

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

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

DOCKET NO. PU-399-01-186

PREPARED SURREBUTTAL TESTIMONY OF

J. STEPHEN GASKE

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

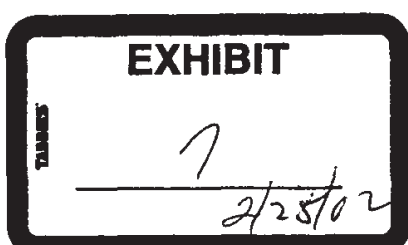
2 A. My name is J. Stephen Gaske and I am President of Zinder Companies,  
3 Inc., 7720 Wisconsin Avenue, Suite B-102 Bethesda, MD 20814.

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

6 A. Yes.

7 **Q3. What is the purpose of your Prepared Surrebuttal Testimony?**

8 A. I have been asked by Montana-Dakota Utilities Co. ("Montana-Dakota") to  
9 evaluate the Rebuttal Testimony of Charles W. King filed on behalf of the Staff of  
10 the North Dakota Public Service Commission ("PSC") on February 11, 2002. In his  
11 rebuttal testimony, Mr. King makes a number of errors in analysis that lead him to  
12 recommend an inadequate allowed rate of return for setting Montana-Dakota's  
13 North Dakota electric rates. Consequently, I will respond to various issues  
14 addressed in Mr. King's rebuttal testimony including: the cost of debt, the need for a  
15 flotation cost adjustment, the dividend yield adjustment to the DCF model, the  
16 relevance of the Risk Premium and Alternative Equity Investment analyses in my



1 Prepared Direct testimony, the selection of a proxy group, and the risk implications  
2 of being a diversified, regulated company.

3 In addition, I have been asked to comment on some of the economic  
4 assumptions that PSC Staff witness Mike Diller has relied upon in attempting to  
5 establish a test-year amount of margins from sales for resale to be credited to North  
6 Dakota ratepayers.

7 Debt Cost

8 **Q4. Do you have any comments on Mr. King's recommended cost of debt for**  
9 **Montana-Dakota?**

10  
11 A. Yes. In his rebuttal testimony, Mr. King concedes that he had incorrectly  
12 calculated the cost of debt for Montana-Dakota in his direct testimony.  
13 Nevertheless, he recommends that the PSC adopt his admittedly incorrect debt cost  
14 because his incorrect number is lower than the correct number. Mr. King's rationale  
15 for recommending use of an incorrect number is that the cost of Montana-Dakota's  
16 debt currently is higher than the cost of debt experienced by some other utilities in  
17 North Dakota. By recommending that the PSC effectively disallow a portion of  
18 Montana-Dakota's debt cost, the implication is that Montana-Dakota has been  
19 imprudent in managing its cost of debt. However, Mr. King does not present any  
20 evidence that the Montana-Dakota debt cost is excessive, unreasonable or  
21 imprudent.

1 **Q5. Is it normal for different utilities to have different costs of debt?**

2 A. Yes. The cost of debt in the capital markets fluctuates over time. As  
3 companies need to issue new debt to finance new plant, or repay existing debt as it  
4 comes due, or for other purposes, they go to the capital markets and must pay the  
5 competitive cost that is available in the market at that time. If all utilities in North  
6 Dakota were to issue all of their debt at the same time, they might have debt costs  
7 that are nearly identical. However, all utilities in North Dakota do not have the same  
8 simultaneous needs to issue debt. Thus, differences in debt costs are often explained  
9 by the vintage of the debt obligations of different utilities.

10 **Q6. How does the vintage of its debt affect Montana-Dakota's debt costs?**

11 A. Because the cost of long-term debt has declined considerably during the  
12 past 15-20 years, the timing of Montana-Dakota's debt issuances explains nearly all  
13 of the differences between Montana-Dakota and the other two North Dakota  
14 comparison utilities referenced by Mr. King. For example, Montana-Dakota's long-  
15 term debt issued after April 1992 has an average cost of 7.31 percent. This is lower  
16 than the 7.68 percent debt costs of Otter Tail Power Company that Mr. King cites in  
17 his rebuttal testimony and very close to Northern States Power Company's 6.99  
18 percent long-term debt costs that he cites.

19 The primary reason that Montana-Dakota has higher debt costs than these  
20 other North Dakota companies is the cost associated with debt refinancing in April  
21 1992. As described in the Prepared Surrebuttal Testimony of Mr. Mahowald, in  
22 order to obtain lower debt costs, Montana-Dakota refinanced a large amount of debt

1 at that time. The costs, as well as the benefits, of this refinancing are still a part of  
2 Montana-Dakota's cost of debt.

3 **Q7. Are there other reasons for the magnitude of the differences between Montana-**  
4 **Dakota and the other utilities?**

5 A. Another reason that Montana-Dakota appears to have higher debt costs  
6 than the other two North Dakota companies may be attributable to differences in the  
7 methods used to calculate Montana-Dakota's debt costs and the debt costs of the  
8 other two utilities. In response to a data request, Mr. King provided a copy of the  
9 calculation of the 6.99 percent debt cost for Northern States Power Company  
10 ("NSP"). This calculation shows that the debt costs were calculated using the same  
11 accounting-based approach that Mr. King advocates in this proceeding. As I  
12 discussed in my Prepared Direct Testimony, and as Mr. King concedes, this  
13 accounting-based calculation understates the effective cost of debt and is contrary to  
14 the usual method of calculating effective debt costs for ratemaking, which uses a  
15 "yield-to-maturity" calculation. If the effective NSP debt costs were to be calculated  
16 using the "yield-to-maturity" approach that is appropriate for ratemaking, the cost of  
17 NSP's debt for ratemaking purposes undoubtedly would be higher than the  
18 "accounting-based" cost. Mr. King also indicated in his data response that he did  
19 not know the details of how the Otter Tail debt cost was calculated.

20 **Q8. What do you conclude with regard to Mr. King's debt cost recommendation?**

21 A. Although Mr. King concludes that Montana-Dakota has "... what *appears*  
22 *to be* an unreasonably high debt cost,"<sup>1</sup> his analysis did not attempt to determine the

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<sup>1</sup> Rebuttal Testimony of Charles W. King, page 2, lines 25-26, emphasis added.



1 companies by trading new shares of its stock for the stock of those companies. As  
2 Mr. King shows, the cost of *exchanging* MDU shares for shares in a company being  
3 acquired are quite low. No additional capital was raised in these transactions and  
4 there were no cash funds raised that could be used to maintain or construct utility  
5 plant. Consequently, costs associated with issuing new stock as part of acquisitions  
6 have no bearing on the costs that Montana-Dakota or MDU Resources would incur  
7 if it needed to attract capital to fund cash investment in its utility operations.

