MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
(701) 222-7900

August 2, 2004

Executive Secretary
North Dakota Public Service Commission
State Capitol Building
Bismarck, ND 58505

Re: General Natural Gas Rate Application
Case No. PU-04-97

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and seven (7) copies of the rebuttal testimony of Dr. J. Stephen Gaske, Mr. Craig A. Keller, Mr. Paul W. Conley, Ms. Rita A. Mulkern and Ms. Tamie A. Aberle. Due to the availability of rebuttal witness Mr. Richard D. Spratt, his testimony will be filed on Wednesday, August 4, 2004.

One (1) copy of the rebuttal testimony has been mailed to Snavely King Majoros O'Conner & Lee, Inc., 1220 L St NW, Suite 410, Washington, DC 20005.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

Attachment
cc: B.T. Imsdahl
D.W. Schulz
D.S. Kuntz

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Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and seven (7) copies of the rebuttal testimony of Mr. Richard D. Spratt.

One (1) copy of the rebuttal testimony has been mailed to Snavely King Majoros O'Conner & Lee, Inc., 1220 L St NW, Suite 410, Washington, DC 20005.

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MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

CASE NO. PU-04-97

PREPARED REBUTTAL TESTIMONY OF

J. STEPHEN GASKE

Q1. Please state your name, position and business address.

A. My name is J. Stephen Gaske and I am President of Zinder Companies, Inc., 7508 Wisconsin Avenue, Suite 300 Bethesda, MD 20814.

Q2. Are you the same J. Stephen Gaske who filed Prepared Direct Testimony earlier in this proceeding?

A. Yes.

Q3. What is the purpose of this rebuttal testimony?

A. Montana-Dakota Utilities Co. ("Montana-Dakota") has asked me to analyze and respond to the testimony submitted by Charles W. King on behalf of the Commission Adversary Staff concerning the rate of return on common equity that is required for Montana-Dakota's North Dakota natural gas distribution operations.

Q4. Please describe Mr. King's testimony concerning the cost of common equity capital.

A. Mr. King's testimony is quite short and is limited only to replicating the Discounted Cash Flow ("DCF") analyses of a group of 10 proxy companies contained in my testimony. For example, his Exhibit CWK-3 is identical to pages 6 and 7 of Schedule 2 of Exhibit No. ___(JSG-2) in my testimony. However, Mr. King has omitted the last two columns of my schedules. Those columns apply a flotation cost adjustment that is required to convert the rate of return required by investors for secondary market investments into the cost of capital for the proxy companies in primary financial markets for investment funds. In his Exhibit CWK-4, Mr. King simply updates the numbers that appear on his Exhibit CWK-3 and pages 6 and 7 of Schedule 2 of Exhibit No. ___(JSG-2) in my testimony. Based on his updated calculations for the proxy companies, Mr. King recommends an allowed rate of return on common equity of 9.0 percent.

Q5. Do you agree with Mr. King's calculations and recommendation?

A. No. There are two main flaws in his testimony and recommendations. First, he excludes the flotation cost adjustment that is required to convert the results of a study of secondary financial markets into the rate of return required to raise capital in primary financial markets. Second, it is obvious that he has made no attempt to analyze the risks of Montana-Dakota's North Dakota gas distribution operations and compare these risks to those of the proxy group. These flaws contribute to his recommendation of an inadequate rate of return on common equity for Montana-Dakota.

Q6. Would you elaborate on the reasons that a flotation cost adjustment to the DCF results is necessary in order to estimate the rate of return required to allow a regulated company to attract common equity capital on reasonable terms?

A. There are significant costs associated with issuing new common equity capital and these costs must be considered in determining the cost of capital. Anyone who has ever taken out a mortgage to buy a house is aware that the "effective" interest rate is higher than the "stated" interest rate because the homebuyer pays loan origination fees, points and closing costs in connection with raising the capital to buy a house. This same concept applies to public utility companies: the "effective" cost of capital is higher than the "stated" cost of capital because there are flotation costs associated with raising new common equity capital.

The need for a flotation cost adjustment is especially acute when the cost of common equity is estimated by conducting a DCF analysis that is based on the prices of common stocks traded in the "secondary" markets on stock exchanges. Because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital that the regulated company would incur to raise money in the "primary" markets, a DCF estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost-of-capital that the regulated company requires in order to raise capital on reasonable terms in the "primary" markets.

Q7. Please describe the difference between "primary" and "secondary" markets for common equity.

A. When a company issues new common equity in order to raise cash for investment in plant, or to otherwise run its operations, it does so in the "primary" market. The "primary" market is defined very simply as the market in which the stock is first sold in order to raise cash funds to be used by the issuer. In this "primary" market, the company generally hires an investment banker, or a syndicate of bankers and brokers, to float its stock issue to the public. Associated with a company raising cash funds through a "primary" market sale of common stock there are significant costs of preparing and filing documents with the Securities and Exchange Commission ("SEC"), as well as other regulatory agencies, and issuing prospectuses. In addition, in the "primary" market the issuing company generally must pay a significant percentage of the proceeds from the stock issuance to the investment banker, or the syndicate of bankers and brokers, who undertakes to find investors that will provide cash to the issuing company.

Once stock has been issued to investors in the "primary market," those investors who initially provided cash to the issuing company may re-sell or "trade" the stock with other investors in the "secondary" market. Much of the trading in the "secondary" market occurs on stock exchanges and buyers and sellers are not required to file prospectuses with the SEC. The crucial difference between stock issued in the "primary" market and stock traded in the "secondary" market is that the issuing company does not receive any additional funds when its stock trades in the "secondary" market. Instead, the ownership of the stock merely changes hands between various investors. In addition, the brokerage fees associated with buying and selling stock in the "secondary" market generally are incurred by both the buyer and the seller, and are a small fraction of the level of the flotation costs incurred by a company that attempts to raise cash by issuing stock in the "primary" market.

Q8. Is the need for a flotation cost adjustment to the rate of return widely recognized among economists as a required part of an allowed rate of return that will attract capital without diluting the value of existing investors' equity?

A. Yes. In commenting on the fair rate of return in his classic treatise on public utility ratemaking, Bonbright stated that:

> *"...book values (with allowances for the probable need to underprice new common-stock offering) should set a floor to the market values..."*

James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with having developed the DCF model for estimating rate of return, has stated that a regulatory agency should set the allowed rate of return greater than the investor return requirement so as to allow the firm to issue stock at a price that will yield net proceeds equal to book value. Professor Gordon advocates the following adjustment:

> *"The agency need only estimate the proportion that the proceeds per share on an issue bear to the price of the stock and adjust the allowed rate of return so that the price per share is the indicated ratio of the book value per share. If the proceeds on an issue are 91 percent of market price, the agency should maintain market price at about 110 percent of book value."*

Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State University, 1974, pages 165-166. In order to meet this requirement, the flotation cost adjustment must be applied to the entire rate of return. The flotation cost adjustment that I have proposed attempts to meet the same standards advocated by these other economists.

Q9. How is a flotation cost adjustment relevant in meeting legal standards for a reasonable rate of return?

A. The Supreme Court established the "Capital Attraction" standard as one test of a reasonable allowed rate of return. For example, in *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> *"The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and*

> *support its credit and* ***enable*** *it to raise the money necessary for the proper discharge of its public duties.*"[1]

Similarly, in *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 603 (1944))* the Court described the relevant criteria as follows:

> "*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... That return,* ***moreover****, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*"[2]

The Court's requirement that the allowed return must "enable" a company to raise capital does not mean that the company must raise capital within some specified time period. Instead, it means that the company must have in place the ability to attract capital so that it can exercise that ability if and when required. By its use of the word "moreover" the Court made it clear that an allowed return is not sufficient if it merely allows the company to meet its current financial obligations. Instead, an additional and overriding requirement is that the return also must be sufficient to assure that the company can attract, or raise, new investment capital in the primary capital markets, and maintain its financial integrity.

Because flotation costs are the additional component of capital costs that apply above and beyond the return required to service current capital needs, an allowance for flotation costs is required in order to meet the "Capital Attraction" standard. This standard applies to companies that are not planning to issue new common stock, as well as to those that are planning to issue such stock. In other words, the capital attraction standard is a "yardstick" established by the Court that

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[1] Emphasis added.
[2] Emphasis added.

poses a hypothetical stock issue as a means for measuring the reasonableness of the allowed rate of return: *if* the allowed rate of return is sufficient to allow the company to raise new capital on reasonable terms, *then* the rate of return is legally adequate.

As discussed earlier in this testimony, when a DCF analysis based on stock prices and dividend yields in the "secondary" market is used to estimate the required rate of return, a flotation cost adjustment is essential in order to account for the difference between (i) stocks traded between investors in the secondary markets and (ii) stock issued in the primary market to raise capital for plant construction and utility operations. Thus, a flotation cost adjustment is necessary in order to correctly estimate the return that is required to attract, or raise, new common equity capital.

Q10. In his testimony, did Mr. King address your analysis and conclusion that the overall risks of Montana-Dakota's North Dakota natural gas distribution operations are well above average relative to the risks of the proxy companies?

A. No. He makes no mention of the risks of Montana-Dakota's North Dakota natural gas distribution operations relative to those of the proxy companies. His failure to present any analysis of relative risks whatsoever, and his failure to address or recognize my analysis and conclusion concerning relative risks, are important reasons that his recommended rate of return is inadequate.

Q11. Does this conclude your Prepared Rebuttal Testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-04-97

Rebuttal Testimony
of
Craig A. Keller

Q. Would you please state your name and business address?

A. Yes. My name is Craig A. Keller and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Vice President, Controller and Chief Accounting Officer (CAO) for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Craig A. Keller who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain adjustments proposed by Mr. Charles W. King in his calculation of the capital structure, specifically the short term debt levels and rates. I am also sponsoring Exhibit No.___(CAK-1).

Q. Do you agree with the capital structure components proposed by Mr. King on Exhibit CWK-2 of his testimony?

A. I do not agree with the short term debt amounts and rates used by Mr. King in his testimony when calculating the capital structure and cost.

Q. What short term debt and rates did Mr. King use in his testimony?

A. Mr. King used the 2003 average of short term debt and rates in his testimony on Exhibit CWK-2 of his rate of return calculation.

Q. What balances and short-term rates should be reflected in the calculation?

A. The average debt levels and rates for projected 2005 should be included in the calculation as that matches the time period of the other components included in the capital structure and the test period for this filing.

Q. What are the projected 2005 average debt levels and rates?

A. As shown on Exhibit No.___(CAK-1), the projected average short term debt for 2005 is $26.8 million and the projected average rate is 2.90%.

Q. What is the required return as a result of using the 2005 projected data?

A. The revised rate of return reflecting the addition of projected 2005 short-term debt and Montana-Dakota's requested return on equity of 11.50 percent is 9.934 percent, as calculated on Exhibit No.___(CAK-1).

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

MONTANA-DAKOTA UTILITIES CO.
AVERAGE UTILITY CAPITAL STRUCTURE
PROJECTED 2005

	Balance	Capital Ratio	Cost	Required Return
Long Term Debt	$153,350,000	40.460%	8.518%	3.446%
Short-Term Debt 1/	$26,775,000	7.064%	2.900%	0.205%
Preferred Stock	16,050,000	4.235%	4.614%	0.195%
Common Equity	182,843,012	48.241%	11.500%	5.548%
Total	$379,018,012	100.000%		9.394%

1/ 2005 projected average short term debt balances and short term rates.

Q. Please state your name and business address.

A. My name is Paul W. Conley. I am employed by Towers Perrin at 8000 Norman Center Drive, Suite 1200, Minneapolis, Minnesota 55437-1097.

Q. Are you the same Paul W. Conley who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Mr. King's adjustments to the Supplemental Income Security Plan (SISP), pension expense and postretirement expense.

Q. Have you reviewed the direct testimony of Charles W. King submitted in this proceeding on behalf of the North Dakota Public Service Commission Advocacy Staff?

A. Yes, I have.

Q. Do you agree with the analysis and recommendations of Mr. King regarding the treatment of SISP expense for ratemaking purposes?

A. No, I do not.

Q. Explain why you disagree with Mr. King's analysis of whether SISP expenses should be included in the determination of retail natural gas rates.

A. Mr. King recommends that SISP expenses be disallowed in determining the reasonableness of Montana-Dakota's proposed natural gas rates for North Dakota, beginning on page 11 of his testimony. Mr. King supports his recommendation based on three considerations. First, he recommends SISP expenses be disallowed because Montana-Dakota did not seek recovery of SISP expenses until the company filed an application to increase its electric rates in 2001 even though the SISP had been in effect since 1982. Mr. King notes that the Commission agreed with a staff recommendation in the 2001 case and a subsequent 2002 gas rate case to deny recovery of SISP expenses. Whether or not SISP expense was included in a prior rate filing does not establish either the appropriateness or the reasonableness of that expense as a part of Montana-Dakota's executive compensation package for ratemaking purposes.

