamentals," American Gas Association, Fourth Edition, 1987. However, Commission staff and MGE modified their cost-of-service models to comply with the Commission's generic order in docket 05-GI-108, Phase I. This order required the identification or functionalization of costs into five basic utility service categories: Basic Distribution, Peak-Day Backup, Competitive/Basic Supply Procurement, Daily Balancing, and

Enhanced/Other Services. Previous cost-of-service studies were developed prior to the restructuring of natural gas interstate pipeline services under FERC Order 636, and did not reflect the changed role of the local distribution companies in purchasing, transporting, storing and distributing gas to their customers. It should be noted that the models fall short of full adherence to the principles set forth in the order in docket 05-GI-108, Phase I; however, the models have moved in that direction and future improvements are anticipated.

The Commission recognizes that cost-of-service studies are not precise reflections of cost causality, but rather depend heavily on the accuracy of data used and the many judgments and assumptions of the analyst performing the study. The Commission does not consider any single study to be accurate enough to establish the precise cost of providing service to any class, although all have some value. Therefore, the Commission does not adopt any single method or set of assumptions, but rather considers it appropriate that all of the cost studies presented in this proceeding be used in determining class cost responsibility. The Commission finds that consideration of all cost studies presents a balanced guideline to be used in allocating revenue responsibility to the various customer classes.

Intervenor Select Energy Consulting (SEC) challenged the allocation of administrative costs to the service option CBS-1, Comprehensive Balancing Service. SEC stated that the costs were high given the incremental cost of providing the service, and compared to the cost of providing Daily Balancing Service (DBS). SEC stated that DBS throughput volume is approximately 19 times greater than the CBS throughput volume, and concluded that it was questionable that the cost of providing DBS would be identical to the cost of providing CBS. However, the cost of providing CBS and DBS are approximately equal on a per-customer cost basis. The cost of providing CBS and DBS is a function of the number of customers served and is not proportionate to the throughput. The Commission finds that the Commission staff's allocation of costs for CBS is reasonable.

Natural Gas Rates and Rules

Gas service rates authorized in this proceeding will result in an estimated net operating income of approximately \$8,571,000 which provides an 11.01 percent return on the gas utility net investment rate base of \$77,848,000.

Both MGE and Commission staff submitted rate designs in this proceeding. To provide for historical continuity in MGE's rates, the Commission finds it reasonable to authorize gas service rates that move in the direction of the cost analysis as described above, with the intent to make further adjustments in that direction in subsequent rate proceedings. In moving toward the cost of service, the Commission tempers the rate increase to the customer classes that, according to the cost analysis, should receive the largest percentage increases. The resulting revenue difference is recovered through the rates charged to the remaining customer classes. The percentage rate increase to any individual customer will not necessarily equal the overall

percentage increase to the associated customer class, but will depend on that customer's specific usage level.

Authorized rates as set forth in Appendix C are based on the cost of supplying various classes or types of service. These rates are reasonable and just.

Some typical gas bills for residential customers were computed to compare existing rates with the new rates. These are set forth in Appendix C.

Comprehensive Balancing Service (CBS). CBS is a relatively new nontelemetered service offering that gives the Company's GSD-2 customers an opportunity to purchase gas with a competitive supplier and transport the gas using firm pipeline capacity that is released by MGE. Staff prepared two rate designs: 1) a rate design that recovers the cost of providing CBS within the cost-of-service bookends, and 2) an alternative rate design to promote CBS by aligning the rates with firm gas sales service.

The cost of telemetering can make typical gas transportation service cost prohibitive for small-volume users. Eliminating the costs associated with telemeters gives small-volume users access to the competitive gas markets. In the absence of telemetering, a gas utility needs to implement processes to determine daily transport quantities for the purpose of maintaining system reliability and avoiding pipeline penalties. CBS was designed to be simple for supplier agents to use. MGE forecasts the load for each customer and aggregates the loads to develop a level daily delivery volume each month. MGE's forecasting and delivery adjustment processes are labor intensive and not very cost effective. However, the Commission has shown an interest in nontelemetered service because it provides small-volume users access to the competitive gas markets. In the short run, the Commission believes it is reasonable to authorize a promotional rate for CBS to open competitive markets to the Company's GSD-2 system sales customers. In the long run, the Commission believes that the Company will gain economies of scale and improve process efficiencies to the point where this type of pricing would no longer be necessary. Therefore, the Commission finds that it is reasonable to lower the administrative charge for CBS to that of the administrative charge for firm gas sales service to encourage CBS service in the short term.