8 MDU also issues new shares through its dividend reinvestment plan  
9 (“DRIP”), and its employee 401K and Stock Option plans. However, none of these  
10 plans has been a significant source of capital for the company in recent years. For  
11 example, no shares have been issued through the DRIP or 401K plans since March  
12 1999. Thus, the cost of issuing these shares tells us little or nothing about MDU’s  
13 cost of attracting capital funds for investment in its electric utility rate base.

14 **Q11. Which of the types of stock issuances shown on Exhibit \_\_\_ (CWK-1R) are**  
15 **relevant for estimating Montana-Dakota’s cost of attracting common equity**  
16 **capital for investment in its electric operations?**

17 A. The most relevant type of issuance is shown on line 4 of Exhibit  
18 \_\_\_ (CWK-1R) and is labeled as “Equity Draw Down.” This line indicates the  
19 flotation costs that MDU Resources has incurred in the recent past in connection  
20 with approximately 90 percent of the new common equity capital amounts raised  
21 through stock issuances that were available for investment in rate base since 1997.  
22 In fact, during the past three years, the “Equity Draw Down” category has accounted  
23 for more than 95 percent of the new common equity capital issued to raise funds that

1 could be invested in rate base. The flotation cost associated with obtaining this  
2 capital was 3.43 percent, computed as follows:

3	Amount Raised	\$157,411,736
4	Flotation Cost	<u>5,214,211</u>
5	Net Funds Available	\$152,197,525
6	Flotation Cost/Net Funds	3.43%

7  
8 Thus, if one focuses on the portion of Mr. King's analysis that is relevant for  
9 estimating Montana-Dakota's cost of attracting new common equity capital for  
10 investment in its electric utility operations, that past experience indicates a cost of  
11 3.43 percent. Since the recent past experience of MDU Resources is close to the  
12 cost experienced by other electric companies on some stock issuances, as shown on  
13 Exhibit No. \_\_\_(JSG-2), Schedule 5, it is clear that the flotation cost adjustment  
14 should be at least 3.43 percent. However, the experience of other electric companies  
15 suggests that a flotation cost adjustment of 4.75 percent is required to ensure that the  
16 allowed rate of return is sufficient to attract capital on reasonable terms.

17 **Q12. Mr. King also objects to the fact that you have applied the flotation cost**  
18 **adjustment to the entire equity amount. Why is this treatment appropriate for**  
19 **setting the allowed rate of return?**

20 A. As I explained in my Prepared Direct Testimony, a healthy company  
21 should be in a position to issue common stock on reasonable terms at all times.  
22 This requires that the entire investor return requirement be increased so that the  
23 stock price is sufficiently above book value that stock can be issued without  
24 diluting the value of existing shareholders' investments. Flotation costs are a  
25 necessary component of the cost of attracting capital. Thus, without a flotation  
26 cost adjustment, the return would be insufficient to "assure confidence in the

1 financial integrity of the enterprise, so as to maintain its credit and to attract  
2 capital.”

3 **Q13. Is the need for a flotation cost adjustment to the entire return widely**  
4 **recognized among economists as a required part of an allowed rate of return**  
5 **that will attract capital without diluting the value of existing investors’ equity?**

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

8 *“...book values (with allowances for the probable need to*  
9 *underprice new common-stock offering) should set a floor to the*  
10 *market values...”*

11  
12 James C. Bonbright, *Principles of Public Utility Rates*, Columbia University  
13 Press, 1961, p. 249. Similarly, Myron Gordon, the man who is credited with  
14 having developed the DCF model for estimating rate of return, has stated that a  
15 regulatory agency should set the allowed rate of return greater than the investor  
16 return requirement so as to allow the firm to issue stock at a price that will yield  
17 net proceeds equal to book value. Professor Gordon advocates the following  
18 adjustment:

19 *“The agency need only estimate the proportion that the proceeds*  
20 *per share on an issue bear to the price of the stock and adjust the*  
21 *allowed rate of return so that the price per share is the indicated*  
22 *ratio of the book value per share. If the proceeds on an issue are*  
23 *91 percent of market price, the agency should maintain market*  
24 *price at about 110 percent of book value.”*

25  
26 Myron J. Gordon, *The Cost of Capital to a Public Utility*, Michigan State  
27 University, 1974, pages 165-166. In order to meet this requirement, the flotation  
28 cost adjustment must be applied to the entire rate of return. The flotation cost

1 adjustment that I have proposed attempts to meet the same standards advocated by  
2 these other economists.

3 **Q14. Mr. King suggests at pages 4-5 that because MDU Resources common stock is**  
4 **selling at a premium to book value, no flotation cost adjustment is required. Do**  
5 **you agree with this assessment?**

6 A. No. MDU Resources is a diversified company with significant  
7 unregulated operations. There is no evidence whatsoever that the North Dakota  
8 electric operations contribute to the fact that MDU Resources' common stock is  
9 selling at a premium over book value. In fact, at a market-to-book ratio of 1.78  
10 MDU Resources' stock premium, 0.78, is less than one-sixth of the 5.23 average  
11 premium for industrial companies.<sup>2</sup> The fact that MDU Resources has such an  
12 exceptionally low premium may be attributable to the relatively lower value of its  
13 regulated operations. With such a low premium for MDU, it is reasonable to  
14 expect that the market value of the North Dakota electric utility operations is  
15 close to, or possibly even less than, book value in order to offset the probable  
16 market-to-book ratios of MDU Resources' other unregulated operations.

17 At page 5, lines 2-3, Mr. King asserts that "(a)ny sales of new MDU's  
18 stock would cause book value appreciation, not dilution." This observation is  
19 correct, but irrelevant for setting an allowed rate of return in this proceeding.  
20 Although the book value can increase when new shares are issued, the effect on  
21 the *market* value of the stock is far more relevant. If MDU Resources invests the  
22 newly-raised equity funds in a regulated operation that has a market value equal

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<sup>2</sup> The average market-to-book ratio for the S&P Industrial Index is 6.23 according to *Barron's*, February 11, 2002, page MW 46.

1 to book value, it drives down the market value of existing investors' stock by an  
2 amount equal to the flotation costs. Thus, in the absence of a flotation cost  
3 adjustment to the investor-required return, Mr. King's recommendation would be  
4 relying on MDU Resources' investors to cross-subsidize the North Dakota electric  
5 operations by forfeiting a portion of the value of their unregulated operations if  
6 there is a need to issue stock to finance the North Dakota electric operations.