Q. Mr. King discusses the treatment of retirement plans, such as the SISP, by the Internal Revenue Service (IRS). Is his conclusion correct?

A. No. Mr. King also recommends SISP costs should not be recovered in retail rates because he asserts the IRS treats such payments as taxable income and if the costs were allowed as deductible expenses for tax purposes managers and directors would have an incentive to hide corporate income by paying themselves benefits through these plans. The premise of Mr. King's argument is incorrect. Mr. King acknowledges in a footnote to his testimony that the IRS allows deduction of pension payments to retired employees. Similarly, the IRS allows the company to deduct supplemental pension payments such as payments from the SISP as these benefits are paid to retired employees. The IRS recognizes that these types of supplemental pension payments are a legitimate and reasonable business expense for income tax purposes. The IRS treats these payments in the same manner as it treats other pension expenses, which are accrued for book purposes but may not be deductible in the current year for income tax purposes. Accounting standards require that public companies recognize and disclose the cost of supplemental pension benefits within the pension footnote of the annual report and incorporate this cost within the Company's income statement each year. There is neither an ability nor an incentive to hide corporate income through supplemental pension programs. Mr. King's contention that an incentive would exist to make supplemental pension benefits more generous if they were included in the cost of service is also flawed. The argument is contrary to Mr. King's earlier observation that Montana-Dakota implemented its present SISP program before it sought recovery of the program expense in retail rates. I understand that the major portion of the costs of MDU Resources Group's SISP program is allocated to its nonregulated business units and that SISP benefits are largely formulaic such that ratemaking treatment for the regulated business units would not provide an incentive to make the program benefits more generous.

Q. **Mr. King states that the personnel that make the recommendation regarding benefits such as SISP are the same people that receive the benefit. Do you agree?**

A. No. As stated above, SISP program benefits are largely formulaic under the existing plan. In addition, as explained in our direct testimony and acknowledged in the footnote to Mr. King's testimony, executive compensation is reviewed by an independent Compensation Committee consisting of four outside directors of MDU Resources who are not participants in SISP. The Compensation Committee relies upon information received from consultants such as Towers Perrin. Towers Perrin was specifically hired as an independent outside third party to gather and report information on compensation and benefit packages at companies that compete for MDU Resources' and Montana-Dakota's managerial and executive talent. Towers Perrin adheres to the highest quality and ethical standards and does not manipulate its findings to suit any stakeholder.

Q. Has Mr. King offered any other argument for excluding SISP expense from the test year?

Mr. King argues that executive employees are the direct representatives of the company's stockholders and are the employees most responsible for providing profits to those stockholders. Mr. King therefore concludes that stockholders, not customers, should bear the relatively minor cost of supplemental pension expenses. MDU Resources/Montana-Dakota intend to provide reasonable and appropriate compensation and benefits in order to recruit, motivate and retain all employees, including managerial and executive staff. The maintenance of a qualified managerial and executive staff is critical to all aspects of the Company's business including supplying dependable and efficient services to its customers at a reasonable cost. This motivation is to the mutual benefit of shareholders and customers. Mr. King's testimony includes no challenge to the reasonableness and appropriateness of

Montana-Dakota's SISP benefits but simply recommends against recovery of such costs. Supplemental pension expenses are just one part of a total compensation program for these executives. Mr. King does not provide any support for his recommendation that it is appropriate to exclude from rate recovery one portion (SISP) of an overall reasonable and appropriate rewards program for executives whereas he obviously recognizes the necessity of other pieces of such a compensation program as a legitimate business expense for rate recovery.

In summary, the Internal Revenue Service and accounting standards recognize supplemental pension benefits as a legitimate business expense and a cost of doing business. Competitors recover these costs through the prices for their services and accordingly, the costs are appropriately recovered in the prices for utility services. The recommendation of Mr. King would deny recovery of a reasonable and legitimate business expense.by Montana-Dakota .

Q. Have you reviewed Mr. King's testimony and recommendations regarding pension and postretirement costs?

A. Yes, I have.

Q. What are Mr. King's recommendations regarding these costs?

A. Mr. King recommends that the latest "known and measurable" cost of pensions, which he asserts is the 2004 cost calculated at the beginning of that year, be used as the amount of such expense for the 2005 test year. Mr. King supports that recommendation because the Company's forecast of the pension fund value, the earnings of the pension fund, and interest rates are not "known and measurable" factors for determining 2005 test year expenses. He makes the same adjustment to postretirement expense.

Q. Do you agree with Mr. King's analysis?

A. No, I do not.

Q. Why is Mr. King's analysis not correct?

A.

The costs of a pension or postretirement plan can never be known in actuality until the plan is terminated or the last participant dies. However, in order to sufficiently fund these plans in advance and to account for the benefits during the working life of the participants, the company is required to employ actuaries to produce a reasonable and reliable annual cost for the plan. The need for annual valuations and accounting accruals during the working life of participants is set forth by the SEC's GAAP requirements, and these standards are promulgated by the Financial Accounting Standards Board (FASB). MDU Resources retains Towers Perrin to perform these valuations and cost measurements, as well as to forecast future costs. The 2004 costs recommended by Mr. King, and the 2005 costs included in the Montana Dakota projected test year, are both based on such forecasts. When performing these forecasts, Towers Perrin's actuaries are subject to the rigorous Actuarial Standards of Practice (ASOP) promulgated by the American Academy of Actuaries (AAA) as applicable to future cost projections. These forecasts use reasonable assumptions and take into account known events. In providing Montana-Dakota with forecasted pension expense, Towers Perrin uses the most recent information available to ensure that the assumptions used in the forecast are reasonable and appropriate. This includes:

- Reflecting the current interest rate environment for high-quality corporate bonds used in setting the discount rate.
- The latest estimate of the expected fair market value for the plan's assets at year-end, taking into account the actuarial estimate of remaining benefits to be paid by year end, the year-to-date actual earnings of the trust's assets, and the expected asset performance for the remainder of the year based on recent economic reports and market expectations. Because the variances between the actual and the expected performance of the plan's assets are spread over the remaining service life of the participants, differences between the actual and expected fair market value of the trust's assets at the end of the year are typically not a significant source of differences between forecasted and actual pension expense.
- Significant known benefit design changes that have been implemented since the beginning of the year (no additional changes in the MDU Resources plan were assumed to occur).
- Removal of amortization bases known to disappear before the forecasted year (primarily liabilities for previous plan design changes which were amortized at implementation and will be fully amortized before the forecasted year).

- Losses that have already occurred but have not yet been fully amortized. The most significant sources of these known losses are liability losses due to the historically low level of discount rates (discount rates are dictated by the state of the corporate bond market) and asset losses that occurred during the last five years.

Because the most recent information is taken into account and a significant portion of cost is based on recognition of past events that have occurred, Towers Perrin's estimates of future cost are reasonable and reliable. Indeed, the 2005 forecasts take into consideration several past events and current market conditions that are known and measurable. In comparison, use of 2004 costs as a proxy for 2005 cost is unreasonable and would not be suitable as a reliable basis for any projection of actuarial cost. The entire increase in projected costs from 2004 to 2005 is attributable to the recognition of a portion of the liability and asset losses from prior years. That is to say, even if we were to ignore changing discount rate assumptions and asset levels, we would still experience the significant increase in 2005 cost due to known past losses that have yet to be amortized. These amortizations are a direct application of the FASB's guidance on accounting for benefit costs, and take into account the application of GAAP standards. These standards balance the need to recognize costs during the working lives of the employees (that is, applying the principles of accrual accounting and intergeneration equity) with the need for companies and their constituents to understand the direction and magnitude of future costs.

Q. Does that complete your rebuttal testimony?

A. Yes.

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-04-97

Rebuttal Testimony
of
Richard D. Spratt

Q. Would you please state your name and business address?

A. Yes, my name is Richard D. Spratt. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Vice President – Human Resources of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your duties and responsibilities with Montana-Dakota?

A. I am responsible for all the disciplines in the Human Resources (HR) arena including staffing, compensation and benefits, organization development and training, organizational structure, labor and employee relations and governmental compliance with employment and employee relation's laws and practices.

Q. Would you please outline your educational and professional background?

A. Yes. I have a Bachelor of Science and Master's degree in Labor and Industrial Relations from Michigan State University. I began my HR career 26 years ago with Eaton Corporation (a $9 billion fortune 100 corporation) where I was promoted through a series of HR generalist jobs, including HR Professional, Asst. HR Manager, HR Manager, Division HR

Manager and Group HR Manager. The last position I held with Eaton was HR Group Director for Cutler Hammer's Power Distribution Production and International Group. I was with Eaton for approximately 21 years. I then accepted the position of VP Human Resources Controls Group with Invensys, a $20 billion company based in London, UK. I was in that job approximately two years and joined Montana-Dakota in 2001 as Vice President - Human Resources, which is my current position.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the recommendation by Mr. Charles King to disallow a portion of the employee bonuses and a portion of the officers' salary expense from the Company's test year.

Q. On page 14 of his testimony, Mr. King recommends adjusting a portion of test year employee bonuses that he attributes to profitability. Do you agree with his adjustment?

A. No. Mr. King eliminates a portion of the increase in bonuses above the 2002 bonus level which he surmises is due to profitability. His adjustment is not appropriate.

Q. Would you please explain why the Commission should allow the full amount of the employee bonuses included in the test year?

A. Yes. Employee bonuses represent a critical competitive component of the cost of the total compensation package provided to employees. Montana-Dakota's employee bonus programs are used by the Company to execute its business strategy; they are consistent with industry norms, and they are consistent with the Company's compensation philosophy. Employee bonuses have been consistently included in the Company's test years and allowed as legitimate business expenses. Employee bonuses were most recently recognized as appropriate in the Commission's Order in Case No. PU-399-02-183.

The Commission, in Findings of Fact 87 in Case No. PU-399-02-183, determined that: "*the overall wage increases projected by MDU are fair and reasonable. The Commission believes that how raises were distributed remains the responsibility of MDU's management and therefore will not delineate between the portion attributable to a general wage increase or bonuses.*" The Commission also found that "*we do not find the practice of paying bonuses based on profitability objectionable. In fact, the payment or lack of payment of bonuses depending on profitability smoothes out earnings and at the same time puts pressure on employees to perform.*" Clearly the payment of compensation bonuses and the inclusion of those bonuses as part of the Company's test year labor expenses are in accordance with the Commission's past decisions.

Q. Have the Company's bonus plans changed since the Commission issued its Order in 2002?

A. No, the bonus plan documents have the same provisions as those in effect in 2002, the time of the Commission Order in Case No. PU-399-02-183.

Q. On page 15, Mr. King states that it appears that the rate increase from the North Dakota gas rate case in Case No. PU-399-02-183 was the reason the bonuses increased from 2002 to 2003. He also speculates that the increase requested in this case accounts for the increase in bonuses from 2003 to projected 2004. Is he correct?

A. No. Mr. King states that he has no objection to allowing bonuses to employees when prices are stable but objects to bonuses that are the result of rate increases. His speculation that the Company's 2003 bonus is the result of the rate increase from Case No. PU-399-02-183 and the 2004 bonus increase is the result of the rate increase request from this proceeding is incorrect. Bonuses are paid to employees the year after they are earned. For example, the bonuses paid out in 2003 were the result of 2002 operations. Since the North Dakota gas rate increase became effective with service rendered on and after December 12, 2002, the rate increase from Case No. PU-399-02-183 had virtually no effect on 2002 earnings, the basis of the 2003 bonus. Similarly, the 2004 bonuses were based on 2003 operations and the rate increase requested in this case had absolutely no effect on the increase in the bonuses from 2003 to 2004.

As I stated earlier, the bonuses can fluctuate year to year, which is why the Company used a three year average of bonuses in this case. All other things being equal, bonuses will increase as salaries and wages increase since the bonuses are tied to a percentage of salaries and wages. In addition, Mr. King picked 2002 as his base level for bonuses, which was the lowest bonus level in five years. Indeed, the "increase" in bonuses between 2002 and 2003 was largely attributable to the low level of bonuses in 2002 as the result of earnings levels in 2001 that were adversely affected by weather conditions. When compared to 2001, employee bonuses increased less than 6 percent in the two years between 2001 and 2003. The use of a three year average of bonuses as used in the Company's test year, and which is actually below the level of the 2003 bonuses, certainly reflects a more normal level of bonuses than Mr. King's proposal.

Q. Would you please describe how Montana-Dakota's bonus plans fit into the overall compensation package?

A. Montana-Dakota's bonus plans are an important part of the total compensation package. They are offered to all employees in an effort to remain competitive within the industry and to focus employee efforts on achieving important business objectives. Achievement of these objectives requires controlling or reducing costs, identifying opportunities for greater efficiencies and implementing innovative ideas that ultimately serve to benefit customers. Through the design of bonus plans, part of the employees' total compensation package is "at risk". The higher an individual's position is in the organization, the greater the percentage of overall compensation that is at risk based on the recognition that personnel higher in the organization have a greater opportunity and responsibility to achieve those objectives. Mr. King's proposed adjustment would deny bonuses tied to profitability even though cost controls, efficiencies, and innovations frequently contribute more to profitability than rate relief. In contrast to the real effect of Mr. King's recommendation, incentive bonuses decrease the need for rate increases because they encourage efficiencies.