SEC objected to six elements of the CBS offering stating that: 1) the administrative rate for CBS should be a flat customer charge versus a volumetric rate; 2) the Commission should audit the CBS program for discovery and elimination of Company mismanagement; 3) customers should be informed of their monthly Gas Commodity Account (GCA) Balance; 4) customers should be allowed to transfer GCA balances between accounts; 5) MGE should cash out the GCA balance on a monthly basis using a market index or cash out on a higher of the customer's purchase price or the weighted average cost of gas (WACOG) basis when service is terminated, and 6) CBS should be offered to additional customer classes.

MGE and Commission staff proposed that the administrative charge for CBS be changed to a volumetric rate versus a customer service charge. SEC argued that volumetric fees disregard economies of scale and over recover costs from larger-volume customers. MGE and staff stated that the purpose of the volumetric rate is to create a competitive balance between CBS and firm gas sales service. A volumetric rate also makes CBS more attractive to the large majority of customers in the GSD-2 class whose usage is closer to the lower volume threshold of the class and for whom telemetering is economically unfeasible. The Commission finds that an administrative charge for CBS computed on a volumetric basis is reasonable.

SEC states that MGE forecasting errors can cause financial harm to a CBS customer. SEC believes that an inordinate amount of overestimating is indicative of a Company bias that places a financial burden on the customer. If the month's transport quantity is overestimated, then the customer's dollars are used to leave gas on the system. Any GCA mismanagement has the potential to impact customer gas costs beyond what one would consider reasonable within the parameters of the program. Therefore, SEC believes that Commission staff should review the CBS process and provide input on improvement.

The Company stated that a large number of GCA balances accumulated during the first month of service for some customers as a result of the Company's failure to adjust for partial month deliveries. However, most overestimates can be reasonably attributed to a warmer than normal winter. The Company indicated that it has improved the forecast model and that it can now determine partial month deliveries. Because the model forecasts consumption for normal weather, the forecast will be closer to actual if the winter is closer to normal weather. MGE noted that last winter was warmer than normal; therefore, a winter that is more normal than last year will result in improved forecast accuracy when compared to actual usage. The Company is interested in reviewing the results this spring and would not oppose a comprehensive review of the program with Commission staff at that time. The Commission finds that performing a comprehensive review of the program is reasonable and that Commission staff should participate in the review.

SEC argued that MGE should be ordered to add CGA balance information to the customer's monthly gas bill and in the interim period MGE should be required to insert a GCA statement for CBS customers with the regular monthly bill. SEC indicated that it is difficult to reconcile consumption to ordered quantities without this information.

MGE stated that it intends to provide such information on the bill; however, the priority is lower than many others, including Y2K. Presently, MGE makes this information available upon request and would continue to do so until the information is made available electronically or placed on the customer's monthly billing statement.

Given the number of customers and the resources involved, the Commission finds that it would be reasonable to delay implementation until after the program review as long as MGE makes this information available upon request.

SEC requested the right to transfer GCA balances between accounts. MGE stated that the CBS program is designed to meet account-specific needs, that account balance swapping would be difficult to administer and not worthwhile for the few customers that would request swapping. The Commission finds that it is not appropriate to order the Company to allow GCA swapping between accounts.

SEC requested that cash outs be made on a monthly basis using a market index or when service is terminated using the higher of the customer's purchase price or WACOG. Monthly cash outs would increase the number of transactions substantially resulting in increased administrative costs. The use of the index would encourage customers to arbitrage the difference between WACOG and the prevailing market price to the financial detriment of system sales customers. The alternative, cash outs at service termination using the higher of the customer's purchase price or WACOG, would certainly increase costs to the system sales customers. The Commission finds that applying GCA account balances to future deliveries is a reasonable disposition of monthly GCA balances and that cash outs determined by WACOG for service termination is reasonable.

SEC requested that CBS be offered to additional customer classes. CBS is a relatively new service offering and has little GSD-2 customer participation at this time. The Commission finds that the Company has not had the experience or the ability to make the process improvements that would be necessary if CBS were to be expanded to the users served by the Company's small-volume rates. The market potential of the rate, the economies of scale and the process improvements will be reviewed in the near future. The Commission would like to see this program succeed with respect to small-volume customers, but does not plan to expand the program to smaller customer classes until MGE has improved its marketability and its processes. Therefore, the Commission does not require expansion to smaller-volume customer classes at this time.

