YEAR ENDING 2004

# ANNUAL REPORT
OF

# Montana-Dakota Utilities Company

## GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

# Gas Annual Report

Instructions

## General

1. A Microsoft EXCEL 2000 workbook of the annual report is being provided on computer disk for your convenience. The workbook contains the schedules of the annual report. Each schedule is on the worksheet named that schedule. For example, Schedule 1 is on the sheet titled "Schedule 1 . By entering your company name in the cell named "Company" of the first worksheet, the spreadsheet will put your company name on all the worksheets in the workbook. The same is true for inputting the year of the report in the cell named "YEAR". You can "GOTO" the proper cell by using the F5 key and selecting the name of the cell.

2. The workbook contains input sections that are unprotected, and non-input sections that are protected. Cell protection can be disabled or enabled through "TOOLS – PROTECTION – UNPROTECT SHEET" on your toolbar. Formulas and checks are built into most of the templates.

3. Use of the disk is optional. The disk and the report cover shall be returned when the report is filed. There are macros built into the workbook to assist you with the report. An explanation of the macros is on the "Control" worksheet at the front of the workbook. The explanations start at cell A1.

4. All forms must be filled out in permanent ink and be legible. Note: Even if the computer disk is used, a printed version of the report shall be filed. **Please submit one unbound copy of the annual report along with the regular number of annual reports that you submit.** This aids in scanning the report so that it may be published on our web site. The orientation and margins are set up on each individual worksheet and should print on one page. If you elect not to use the disk, please format your reports to fit on one 8.5 by 11 page with the left binding edge (top if landscaped) set at .85 , the right edge (bottom if landscaped) set at .4 , and the remaining two margins at .5 . You may select specific schedules to print – See the worksheet "CONTROL".

5. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

6. Where space is a consideration, information on financial schedules may be rounded to thousands of dollars. Companies submitting schedules rounded to thousands shall so indicate at the top of the schedule.

7. Where more space is needed or more than one schedule is needed additional schedules may be attached and shall be included directly behind the original schedule to which it pertains and be labeled accordingly (for example, Schedule 1A).

8. The information required with respect to any statement shall be furnished as a minimum requirement to which shall be added such further information as is necessary to make the required schedules not misleading.
9. All companies owned by another company shall attach a corporate structure chart of the holding company.

10. Schedules that have no activity during the year or are not applicable to the respondent shall be marked as not applicable and submitted with the report.

11. The following schedules shall be filled out with information on a total company basis:

    Schedules 1 through 5
    Schedules 6 and 7
    Schedule 14
    Schedule 17 and 18
    Schedules 23 through 26
    Schedule 33

    All other schedules shall be filled out with either Montana specific data, or both total company and Montana specific data, as indicated in the schedule titles and headings.

    Financial schedules shall include all amounts originating in Montana or allocated to Montana from other jurisdictions.

12. For schedules where information may be provided using Mcf or Dkt, circle Mcf or Dkt to indicate which measurement is being reported. (For example, schedules 28, 32, 33 and 34).

13. FERC Form-2 sheets may not be substituted in lieu of completing annual report schedules.

14. Common sense must be used when filling out all schedules.

## Specific Instructions

**Schedules 6 and 7**

1. All transactions with affiliated companies shall be reported. The definition of affiliated companies as set out in 18 C.F.R. Part 201 shall be used.

2. Column (c). Respondents shall indicate in column (c) the method used to determine the price. Respondents shall indicate if a contract is in place between the Affiliate and the Utility. If a contract is in place, respondents shall indicate the year the contract was initiated, the term of the contract and the method used to determine the contract price.

3. Column (c). If the method used to determine the price is different than the previous year, respondents shall provide an explanation, including the reason for the change.

**Schedules 8, 18, and 23**

1. Include all notes to the financial statements required by the FERC or included in the financial statements issued as audited financial statements. These notes shall be included in the report directly behind the schedules and shall be labeled appropriately (Schedule 8A, etc.).

**Schedule 12**

1. Respondents shall disclose all payments made during the year for services where the aggregate payment to the recipient was $5,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall report aggregate payments of $25,000 or more. Utilities having jurisdictional revenue

equal to or in excess of $10,000,000 shall report aggregate payments of $75,000 or more. Payments must include fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payment for services or as a donation.