Q. How are the payouts for the bonus plans determined?

A. All Company bonus plans have financial thresholds such as earnings and return on invested capital targets that must be met prior to generating a payout from the bonus plans. Establishing these financial performance measures insures that incentive rewards reflect the success of the business unit. Only when the minimum business performance threshold is met do employees have the opportunity to share in the profits if the other bonus measures are met.

Q. How do customers benefit through the use of bonus and incentive pay?

A. Customers benefit because placing a portion of the employee's pay at risk for good performance focuses employees on working more efficiently to achieve better results. For example, to achieve payout of the bonus under the BETA plan, which applies to approximately 88 percent of Montana-Dakota employees, certain goals must be met. Those goals include a contribution to earnings, customer service and safety measures. All of these items directly affect the cost of utility service and to the extent the goals are met, the customers, the employees and the stockholders all benefit.

Q. Is Montana-Dakota's compensation philosophy different from other companies in the utility industry?

A. Montana-Dakota's compensation philosophy is similar to most utility organizations. Each year Human Resource professionals gather data to assure company programs are appropriate and competitive. Data from the 2003-2004 Watson Wyatt Data Service Compensation Series indicated a strong trend continues to provide employees in the utility industry the opportunity for bonuses and other incentives. Approximately 70 percent of hourly employees, 86 percent of management employees, and 94 percent of executive employees are eligible for bonuses in our industry. The relevant survey pages are attached as Exhibit No. ___(RDS-1).

I would also note that Montana-Dakota's base pay philosophy is more conservative than many organizations in the Watson Wyatt surveys. Approximately half of the participating organizations in the survey strive to provide a total compensation package that is above the market average. Montana-Dakota strives to pay at market average.

Q. On page 25 of his testimony, Mr. King recommends an adjustment to labor expense to exclude a portion of officers' salaries. Do you agree with his adjustment?

A. No, I do not. Mr. King recommends that the base year 2003 revenue requirement be reduced by the amount of the increases in officer compensation since 1999 to the extent such increase exceeded increases in compensation to all other employees. Not only is this retroactive expense adjustment clearly inappropriate, Mr. King's recommendation on this issue as well as his recommendation on SISP and bonus expenses effectively attempts to indirectly control the discretion of MDU Resources Group's Board of Directors regarding the type and amount of the overall compensation package provided to the Company's officers and employees.

Montana-Dakota strives to compensate all employees competitively for the services they provide to the organization. MDU Resources subscribes to a "Total Compensation" philosophy that reflects competitive forces in the market place and is designed to recruit, motivate, reward and retain high performing employees, including executives.

Q. How does Montana-Dakota establish the pay structure for officers?

A. In establishing the pay structure for officers at Montana-Dakota, the competitive level for each position's market value and targeted incentive compensation are determined through surveys conducted by an external consulting firm that is engaged by and reports to the MDU Resources Board of Directors Compensation Committee. The external consultant compares Montana-Dakota's executive positions within the industry to establish competitive market values and ultimately uses these values to establish a compensation structure.

Market values and incentive compensation targets are reviewed annually and necessary adjustments are made to maintain a fair and competitive compensation program. The base compensation structure and the incentive compensation guidelines are based on target levels that reflect the fiftieth percentile, or market average, of the market data.

As Mr. King points out, these managers and directors are the individuals most responsible for the future health of Montana-Dakota's business. Controlling costs, improving efficiencies, and providing safe and reliable service benefits customers, which in turn helps insure a profitable business, which also benefits customers by assuring the viability of the dependable service they need and expect.

Q. How does Montana-Dakota target salary levels that are at the market average?

A. Historically, officers were targeted at 95 percent of the market average. At this level, executive salaries were not competitive with the market. In 2001 the executive compensation consultant recommended that executive pay be targeted at 100 percent of the market average of the competitive labor market, consistent with other groups of employees. The Board of Directors implemented this recommendation in 2002, bringing salaries in line with the competitive labor market. This resulted in relatively larger increases in officer compensation in 2002 and 2003. Mr.

King's recommendation is particularly inappropriate because he not only makes retroactive adjustments to these compensation levels, but also to the prior years when Montana-Dakota's management was being compensated below market levels.

Q. How does Montana-Dakota determine the percentage wage increases allowed for employees?

A. Montana-Dakota uses a method that is common to most companies in that salaries are surveyed and can vary across four distinct groups of employees. The four groups are bargaining unit employees, hourly employees, exempt employees, and executives. The reason for the variation between groups is based upon how the group as a whole is paid in relation to the market, how much the labor market rates are changing, and MDU Resources' compensation philosophy.

MDU Resources and Montana-Dakota conduct total compensation studies for each of these groups and make individual wage adjustments to reflect a total compensation package, including benefits, that is competitive in the marketplace.

Q. Why is officer compensation important to Montana-Dakota?

A. The utility and MDU Resources Board of Directors are concerned about paying a competitive wage that supports efforts to attract and retain quality people required to run the business. This is especially critical now, when we have many key positions held by individuals nearing retirement and with the ever increasing scope of government mandated regulations, such as in the financial and environmental areas, and increased regulatory requirements primarily related to federal initiatives.

Q. On pages 27-28 of his testimony, Mr. King states that the officers should not receive an increase because the Company has filed for a rate increase. Is this appropriate?

A. No. It is largely because of the actions of the officers and all other employees that Montana-Dakota has only had to file its second rate case in the last ten years. Not increasing distribution prices to the customers of the utility for a period of eight years while other goods and services increased by 21 percent should hardly be characterized as a management failure. Management continues to look for efficiencies that can be feasibly implemented as an alternative to raising prices. For example, through the Company's efforts, technician productivity increased 10 percent in the first six months of 2004 compared to the same period in 2003. The Company also implemented changes to help mitigate rising health care costs. However, as a utility with very low customer growth it is not possible to avoid price increases forever while inflation continues to increase with respect to the utility's cost of providing natural gas service.

The Company has received national recognition for the management practices of its management team over the past several years. MDU Resources was recognized as the Best Managed Company in the utilities industry by Forbes magazine in 2004. Martin A. White, Chairman, President and Chief Executive Officer of MDU Resources won a Stevie Award for Best Executive, the business world's "Oscars", in the 2004 American Business Awards. MDU Resources has also been able to maintain its "A" credit rating during a period of time when many utilities lost their investment grade credit ratings and in some cases went bankrupt.

Q. Mr. King noted in his testimony that there have been changes in the number of officers within the Company with a net increase from seven officers in 1999 to ten in 2003. Can you explain?

A. Montana-Dakota has expanded officer roles to include the CEO of Montana-Dakota and the President and Chief Operating Officer (COO) of Utility Services, Inc. (USI), a non-regulated business unit. The USI President and COO's compensation is assigned to the non-regulated business. In addition, the Director of Human Resources position was upgraded from a non-officer director position to the level of Vice President – Human Resources, an officer position, in 2001 to reflect the expanding role of its responsibilities. While there has been an increase in the total number of Montana-Dakota officers, the increase is largely due to the expanded business activities of the non-regulated segment. The net number of officers allocated to the utility has increased by less than one person, which reflects the reclassification of a position from a director to an officer level.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

EXHIBIT NO. ___(RDS-1)

2003 / 2004

Industry Report on Middle Management Compensation

Volume 2

Watson Wyatt
Data Services

Watson Wyatt
Worldwide

Bonus, Variable Pay and Long-Term Incentive Programs

SHORT-TERM PLAN PREVALENCE

BONUS AND/OR OTHER VARIABLE PAY PROGRAM(S) IN WHICH OFFICE PERSONNEL ARE ELIGIBLE

	% of Organizations with at Least One Plan	# of Responses	Prevalence of Various Plan Types (as a % of Organizations with Plans)							
			Bonus	Current Cash Profit Sharing	Team/ Small Group Incentives	Individual Incentives	Spot or Technical Achievement Awards	Gainsharing	Lump Sum Merit Pay (Not Added to Base)	Lump Sum Merit Pay (Added to Base)
Entire Sample Combined	**65.1%**	**1,126**	**66.7%**	**14.7%**	**13.8%**	**20.6%**	**31.5%**	**6.3%**	**25.1%**	**16.4%**
Profit Status										
For-Profit Organizations	72.3%	853	68.8%	17.0%	13.5%	20.4%	30.2%	5.7%	21.7%	14.9%
Not-For-Profit Organizations	42.5%	273	55.8%	2.7%	15.0%	22.1%	38.1%	9.7%	43.4%	24.8%
Industry Sector										
Durable Goods Manufacturing	67.4%	242	59.5%	25.9%	7.6%	10.1%	22.2%	10.1%	19.0%	12.0%
Non-Durable Goods Manufacturing	71.0%	124	75.9%	20.5%	8.4%	16.9%	16.9%	6.0%	14.5%	16.9%
Utilities and Energy	84.1%	63	69.8%	5.7%	15.1%	26.4%	52.8%	9.4%	41.5%	26.4%
Retail and Wholesale Trade	67.0%	91	71.7%	6.7%	5.0%	20.0%	18.3%	5.0%	16.7%	8.3%
Services	55.1%	352	70.1%	10.2%	14.4%	23.0%	39.6%	3.2%	25.1%	15.5%
Health Care	46.4%	110	46.9%	6.1%	14.3%	24.5%	24.5%	8.2%	49.0%	24.5%
Banking and Finance	83.1%	77	65.1%	12.7%	41.3%	42.9%	41.3%	3.2%	27.0%	14.3%
Insurance	88.1%	67	72.9%	16.9%	13.6%	15.3%	40.7%	6.8%	28.8%	25.4%
Organization Size										
Under 250 FTEs	63.0%	165	70.6%	17.6%	8.8%	17.6%	25.5%	3.9%	13.7%	13.7%
250 to 999 FTEs	70.5%	268	70.3%	17.0%	14.3%	17.6%	29.1%	5.5%	18.1%	20.3%
1,000 to 1,999 FTEs	64.6%	164	64.1%	16.5%	14.6%	21.4%	29.1%	9.7%	30.1%	16.5%
2,000 to 4,999 FTEs	62.8%	234	63.6%	13.3%	13.3%	21.7%	30.1%	7.7%	30.8%	16.8%
5,000 or More FTEs	63.4%	295	64.8%	11.0%	15.9%	24.2%	39.6%	5.5%	31.3%	13.7%

NUMBER OF BONUS AND/OR OTHER VARIABLE PAY PLANS IN WHICH OFFICE PERSONNEL ARE ELIGIBLE

	# of Plans in Place (as a % of Organizations with Plan[s])					
	One	Two	Three	Four	Five	Six or More
Entire Sample Combined	**43.8%**	**28.2%**	**13.9%**	**8.3%**	**3.7%**	**2.1%**
Profit Status						
For-Profit Organizations	44.6%	29.2%	12.5%	8.5%	3.3%	1.8%
Not-For-Profit Organizations	39.8%	23.0%	21.2%	7.1%	5.3%	3.5%
Industry Sector						
Durable Goods Manufacturing	53.2%	29.7%	8.9%	7.6%	0.6%	0.0%
Non-Durable Goods Manufacturing	47.0%	32.5%	13.3%	3.6%	1.2%	2.4%
Utilities and Energy	30.2%	24.5%	20.8%	15.1%	3.8%	5.7%
Retail and Wholesale Trade	60.0%	28.3%	5.0%	3.3%	1.7%	1.7%
Services	43.3%	26.2%	13.9%	8.6%	5.3%	2.7%
Health Care	44.9%	22.4%	16.3%	12.2%	2.0%	2.0%
Banking and Finance	20.6%	34.9%	22.2%	9.5%	11.1%	1.6%
Insurance	35.6%	25.4%	20.3%	10.2%	5.1%	3.4%
Organization Size						
Under 250 FTEs	49.0%	29.4%	12.7%	4.9%	2.9%	1.0%
250 to 999 FTEs	44.5%	29.1%	13.7%	7.7%	2.7%	2.2%
1,000 to 1,999 FTEs	41.7%	26.2%	13.6%	11.7%	3.9%	2.9%
2,000 to 4,999 FTEs	43.4%	28.7%	14.7%	7.7%	3.5%	2.1%
5,000 or More FTEs	41.8%	27.5%	14.3%	9.3%	4.9%	2.2%