The cost of telemeters is not cost prohibitive for large-volume customers and therefore is not a barrier to competition for these customers. Therefore, the Commission does not require service expansion to larger-volume customer classes.

Notification Requirement for Transfers to Transportation Service. SEC requested that the current 12-month notice requirement for transfers to transportation service be revised to give notice between April 1 (when storage replenishment begins) and July 15 (when nominations are due from the Company's nominated firm sales customers) for transfers to transportation service at the start of MGE's gas year beginning November 1.

The Company designed the current one-year transfer provision to balance the needs of customers wishing to leave FS-1 service and customers who pay for the Company's firm pipeline capacity. The Company would rather reduce its pipeline capacity contracts to adjust for a customer leaving its firm gas sales service than to have the remaining customers pay for the cost of capacity left by the transferring customer. However, adjusting pipeline capacity contracts

takes time. The Company's current notification period is within the ranges considered reasonable in the order issued in docket 05-GI-103, dated December 19, 1991. Therefore, the Commission finds that the Company's current notification condition is reasonable.

Intraday Constraints. MGE requested the right to call intraday constraint days or selective constraints. A recent FERC ruling would allow shippers to make intraday nominations and this may put MGE into a constraint condition. The Commission finds that it is reasonable for MGE to call intraday constraint days or selective constraints.

Revisions to Gas Utility Rules. MGE proposed a number of revisions to its gas rules. The first revision sets forth a condition stating that the installation of a gas meter shall be made at a Company prescribed location. The second revision provides for additional service lateral installation charges in situations where the service lateral is installed beyond the prescribed meter location. The third revision changed the charges for the installation of service lateral footage in excess of the free limit. This revision, in general, lowers the charges from current levels. The fourth revision changed the winter gas service lateral installations to a policy consistent with the winter electric service installations. The fifth revision created a policy with respect to winter distribution main installations. The sixth revision revised the methodology used to determine charges for distribution main installations. MGE provided these revisions to the parties prior to the hearing and received no objection to them. The proposed gas rules and charges with respect to mains, service laterals and meters are reasonable and just and in accordance with Commission policy and the Wisconsin Administrative Code. The rules, as revised, are set forth in Appendix C.

Gas Cost Recovery Mechanism (GCRM)

The order in docket 05-GI-106, issued November 8, 1996, directed all natural gas local distribution companies (LDCs) whose sales are equal to or exceed those of Superior Water, Light and Power to use either an incentive Gas Cost Recovery Mechanism (GCRM) or a modified one-for-one GCRM, with the exception that two or more LDCs within the same corporate structure may not have different types of GCRMs. In the Company's last rate proceeding, docket 3270-UR-108, the Commission approved a modified one-for-one mechanism.

A variance from the docket 05-GI-106 order occurred in MGE's last rate proceeding. In that docket, the Commission ordered continuance of a separate, status quo GCRM for the area previously served by the Muny Natural Gas Utility (Muny) based on the order in dockets 3990-GA-100 and 3270-GB-100, issued February 24, 1993. That order permitted the acquisition of Muny by MGE and prohibited MGE from increasing rates in the former Muny service territory for a period of five years. In the sixth year, MGE could begin phasing in its

rates for the Muny service territory, with the phase-in to be completed over a three-year period. The order also provided that the cost of gas for the Muny service territory must be kept separate from MGE's until the completion of the phase-in period. The phase-in period began in May of 1998. MGE will continue to keep the cost of gas for the Muny service territory separate until the phase-in period is complete.

In this proceeding, the Company proposed an incentive GCRM based largely on the design of its current modified one-for-one mechanism. The proposal consists of three categories. The first category is for approved costs that will pass directly to ratepayers through the Purchased Gas Adjustment Clause (PGA), and include:

1. Pipeline Capacity Costs, including costs paid to the pipeline to reserve pipeline capacity as well as storage capacity. The rates for these costs are approved by the Federal Energy Regulatory Commission and the amount of capacity contracted for must be pre-approved in the annual supply plan.
2. FERC Approved/Mandated Rates and Charges, including costs resulting from Northern Natural Pipeline's requirement to source natural gas supplies at Carlton, and costs for gas supplies associated with the Reverse Auction.
3. Gas Supply Demand Charges paid in exchange for a lower commodity cost of gas, provided they were approved in the Company's annual supply plan.