**Schedule 14**

1. Companies with more than one plan (for example, both a retirement plan and a deferred savings plan) shall complete a schedule for each plan.

2. Companies with defined benefit plans must complete the entire form using FASB 87 and132 guidelines.

3. Interest rate percentages shall be listed to two decimal places.

**Schedule 15**

1. All changes in the employee benefit plans shall be explained in a narrative on lines 15 and 16. All cost containment measures implemented in the reporting year shall be explained and quantified in a narrative on lines 15 and 16. All assumptions used in quantifying cost containment results shall be disclosed.

2. Schedule 15 shall be filled out using FASB 106 and 132 guidelines.

**Schedule 16**

1. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

2. The above compensation items shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

**Schedule 17**

1. Respondents shall provide all executive compensation information in conformance with that required by the Securities and Exchange Commission (SEC) (Regulation S-K Item 402, Executive Compensation).

2. Include in the "other" column ALL additional forms of compensation, including, but not limited to: deferred compensation, deferred savings plan, profit sharing, supplemental or non-qualified retirement plan, employee stock ownership plan, restricted stock, stock options, stock appreciation rights, performance share awards, dividend equivalent shares, mortgage payments, use of company cars or car lease payments, tax preparation consulting, financial consulting, home security systems, company-paid physicals, subscriptions to periodicals, memberships, association or club dues, tuition reimbursement, employee discounts, and spouse travel.

3. All items included in the "other" compensation column shall be listed separately. Where more space is needed additional schedules may be attached directly behind the original schedule.

4. In addition, respondents shall attach a copy of the executive compensation information provided to the SEC.

**Schedule 24**

1. Interest expense and debt issuance expense shall be included in the annual net cost column.

**Schedule 26**

1. Earnings per share and dividends per share shall be reported on a quarterly basis and entries shall be made only to the months that end the respective quarters (for example, March, June, September, and December.)

2. The retention and price/earnings ratios shall be calculated on a year end basis. Enter the actual year end market price in the "TOTAL Year End" row. If the computer disk is used, enter the year end market price in the "High" column.

**Schedule 27**

1. All entries to lines 9 or 16 must be detailed separately on an attached sheet.

2. Only companies who have specifically been authorized in a Commission Order to include cash working capital in ratebase may include cash working capital in lines 9 or 16. Cash working capital must be calculated using the methodology approved in the Commission Order. The Commission Order specifying cash working capital shall be noted on the attached sheet.

2. Indicate, for each adjustment on lines 28 through 46, if the amount is updated or is from the last rate case. All adjustments shall be calculated using Commission methodology.

**Schedule 28**

1. Information from this schedule is consolidated with information from other Utilities and reported to the National Association of Regulatory Utility Commissioners (NARUC). Your assistance in completing this schedule, even though information may be located in other areas of the annual report, expedites reporting to the NARUC and is appreciated.

**Schedule 31**

1. This schedule shall be completed for the year following the reporting year.

2. Respondents shall itemize projects of $50,000 or more. Utilities having jurisdictional revenue equal to or in excess of $1,000,000 shall itemize projects of $100,000 or more. Utilities having jurisdictional revenue equal to or in excess of $10,000,000 shall itemize projects of $1,000,000 or more. All projects that are not itemized shall be reported in aggregate and labeled as Other.

**Schedule 34**

1. In addition to a description, the year the program was initiated and the projected life of the program shall be included in the program description column.

2. On an attached sheet, define program "participant" and program conservation "unit" for each program. Also, provide the number of program participants and the number of units acquired or processed during this reporting year.

# Gas Annual Report

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## IDENTIFICATION

Year: 2004

| | | |
|---|---|---|
| 1. | Legal Name of Respondent: | MDU Resources Group, Inc. |
| 2. | Name Under Which Respondent Does Business: | Montana-Dakota Utilities Co. |
| 3. | Date Utility Service First Offered in Montana | 1920 |
| 4. | Address to send Correspondence Concerning Report: | Montana-Dakota Utilities Co.<br>400 North Fourth Street<br>Bismarck, ND 58501 |
| 5. | Person Responsible for This Report: | Donald R. Ball |
| 5a. | Telephone Number: | (701) 222-7630 |

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:

   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

**SCHEDULE 2**

### Board of Directors 1/

| Line No. | Name of Director and Address (City, State) (a) | Remuneration (b) |
|---|---|---|
| 1 | Martin A. White, Bismarck, ND | - |
| 2 | Warren L. Robinson, Bismarck, ND | - |
| 3 | Cynthia J. Norland, Bismarck, ND 2/ | - |
| 4 | Paul K. Sandness, Bismarck, ND 3/ | - |
| 5 | Lester H. Loble, II, Bismarck, ND 4/ | - |
| 6 | Ronald D. Tipton, Bismarck, ND 5/ | - |
| 7 | Bruce T. Imsdahl, Bismarck, ND | |
| 8 | | |
| 9 | 1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc., | |
| 10 | and has no Board of Directors. The affairs of the Company are managed by | |
| 11 | a Managing Committee, the members of which are provided herein rather | |
| 12 | than the directors of MDU Resources Group, Inc. | |
| 13 | 2/ Cynthia J. Norland served on the Managing Committee from 1/02/04 to | |
| 14 | 4/05/04. | |
| 15 | 3/ Paul K. Sandness served on the Managing Committee starting 4/06/04. | |
| 16 | 4/ Lester H Loble, II retired on 1/02/04. | |
| 17 | 5/ Ronald D. Tipton resigned his position as Chief Executive Officer effective | |
| 18 | 9/28/04 and retired 1/02/05. | |

## Officers

Year: 2004

| Line No. | Title of Officer (a) | Department Supervised (b) | Name (c) |
|---|---|---|---|
| 1 | President and Chief | Executive | Bruce T. Imsdahl |
| 2 | Executive Officer | | |
| 3 | | | |
| 4 | Vice President | Gas Supply and Office Services | Donald F. Klempel |
| 5 | | | |
| 6 | Vice President | Electric Supply | Andrea L. Stomberg |
| 7 | | | |
| 8 | Executive Vice President | Business Development and | Dennis L. Haider |
| 9 | | Strategic Planning | |
| 10 | | | |
| 11 | Vice President | Operations | David L. Goodin |
| 12 | | | |
| 13 | Vice President, Controller | Accounting, Information Systems | John F. Renner |
| 14 | and Chief Accounting | and Fleet and Procurement | |
| 15 | Officer 1/ | | |
| 16 | | | |
| 17 | Vice President | Human Resources | Richard D. Spratt |
| 18 | | | |
| 19 | Assistant Vice President | Regulatory Affairs | Donald R. Ball |
| 20 | | | |
| 21 | | | |
| 22 | | | |
| 23 | | | |
| 24 | | | |
| 25 | | | |
| 26 | | | |
| 27 | | | |
| 28 | 1/ Effective 11/1/04 John F. Renner assumed the title of Vice President, Controller and Chief | | |
| 29 | Accounting Officer. Craig A. Keller held this position until 11/1/04. | | |
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| 40 | | | |

# CORPORATE STRUCTURE

Year: 2004

| | Subsidiary/Company Name | Line of Business | Earnings (000's) | Percent of Total |
|---|---|---|---|---|
| 1 | Montana-Dakota Utilities Co./ | Electric and Natural Gas | $14,972 | 7.25% |
| 2 | Great Plains Natural Gas Co. | Distribution | | |
| 3 | (Divisions of MDU Resources | | | |
| 4 | Group, Inc.) | | | |
| 6 | WBI Holdings, Inc. | Pipeline and Energy Services and | 119,723 | 58.01% |
| 7 | | Natural Gas and Oil Production | | |
| 9 | Knife River Corporation | Construction Materials and | 50,707 | 24.57% |
| 10 | | Mining | | |
| 12 | Utility Services, Inc. | Utility Services | (5,650) | -2.74% |
| 14 | Centennial Energy Resources LLC | Independent Power Production | 26,309 | 12.75% |
| 16 | Centennial Holdings Capital Corp. | Other | 321 | 0.16% |
| 50 | **TOTAL** | | $206,382 | 100.00% |