Bonus, Variable Pay and Long-Term Incentive Programs

S 'RT-TERM PLAN PREVALENCE

BONUS AND/OR OTHER VARIABLE PAY PROGRAM(S) IN WHICH EXECUTIVES ARE ELIGIBLE

	% of Organizations with at Least One Plan	# of Responses	Prevalence of Various Plan Types (as a % of Organizations with Plans)						
			Bonus	Current Cash Profit Sharing	Team/ Small Group Incentives	Individual Incentives	Lump Sum Merit Pay (Not Added to Base)	Lump Sum Merit Pay (Added to Base)	Other Short-Term Incentives
Entire Sample Combined	**82.0%**	**845**	**92.1%**	**6.3%**	**5.2%**	**20.1%**	**17.6%**	**12.4%**	**1.9%**
Profit Status									
For-Profit Organizations	88.6%	660	95.2%	7.5%	4.8%	19.0%	14.7%	10.4%	1.7%
Not-For-Profit Organizations	58.4%	185	75.0%	0.0%	7.4%	25.9%	33.3%	23.1%	2.8%
Industry Sector									
Durable Goods Manufacturing	85.5%	186	98.1%	6.3%	1.9%	13.2%	10.7%	6.3%	0.0%
Non-Durable Goods Manufacturing	89.2%	93	97.6%	7.2%	3.6%	16.9%	14.5%	9.6%	1.2%
Utilities and Energy	81.0%	63	94.1%	3.9%	5.9%	23.5%	19.6%	15.7%	3.9%
Retail and Wholesale Trade	93.2%	73	91.2%	4.4%	2.9%	13.2%	13.2%	7.4%	2.9%
Services	73.3%	243	88.2%	7.3%	5.1%	24.7%	20.8%	14.6%	1.7%
Health Care	65.5%	58	73.7%	0.0%	10.5%	21.1%	34.2%	18.4%	0.0%
Banking and Finance	90.6%	64	86.2%	10.3%	15.5%	43.1%	17.2%	20.7%	3.4%
Insurance	89.2%	65	96.6%	6.9%	5.2%	10.3%	24.1%	17.2%	5.2%
Organization Size									
Under 500 FTEs	73.9%	218	92.5%	6.8%	2.5%	19.3%	8.7%	13.7%	1.9%
500 to 999 FTEs	82.4%	102	89.3%	6.0%	6.0%	23.8%	20.2%	20.2%	2.4%
1,000 to 1,999 FTEs	89.3%	121	90.7%	5.6%	7.4%	24.1%	17.6%	10.2%	0.9%
2,000 to 4,999 FTEs	84.8%	184	91.7%	8.3%	3.2%	22.4%	19.9%	11.5%	3.2%
5,000 or More FTEs	83.6%	220	94.0%	4.9%	7.6%	14.7%	22.3%	9.8%	1.1%

NUMBER OF BONUS AND/OR OTHER VARIABLE PAY PLANS IN WHICH EXECUTIVES ARE ELIGIBLE

	# of Plans in Place (as a % of Organizations with Plan[s])					
	One	Two	Three	Four	Five	Six or More
Entire Sample Combined	**61.5%**	**26.1%**	**8.7%**	**2.9%**	**0.9%**	**0.0%**
Profit Status						
For-Profit Organizations	63.9%	24.1%	7.7%	3.2%	1.0%	0.0%
Not-For-Profit Organizations	48.1%	37.0%	13.9%	0.9%	0.0%	0.0%
Industry Sector						
Durable Goods Manufacturing	73.0%	20.1%	4.4%	2.5%	0.0%	0.0%
Non-Durable Goods Manufacturing	65.1%	24.1%	7.2%	2.4%	1.2%	0.0%
Utilities and Energy	58.8%	19.6%	17.6%	3.9%	0.0%	0.0%
Retail and Wholesale Trade	70.6%	25.0%	2.9%	1.5%	0.0%	0.0%
Services	57.3%	28.7%	10.1%	2.2%	1.7%	0.0%
Health Care	57.9%	26.3%	15.8%	0.0%	0.0%	0.0%
Banking and Finance	39.7%	37.9%	12.1%	6.9%	3.4%	0.0%
Insurance	53.4%	32.8%	8.6%	5.2%	0.0%	0.0%
Organization Size						
Under 500 FTEs	65.8%	28.0%	2.5%	2.5%	1.2%	0.0%
500 to 999 FTEs	53.6%	31.0%	10.7%	3.6%	1.2%	0.0%
1,000 to 1,999 FTEs	62.0%	25.0%	8.3%	3.7%	0.9%	0.0%
2,000 to 4,999 FTEs	59.6%	25.0%	11.5%	3.2%	0.6%	0.0%
5,000 or More FTEs	62.5%	23.9%	10.9%	2.2%	0.5%	0.0%

Bonus, Variable Pay and Long-Term Incentive Programs

SHORT-TERM PLAN PREVALENCE

BONUS AND/OR OTHER VARIABLE PAY PROGRAM(S) IN WHICH MIDDLE MANAGERS ARE ELIGIBLE

	% of Organizations with at Least One Plan	# of Responses	Prevalence of Various Plan Types (as a % of Organizations with Plans) Bonus	Current Cash Profit Sharing	Team/ Small Group Incentives	Individual Incentives	Spot or Technical Achievement Awards	Gainsharing	Lump Sum Merit Pay (Not Added to Base)	Lump Sum Merit Pay (Added to Base)	Other Short-Term Incentives
Entire Sample Combined	**84.0%**	**1,037**	**86.9%**	**12.1%**	**10.4%**	**21.5%**	**26.8%**	**4.3%**	**25.1%**	**12.2%**	**7.4%**
Profit Status											
For-Profit Organizations	92.2%	816	89.2%	13.7%	9.6%	20.6%	25.4%	3.9%	22.3%	10.8%	6.9%
Not-For-Profit Organizations	53.8%	221	71.9%	1.8%	15.8%	27.2%	36.0%	7.0%	43.0%	21.1%	10.5%
Industry Sector											
Durable Goods Manufacturing	89.9%	247	85.4%	19.2%	7.3%	14.2%	20.1%	6.4%	18.3%	6.8%	6.4%
Non-Durable Goods Manufacturing	94.5%	128	92.4%	13.4%	7.6%	18.5%	14.3%	4.2%	21.0%	10.9%	9.2%
Utilities and Energy	92.2%	64	86.2%	5.2%	12.1%	25.9%	48.3%	3.4%	44.8%	15.5%	10.3%
Retail and Wholesale Trade	93.6%	78	89.7%	13.2%	5.9%	17.6%	19.1%	1.5%	23.5%	13.2%	1.5%
Services	71.6%	292	84.5%	8.2%	11.1%	27.5%	31.9%	3.4%	24.6%	13.5%	7.7%
Health Care	58.5%	82	72.7%	4.5%	15.9%	25.0%	27.3%	6.8%	40.9%	13.6%	2.3%
Banking and Finance	95.6%	68	87.5%	7.8%	23.4%	34.4%	34.4%	1.6%	25.0%	14.1%	7.8%
Insurance	94.9%	78	94.6%	12.2%	10.8%	17.6%	36.5%	5.4%	29.7%	20.3%	12.2%
Organization Size											
Under 500 FTEs	80.3%	254	86.6%	15.8%	7.9%	18.3%	21.3%	2.5%	12.4%	7.9%	9.4%
500 to 1,999 FTEs	87.0%	285	86.4%	12.8%	10.3%	21.5%	23.1%	2.9%	24.0%	12.8%	10.7%
2,000 to 7,499 FTEs	83.1%	295	86.3%	10.8%	12.1%	24.2%	29.6%	6.7%	30.0%	16.3%	3.8%
7,500 or More FTEs	85.7%	203	88.8%	8.3%	11.2%	21.3%	34.9%	5.3%	34.9%	10.7%	5.3%

NUMBER OF BONUS AND/OR OTHER VARIABLE PAY PLANS IN WHICH MIDDLE MANAGERS ARE ELIGIBLE

	# of Plans in Place (as a % of Organizations with Plan[s]) One	Two	Three	Four	Five	Six or More
Entire Sample Combined	**44.2%**	**25.8%**	**16.5%**	**8.3%**	**3.3%**	**1.9%**
Profit Status						
For-Profit Organizations	45.7%	25.3%	16.6%	7.8%	2.4%	2.0%
Not-For-Profit Organizations	34.2%	28.9%	15.8%	11.4%	8.8%	0.9%
Industry Sector						
Durable Goods Manufacturing	48.4%	29.2%	15.5%	4.6%	1.4%	0.9%
Non-Durable Goods Manufacturing	50.4%	25.2%	13.4%	6.7%	1.7%	2.5%
Utilities and Energy	31.0%	20.7%	25.9%	12.1%	8.6%	1.7%
Retail and Wholesale Trade	54.4%	23.5%	14.7%	1.5%	2.9%	2.9%
Services	42.0%	24.2%	17.4%	12.6%	3.4%	0.5%
Health Care	47.7%	20.5%	15.9%	11.4%	0.0%	4.5%
Banking and Finance	35.9%	26.6%	15.6%	12.5%	6.3%	3.1%
Insurance	33.8%	29.7%	17.6%	8.1%	6.8%	4.1%
Organization Size						
Under 500 FTEs	50.0%	28.7%	13.4%	5.4%	2.0%	0.5%
500 to 1,999 FTEs	43.0%	27.3%	18.2%	7.9%	2.1%	1.7%
2,000 to 7,499 FTEs	42.9%	23.3%	16.3%	9.6%	5.0%	2.9%
7,500 or More FTEs	40.8%	23.7%	18.3%	10.7%	4.1%	2.4%

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-04-97

Rebuttal Testimony
of
Rita A. Mulkern

Q. Would you please state your name and business address?

A. Yes. My name is Rita A. Mulkern and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Regulatory Analysis Manager of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Rita A. Mulkern who filed direct testimony earlier in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address certain adjustments proposed by Mr. Charles King, testifying on behalf of the North Dakota Public Service Commission Staff (Staff), specifically his adjustments to firm volumes, rate case expense, institutional advertising, transportation and work equipment, the 2005 operation and maintenance (O&M) increases, customer advances for construction and income taxes. I am sponsoring Exhibit No.___(RAM-3) through Exhibit No.___(RAM-4)

Q. On page 10 of Mr. King's testimony, he proposes to eliminate the one percent conservation factor for the firm general service class. Do you agree with his adjustment?

A. No, I do not. Mr. King recommends disallowing the conservation adjustment because he believes the Company did not provide support for the conservation factor for the firm general service class. The reasons that conservation is occurring are the same for firm customers as for residential customers, namely increased appliance and building efficiencies. Exhibit No.___(RAM-3) is a report prepared by the American Gas Association (AGA) entitled *Trends in the Commercial Natural Gas Market* dated October 23, 2002, that discusses the effects of conservation occurring in the commercial sector. The report states on page 2 that per unit consumption in the commercial market decreased 27 percent between 1979 and 1999 in the Midwest, which includes North Dakota, or an average of 1.35 percent per year, thus supporting Montana-Dakota's use of a one percent conservation factor for the firm general service class. The trend is anticipated to continue due to the continued replacement of older, less efficient appliances with new appliances and improved building efficiencies.

Q. Were there any errors in Mr. King's calculation to eliminate the one percent conservation in the use per customer for the firm general service class?

A. Yes. Mr. King has made an error in calculating his adjustment on Exhibit CWK-1, page 2. On this exhibit, Mr. King calculates the use per customer with and without the conservation factor, multiplies the annual consumption by the number of billing units, or bills, and calculates the difference in volumes. He errs in that multiplying annual consumption by the annual number of bills vastly overstates annual volumes by a factor of twelve. The correct calculation would be to multiply annual consumption by average billing units, or bills.

Q. What would Mr. King's adjustment be, if corrected to reflect the elimination of the one percent conservation?

A. Mr. King has a volume adjustment of 687,950 dk for the firm general service class and a margin adjustment of $358,361. If corrected his adjustment would be 57,329 dk and a margin adjustment of $35,357.

Q. On page 11 of his testimony, Mr. King states that Montana-Dakota did not seek recovery of SISP until Case No. PU-399-01-186 in 2001, even though the SISP plan had been effect since 1982. Is there a reason Montana-Dakota did not request recovery of SISP prior to 2001?

A. Yes. Montana-Dakota implemented the SISP program in 1982. From 1982 through 1992 Montana-Dakota accounted for the SISP costs on a pay-as-you-go, or a cash basis method, which was similar to the accounting treatment used by the Company for post retirement benefits. In 1993 the Company adopted FAS 106, Accounting for Post Retirement Benefits, which required the Company to change from the pay-as-you-go method to the accrual method for post retirement benefits. At that time the Company also changed its accounting for the SISP costs from the pay-as-you-go method to the accrual method (FAS 87 Employers Accounting for Pensions). The first opportunity Montana-Dakota had to request inclusion of these costs was in Case No. PU-399-94-297, where it was overlooked and not included in the filing. Montana-Dakota did request inclusion at the next opportunity, in Case No. PU-399-01-186, the case cited by Mr. King. Montana-Dakota did not wait almost 20 years to request recovery, but did so at the appropriate time.