7 **Selection of Combination Companies as Electric Proxies**

8 **Q15. At page 5, lines 20-25 of his Rebuttal Testimony, Mr. King asserts that the fact**  
9 **that two groups of companies do not have statistically significant difference in**  
10 **the averages of their DCF results "does not mean that the risks are not**  
11 **different ... and the required returns are not higher." Is this observation**  
12 **germane to the point that you made in your Direct Testimony?**

13 A. No. In his Direct Testimony at page 23, lines 1-9 Mr. King asserted that  
14 the difference in risk between electric companies and combination companies is  
15 shown by the fact that his combination company group has a lower average DCF  
16 result than his electric company group. Because Mr. King suggested that the  
17 difference in DCF results implies a lower risk and return requirement for  
18 combination companies, I performed a statistical test of Mr. King's proffered  
19 evidence. This test indicated that Mr. King could not assert that a difference in  
20 the average returns necessarily implies a difference in risk as between the two  
21 groups. I would agree with Mr. King that the DCF results for the two groups does  
22 not mean that the risks are not different. However, as my Direct Testimony  
23 demonstrated it also would be wrong to suggest that the DCF results mean that the

1 risks are different. The point is that no risk conclusions can be drawn from the  
2 DCF results.

3 **Q16. Even if there are other reasons for believing that combination companies have**  
4 **different risks than electric companies, would Mr. King be correct in throwing**  
5 **out the results for electric companies and replacing these with results for**  
6 **combination companies?**

7 A. No. As I discuss at pages 23-25 of my Prepared Direct Testimony, the  
8 purpose of this proceeding is to set rates for electric operations. Consequently, it  
9 is most appropriate to use a proxy group of companies that have a high percentage  
10 of their business in electric operations. It may be true that a diversified company,  
11 such as a combination company or a conglomerate, poses less risk to stockholders  
12 than any of its subsidiaries individually, but that does not mean that those  
13 individual operations have a lower risk or cost of capital by virtue of being part of  
14 a diversified combination company or conglomerate. Indeed, Mr. King indicated  
15 at page 13, lines 15-17 that his purpose was to determine a rate of return for  
16 equity capital investment in Montana-Dakota's North Dakota electric operations.  
17 However, in the conduct of his study he abandoned that goal and replaced it with  
18 the goal of setting a rate of return for a combination company.

19 **Q17. Is Mr. King's intuitive reason for using combination companies in place of**  
20 **electric companies correct?**

21 A. No. His reasoning is incorrect for two reasons.

22 First, as a general matter, ownership of natural gas distribution operations  
23 does not reduce the risk of investing in electric utility operations as Mr. King

1 claims. For example, if Montana-Dakota invests \$50 million in a new electric  
2 generating plant and its customers decide that they do not want to use electricity  
3 but, instead, prefer to use natural gas, Montana-Dakota's investment in electric  
4 plant would become worthless. This is true regardless of who owns the local  
5 natural gas distribution company. If the customers all switch to natural gas for all  
6 of their energy needs, Montana-Dakota would then need to go out and invest  
7 additional funds in its natural gas operations to accommodate the increase in  
8 demand for natural gas and, under regulated ratemaking, it should get additional  
9 revenues associated with that increased investment in natural gas plant. However,  
10 that increased investment and revenue on the gas side would not change the fact  
11 that the electric plant is rendered worthless. Consequently, the decision to invest  
12 in electric plant depends solely upon the risk of the electric operations.

13 **Q18. Could there be circumstances under which Mr. King's theory, stated at page**  
14 **23, lines 5-9 of his Direct Testimony, is correct that a combination company has**  
15 **lower risks associated with investing in electric plant because "... when it offers**  
16 **both gas and electricity, it has a reasonable guarantee that regardless of**  
17 **changes in heating technology or consumer preference, it will control most of**  
18 **the market for heating fuel?"**

19 A. Yes. Investors are not so much concerned with the total share of the fuels  
20 market that a company "controls" as they are concerned about whether they will  
21 recover the costs of their investments plus a reasonable return on those  
22 investments. It is the risk associated with cost recovery that concerns investors  
23 when they commit capital to an operation. This risk could be reduced in a

1 combination company if, for example, the North Dakota PSC were to adopt a  
2 policy that Montana-Dakota's electric utility costs will be recovered in an adder to  
3 its rates for natural gas distribution service any time Montana-Dakota loses  
4 electric business to its natural gas distribution operation. In that unlikely  
5 circumstance, any revenue and cost recovery that cannot be obtained from electric  
6 operations would be recovered from natural gas customers and Mr. King's theory  
7 would be correct that risks of recovering costs invested in electric plant are  
8 relatively unaffected "regardless of changes in heating technology or consumer  
9 preference."

10 **Q19. Has the North Dakota PSC guaranteed that any stranded electric investments**  
11 **can be recovered from gas distribution customers?**

12 A. No, and it is unlikely that the PSC has the statutory authority to include  
13 electric costs in gas rates. For that reason, Mr. King's reasoning is simply  
14 incorrect. The risk of investing capital in electric operations is not reduced by  
15 virtue of being a combination company and the correct proxy group for setting  
16 electric rates would include electric companies, even if they do not also own gas  
17 distribution operations.

18 **Q20. What is the other reason that Mr. King is wrong about the effect of being a**  
19 **combination company on the Montana-Dakota's risk of electric operations?**

20 A. He has provided an incomplete analysis of the gas and electric operations  
21 of Montana-Dakota. For example, at page 6, lines 19-24, he cites the fact that  
22 some of Montana-Dakota's North Dakota customers use electricity for space

1 heating and water heating. However, a large portion of those customers are  
 2 located in areas where natural gas is not available.