The proposed incentive GCRM treats costs in this first category in much the same manner as they are treated in the current modified one-for-one GCRM. The Commission finds it reasonable for MGE to continue direct pass-through of approved costs in this category.

The second category of the Company's incentive GCRM proposal covers revenue from Capacity Release/Opportunity Sales. The Company proposed developing its target revenues following the same method that it currently practices. MGE will include, in its annual supply plan, the volume of capacity it plans to release each year. MGE will send Requests for Proposals (RFPs) to potential purchasers based on the volumes approved in the supply plan. The responses to the RFPs will be the basis for MGE's target capacity release revenue.

MGE proposed basing the volumes available for release on ten percent colder than normal weather, and sharing all revenues in excess of the target, as well as revenue shortfalls, on a 50 percent ratepayer/50 percent shareholder basis. In the Company's last rate proceeding, the Commission approved a target based on ten percent colder than normal weather, but noted that this target was asymmetrical, and ordered an asymmetrical sharing mechanism to compensate for that fact. The Company was allowed a 40 percent share of the revenues above the target, but was responsible for 60 percent of revenue shortfalls. In this proceeding, Commission staff presented testimony supporting the 50/50 sharing, but, in order to appropriately balance risk and reward between shareholders and ratepayers, recommended that the target level be based on normal weather. The Commission finds that a 50 percent shareholder/50 percent ratepayer sharing

mechanism for capacity release/opportunity sales revenues is reasonable, but the target level must be based on normal weather.

The third category of the Company's incentive GCRM proposal involves the commodity benchmark. The benchmark will be based on *Inside FERC Gas Market Report* first-of-the-month index prices by supply area. For Northern Natural (NN) volumes, a weighted average, based on MGE's approved supply plan volumes, of the first of the month spot gas price index at NN-Ventura, Iowa, and at NN-Demarcation will be used. For ANR Pipeline Company (ANR) volumes, the first of the month spot gas price index at ANR-Louisiana and ANR-Oklahoma will be used for volumes from ANR Southeast pipeline and ANR Southwest pipeline, respectively. If additional receipt points become available to MGE, appropriate first-of-the-month indices will be used for those volumes expected to flow from those receipt points. The index used for a new receipt point may not necessarily come from *Inside FERC* but instead may be attained from the industry standard publication for that point. Gas injections into storage will be recorded at cost. The Commission finds this method to be reasonable, and directs the Company to work with Commission staff to determine the appropriate indices to be used for additional receipt points that become available to the Company.

The Company also proposed a 4.77 percent adder to the commodity benchmark to account for reliability of supply, midmonth volume and pricing volatility, variable no notice service charges, weather risk protection and the additional risk to MGE involved in the incentive mechanism. The weather risk component accounts for 1.15 percentage points of the total 4.77 percent adder. Staff presented testimony comparing the need for weather risk protection for commodity in a one-for-one GCRM versus an incentive GCRM. Staff stated that incentive GCRMs are reviewed on an annual basis, and an adder for colder than normal weather with no accompanying credit for warmer than normal weather would be asymmetrical, since, in the long term, half the time it will be warmer than normal, the other half it will be colder than normal, and the two will average out. The Commission finds that a weather risk adder for MGE's proposed incentive GCRM is neither necessary nor appropriate. Eliminating the weather risk adder results in a commodity adder of 3.62 percent.

Commission staff also presented testimony questioning the need for the adder to cover additional risk of the incentive GCRM. The risk factor accounts for .5 percentage points of the 4.77 percent adder. Staff compared MGE's proposal with Wisconsin Gas Company's (WGC) incentive GCRM, which does not include a risk component in its adder. The Commission determined that MGE's service territory is different from WGC's, that WGC's GCRM alone does not provide enough history, and that the .5 percent risk factor is appropriate for MGE. Commissioner Farrow dissented.

The Company proposed a sharing level capped at \$1,500,000 above or below the benchmark. Any annual savings or excess costs within this band would be shared between ratepayers and shareholders on a 50/50 basis. Any annual savings or excess costs outside the band would flow entirely to customers. The Commission finds this sharing level to be reasonable.