Q. On page 13 of Mr. King's testimony, he proposes a four-year amortization of rate case expense instead of the three years the Company is requesting. Do you agree with his proposal?

A. No, I do not. Mr. King uses a four-year amortization as that was the amortization period authorized in the last case. Montana-Dakota proposed a three year amortization period to more closely match the filing frequency of general rate cases. The last general rate case was filed two years ago, in 2002. Mr. Imsdahl, in his direct testimony indicated that Montana-Dakota will continue to strive for operating efficiencies and cost reductions, but it is not anticipated that it can refrain from filing for another four years. Montana-Dakota believes that a three-year amortization provides the best time frame for rate case expense amortization to match the frequency of filings.

Optionally, if the Commission does decide that a four-year amortization is appropriate, the unamortized rate case expense balance should be included as a rate base addition.

Q. On page 17 of his testimony, Mr. King proposes to exclude the institutional advertising from O&M expense on the basis that the primary benefit is to the stockholder and it is designed to influence investors favorably. Do you agree with his adjustment?

A. No, I do not. First, this Commission has previously authorized the inclusion of institutional advertising. In Case No. PU-399-02-183, Montana-Dakota proposed to include institutional advertising. The Advocacy Staff witness, Mr. Michael Majoros, Jr. of Snavely King Majoros O'Conner & Lee, Inc., did not disagree with the inclusion of institutional advertising and it was authorized in the final order.

Also, Mr. King's characterization of this advertising as "designed to influence investors favorably, with the immediate effect of increasing the share prices of the Company's stock" is not accurate. As a corporate citizen, Montana-Dakota needs to be active in the communities that it serves. Our communities expect nothing less and advertising in the local newspapers, school yearbooks, sport and activity programs, etc., is a necessary part of being active in the community and contributing to the health of the community. This advertising benefits the community and the customers in that community, thus serving the public interest. Another example of this type of advertising is the Community Matters publication, which is included as a supplement in various local newspapers in the state. This supplement contains articles on topics such as gas prices, Montana-Dakota's community involvement and safety related articles.

The Community Matters supplement serves to inform customers about what is important to them and to confirm that Montana-Dakota is a part of the community, which benefits both the customers and their communities. The advertising benefits the communities and, as the Commission allowed in Case No. PU-399-02-183, it is appropriate to include these types of advertising in expense.

Q. On page 19 of his testimony, Mr. King proposes to disallow the Company's projected O&M expense on vehicles and work equipment because he states that O&M expenses would not change due to the change in depreciation expense. Is he correct?

A. No, he is not. Mr. King errs in stating that O&M expenses would not change as a result of new depreciation rates. He is incorrect because there is a direct correlation between the depreciation expense on vehicles and work equipment and O&M expense. The projected O&M for vehicles and work equipment restates the expense to reflect the depreciation rates authorized in Case No. PU-399-02-183 that became effective September 1, 2003 and the projected plant in service for these accounts.

Q. Would you please explain how the depreciation expense on vehicles and work equipment flows through to O&M expense?

A. Yes. Depreciation expense on vehicles and work equipment is calculated, but is not recorded in depreciation expense; rather it is recorded in a clearing account for vehicles or work equipment. All expenses incurred in the use of vehicles or work equipment, including gasoline, maintenance expense, depreciation, etc., are recorded in the appropriate clearing account. As the vehicle or work equipment is used, the expense for that vehicle or work equipment is charged to the appropriate expense or capital account on a cost per mile or per hour basis and the clearing account is correspondingly reduced. For example, if a back-hoe is used as part of a construction project, the job order for that project is charged with the use of that back-hoe and that expense becomes part of the cost of that project. If a vehicle is used as part of maintaining the distribution system, the expense associated with that vehicle is recorded as a distribution expense. Statement O, pages 5 and 6 show the calculation of depreciation expense and the amount carried forward to the income statement excludes the depreciation expense on transportation, tools and work equipment. Mr. King's adjustment is in error and should not be accepted.

Q. In his adjustment to pension and postretirement expense on page 22, Mr. King states that the Company's forecast for these items for 2005 is not based on information that is "known and measurable." Would you address his statement?

A. Yes. Three types of test years are commonly used for utility rate analysis: historic, current, and future. Some jurisdictions may only allow use of the first two types of test years (historic and current), but actual expenses for these types of test years are generally allowed to be adjusted for "known and measurable" changes from the actual operating results. As recognized by Mr. King, North Dakota law allows such adjustments to historical and current test years for "all known and measurable changes in operating results as measured in the test year." Mr. King's testimony, however, also includes a quotation of North Dakota law that allows use of a future test year which by definition is a forecast of future operating results. "Known and measurable" adjustments to historic and current test years have no application to a future test year. Rather, future, or projected test year forecasts are evaluated on whether they are reasonable, reliable, and made in good faith. The Company's projected pension and postretirement expenses meet that standard, as do its other projected expenses.

Q. On page 23 of his testimony, Mr. King proposes to eliminate the escalation factor used in some of the O&M projections for 2005. Is this adjustment appropriate?

A. No. Mr. King provides alternatives on the use of an escalation factor but bases his disallowance on his belief that the Company has no basis for its 2.5 percent escalation factor for 2005. Mr. King states that the forecasts for 2005 do not support the 2.5 percent used by the Company. Montana-Dakota based its escalation factor for 2005 on projections in the CPI from institutions such as the Congressional Budget Office, Standard and Poors and the Conference Board. The projected increases in the CPI ranged from 1.3 percent to 3 percent for 2005. Montana-Dakota used 2.5 percent for 2005 which is supported by the source data.

Mr. King also states that Montana-Dakota has put forth no data to demonstrate that the specified items will increase with inflation, because some expenses decreased from 2003 to 2004. In developing the projected 2004 data, Montana-Dakota adjusted expenses when necessary to determine a "normalized" revenue or expense. In that process, expenses both increased and decreased. The 2005 test year is based on the 2004 test year and as such represents normalized revenue and expense levels. If non-recurring expenses were to occur in 2005, they would be excluded from the development of the revenue requirement.

Mr. King also states that Montana-Dakota's rates did not increase between November 1993 and December 2003. His dates are incorrect. Montana-Dakota was able to refrain from increasing its rates between November 1994 and December 2002 by finding ways of operating more efficiently and taking advantage of new technologies where it made economic sense to do so. But, although such efforts will continue, as stated by Mr. Imsdahl in his direct testimony, at this point the Company does not anticipate cost efficiencies that will offset inflation and conservation. It is reasonable to conclude that inflation will have an effect on Montana-Dakota's expenses.

And, as stated earlier, Mr. King's testimony confuses the requirements for "current" versus "future" test years. Montana-Dakota's forecast must be reasonable, reliable and made in good faith. Montana-Dakota's escalation factor meets those criteria.

Montana-Dakota's 2005 escalation factor is necessary in determining expenses for 2005 and should be approved.

Q. On page 28 of his testimony, Mr. King proposes to increase customer advances for construction to match increases in plant additions. Do you agree with his adjustment?

A. No, I do not. Mr. King erroneously assumes that there is a direct correlation between additions to plant and customer advances for construction (customer advances).

Q. Would you please explain how customer advances work?

A. Yes. Montana-Dakota adds new customers to its distribution system each year. Montana-Dakota's Firm Gas Service Extension Policy Rate 120 specifies that if an estimated capital expenditure is not cost justified, the Company may require the customer to provide a refundable contribution. If certain conditions are met, the customer is eligible for a whole/partial refund of the contribution. The Company records the gross amount of investment in plant in service and the contribution is recorded in FERC Account 2520, which is a rate base deduction. The balance in the customer advances account changes dependent on new contributions, refunds and, if the conditions for refunds are not met within five years, reductions to transfer any non-refundable portion of an advance as a credit to plant. Not all plant additions require a customer advance and there is not a direct correlation between plant additions and customer advances. Exhibit No.___(RAM-4) is a schedule showing the customer advance balances for the period January 2000 through May 2004. The exhibit shows that there is not a steady increase in the customer advance balances over time but fluctuating balances. An adjustment to customer advances is not appropriate.

Q. Mr. King has adjusted income taxes to eliminate a tax deduction related to pension expense. Is his adjustment correct?

A. No, it is not. Exhibit CWK-1, page 10 shows the calculation of income tax expense. On line 9 of that exhibit, Mr. King eliminates a tax deduction, labeled "SISP". While Mr. King has labeled the item SISP, the tax deduction is for pension expense, as shown on Statement N, page 37, and represents the timing difference between the pension accrual and payments to the trust. It is not related to SISP and is a proper tax deduction. Furthermore, for each tax deduction that represents a timing difference, such as the deduction for pension expense, there is a corresponding deferred income tax. Mr. King eliminated the pension tax deduction but neglected to eliminate the associated deferred tax, which is also incorrect. His adjustment is in error and should not be accepted.

Q. Would you please summarize your testimony?

A. Yes. Montana-Dakota's projected expenses should be accepted as filed because Mr. King's adjustments were not appropriate and contained numerous errors.

Q. Does that complete your rebuttal testimony?

A. Yes, it does.

EXHIBIT NO. ___ (RAM-3)

AGA
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TRENDS IN THE COMMERCIAL NATURAL GAS MARKET

I. Introduction

Nationally, the commercial natural gas sector comprises 16 percent of total gas consumption. While total volumes to commercial customers increased 20 percent (weather normalized) from 1979 to 1999, use per customer dropped 18 percent. The purposes of this analysis are to: 1) provide an overview of natural gas consumption by commercial customers during the last 20 years, 2) identify the primary factors affecting use per customer, 3) examine natural gas use trends for the various types of commercial customers, and 4) highlight emerging technologies and markets that could offset this declining use trend.

II. Executive Summary

The commercial sector is important to natural gas utilities, accounting for 16 percent of total consumption. On a weather-normalized basis, total consumption by this sector grew 20 percent during the 1980's & 1990's, reaching 3.2 trillion cubic feet by 1999. The number of customers increased at a greater rate, 46 percent, over that time period. However, commercial energy trends have been mixed over the past two decades.

- Similar to the trend that has been exhibited in the residential sector, weather-normalized use per customer in the commercial sector declined by 18 percent between 1979 and 1999. This occurred because the growth in number of customers outpaced consumption growth.
  - Increased efficiency in space-heating appliances accounted for roughly half of the national average commercial load loss.
  - Water heating efficiency gains contributed about five percent of the average commercial load loss.

- Better insulation, more efficient windows, and other building envelope conservation measures increased substantially over the period, although the impact has not been quantified in this analysis.

- Regionally, the changes in use per commercial customer varied considerably.
  - The Northeast region's use per commercial customer **increased** 47 percent, primarily due to an increase in average floorspace per building and the increase in gas space heat penetration.
  - The Midwest region's use per customer declined almost 27 percent, while the South declined 30 percent, partially due to improved appliance and building efficiencies.
  - The West region's use per customer decline mirrored the national trend at 18 percent.

Another measure of customer conservation is consumption intensity (use per square foot of space). An examination of natural gas use per square foot confirms that the average commercial building uses less gas compared to 1979 levels. This measure fell roughly 40 percent over the two decades. This decline is greater than the use per customer measure because average floorspace per commercial building increased since 1979 and the intensity measure could not be adjusted for normal weather.

- For all commercial facilities (including those not using natural gas), changes in market share for natural gas have shown mixed results.
  - Nationally, the share of buildings with gas service fell from 62 percent to 61 percent.
  - Similar to the decline in overall market share, the natural gas share of the market for water heating fell slightly (48 percent to 47 percent).
  - Conversely, increasing market shares were realized in the commercial space heating (57 percent to 60 percent) and cooking (45 percent to 59 percent).

- For commercial facilities that use natural gas, the percentage of those customers that use gas for space heat and hot water have both increased, indicating that customers will choose gas for these applications where gas is available. The challenge remains for utilities to extend gas lines to unserved areas.
  - Over 89 percent of all commercial customers with gas service used gas for heat in 1999, up from 86 percent in 1979.
  - A similar trend was evident with waters heaters – increasing from 55 percent to 57 percent.
  - In the Northeast and Midwest, market penetration of space heaters increased while that of water heaters decreased.
  - The opposite was true in the South, where the penetration of gas space heating declined slightly but that of water heating increased dramatically.
  - Significant gains were realized for both applications in the West.

A number of commercial natural gas applications show promise in helping offset falling use per customer. Distributed energy, an application in which customers generate electricity on-site with natural gas, has moved beyond the demonstration phase. Natural gas space cooling is becoming more popular due to technological advances. Natural gas desiccant dehumidification applications are also increasing. One forecast estimated that these three items accounted for nine percent of 1999 commercial gas consumption but will account for 28 percent by 2020.

II. Overview of the Commercial Natural Gas Market

The number of commercial natural gas customers increased 46 percent over the two decades, from 3.4 million to 5 million (Table 1). Consumption (normalized to reflect normal weather) increased 20 percent. The number of buildings with natural gas service increased 43 percent, while the amount of floorspace for those buildings increased by half. Revenues from retail sales doubled, reflecting both the higher cost and use of natural gas.