# CORPORATE ALLOCATIONS - GAS

Year: 2004

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1<br>2 | Audit Costs | Administrative & General | Various Corporate Overhead Allocation Factors | $3,129 | 2.55% | $119,571 |
| 3<br>4<br>5 | Advertising | Administrative & General | Various Corporate Overhead Allocation Factors, and/or Actual Costs Incurred | 2,626 | 2.47% | 103,645 |
| 6<br>7<br>8 | Air Service | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 3,162 | 1.77% | 175,019 |
| 9<br>10<br>11 | Automobile | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 1,267 | 2.72% | 45,259 |
| 12<br>13<br>14 | Bank Services | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 11,693 | 2.55% | 446,829 |
| 15<br>16<br>17 | Corporate Aircraft | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 3,460 | 2.54% | 132,890 |
| 18<br>19<br>20 | Consultant Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 41,399 | 4.85% | 812,420 |
| 21<br>22<br>23 | Contract Services | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 53,154 | 3.53% | 1,451,876 |
| 24<br>25<br>26<br>27 | Directors Expenses | Administrative & General | Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees | 50,728 | 2.57% | 1,921,981 |
| 28<br>29 | Employee Benefits | Administrative & General | Corporate Overhead Allocation Factor Based on Number of Employees | 4,767 | 2.51% | 185,181 |

# CORPORATE ALLOCATIONS - GAS

Year: 2004

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1 | Employee Meetings | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 3,939 | 2.64% | 145,075 |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | Employee Reimbursable Expenses | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 5,943 | 2.28% | 254,929 |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | Express Mail | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 5 | 3.07% | 158 |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | Legal Retainers & Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 31,443 | 2.57% | 1,192,126 |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | Meal Allowance | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 125 | 2.65% | 4,591 |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | Meals & Entertainment | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 3,223 | 2.55% | 123,275 |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | Moving Expense | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 7,708 | 2.54% | 295,759 |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | Industry Dues & Licenses | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 3,155 | 2.65% | 115,980 |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | Office Expenses | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 2,595 | 2.66% | 94,884 |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | Prepaid Insurance | Administrative & General | Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience | 76,132 | 3.82% | 1,916,335 |
| 29 | | | | | | |

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 5**

# CORPORATE ALLOCATIONS - GAS

Year: 2004

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1 | Permits and Filing Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 480 | 2.53% | 18,522 |
| 4 | Postage | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 972 | 2.55% | 37,082 |
| 7 | Payroll | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 488,284 | 2.60% | 18,325,586 |
| 10 | Rental | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 285 | 4.32% | 6,315 |
| 13 | Reference Materials | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 2,464 | 2.49% | 96,536 |
| 16 | Seminars & Meeting Registrations | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 2,339 | 2.62% | 86,918 |
| 19 | Software Maintenance | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 5,439 | 2.46% | 215,781 |
| 22 | Training Material | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 3,082 | 2.55% | 117,822 |
| 25 | **TOTAL** | | | $812,998 | 2.78% | $28,442,345 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Utility | (e) % Total Affil. Revs. | (f) Charges to MT Utility |
|---|---|---|---|---|---|---|
| 1 | **KNIFE RIVER CORPORATION** | Expense | Actual Costs Incurred | | | |
| 2 | | Materials | | $2,459 | | $2,263 |
| 3 | | Contract Services | | 180 | | 26 |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | Capital | Actual Costs Incurred | 7,281 | | |
| 7 | | Contract Services | | 86 | | |
| 8 | | Materials | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
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| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | Total Knife River Corporation Operating | Revenues for the Year 2004 | | 1,322,161,097 | |
| 22 | | Excludes Intersegment Eliminations | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | **TOTAL** | **Grand Total Affiliate Transactions** | | $10,006 | 0.0008% | $2,289 |

# AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Utility | (e) % Total Affil. Revs. | (f) Charges to MT Utility |
|---|---|---|---|---|---|---|
| 1 | **WBI HOLDINGS, INC** | Natural Gas | Actual Costs Incurred | | | |
| 2 | | Purchases/Transportation | | $68,288,462 | | $19,640,177 |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | Expense | Actual Costs Incurred | | | |
| 7 | | Contract Services | | 4,161 | | 958 |
| 8 | | Legal Fees | | 36,488 | | 9,495 |
| 9 | | Materials | | 88 | | 88 |
| 10 | | Seminars and Meeting Reg. | | 893 | | 291 |
| 11 | | Office Supplies | | 468 | | 122 |
| 12 | | Software Maintenance | | 521 | | 157 |
| 13 | | Reference Materials | | 6,336 | | 1,563 |
| 14 | | Reimbursable Expense | | 140 | | 36 |
| 15 | | | | | | |
| 16 | | Capital | Actual Costs Incurred | | | |
| 17 | | Contract Services | | 12,137 | | |
| 18 | | Miscellaneous | | 329 | | |
| 19 | | Reimbursable Expense | | 176 | | |
| 20 | | Material | | 3,892 | | |
| 21 | | | | | | |
| 22 | | Other Transactions/Reimbursements | Actual Costs Incurred | | | |
| 23 | | Miscellaneous | | 20,972 | | |
| 24 | | Auto Clearing | | 106 | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | Total WBI Operating Revenues for the Year 2004 | | | $700,068,230 | |
| 28 | | Excludes Intersegment Eliminations | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | **TOTAL** | **Grand Total Affiliate Transactions** | | $68,375,169 | 9.7669% | $19,652,886 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Utility | (e) % Total Affil. Revs. | (f) Charges to MT Utility |
|---|---|---|---|---|---|---|
| 1 | **UTILITY SERVICES, INC.** | Capital | | | | |
| 2 | | Freight | Actual Costs Incurred | $650 | | |
| 3 | | | | | | |
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| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | Total USI Operating Revenues for the Year 2004 | | | $426,820,871 | |
| 29 | | Excludes Intersegment Eliminations | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | **TOTAL** | **Grand Total Affiliate Transactions** | | $650 | 0.0002% | $0 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Utility | (e) % Total Affil. Revs. | (f) Charges to MT Utility |
|---|---|---|---|---|---|---|
| 1 | **CENTENNIAL ENERGY** | Expense | * Various Corporate Overhead | | | |
| 2 | **RESOURCES/CHCC** | Corporate Aircraft | Allocation Factors and/or | $203,691 | | $52,231 |
| 3 | | Rent | Actual Costs Incurred | 54,390 | | 14,153 |
| 4 | | Cost of Service | | 79,462 | | 20,677 |
| 5 | | Legal | | 73 | | 18 |
| 6 | | | | | | |
| 7 | | Capital | | | | |
| 8 | | Corporate Aircraft | Actual Costs Incurred | 15,620 | | |
| 9 | | | | | | |
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| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | Total Centennial Energy Resources/CHCC Operating Revenues for the Year 2004 | | | $47,482,460 | |
| 23 | | Excludes Intersegment Eliminations | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | **TOTAL** | **Grand Total Affiliate Transactions** | | $353,235 | 0.7439% | $87,079 |