3 **Selection of Electric Companies as Electric Proxies**

4 **Q21. Mr. King objects to the use of three companies in your proxy group that derive**  
 5 **more than 75 percent, but less than 85 percent, of their revenues from electric**  
 6 **operations. Do you agree with his reasons for attempting to exclude such**  
 7 **companies from the proxy group?**

8 A. No. On page 7, line 19 to page 8, line 4 Mr. King indicates that he objects  
 9 to including these companies in the proxy group primarily because they have  
 10 required returns that are above average. At page 8, lines 7-9 Mr. King also says  
 11 that these three companies should be excluded because:

12 “In each case, the driving factor in investors’ assessments of these  
 13 companies is either their *wholesale electric operations, which are*  
 14 *effectively unregulated*, or their non-utility operations.”  
 15 (Emphasis added.)  
 16

17 However, as shown below, these three companies derive a greater share of their  
 18 revenue from electric operations than at least three companies that Mr. King  
 19 would prefer to include in the proxy group:<sup>3</sup>

Companies Excluded By Mr. King	% Electric Revenue	Companies Included By Mr. King	% Electric Revenue
IDACORP	82.0	Consolidated Edison	73.6
American Electric Pwr.	79.1	Alliant	68.5
Cleco Corp.	75.5	Energy East	68.4

20  
 21 Under the circumstances, it is difficult to understand what principle Mr. King  
 22 could invoke to exclude the three companies that derive more than 75 percent of

<sup>3</sup> Exhibit No. \_\_\_(JSG-2), Schedule 3, Page 1.

1 their revenue from regulated electric operations and replace them with three  
2 companies that derive less revenue from regulated electric operations.

3 **Q22. In your opinion, are companies that derive revenues from wholesale electric**  
4 **operations comparable to Montana-Dakota's electric operations?**

5 A. Yes. The primary impetus for this proceeding was the revenues that  
6 Montana-Dakota derived from wholesale electric operations when wholesale electric  
7 demand and prices were unusually high. The Staff of the PSC is advocating that  
8 expected future wholesale revenues be credited to the retail cost of service for the  
9 benefit of North Dakota ratepayers. Consequently, those companies that Mr. King  
10 would exclude because they also sell power in wholesale markets are precisely those  
11 companies that are most comparable to Montana-Dakota's North Dakota electric  
12 operations. In this regard, the *Value Line* summary for IDACORP that Mr. King  
13 quotes at page 8 of his Rebuttal testimony is particularly germane. A portion of the  
14 summary that Mr. King did not quote states the following:

15 *"Earnings probably won't match 2000's record performance.*  
16 *Though wholesale energy sales were strong, they will be less than*  
17 *those of last year. ... Thus, despite a 2% increase in retail sales, we*  
18 *estimate a 7% decline in 2001 earnings, to \$3.25 a share. An*  
19 *expected drop in wholesale energy prices indicates a further*  
20 *decline next year."*<sup>4</sup>

21  
22 In this respect, IDACORP is very similar in risks to Montana-Dakota. Nevertheless,  
23 Mr. King would exclude IDACORP from the proxy group specifically for that  
24 reason which makes it most similar in risk to the Montana-Dakota North Dakota  
25 electric operations.

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<sup>4</sup> *Value Line*, page 1786, November 16, 2001, emphasis added.

**Dividend Yield Adjustment Factor**

1

2 **Q23. Is Mr. King correct in his description and assessment of the 0.625g dividend**  
 3 **yield adjustment factor that you recommend?**

4 A. No. Mr. King's first error occurs at page 9, lines 7-8 when he says that my  
 5 0.625g factor "assumes that the investor will not receive his/her first dividend until  
 6 exactly three months from the date of purchase." This statement is incorrect.  
 7 Attached as Exhibit \_\_\_(JSG-4), Schedule 1 is a copy of the response that was  
 8 provided to Mr. King's request for the derivation of the 0.625g factor. That response  
 9 clearly indicates that if one assumes that the investor will not receive his/her first  
 10 dividend until exactly three months from the date of purchase, the correct adjustment  
 11 factor is **0.75g**. Thus, it is clear that the 0.625g is not based on that assumption.

12 Mr. King's second error occurs at page 9, lines 8-9 where he says that  
 13 "(t)he average for the next dividend increase is thus  $(.25+.50+.75+1.0)/4 = .625$ ."  
 14 However, as shown on the attached data response this calculation of Mr. King's mis-  
 15 states the source and derivation of the 0.625g factor. Instead, the 0.625 is the  
 16 average of two far more complex calculations that incorporate the timing and time  
 17 value of both dividends and dividend growth. The assumptions and results of these  
 18 two complex calculations can be summarized as follows:

<u>First Dividend Received In:</u>	<u>Dividend Increase In:</u>	<u>Factor Derived</u>
3 months	6 months	0.75
0 months	6 months	<u>0.50</u>
<b>Average</b>		<b>0.625</b>

19

20 Thus, the 0.625 factor is the average of the assumption that the first dividend is  
 21 received in (i) 3 months, and (ii) it is received immediately. The average of these

1 two assumptions approximates the assumption that the first dividend could be  
2 received at any time during the first three months. In addition, both calculations  
3 assume that the dividend increase occurs in 6 months, which is consistent with Mr.  
4 King's assumption.

5 Mr. King's third error occurs when he states that his .5g factor reflects the  
6 assumption that the dividend increase is randomly distributed throughout the year  
7 and that the average delay in the dividend increase under Mr. King's assumption is  
8 one-half a year. As shown in the preceding paragraph and the attached data  
9 response, Mr. King's 0.5g factor is correct only in the extreme case that the next  
10 dividend is to be received immediately upon purchase of the stock, with no delay.  
11 However, if one must wait 3 months for the first dividend, the correct factor is 0.75g.  
12 The average of these two extremes produces the most reasonable dividend  
13 adjustment factor: 0.625g.

14 **Q24. If you and Mr. King both agree that it is most reasonable to assume that the**  
15 **next dividend increase is one-half year away, why is the appropriate dividend**  
16 **adjustment factor 0.625 and not 0.5?**

17 A. Although Mr. King is correct about the assumed timing of the dividend  
18 increase, his error occurs when he mistakenly concludes that the timing assumption  
19 is identical to value. However, one of the salient features of the DCF model is that it  
20 also incorporates the time value of money in order to find the cost of capital that  
21 equates the market price of a share of stock with the expected timing and amount of  
22 future dividends. For example, if there is a 50% chance that a dividend increase will  
23 occur at the beginning of the year and a 50% chance that it will occur at the end of

1 the year, the average expected timing of the dividend increase would be at mid-year.  
2 However, because a dividend increase received at the beginning of the year has a  
3 greater discounted present value than a dividend increase received at the end of the  
4 year, the effect of a mid-year timing assumption results in a dividend adjustment  
5 factor that is greater than one-half.

6 **Significance of Benchmark Analyses**

7 **Q25. At pages 9-11, Mr. King criticizes your benchmark analyses. Are his criticisms**  
8 **misplaced?**

9 A. Yes. For example, in discussing my Risk Premium analyses Mr. King sets up a  
10 “straw man” by stating that “(t)he theory is that over a long enough period, actual  
11 return differentials between stocks and bonds will equate to required or expected  
12 return differentials.” However, that is neither my theory nor the theory that  
13 guides how I have used these analyses.