Table 1
Overview of the U.S. Commercial Natural Gas Market

	1979	1999
Number of Customers (millions)	3.43	5.00
Normalized Consumption (Trillion cubic feet)	2.68	3.20
Number of Buildings with Gas (thousands)	1,864	2,670
Floorspace of Buildings with Gas (mil. sq. ft.)	30,477	45,525
Revenues from Sales (millions)	$6,624	$13,648

Sources: Energy Information Administration and AGA

Importance of Market to Gas Utilities

Commercial natural gas customers:

- Accounts for 16 percent of total gas consumption.
- Exhibit use patterns that are less seasonal relative to residential customers, allowing LDCs to better utilize gas distribution assets.
- Consume 7.5 times more gas, on a per customer basis, than the residential sector, allowing for more efficient use of utility resources.
- Normally operate under a firm rate, paying a premium compared to industrial customers that typically elect interruptible service.

End-Uses of Gas By Commercial Sector

Most of the natural gas consumed in the commercial sector is used for space heating and, to a lesser extent, water heating (Table 2). Cooking is third, followed by cooling/desiccant and power applications. Since 1979, space heating and, to a lesser extent, water heating end-uses have accounted for a declining portion of total commercial gas consumption. Cooking, cooling/desiccant, and power generation end-uses accounted for a greater proportion of commercial gas use in 1999 compared to 1979.

Table 2
Estimated Commercial Natural Gas Proportional Consumption by End-Use

	1979	1999
Space Heating	65%	54%
Water Heating	16%	14%
Cooking	7%	10%
Cooling/Desiccant	3%	4%
Power Generation	1%	5%
Other	8%	13%
Total	100%	100%

Sources: American Gas Association *Commercial Gas Market Survey* and Gas Research Institute *Baseline Projection Data Book 2001*

Commercial Energy Market Shares

Natural gas has been losing market share to electricity in most end-uses except cooking (Table 3). The loss was largest in the cooling sector, but gas use was probably most impacted by the loss in the space heating market.

Table 3
Market Shares in Commercial Buildings

	1979			1999	
	Natural Gas	Electricity		Natural Gas	Electricity
In Building	61.8%	99.6%		60.6%	99.8%
Space Heating	57.0%	27.3%		59.8%	28.4%
Water Heating	47.7%	46.5%		46.9%	47.7%
Cooking	44.5%	58.5%		58.9%	51.0%
Cooling	6.5%	94.3%		4.0%	96.9%

Note: Totals may exceed 100% as some buildings use both energy sources for that end use
Source: Energy Information Administration, *Commercial Buildings Energy Consumption Survey* (CBECS)

III. Use Per Customer

Background and Limitations

This section attempts to provide a broad-based identification and quantification of factors that impacted the average annual natural gas use per commercial customer from 1979 to 1999. Most natural gas distribution utilities experienced a much slower growth rate in commercial demand compared to the growth rate in the number of commercial customers during that time period. This trend makes it more difficult for gas companies to achieve expected revenues and to connect new customers economically. This section is intended to help companies understand the driving forces behind the declining use trend and to estimate future trends.

The results herein estimate the overall impacts of several contributing factors based on national and regional data. Analysis of utility-specific factors could result in conclusions different from those in this report. Individual companies should use this report as a guide in calculating their specific impacts, and they should include factors and influences pertinent to their systems that may not be considered and/or quantified here.

These contributing factors were examined separately. Some of them may have synergistic properties that compound or offset impacts when considered together. Also, the quantification of these factors is not an attempt to determine absolute values for each influence, but rather to indicate the proportional impact that they have on residential use per customer.

It must be recognized that the commercial natural gas market is quite diverse, particularly when compared to the residential market. An earlier American Gas Association (AGA) study on gas consumption patterns in the residential sector[1] more precisely quantified impacts of efficiency and demographic factors on customer use, in part due to the more homogeneous nature of the market relative to the commercial sector. Therefore, this section is designed to identify and give a relative measure of influencing factors.

Much of the data used in this analysis come from government and AGA surveys. While this information is the best available for national and regional analysis, survey sampling, structure, and/or extrapolation techniques can be flawed, particularly when ascribing results to smaller populations such as regions and states.

National/Regional Averages

From 1958 to 1978, natural gas demand in the commercial sector averaged an annual growth rate of 6.1 percent, and use per customer increased from 350 thousand cubic feet (Mcf) to 743 Mcf.[2] Utilities were expanding their pipeline systems to reach more customers, prices were kept artificially low by government regulation, and gas appliances offered superior performance, cost, and efficiency compared to competing fuel technologies.

During the mid to late 1970's, three factors led consumers to start conserving energy. First, foreign oil embargoes led to fears regarding long-term energy supplies. Second, heightened environmental awareness and energy's impact on the environment led to a reexamination of energy-use practices. Finally, the federal government deregulated energy prices, which led to a significant short-term price increase, particularly for natural gas.

Efforts to reduce energy consumption are clearly reflected in gas use per customer. On a national average basis, natural gas use per commercial customer dropped 18 percent from 1979 to 1999 from 780 Mcf/year to 640 Mcf/year (Table 4). On a regional basis, these impacts varied. For the Northeast, the average gas use per customer increased substantially, roughly 47 percent. Commercial gas use per

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[1] Patterns in Residential Natural Gas Consumption Since 1980, February 11, 2000, American Gas Association, Washington, DC.
[2] Gas Facts, 1980 Data, American Gas Association, Arlington, VA, 1981.

customer dropped 27 percent for the Midwest, 30 percent in the South, and 18 percent in the West.

Table 4
Trends in Commercial Natural Gas Use
(Weather Normalized Mcf/Customer/Year)

	1979	1999	Change
United States	780	640	-140
Northeast	568	838	270
Midwest	901	660	-241
South	738	516	-222
West	744	611	-133

Contributing Factors

Appliance Efficiency

In response to the energy disruptions of the 1970s, Congress passed the Energy Policy and Conservation Act (EPCA) of 1975. EPCA established an energy conservation program for major household appliances including furnaces, water heaters, refrigerators and freezers, central air conditioners and central air conditioning heat pumps, room air conditioners, dishwashers, clothes washers, clothes dryers, direct heating equipment, pool heaters, kitchen ranges and ovens, fluorescent lamp ballasts, and television sets. The Energy Policy and Conservation Act (EPACT) of 1978 expanded the coverage of EPCA to include commercial building heating and air conditioning equipment, water heaters, certain incandescent and fluorescent lamps, distribution transformers, and electric motors. In 1987, the National Appliance Energy Conservation Act (NAECA), which also incorporates EPCA and EPACT, authorized the U. S. Department of Energy (DOE) to set energy efficiency standards for major home appliances according to a statutory time schedule stretching into the next century.

DOE's Office of Codes and Standards sets the minimum efficiency ratings of many residential appliances. DOE has set standards for such natural gas appliances as space heaters, water heaters, ovens, and ranges.

Furnaces

During the 1970's natural gas furnaces averaged about 65 percent annual fuel utilization efficiency (AFUE). As interest in more energy-efficient appliances increased, the average AFUE for new furnaces increased. DOE, through authority granted by NAECA, set 78 percent AFUE as a minimum for gas furnaces manufactured after January 1, 1992. Furnaces with AFUE ratings up to the mid-90's are available to consumers, and the average AFUE of new furnace shipments is currently in the mid-eighties. As the higher efficiency furnaces have worked their way into the market for new and replacement units, the average AFUE for all natural gas furnaces has increased from 65 percent in 1979 to 75 percent in 1999 (Table 5).

Table 5
Natural Gas Furnace Average AFUE
(Percent)

	1979	1990	1999
New Furnace Shipments	65%	76%	85%
All Furnaces In Place	65%	68%	75%

Source for shipment information: Gas Appliance Manufacturers Association

The impact on a national average was to lower use per commercial natural gas customer about 70 Mcf per year, half of the total decrease (Table 6). The impact in terms of sales volume varied by region due to the weather differences and market penetration. Use per customer dropped around 53-56 Mcf in all regions except the Midwest, where the decline was 93 Mcf per year.

Table 6
Impact of Gas Space-Heating Efficiency Gains on Use per Customer
(Weather-normalized Mcf/year, 1999 vs. 1979)

United States	-70
Northeast	-53
Midwest	-93
South	-56
West	-56

Note: Assumes national average furnace efficiency for all regions.

Water Heaters

DOE set the minimum efficiency of natural gas water heater at 0.54 energy factor (EF) for units manufactured after 1989. Previously, water heaters averaged about 0.5 EF. Industry analysts estimated that the availability of even higher efficiency units raised the average EF of new units sold to 0.56 by the mid-90s (Table 7). Based on shipment data and typical retirement rates, the average EF of water heaters went from 0.5 in both 1979 and 1990 to 0.54 in 1999.

Table 7
Natural Gas Water Heater Average Energy Factor

	1979	1990	1999
New Water Heater Shipments	.50	.54	.56
In-Place Water Heaters	.50	.50	.54

Since the average water heater EF improved about six percent from 1990, the typical consumption by customers that have water heaters declined in the same proportion. The average decline was seven Mcf per customer, with regions not varying much from that average (Table 8).

Table 8
Impact of Gas Space Water Heating Efficiency Gains on Use per Customer
(Mcf/year)

United States	-7
Northeast	-9
Midwest	-7
South	-5
West	-6

Other

Natural gas cooking equipment has not yet been affected significantly by efficiency changes. Improvements in efficiency have occurred due to marketplace demand, most of which stemmed from the development of electronic ignition devices for these appliances. While electronic ignitions can reduce annual demand for gas from these appliances by almost half, penetration of these devices into the market could not be determined. Therefore, no estimate of the improved efficiency impacts for these appliances is provided.

Appliance Saturation

The most common natural gas appliances found in businesses are space heaters, water heaters, and cooking equipment. All of these applications face competition from other energy forms, particularly electricity. Since 1979, the percentage of gas buildings with both gas space and waters heaters increased. The opposite trend was exhibited for gas cooking and cooling equipment.

Space Heaters

The percentage of gas customers that use natural gas for space heating increased by three percentage points over the period (Table 9). Regionally, the Northeast sector saw a significant increase in this market penetration among its customers, apparently at the expense of fuel oil heating. The Midwest slightly increased its high market penetration for gas heating over the period. The West also enjoyed a slight increase in the proportion of their customers that use gas for their main space heating fuel. Only the South showed a slight decrease due to the increasing popularity of the electric heat pump during this time.

Table 9
Natural Gas Space Heating Appliance Market Penetration
(Percent of all gas customers)

	1979	**1999**
United States	86.1%	89.1%
Northeast	74.9%	87.8%
Midwest	93.0%	95.4%
South	83.2%	82.6%
West	87.1%	89.5%

Source: Energy Information Administration, CBECS, various years

Increasing the percentage of gas customers that use gas for space heating helped to offset the reduction-in-use trend. On a national level, throughput per commercial customer increased 10 Mcf/year because of increased penetration (Table 10). The greatest increase occurred in the Northeast, 66 Mcf/year. The gains in the Midwest (nine Mcf) and the West (six Mcf) were more modest, and the South showed a decline (two Mcf).

Table 10
Impact of Gas Space Heating Market Penetration on Use per Customer
(Mcf/year)

United States	10.0
Northeast	66.2
Midwest	9.2
South	-1.6
West	5.9

Water Heaters

Overall, more commercial buildings employ natural gas water heaters compared to 20 years ago. In 1979 natural gas water heaters were in about 55 percent of U. S. businesses with natural gas service (Table 11). By 1999 this market penetration had increased to 57 percent. Regionally, the Northeast's and Midwest's market penetration decreased, with the other regions showing significant increases.

Table 11
Natural Gas Water Heater Market Penetration
(Percent of all gas customers)

	1979	1999
United States	54.9%	56.9%
Northeast	59.9%	54.0%
Midwest	60.2%	51.7%
South	42.0%	57.3%
West	58.4%	64.8%

Source Energy Information Administration, CBECS, various years

When the proportion of gas customers with gas water heaters increases, the weighted average gas use per customer rises. For example, the national average penetration of water heaters climbed about two percentage points from 1979 to 1999, resulting in an increase in overall gas use per customer of two Mcf/year (Table 12). The South (11.3 Mcf/year gain) and the West (5.6 Mcf/year gain) experienced higher growth. On the other hand, the Northeast and Midwest experienced declines in market penetration, causing load losses of about seven to eight Mcf/year.

Table 12
Impact of Gas Water Heater Market Penetration on Use per Customer
(Mcf/year)

United States	1.8
Northeast	-7.0
Midwest	-8.0
South	11.3
West	5.6

Cooking

While overall natural gas market share for commercial gas cooking increased, the percent of commercial establishments that cook on-site decreased. Thus, the percentage of commercial customers with natural gas service that also cook with gas declined in all regions of the country -- the number of gas buildings without cooking increased at a faster rate compared to those commercial gas sites with cooking. Nationally, cooking market penetration for gas customers fell 4.6 percentage points, with the Northeast region falling 16 percentage points, the Midwest four percentage points, the South less than one percentage point, and the West two percentage points (Table 13).