Commission staff review of the incentive GCRM will be on an annual basis, as opposed to the monthly review required for modified one-for-one mechanisms. The implementation date will be November 1, 1999, to coincide with the Company's gas supply planning period of November through October of the following year. The current modified one-for-one GCRM will continue until November 1, 1999.

Net penalty revenues from transportation and interruptible customers will flow back through the Purchased Gas Adjustment Clause (PGA) to system firm customers. Costs associated with penalties refers to unauthorized use charges, rather than costs for authorized usage, such as no-notice overrun, which is included in the adder. Costs incurred on behalf of system customers will also be included in this amount, and are subject to Commission staff review. This change in general policy is meant to allow for easier record keeping, and to acknowledge that the level of penalties incurred on behalf of system customers is usually small and often difficult to avoid. In order to track the system penalties that may flow back to customers, the level of penalties incurred on behalf of system customers must be identified separately in the monthly standard reporting filing of the GCRM with the Commission.

Effective Date of Order

The test year in this case commences January 1, 1999. Under Wis. Stat. § 196.40, an order or determination of the Commission shall take effect 20 days after the order or determination has been filed and served on the parties to the proceeding unless the Commission specifies a different effective date in the order or determination.

The Commission finds, because the test year has already commenced, that it is reasonable this order be effective on the day of mailing. It is also reasonable to specify when a utility must file its new schedules with the Commission and at pay stations, as required under Wis. Stat. § § 196.19 and 196.21, and when these new schedules will take effect after their filing. MGE shall file the new schedules, as required in Wis. Stat. § § 196.19 and 196.21, no later than seven days after the effective date of this order. These rate schedules shall take effect on the effective date of this order.

Environmental Review

This is a Type III action under Wis. Admin. Code § PSC 4.10(3). Furthermore, since no unusual circumstances have come to the attention of the Commission which indicate that significant environmental consequences are likely, neither an environmental impact statement under Wis. Stat. § 1.11, nor an environmental assessment is required.

ULTIMATE FINDINGS OF FACT

THE COMMISSION FINDS:

1. That at present rates, the estimated electric utility adjusted net operating income of MGE for the test year ending December 31, 1999, is \$22,679,000. The estimated net operating income applicable to gas utility operations for the test year ending December 31, 1999, at present rates is \$8,135,000.
2. That the estimated average net investment rate base applicable to electric utility operations for the test year ending December 31, 1999, is \$246,569,000. The average net investment rate base for gas utility operations for the test year ending December 31, 1999, is \$77,848,000.
3. That the pro forma rate of return on average net investment rate base at present rates for electric utility operations for the test year ending December 31, 1999, is 9.20 percent. For gas utility operations, the pro forma rate of return at present rates for the test year ending December 31, 1999, is 10.45 percent.
4. That the level of expensed conservation costs recoverable in rates for the test year ending December 31, 1999, is \$2,549,324 for electric utility operations and \$2,160,972 for gas utility operations. The level for electric utility operations consists of the conservation budget of \$2,920,324 less an escrow adjustment of \$371,000. The level for gas operations consists of the conservation budget of \$1,996,972 plus an escrow adjustment of \$164,000.
5. That it is reasonable for MGE to continue accounting for allowable electric and gas conservation expenditures on an escrow basis.
6. That MGE shall amortize the estimated unamortized electric and gas capitalized conservation balances on December 31, 1998 over a four year period.
7. That the advertising included in the electric and gas utility revenue requirements as described in the Findings of Fact, provides direct and substantial benefits to ratepayers.
8. That the electric utility revenue requirement includes \$11,666,440 for nuclear plant decommissioning expenses. Included in this amount are cash payments of \$7,730,000 to a tax qualified external trust fund, cash payments of \$361,000 to a nonqualified external trust fund, and net of tax realized earnings of \$3,575,440 on the qualified and nonqualified trust funds.
9. That it is reasonable to reopen this docket in mid-1999, in order to consider the rate impacts of the proposed sale of the Kewaunee Nuclear Power Plant and any change in fuel costs estimated to occur in calendar year 2000.

10. That it is reasonable and appropriate to eliminate the natural gas sales promotion budget for the 1999 and 2000 biennial period.

11. That it is reasonable to allow MGE to defer the costs of utilizing its Power Control Program for the summers of 1999 and 2000. It is also reasonable that MGE should defer any revenues it receives from selling the additional energy or capacity available on its system resulting from the use of the program.