14 The return required by investors is estimated by my DCF analysis. But it is  
15 also true that when investors decide to purchase common stocks, rather than buy a  
16 new car or invest in long-term bonds, they are aware of and influenced by the  
17 premium that common stocks have historically earned relative to bonds. In fact, if  
18 the long-term average premium were zero or negative, it is doubtful that investors  
19 would purchase common stocks or make any equity investments at all. Indeed,  
20 through the workings of competitive markets equity investments, stock prices and  
21 bond yields all interact to force the long-term average premium to be a positive  
22 number. On a year-to-year basis, actual results are bound to differ from the long-  
23 term average and the expected risk premiums that investors require will vary

1 significantly. However, the Risk Premium analysis is a good benchmark to  
2 determine whether the return generated by my DCF analyses is within a reasonable  
3 ballpark relative to historic average risk premiums. The greater the difference  
4 between the DCF results, the more one would have to question whether the DCF  
5 results are valid. Thus, although I do not believe that the Risk Premium results are  
6 equal to the required rate of return, such results still provide an important perspective  
7 for evaluating the DCF results.

8 **Q26. Are Mr. King's criticisms of your Alternative Equity Investment analysis**  
9 **similarly misplaced?**

10 A. Yes. I have no doubt that investors in electric utility assets similar to Montana-  
11 Dakota's North Dakota operations do not require the 29.4 percent return on  
12 average book value that investors in industrial companies have achieved in recent  
13 years. However, that is the level of returns that Montana-Dakota must compete  
14 against in attracting capital.

15 An allowed rate of return established by the DCF method should make the  
16 value of the electric operations equal to the book value of those operations in the  
17 absence of a flotation cost adjustment. In other words, the purpose of the DCF  
18 analysis is to find the rate of return that will make investors indifferent between  
19 investing to provide electric service to the public or investing in, for example,  
20 U.S. Treasury bills. In contrast, when investors or corporations invest in non-  
21 regulated assets the market value of those investments has been many times the  
22 book value.

1                   Consequently, when managers of a company evaluate possible  
2 investments they must consider the possibility of investing \$1.00 in electric utility  
3 assets with the expectation that the market value of those assets will be \$1.00 and,  
4 thus, no value will be created for investors. On the other hand, when managers  
5 invest \$1.00 in non-utility assets, they have a reasonable possibility of earning a  
6 29 percent return on that investment and turning \$1.00 of book value into \$6.23 of  
7 market value.<sup>5</sup> Thus, while Montana-Dakota does not require anything close to a  
8 return of 29 percent on its electric investments, knowledge of such average  
9 returns that Montana-Dakota must compete against helps place Montana-Dakota's  
10 required rate of return of 12.75 percent in perspective.

11                   **Factors Affecting Sales for Resale Margins**

12 **Q27. What is the difference in the estimates of sales for resale advocated by Mr.**  
13 **Diller for the PSC Staff and the estimates developed by Mr. Blinsky of**  
14 **Montana-Dakota?**

15 A.               At page 3 of his Rebuttal Testimony, Mr. Diller advocates use of a sales for  
16 resale margin of \$13,667,000 based on 2001 actual sales for resale data. In contrast,  
17 Montana-Dakota estimates a margin of \$7,247,000. The primary difference in their  
18 results occurs because Mr. Diller has not adjusted his test-year data for changes that  
19 have occurred in the wholesale markets for electricity, whereas Mr. Blinsky has  
20 made such adjustments.

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<sup>5</sup> The average market-to-book ratio for the S&P Industrial Index is 6.23 according to *Barron's*, February 11, 2002, page MW 46.

1 **Q28. At page 11 of his Rebuttal Testimony, Mr. Diller indicates that the Commission**  
2 **should use actual results and he indicates that adjustments to reflect prices in**  
3 **the futures markets should not be used. Are futures prices an accurate**  
4 **indicator of expected future prices?**

5 A. Yes. Although actual results in the future undoubtedly will vary from the  
6 current prices in futures markets, these futures prices provide the best estimate of  
7 prices that can be expected in the future.

8 In fact, prices projected by reference to the futures market can be virtually  
9 assured of becoming actual results for a significant portion of the expected sales for  
10 resale if a seller currently locks in the futures price by selling a futures contract that  
11 commits it to sell electricity in the future at a certain price. Such a sale of a futures  
12 contract is referred to as “hedging” when the seller expects that it will actually make  
13 such sales at the market-based price that prevails in the future. By selling a futures  
14 contract that covers a significant portion of its expected sales for resale output, if  
15 actual prices are lower than the price specified in the futures contract, the electricity  
16 seller will sell its output at the lower-than-expected price, but will also make a profit  
17 on its futures contract. The sum of the actual sales revenue, plus the profit on the  
18 futures contract, less the brokerage fees and other expenses associated with the  
19 futures contract, should provide an effective actual price very close to the price  
20 projected by using the futures market to estimate likely prices. Conversely, if actual  
21 market prices turn out to be higher than the price specified in the futures contract, the  
22 company will sell its output at the higher-than-expected market price, but lose

1 money on the futures contract, so that the effective actual price would still be very  
2 close to the price projected by the futures market.

3 In other words, prices in the futures market are a reliable, unbiased estimate  
4 of the market prices that will be available in the future and should be used for  
5 making test-year adjustments to the sales-for-resale price used to set Montana-  
6 Dakota's rates.

7 **Q29. Is MDU likely to replicate the unusually large sales for resale margins that it**  
8 **generated in 2000 and 2001?**

9 A. No. That was a very unusual period of time in the energy markets when  
10 several factors converged to create high prices for wholesale electric power. Natural  
11 gas prices had temporarily spiked to exceptionally high levels, a drought in the  
12 western states had reduced the amount of hydroelectric power available, and the  
13 economy was strong and had grown rapidly. All of these factors combined to create  
14 very high demand and prices for wholesale electric power. However, these unusual  
15 conditions are not likely to be present in the near future.

16 **Q30. Please describe the changes in the overall U.S. economy that have occurred**  
17 **during the past several years.**

18 A. Measures of economic activity can be seen in Exhibit No. \_\_\_(JSG-2),  
19 Schedule 1, page 1 and Exhibit \_\_\_(JSG-4), Schedule 4, pages 2, 3, 5 and 6. After  
20 growing rapidly from 1997 to 2000 the U.S. economy entered a recession during the  
21 second half of 2001 and continues to be shrinking.