Table 13
Natural Gas Cooking Appliance Market Penetration
(Percent of all gas customers)

	1979	1999
United States	23.5%	18.9%
Northeast	36.0%	20.9%
Midwest	21.4%	17.5%
South	19.7%	19.5%
West	21.0%	19.1%

Source: Energy Information Administration, CBECS, various years.

Despite this decline for gas cooking penetration, the resulting impact is relatively small. This is due to the smaller proportion of gas customers with this appliance combined with the modest annual energy consumption from these units compared to other applications. Nationally, the loss amounted to 3.1 Mcf/year (Table 14). The Northeast experienced the largest decline with 13 Mcf/year. The other regions ranged from less than one Mcf/year (South) to almost three (Midwest).

Table 14
Impact of Gas Cooking Market Penetration on Use per Customer
(Mcf/year)

United States	-3.1
Northeast	-13.1
Midwest	-2.7
South	-0.1
West	-1.2

Cooling

Gas cooling in the commercial sector held a very small market share in 1979, and that share fell through 1999, both in terms of total market and penetration for all gas customers. However, the decline did not impact use per customer significantly because of the small percentage of the customers using gas for cooling. On average, the decline was less than one Mcf/year.

Building Characteristics

Average Floorspace per Heated Building

The average amount of floorspace per gas-heated building increased almost eight percent between 1979 and 1999 (Table 15). The Northeast's average floorspace per gas-heated building increased the most, nearly 40 percent. The Midwest region was the only area to have a decrease (two percent), while the South (13 percent) and the West (four percent) average floorspace per gas-heated building increased.

Table 15
Changing Floorspace per Building
(1999 vs. 1979)

United States	7.8%
Northeast	39.2%
Midwest	-1.6
South	12.8%
West	4.3%

Source: Energy Information Administration, CBECS, various years

This increase resulted in a higher gas use per customer, approximately 26 Mcf/year per customer, on a national level (Table 16). The Northeast use increased the most, slightly more than 200 Mcf/year. The Midwest region was the only area to have a decrease, causing use to fall about six Mcf/year. The South exhibited an increase of more than 30 Mcf/year, while the West showed an increase of ten Mcf/year.

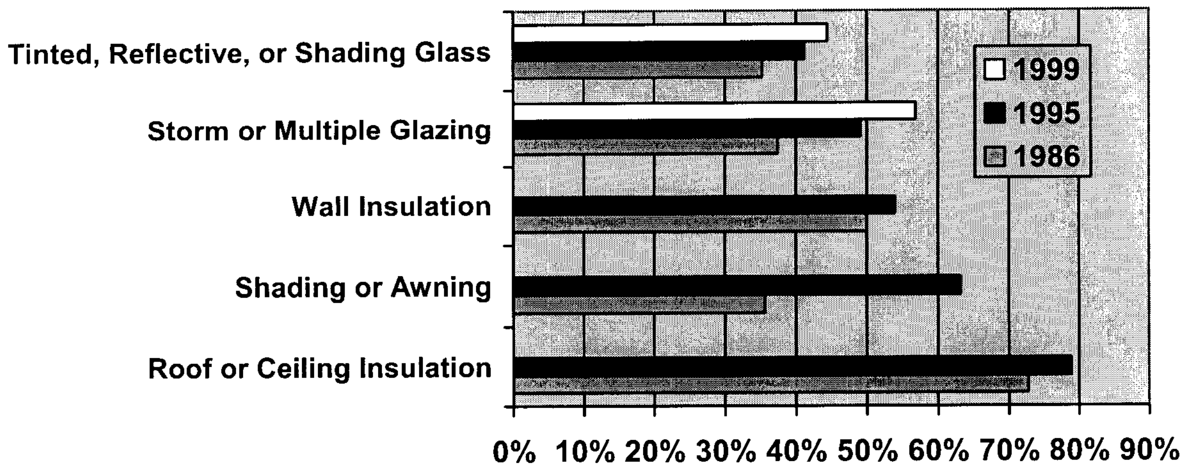
Table 16
Impact of Changing Average Floorspace per Building on Gas Demand
(Mcf per year)

United States	25.9
Northeast	201.8
Midwest	-6.1
South	31.2
West	10.4

Shell Improvements

Since 1979, the average commercial building has become more energy-efficient through improvements in building shell construction. These improvements dealt mainly with insulation and windows. Chart 1 illustrates these improvements since 1986.

Chart 1
Changes In Building Shell Conservation Features
(Percent of Buildings with Feature)



Source: Energy Information Administration, CBECS, various years
NOTE: Data for Wall Insulation, Shading or Awning, and Roof or Ceiling Insulation not available for 1999.

These improvements resulted from two factors. First, new buildings were constructed with these features, and the population of structures completed since 1970 increased over the study period. According to the Energy Information Administration's *Commercial Building Energy Consumption Survey* (CBECS), in 1979, 78% of the commercial buildings were built before 1970. In 1999, only half of the inventory was built before 1970.

Second, more than half of the buildings covered by CBECS reported that they had added conservation features.

- Insulation: 34%
- Weather stripping or calk: 27%
- Storm or multiple glazing windows: 13%
- Exterior or interior shading or awnings: 17%
- Tinted, reflective, or shading glass: 9%

Other

Based on responses to the 1986 CBECS, 13 percent of buildings had energy audits. Almost half of those audited made improvements to the HVAC system, building shell, or lighting system

Off-hours reduction in heating and/or cooling gained in popularity over the study period, according to CBECS. In 1986, 63 percent of buildings employed this conservation feature compared to 71 percent in 1999.

Unfortunately, the buildings within the commercial definition vary greatly, making estimates of these changes' impact on gas demand infeasible. Considering all of the improvements made in building stock and energy management practices since 1979, the impacts should be considerable.

IV. Trends by Type of Commercial Activity

The types of businesses within the commercial sector vary considerably. The Energy Information Administration classifies the activities into nine components – Assembly, Education, Food Sales and Service, Health Care, Lodging, Mercantile and Service, Office, Warehouse, and Other. Size and scope of activities varied substantially even within these categories – Mercantile and Service ranges from a stand-alone mini-mart to a large mall, Health Care ranges from a doctor's office to a hospital, etc. This must be taken into consideration when analyzing the trends presented below.

Natural gas market shares in buildings varied by type of commercial activity. The percentage of buildings with gas service increased significantly in Lodging and Education (Table 17) since 1979. However, the percentage of Health Care facilities with gas service decreased almost 18 percent, and these customers traditionally use large amounts of natural gas.

Table 17
Gas In Building Market Share by Activity

	1979	1999	Change
Assembly	63.8%	66.2%	3.8%
Education	62.0%	68.8%	10.9%
Food Sales & Service	61.5%	64.0%	4.0%
Health Care	70.0%	57.5%	-17.9%
Lodging	57.7%	68.0%	17.7%
Mercantile & Service	66.2%	62.9%	-5.1%
Office	61.1%	61.2%	0.2%
Warehouse	49.6%	45.6%	-8.1%
Other	52.2%	43.8%	-16.0%

Source: Energy Information Administration, CBECS, various years

The gas space heating market shares improved for most activities (Table 18). Greatest gains appeared in the Lodging and Education sectors. Health Care exhibited the only significant decline, indicating that gas space heating lost ground not only in these buildings without gas service but in buildings with gas service as well.

Table 18
Gas Space Heating Market Share by Activity

	1979	1999	Change
Assembly	57.9%	61.9%	7.0%
Education	46.8%	60.1%	28.4%
Food Sales & Service	54.4%	57.7%	5.9%
Health Care	62.0%	49.6%	-20.0%
Lodging	36.8%	49.3%	33.9%
Mercantile & Service	63.5%	62.3%	-1.9%
Office	54.1%	57.6%	6.4%
Warehouse	58.7%	59.1%	0.7%
Other	45.2%	47.6%	5.3%

Source: Energy Information Administration, CBECS, various years

The market shares for gas water heating varied by sector (Table 19). Assembly, Food Sales and Service, and Lodging all exhibited double digit growth over the two decades. Health Care, Mercantile and Service, Office, and Warehouse applications all exhibited double-digit declines in gas water heating market shares.

Table 19
Gas Water Heating Market Share by Activity

	1979	1999	Change
Assembly	44.5%	54.7%	22.8%
Education	55.0%	55.0%	0.1%
Food Sales & Service	50.7%	59.6%	17.5%
Health Care	49.0%	43.7%	-10.9%
Lodging	48.9%	57.7%	18.1%
Mercantile & Service	50.0%	40.5%	-19.1%
Office	43.6%	35.1%	-19.5%
Warehouse	41.8%	37.0%	-11.4%
Other	48.8%	48.6%	-0.4%

Source: Energy Information Administration, CBECS, various years

Market shares for gas cooking increased in all reported activities. Double-digit growth occurred in all sectors except one (Table 20). Ironically, Food Sales and Service grew only eight percent.

Table 20
Gas Cooking Market Share by Activity

	1979	1999	Change
Assembly	42.4%	52.6%	24.2%
Education	51.2%	66.0%	29.1%
Food Sales & Service	57.2%	61.6%	7.7%
Health Care	53.8%	72.7%	35.1%
Lodging	43.1%	56.1%	30.1%
Mercantile & Service	41.8%	60.4%	44.6%
Office	29.5%	52.6%	78.6%
Warehouse	11.1%	N/A	N/A
Other	43.8%	N/A	N/A

Source: Energy Information Administration, CBECS, various years

Energy intensity is similar to use-per-customer in that it illustrates the relative amount of energy consumed, but on a per square foot of commercial space basis. As shown in Table 21, Food Sales and Service and Health Care are the largest consumers of natural gas on a per square foot basis. All sectors experienced double-digit declines in energy intensity since 1979. All sectors appeared to use natural gas much more efficiently in their end-uses.

Table 21
Gas Energy Intensity by Activity
(000 Btu/Sq. Ft./Year)

	1979	1999	Change
Assembly	53.5	28.2	-47%
Education	51.2	33.5	-35%
Food Sales & Service	127.2	111.1	-13%
Health Care	127.0	92.2	-27%
Lodging	75.5	49.6	-34%
Mercantile & Service	55.9	43.4	-22%
Office	59.1	29.0	-51%
Warehouse	83.9	36.0	-57%

Source: Energy Information Administration, CBECS, various years

V. Future Trends

Appliance Efficiency

Most existing space heating and water heating appliances were purchased before government-mandated minimum efficiency ratings were imposed on this equipment. Therefore, the average efficiency for these appliances is lower than the regulatory minimum. Replacement of older, less efficient appliances through normal attrition will make it difficult for gas utilities to reverse the declining demand per customer trend.

Building Characteristics

In 1999, half of existing commercial buildings were built before 1970. These structures, on average, are less thermally efficient than new ones. While some have been renovated to improve their thermal efficiency (wall and ceiling insulation, storm windows and doors), the addition of new buildings and the removal of older stock will increase the average efficiency of a gas utility's commercial base. This, in turn, will contribute to a decline in commercial demand on a per-customer basis.

Emerging Technologies

Distributed energy offers substantial growth opportunities for natural gas utilities in the commercial sector. Distributed generation can be defined as onsite or near-site power generation of less than 25 MW. High efficiencies are possible for installations that supply both power and use the waste heat to meet the heating or cooling needs of a customer. A wide range of power generation technologies is either commercially available or currently emerging to meet the needs of institutional and large commercial customers.

Natural gas is expected to supply a growing portion of commercial space cooling load. Systems such as gas engine-driven, gas absorption, and desiccant dehumidification are growing in popularity due to cost and environmental considerations.

According to the Gas Technology Institute[3], cooling and desiccant systems accounted for 3.5 percent of 1999 natural gas consumption by the commercial sector, and power generation 5.4 percent. GTI forecasts that by 2020, gas sales for cooling and desiccant systems are expected to grow 500 percent (12.9 percent of total gas commercial load), and gas sales for power generation are expected to grow almost 400 percent (15 percent of commercial load). These two factors are expected to help offset continued gains in gas appliances and envelope efficiency in the commercial market.

VI. Data Sources and Methodology

Most of the data used and presented in this report comes from the U. S. Energy Information Administrations' Commercial Building Energy Consumption Survey[4] (CBECS). The report for 1999 and selected other years can be found on the EIA Website: http://www.eia.doe.gov/emeu/cbecs/contents.html. Other data sources included previous AGA surveys on the commercial market[5], AGA's Gas Facts[6], EIA's Natural Gas Annual[7] and the previously cited Gas Research Institute's Baseline Projection Data Book.