12. The Commission finds that the resulting test year fuel costs of \$42,509,681 is reasonable for the purpose of setting just and reasonable rates and reflects the cost of generation, purchased energy, wheeling, and capacity less the revenue from opportunity sales of energy and capacity. The test year fuel cost divided by the test year estimate of net native energy requirements of 2,976,043 MWh results in an average net fuel cost per kWh of \$0.01428.

13. That MGE shall report monthly to the Commission its actual total system cost of generation, purchased energy, capacity and wheeling costs less the revenues from opportunity sales of energy and capacity. MGE shall otherwise comply with the fuel cost determination and monitoring system as set forth in the Findings of Fact.

14. That a reasonable utility capital structure for the test year for ratemaking purposes consists of 53.35 percent common equity, 40.68 percent long-term debt, and 5.97 percent short-term debt.

15. That MGE's ten-year financial forecast is useful in assessing the reasonableness of its capital structure and should be filed in the Company's next rate case proceeding.

16. That a reasonable short-term debt rate is 6.29 percent for the first \$16,000,000 and 4.58 percent for the amount of short-term debt in excess of \$16,000,000.

17. That a reasonable composite long-term debt rate is 7.42 percent.

18. That a reasonable return on utility common equity is 12.20 percent.

19. That a weighted average composite cost of capital rate of 9.88 percent is reasonable for MGE in this proceeding.

20. That it is reasonable for MGE to earn a current return on 50 percent of test year CWIP and that the remaining CWIP accrue an AFUDC return of 10.52 percent.

21. That it is reasonable to include a 0.42 percent adder to the rate of return on electric rate base for the combustion turbine project.

22. That reasonable test year rates of return on net investment rate base are 11.24 percent for electric utility operations and 11.01 percent for gas utility operations.

23. That on the basis of the Findings of Fact, MGE's operating revenue requirement for the test year ending December 31, 1999 to produce a return of 11.24 percent on average net investment rate base for electric utility operations, is \$174,448,000.

24. That on the basis of the Findings of Fact, MGE's operating revenue requirement for gas utility operations for the test year ending December 31, 1999, to produce a return of 11.01 percent on average net investment rate base, is \$102,771,000.

25. That presently authorized rates for electric utility operations will produce operating revenues of \$166,046,000, which results in an annual revenue deficiency of \$8,402,000. Present electric rates of MGE are unreasonable because the revenues produced therefrom are inadequate.

26. That presently authorized rates for gas utility operations will produce operating revenues of \$102,043,000, which results in an annual revenue deficiency of \$728,000. Present gas rates of MGE are unreasonable because the revenues produced therefrom are inadequate.

27. That to provide operating revenues to cover total cost of service for the test year ending December 31, 1999, an increase in revenues applicable to electric utility service in the amount of \$8,402,000 is required and an increase in revenues applicable to gas utility service in the amount of \$728,000 is required. These increases in electric and gas revenues are reasonable and just.

28. That it is reasonable to establish 1999 and 2000 electric DSM goals for MGE as described in the Findings of Fact.

29. That it is reasonable and appropriate for MGE to establish gas energy savings goals for the 1999 and 2000 biennial period as described in the Findings of Fact.

30. That it is reasonable and appropriate for MGE to establish market preparation goals for the 1999 and 2000 biennial period as described in the Findings of Fact.

31. That it is reasonable and appropriate for MGE to adopt the transitional funding and delivery guidelines for low-income energy efficiency services as described in the Findings of Fact.

32. That the rate changes set forth in Appendix B, for retail electric service, will permit MGE to earn the necessary operating revenue requirement, are consistent with the Findings of Fact relating to rate design and cost-of-service, and are just and reasonable.

33. That it is reasonable for MGE to unbundle charges in the streetlighting classes SL-1, SL-2 and SL-3 into three parts: facilities/maintenance charges; distribution charges; and energy charges.

34. That it is reasonable to eliminate the energy cost limiter mechanism for the Cg-1 class, effective January 1, 2000.

35. That it is reasonable and appropriate for MGE to make its Summer Curtailable Service (SCS) a permanent service offering.

36. That it is reasonable to change the dates of the electric winter construction charge period from December 10 through March 16, to the same period as for natural gas charges, December 1 through March 31.

37. That it is reasonable for MGE to begin providing, on an experimental basis, on January 1, 2000, the enhanced services described in the Findings of Fact and detailed in Appendix B.