22 In addition, as shown on page 2 of Schedule 2 of Exhibit \_\_\_(JSG-4),  
23 manufacturing production increased to very high levels in 2000 and 2001, but it is

1 projected to be at significantly lower levels in 2002. As discussed in the Direct  
2 Testimony of Mr. Blinsky, this rapid growth placed strains on the electric and  
3 natural gas infrastructure and contributed to unusually high energy prices in 2000  
4 and 2001. However, the combination of reduced manufacturing production and  
5 large amounts of new, efficient electric generation coming on-line has contributed to  
6 an expectation of greatly reduced energy prices during the next year.

7 **Q31. How does the price of natural gas affect prices in wholesale electric power**  
8 **markets?**

9 A. As discussed in the testimony of Mr. Schiffman, gas-fired generation  
10 competes directly with coal-fired generation in the wholesale electric power  
11 markets. When the price of natural gas increases, the cost of gas-fired generation  
12 also increases, thereby generally driving up the overall market price of electricity.  
13 During the past several years, companies with coal-fired generation, such as  
14 Montana-Dakota, have been able to achieve exceptionally high margins on their  
15 sales for resale because the price of coal has remained relatively constant while the  
16 price of gas temporarily spiked at unusually high levels. In fact Montana-Dakota's  
17 costs of coal at several plants actually declined during the past several years.<sup>6</sup>

18 **Q32. How have natural gas prices changed during the past few years?**

19 A. As shown on page 1 of Schedule 2, average natural gas prices increased from  
20 approximately \$2.50 in the 1998-1999 time frame to approximately \$4.40 in the  
21 years 2000 and 2001. In other words, average natural gas prices increased  
22 approximately 75 percent in the 2000-2001 time period. A number of factors

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<sup>6</sup> Testimony of Mike Diller, page 31.

1 contributed to this large increase in natural gas prices. For example, low water  
2 conditions reduced the amount of hydroelectric generation available in 2000 and  
3 2001 and caused an increase in gas-fired generation. This larger than normal use of  
4 natural gas during summer months, combined with record cold weather in the east  
5 during the Winter of 2000-2001, reduced natural gas storage stocks and increased  
6 the effective market price associated with natural gas transportation and also drove  
7 up the well-head price of natural gas.

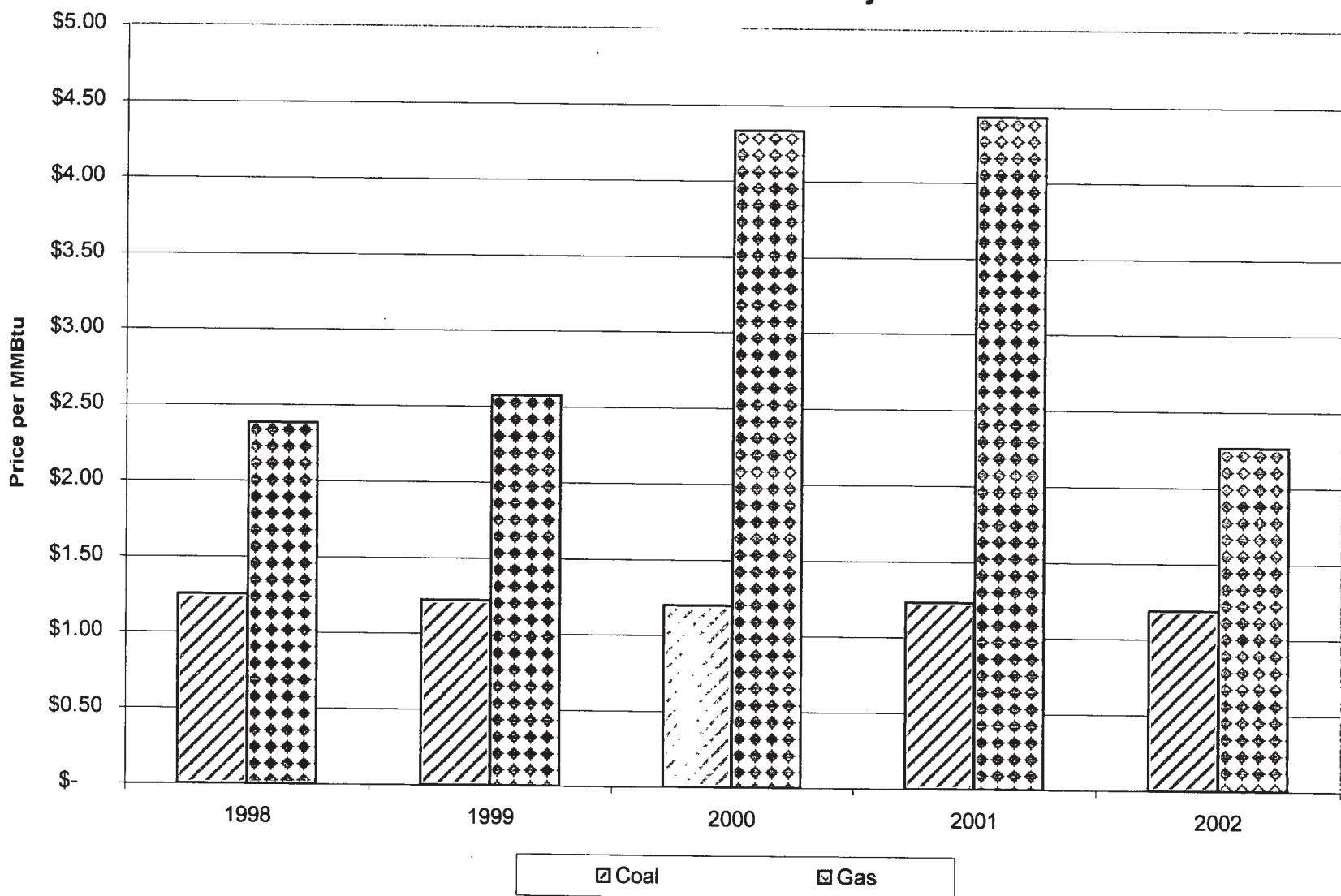
8 **Q33. Are high natural gas prices expected to persist in the future?**

9 A. No. As shown on page 1 of Schedule 2, the average price of natural gas is  
10 projected to decrease to approximately \$2.25 in 2002. This is lower than the average  
11 price of natural gas in any year of the years 1998 to 2001. In fact, it is  
12 approximately one-half of the high average prices experienced during the years 2000  
13 and 2001. Consequently, the cost of gas-fired generation in 2002 is projected to be  
14 lower than it has been at any time during the past four years and far lower than it  
15 was in 2000 and 2001. This greatly reduced gas price, combined with an increased  
16 amount of new, efficient gas-fired generation, should cause a significant decline in  
17 wholesale electric prices in 2002.