[3] Baseline Projection Data Book, 2001 Edition, March 2001, Gas Research Institute, Arlington, VA

[4] Commercial Building Energy Consumption Survey, various years, Energy Information Administration, U. S. Department of Energy, Washington, DC.

[5] Commercial Natural Gas Market Survey, various years, American Gas Association, Washington, DC.

[6] Gas Facts, various years, American Gas Association, Washington, D.C.

[7] Natural Gas Annual, various years, Energy Information Administration, U.S. Department of Energy, Washington, DC

The methodology for determining use per customer trends is summarized below:

Normalized Use Per Customer

- Calculate actual use per commercial customer from EIA data
- Determine heating portion of use based on AGA survey data and the GRI Baseline Report
- Determine weather normalization factor by dividing the 30-year (1961-1990) normal heating degree days into the actual degree days, based on NOAA data[8]
- Divide heating portion by weather normalization factor, and add back in non-heating load

Average Space Heating AFUE

- Assume 65% AFUE as standard in 1979 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas space heating customers from current year's, based on trend analysis of EIA CBECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data[9]
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace AFUE for all existing units based on average AFUE of shipments as provided by GAMA

Space Heating Efficiency Impact

- Calculate average use per customer by multiplying the normalized heating load by the percent of gas customers with gas space heating (based on EIA CBECS data)
- Calculate change in average furnace AFUE by dividing 1979 AFUE value into the selected year's AFUE value
- Calculate the efficiency-adjusted demand by dividing the 1979 average use per customer by the change in average furnace AFUE for the selected year
- Subtract the efficiency-adjusted demand from the 1979 average use per customer to determine impact

Average Water Heating EF

- Assume 0.50 EF as standard in 1979 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas water heating customers from current year's, based on trend analysis of EIA CBECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace EF for all existing units based on average EF of shipments estimated at 0.54 EF to 0.56 EF

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[8] State, Regional, and National Monthly and Seasonal Heating Degree Days, various years, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Washington, DC.

[9] GAMA News, various years, Gas Appliance Manufacturers Association, Arlington, VA.

Water Heating Efficiency Impact

- Calculate average use per customer by multiplying the water heating load (based on AGA survey data) by the percent of gas customers with gas water heating (based on EIA CBECS data)
- Calculate change in average EF by dividing 1979 EF value into the selected year's EF value
- Calculate the efficiency-adjusted demand by dividing the 1979 average use per customer by the change in average water heater EF for the selected year
- Subtract the efficiency-adjusted demand from the 1979 average use per customer to determine impact

Appliance Market Penetration Impact

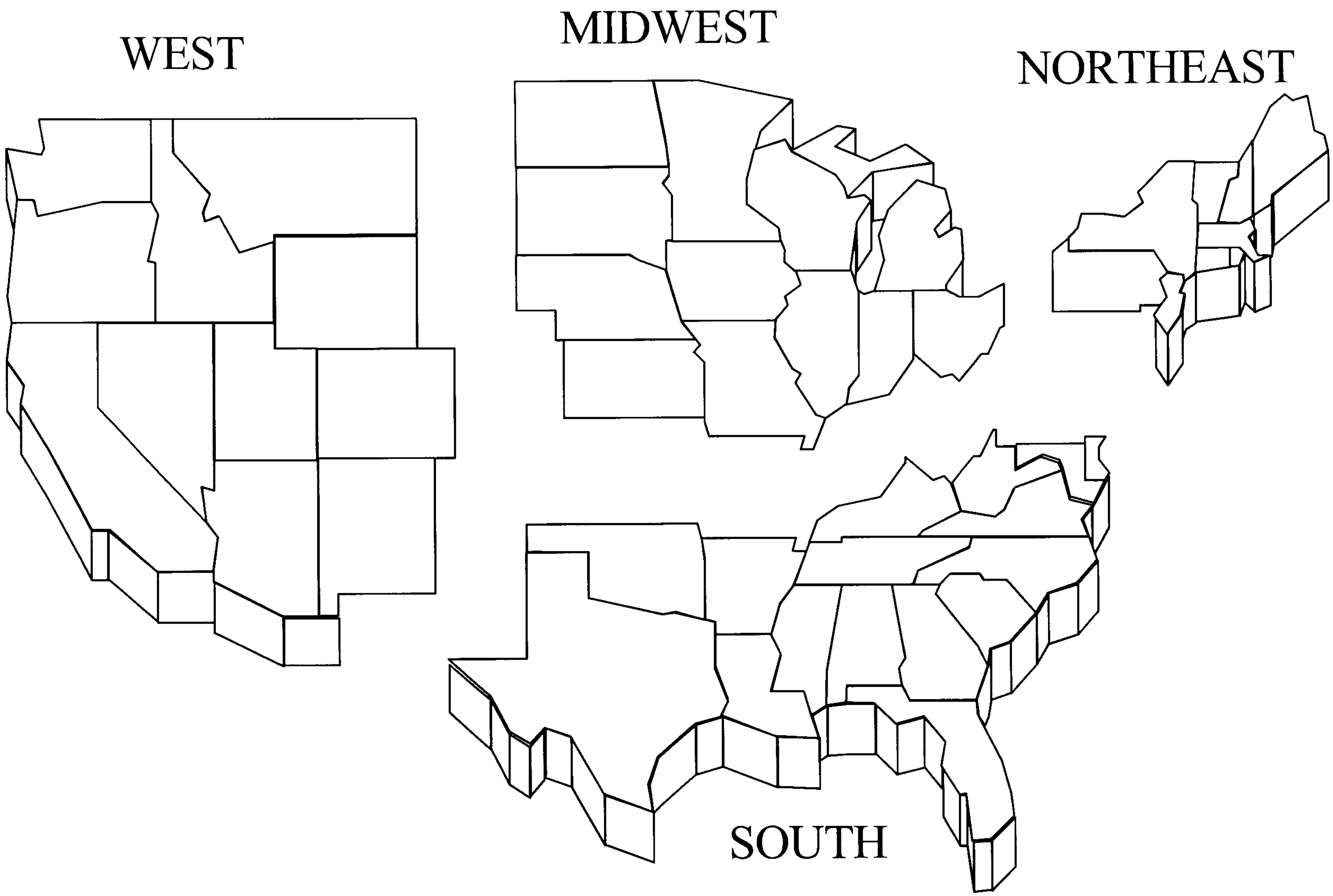
- Calculate appliance penetration by dividing the number of residences with gas service by the number of customers with that appliance, based on EIA CBECS data
- Subtract the impact year penetration from the 1979 penetration to determine the change in market penetration
- Calculate the weighted average gas use per customer for that appliance by multiplying the penetration value times the typical gas use for that appliance
- Multiply the change in market penetration by the 1979 weighted average use of that appliance to determine the reduction in weighted average use per customer for that appliance

Change in Average Heated Floorspace Impact

- Calculate the percent change in average heated floorspace in buildings from EIA CBECS data
- Multiply the change in average heated floorspace by the percent difference in heating load and by the percent of gas buildings with gas space heating to determine impacts

Appendix

US Census Regions



MONTANA-DAKOTA UTILITIES CO.
GAS UTILITY - NORTH DAKOTA
CUSTOMER ADVANCES FOR CONSTRUCTION
2000-2004

	2000	2001	2002	2003	2004
January	$448,227	$482,137	$267,671	$239,365	$333,091
February	482,286	477,034	267,066	191,455	337,896
March	483,044	483,969	272,846	191,701	339,547
April	484,312	434,935	270,874	224,387	345,369
May	488,052	432,293	268,838	223,824	348,564
June	489,228	433,008	273,596	239,570	
July	469,445	280,102	274,276	240,610	
August	475,408	281,008	273,608	241,173	
September	476,322	281,422	276,928	288,906	
October	477,300	278,929	261,431	311,456	
November	473,511	267,366	260,253	311,960	
December	485,978	267,859	286,881	307,320	

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Service Commission of North Dakota

Case No. PU-04-97

Rebuttal Testimony
of
Tamie A. Aberle

Q. Would you please state your name and business address?

A. Yes. My name is Tamie A. Aberle, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Pricing & Tariff Manager in the Regulatory Affairs Department of Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. Are you the same Tamie A. Aberle who filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. The purpose of this rebuttal testimony is to address recommendations made by Mr. Charles King, testifying on behalf of the North Dakota Public Service Commission Staff, regarding the embedded cost of service study and the Distribution Delivery Stabilization Mechanism. I am also sponsoring Exhibit No.____(TAA-3).

Q. Do you agree with Mr. King's position with regard to the Company's allocation of distribution mains as he describes beginning at page 37 of his testimony?

A. No I do not. Mr. King's assessment that approximately 70% of the distribution mains account is fixed in nature is consistent with the Company's allocation of approximately 66% of the distribution mains account to the customer component because that portion of the mains is fixed in nature. However, I do not agree that it is appropriate to allocate the portion of the mains determined to be fixed in nature, on the basis of a variable, volumetric allocation factor. The fixed portion of the mains should be allocated on the customer allocation factor that represents the causation and fixed nature of those costs.

Q. Mr. King asserts that the value of the distribution main is the gas that is being delivered, and should be the allocator of the main's cost. Do you agree?

A. No. Main investment is not a variable cost that increases or decreases as more or less gas is used. The capability to have natural gas service available on demand is the cost of having the main in place to serve customers. The volume of gas being delivered does not correlate to or represent the Company's embedded cost or the causation of the cost associated with the distribution main investment required to provide natural gas service to the customer.

Q. Please comment on Mr. King's proposal of a real-time Distribution Delivery Stabilization Mechanism (DDSM).

A. As noted by Mr. King at page 43, the Company is able to administer the DDSM on a real-time basis and would support adopting a real-time application of the DDSM. However, my understanding of Mr. King's proposal would require a calculation of a class average deviation from normal weather prior to billing each night for the 20 bill cycles processed each month. This is not feasible for Montana-Dakota given the time required for bill processing.

A better alternative, resulting in a more accurate adjustment, would be to calculate the deviation from normal weather based on each individual customer's actual usage and days being billed. The mechanics of the calculation would be similar to that set forth on Exhibit CWK-8 except the calculation would be based on each customer's actual use. This methodology was approved by the South Dakota Public Utilities Commission for Montana-Dakota's South Dakota jurisdiction in Docket No. NG02-011. Please refer to Exhibit No.___(TAA-3) for an alternate tariff reflecting a real-time DDSM.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

APPLICABILITY:

This rate schedule represents a Distribution Delivery Stabilization Mechanism (DDSM) and specifies the procedure to be utilized to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the billing period from November 1 through May 1. Service provided under the Company's Residential Rates 60 and 90 and Firm General Service Rates 70 and 92 shall be subject to decreases or increases under the DDSM.

DISTRIBUTION DELIVERY STABILIZATION MECHANISM:

A DDSM will be determined for each customer taking service under Residential Service Rates 60 and 90 and Firm General Service Rates 70 and 92 beginning with the first billing cycle starting November 1 through the billing cycle ending May 1. The DDSM adjustment will be applied as a surcharge or credit on all rate schedules to which the DDSM is applicable.

DDSM ADJUSTMENT CALCULATION:

The DDSM Adjustment shall be determined for each customer taking service under Residential Rates 60 or 90 or Firm General Services Rate 70 or 92. In order to calculate the respective DDSM adjustment, the ratio of the normal HDDs as compared to the actual HDDs will be determined and multiplied by the temperature sensitive consumption per customer per HDD, as determined in the most recent general rate case. The resulting product shall be multiplied by the applicable Distribution Delivery Charge rate per dk.

$$DDSM_i = R_i\,(DDF_i\,((NDD-ADD)/ADD))$$

Where:

$DDSM_i$	=	Distribution Delivery Stabilization Adjustment
i	=	Customer served under Rate Schedules 60, 70, 90 or 92
R_i	=	Applicable Distribution Delivery Charge per dk
DDF_i	=	Temperature sensitive use per customer
NDD	=	Normal degree days for the applicable bill cycle
ADD	=	Actual heating degree days for the applicable bill cycle

Montana-Dakota Utilities Co.
A Division of MDU Resources Group, Inc.
400 N 4th Street
Bismarck, ND 58501

State of North Dakota
Gas Rate Schedule

DISTRIBUTION DELIVERY STABILIZATION MECHANISM Rate 87

DEFINITIONS:

Heating Degree Days	-	The difference between the average of the daily high and low temperatures subtracted from 60 degrees Fahrenheit.
Normal Degree Days	-	The heating degree days based on the 30-year average for the period 1970-2000.
Temperature Sensitive Use per Customer	-	Customer's actual use less the base use per customer per day, denoted below, multiplied by days in the billing period. Residential Rate Code 60 = .06106 Residential Rate Code 90 = .03177 Firm General Service Rate Code 700 = .08313 Firm General Service Rate Code 701 = .87387 Firm General Service Rate Code 920 = .08139 Firm General Service Rate Code 921 = .73984
Actual Degree Days	-	The actual degree days reported by the National Weather Service Stations for applicable service areas in North Dakota weighted by customers.