38. That the standard parallel generation buy-back rates, Pg-2, set forth in Appendix B are reasonable.

39. That Commission staff's gas cost-of-service studies provide a reasonable base for the purpose of designing natural gas rates in this proceeding.

40. That Commission staff's estimated allocation of costs for providing CBS is reasonable.

41. That authorized rates as set forth in Appendix C are based on the cost of supplying gas service to the various classes or types of service. They will permit MGE to earn the necessary operating revenue requirement, are consistent with the Findings of Fact relating to rate design and cost-of-service studies, and are reasonable and just.

42. That it is reasonable to promote CBS in order to open competitive markets to the Company's GSD-2 system sales customers while MGE seeks to increase the number of customer subscriptions and improve process efficiencies.

43. That a promotional CBS price equal to the rates associated with firm sales service is reasonable.

44. That a CBS administrative charge computed on a volumetric basis is reasonable.

45. That performing a comprehensive review of the CBS program is reasonable and that Commission staff should participate in the review.

46. That is reasonable to delay monthly bill reporting or electronic reporting of the GCA balance until after the program review as long as MGE provides this information upon customer request.

47. That it is not reasonable to order the Company to allow GCA swapping between accounts.

48. That applying GCA account balances to future deliveries is a reasonable disposition of monthly GCA balances and that cash outs determined by WACOG for service termination is reasonable.

49. That it is not reasonable to require CBS expansion to smaller customer classes until MGE has improved its marketability and its processes.

50. That it is reasonable that large-volume transportation customers be telemetered. Consequently, it is not reasonable for MGE to offer CBS to large-volume customer classes.

51. That MGE's notification period is within the ranges considered reasonable in the order issued in docket 05-GI-103, dated December 19, 1991. Therefore, it is not reasonable to require MGE to change its notification period.

52. That given a recent FERC ruling which allows shippers to make intraday nominations, it is reasonable for MGE to call intraday constraint days or selective constraints.

53. That MGE's proposed revisions to its gas rules are reasonable and just and in accordance with Commission policy and the Wisconsin Administrative Code. The revisions are set forth in Appendix C.

54. That it is reasonable for MGE to continue direct pass-through of approved pipeline capacity costs, FERC approved/mandated rates and charges, and gas supply demand charges, as discussed in the Findings of Fact.

55. That the target level for capacity release/opportunity sales revenues must be based on normal weather.

56. That a 50 percent shareholder/50 percent ratepayer sharing mechanism for revenues above the capacity release/opportunity sales revenue target, as well as revenue shortfalls, is reasonable.

57. That the indices proposed for the commodity benchmark, as described in the Findings of Fact, are reasonable.

58. That a 3.62 percent single adder to the commodity benchmark to account for reliability of supply, midmonth volume and pricing volatility, variable no notice service and the additional risk to MGE involved in the incentive mechanism is reasonable.

59. That an adder for weather risk of 1.15 percent is unnecessary and inappropriate for the incentive GCRM.

60. That an adder of .5 percent for the additional risk of the incentive mechanism is appropriate. This .5 percent is already included in the 3.62 percent single adder.

61. That a sharing level capped at \$1,500,000 above or below the benchmark is reasonable. Any annual savings or excess costs within this band will be shared between ratepayers and shareholders on a 50/50 basis. Any annual savings or excess costs outside the band will flow entirely to ratepayers.

62. That Commission staff review of the incentive GCRM will be on an annual basis.

63. That the implementation date of the incentive GCRM will be November 1, 1999. The current modified one-for-one GCRM will continue until that time.

64. That net penalty revenues from transportation and interruptible customers will flow back through the Purchased Gas Adjustment Clause (PGA) to system firm customers, as discussed in the Findings of Fact. Penalties incurred on behalf of system customers must be identified separately in the monthly standard reporting filing of the GCRM with the Commission.

CONCLUSION OF LAW

THE COMMISSION CONCLUDES:

It has jurisdiction under Wis. Stat. § § 1.11, 1.12, 196.02, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40, and Wis. Admin. Code ch. PSC 103 and 116, to enter an order authorizing Madison Gas and Electric Company 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 treatment set forth in Appendix D, subject to the conditions specified in this order.

ORDER

THE COMMISSION ORDERS:

1. Madison Gas and Electric Company (MGE) is authorized to substitute, for its existing rates and rules for electric and natural gas utility service, the rate and rule changes contained in Appendices B and C.