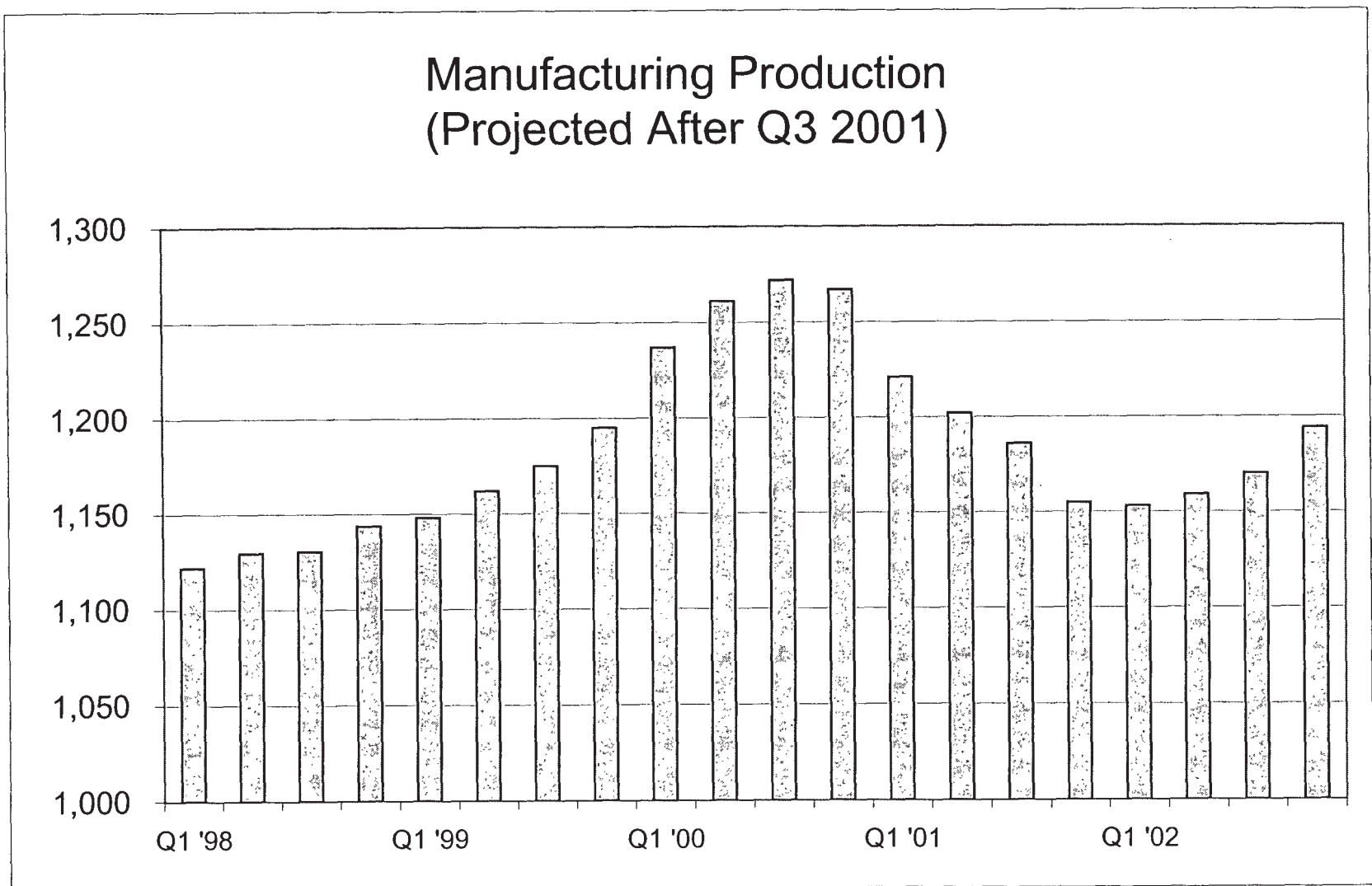
18 **Q34. Does this conclude your Prepared Surrebuttal Testimony?**

19 A. Yes.  
20  
21  
22

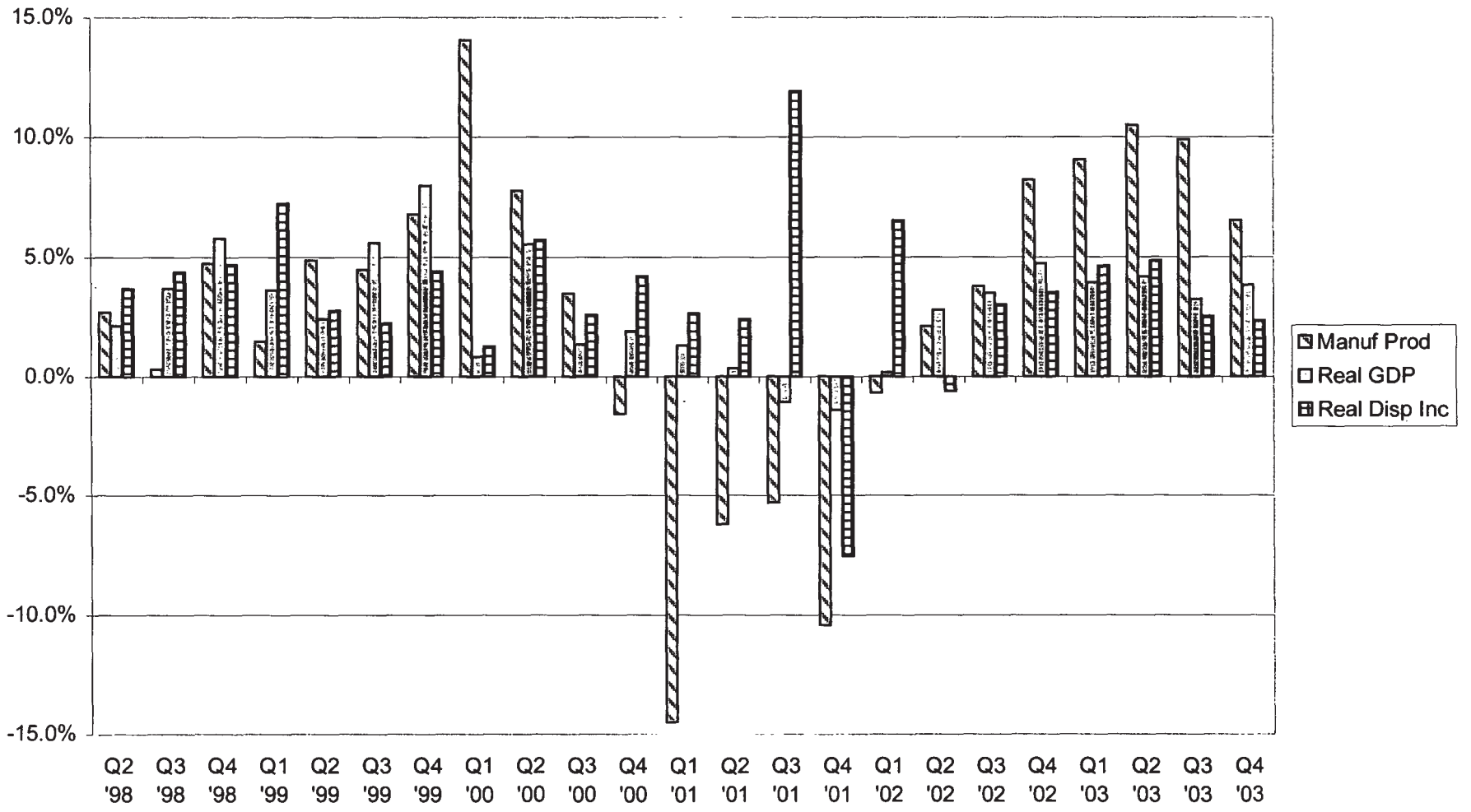
### Average Annual U.S. Energy Prices 1998-2001 Actual - 2002 Projected



Source: U.S. Dept. of Energy, Energy Information Administration, *Short-Term Energy Outlook*, February 2002.



### U.S. Macroeconomic Factors % Change



Annual Average U.S. Energy Prices  
 Cost per MMBtu

Line No.	Description	Year					
		1998	1999	2000	2001 Estimated	2002 Estimated	2003 Estimated
<u>Electric Utility Fuels</u>							
1	Coal	\$ 1.25	\$ 1.22	\$ 1.20	\$ 1.23	\$ 1.19	\$ 1.18
2	Natural Gas	\$ 2.38	\$ 2.57	\$ 4.33	\$ 4.43	\$ 2.26	\$ 2.86

Source: Energy Information Administration/Short-Term Energy Outlook- February 2002. Table A4

Quarterly Data on the Economy

Line No.	Description	1998				1999				2000			
		1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
1	Real GDP *	8,405	8,450	8,528	8,652	8,730	8,783	8,906	9,084	9,103	9,229	9,260	9,304
2	Manuf Production **	1,122	1,130	1,130	1,144	1,148	1,162	1,175	1,195	1,237	1,261	1,272	1,267
3	Real Disposable Personal Income ***	5,960	6,015	6,081	6,153	6,264	6,307	6,342	6,412	6,432	6,524	6,566	6,635
<u>Percentage Change From Previous Qtr.</u>													
4	Real GDP		0.92%	1.10%	1.17%	1.81%	0.69%	0.55%	1.10%	0.31%	1.43%	0.64%	1.05%
5	Manuf Production		0.67%	0.07%	1.19%	0.37%	1.22%	1.12%	1.70%	3.51%	1.94%	0.87%	-0.39%
6	Real Disposable Personal Income		0.53%	0.93%	1.44%	0.91%	0.61%	1.40%	2.00%	0.21%	1.38%	0.34%	0.48%
<u>Annualized Percentage Change From Previous Qtr.</u>													
7	Real GDP		3.7%	4.4%	4.7%	7.2%	2.7%	2.2%	4.4%	1.2%	5.7%	2.6%	4.2%
8	Manuf Production		2.7%	0.3%	4.7%	1.5%	4.9%	4.5%	6.8%	14.1%	7.8%	3.5%	-1.6%
9	Real Disposable Personal Income		2.1%	3.7%	5.8%	3.6%	2.4%	5.6%	8.0%	0.8%	5.5%	1.3%	1.9%

\* - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted upward by 8730/8013.  
 \*\* - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted downward by 1148/1369.  
 \*\*\* - In 1999 the base year changed from 1992 to 1996, therefore 1998 amounts are adjusted upward by 6264/5796.

Source: Energy Information Administration/Short-Term Energy Outlook- Dec. 1999, Dec. 2000, Dec. 2001, and Feb. 2002. Table 1

Line No.	Description	2001				2002 Estimated				2003 Estimated			
		1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.Est.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.	1st Qtr.	2nd Qtr.	3rd Qtr.	4th Qtr.
1	Real GDP *	9,334	9,342	9,317	9,284	9,288	9,353	9,435	9,547	9,641	9,742	9,821	9,915
2	Manuf Production **	1,221	1,202	1,186	1,155	1,153	1,159	1,170	1,194	1,221	1,253	1,284	1,305
3	Real Disposable Personal Income ***	6,679	6,719	6,919	6,788	6,899	6,888	6,940	7,001	7,082	7,168	7,213	7,255
<u>Percentage Change From Previous Qtr.</u>													
4	Real GDP	0.66%	0.60%	2.98%	-1.89%	1.64%	-0.16%	0.75%	0.88%	1.16%	1.21%	0.63%	0.58%
5	Manuf Production	-3.63%	-1.56%	-1.33%	-2.61%	-0.17%	0.52%	0.95%	2.05%	2.26%	2.62%	2.47%	1.64%
6	Real Disposable Personal Income	0.32%	0.09%	-0.27%	-0.35%	0.04%	0.70%	0.88%	1.19%	0.98%	1.05%	0.81%	0.96%
<u>Annualized Percentage Change From P</u>													
7	Real GDP	2.7%	2.4%	11.9%	-7.6%	6.5%	-0.6%	3.0%	3.5%	4.6%	4.9%	2.5%	2.3%
8	Manuf Production	-14.5%	-6.2%	-5.3%	-10.5%	-0.7%	2.1%	3.8%	8.2%	9.0%	10.5%	9.9%	6.5%
9	Real Disposable Personal Income	1.3%	0.3%	-1.1%	-1.4%	0.2%	2.8%	3.5%	4.7%	3.9%	4.2%	3.2%	3.8%

\* - In 1999 the base year changed from  
\*\* - In 1999 the base year changed from  
\*\*\* - In 1999 the base year changed from

Source: Energy Information Administrat