2. MGE shall prepare bill inserts that properly identify the rates authorized in this order. Copies of such inserts shall be sent to the Commission. MGE shall distribute these inserts to customers with the first billing containing the rates authorized in this order.

3. This order shall be effective on the date of mailing. MGE shall file the new schedules, as required in Wis. Stat. §§ 196.19 and 196.21, no later than seven days after the

effective date of this order. These rate schedules shall take effect on the effective date of this order.

4. MGE Company shall continue to use escrow accounting procedures for conservation expenditures.

5. That MGE shall file estimated changes in costs associated with the proposed sale of the Kewaunee Nuclear Power Plant and changes in calendar year 2000 fuel costs. MGE shall file this information so that a hearing can be held on the matter in the fall of 1999, and the Commission can consider the ratemaking impacts of the changes. MGE and Commission staff shall work together to determine an appropriate filing date for this information.

6. A reasonable estimate of fuel costs for each month of the test year is attached as Appendix D. Test year rates reflect the monthly fuel cost estimates in the appendix. The fuel costs in the appendix will be used by MGE for required monthly monitoring of the fuel costs pursuant to Wis. Admin. Code ch. PSC 116.

7. MGE shall report monthly to the Commission its actual total system cost of generation, purchased energy, capacity, and wheeling costs less the revenues from opportunity sales of energy and capacity. MGE shall otherwise comply with the fuel cost determination and monitoring system as set forth in the Findings of Fact.

8. MGE shall submit a ten-year financial forecast in its next rate case filing before this Commission. The forecast shall incorporate a long-term range for the utility's common equity ratio of 55 to 60 percent common equity.

9. MGE shall adopt DSM savings goals of 27 GWh with at least 10 GWh in the residential sector in both 1999 and 2000. Goal achievement through market preparation activities will continue to be approved using the informal process described in the Findings of Fact.

10. MGE establish gas energy savings goals for the 1999 and 2000 biennial period as described in the Findings of Fact.

11. MGE shall establish market preparation goals for the 1999 and 2000 biennial period as described in the Findings of Fact.

12. MGE shall adopt the transitional funding and delivery guidelines for low-income energy efficiency services as described in the Findings of Fact.

13. MGE shall perform a thorough review of its Comprehensive Balancing Service and Commission staff should participate in this review. MGE shall submit, in writing, the results of the review on or before May 28, 1999.

14. MGE shall continue to inform customers of their CGA balance upon request until this information is included with the regular monthly billing statement or provided electronically.

15. MGE shall continue direct pass-through in the GCRM of approved pipeline capacity costs, FERC approved/mandated rates and charges, and gas supply demand charges, as discussed in the Findings of Fact.

16. That the GCRM target level for capacity release/opportunity sales revenues shall be based on normal weather.

17. That the sharing mechanism for revenues above the capacity release/opportunity sales revenue target, as well as revenue shortfalls, shall be 50 percent shareholder/50 percent ratepayer.

18. That the total, single adder to the commodity benchmark to account for reliability of supply, midmonth volume and pricing volatility, variable no notice service and the additional risk to MGE involved in the incentive mechanism shall be 3.62 percent.

19. That the sharing level shall be capped at \$1,500,000 above or below the benchmark. Any annual savings or excess costs within this band will be shared between ratepayers and shareholders on a 50/50 basis. Any annual savings or excess costs outside the band will flow entirely to ratepayers.

20. That the implementation date of the incentive GCRM will be November 1, 1999. The current modified one-for-one GCRM will continue until that time.

21. That net penalty revenues from transportation and interruptible customers will flow back through the Purchased Gas Adjustment Clause (PGA) to system firm customers, as discussed in the Findings of Fact. Penalties incurred on behalf of system customers must be identified separately in the monthly standard reporting filing of the GCRM with the Commission.

Docket 3270-UR-109

22. That jurisdiction is retained.

Dated at Madison, Wisconsin, _____

By the Commission:

Lynda L. Dorr
Secretary to the Commission

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See attached Notice of Appeal Rights

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in Wis. Stat. § 227.53. The petition must be filed within 30 days after the date of mailing of this decision. That 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 Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in Wis. Stat. § 227.01(3), a person aggrieved by the order has the further right to file one petition for rehearing as provided in Wis. Stat. § 227.49. The petition must be filed within 20 days of the date of mailing of this decision.

If this decision is an order after rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not an option.

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.

Revised 9/28/98