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | KNIFE RIVER CORPORATION | MDU RESOURCES GROUP, INC. | | | | |
| 2 | | Corporate Overhead | * Various Corporate Overhead Allocation | | | |
| 3 | | Audit Costs | Factors, Time Studies and/or Actual | $52,638 | | |
| 4 | | Advertising | Costs Incurred | 47,463 | | |
| 5 | | Air Service | | 60,687 | | |
| 6 | | Automobile | | 15,044 | | |
| 7 | | Bank Services | | 196,706 | | |
| 8 | | Corporate Aircraft | | 55,311 | | |
| 9 | | Consultant Fees | | 266,173 | | |
| 10 | | Contract Services | | 571,344 | | |
| 11 | | Directors Expenses | | 839,490 | | |
| 12 | | Employee Benefits | | 81,375 | | |
| 13 | | Employee Meeting | | 63,927 | | |
| 14 | | Employee Reimbursable Expense | | 95,723 | | |
| 15 | | Express Mail | | 58 | | |
| 16 | | Insurance | | 854,768 | | |
| 17 | | Legal Retainers & Fees | | 525,186 | | |
| 18 | | Moving Allowance | | 129,812 | | |
| 19 | | Meal Allowance | | 1,836 | | |
| 20 | | Cash Donations | | 41,742 | | |
| 21 | | Meal & Entertainment | | 48,026 | | |
| 22 | | Industry Dues & Licenses | | 46,458 | | |
| 23 | | Office Expenses | | 40,727 | | |
| 24 | | Supplemental Insurance | | 1,110,347 | | |
| 25 | | Permits & Filing Fees | | 8,104 | | |
| 26 | | Postage | | 16,316 | | |
| 27 | | Payroll | | 7,487,867 | | |
| 28 | | Reference Materials | | 42,042 | | |
| 29 | | Rental | | 1,411 | | |
| 30 | | Seminars & Meeting Registrations | | 35,707 | | |
| 31 | | Software Maintenance | | 96,135 | | |
| 32 | | Training | | 51,865 | | |
| 33 | | **Total MDU Resources Group, Inc.** | | $12,884,288 | 1.0423% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | KNIFE RIVER CORPORATION | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | | Communications Department | * Various Corporate Overhead Allocation | | | |
| 3 | | Automobile | Factors, Cost of Service Factors, Time | $662 | | |
| 4 | | Air Service | Studies and /or Actual Costs Incurred | 104 | | |
| 5 | | Contract Services | | 352 | | |
| 6 | | Employee Reimbursable Expense | | 391 | | |
| 7 | | Materials | | 328 | | |
| 8 | | Meals & Entertainment | | 66 | | |
| 9 | | Moving Allowance | | 157 | | |
| 10 | | Office Expenses | | 857 | | |
| 11 | | Office Telephone | | 155,516 | | |
| 12 | | Organizational Dues | | 64 | | |
| 13 | | Payroll | | 63,614 | | |
| 14 | | Permits & Filing Fees | | 190 | | |
| 15 | | Seminars & Meeting Registrations | | 223 | | |
| 16 | | | | | | |
| 17 | | Office Services | * General Office Complex and Office | | | |
| 18 | | Automobile | Supplies Cost of Service Allocation | 44 | | |
| 19 | | Employee Meetings | Factors | 64 | | |
| 20 | | Express Mail | | 14,861 | | |
| 21 | | Rental of Office Equipment | | 353 | | |
| 22 | | Office Expenses | | 10,448 | | |
| 23 | | Postage | | 10,266 | | |
| 24 | | Cost of Service - General Office Buildings | | 357,438 | | 85,563 |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 28 | | Automobile | Factors and /or Actual Costs Incurred | 22 | | |
| 29 | | Air Service | | 340 | | |
| 30 | | Contract Services | | 356 | | |
| 31 | | Employee Reimbursable Expense | | 278 | | |
| 32 | | Meals & Entertainment | | 55 | | |
| 33 | | Office Expenses | | 7,656 | | |
| 34 | | | | | | |
| 35 | | | | | | |

Company Name: Montana-Dakota Utilities Co. 

SCHEDULE 7

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | KNIFE RIVER CORPORATION | Professional Organ. Dues | | 34 | | |
| 2 | | Payroll | | 20,517 | | |
| 3 | | Seminars & Meeting Registrations | | 95 | | |
| 4 | | Training | | 1,033 | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | Other Miscellaneous Departments | * Various Corporate Overhead Allocation | | | |
| 8 | | Automobile | Factors and /or Actual Costs Incurred | 115 | | |
| 9 | | Office Supplies | | 654 | | |
| 10 | | Employee Reimbursable Expense | | | | |
| 11 | | Moving Allowance | | 89 | | |
| 12 | | Payroll | | 2,664 | | |
| 13 | | | | | | |
| 14 | | Other Direct Charges | Actual Costs Incurred | | | |
| 15 | | Employee Discounts | | 42,746 | | 6,228 |
| 16 | | Corporate/Commercial Air Service | | 18,060 | | |
| 17 | | Computer/Software Support | | 590,301 | | |
| 18 | | Electric Consumption | | 36,170 | | |
| 19 | | Gas Consumption | | 84,732 | | 73,573 |
| 20 | | Telephone | | 2,981 | | |
| 21 | | Miscellaneous | | 78,687 | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | **Total Montana-Dakota Utilities Co.** | | $ 1,503,581 | 0.1216% | $165,364 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | KNIFE RIVER CORPORATION | OTHER TRANSACTIONS/REIMBURSEMENTS | | | | |
| 2 | | | | | | |
| 3 | | Insurance | | 1,132,159 | | |
| 4 | | Federal & State Tax Liability Payments | | 11,479,807 | | |
| 5 | | KESOP carrying costs | | 320,960 | | |
| 6 | | Tax Deferred Savings Plan | | 132,527 | | |
| 7 | | Interest | | (30,289) | | |
| 8 | | Miscellaneous Reimbursements | | (545,907) | | |
| 9 | | | | | | |
| 10 | | **Total Other Transactions/Reimbursements** | | $12,489,257 | 1.0104% | |
| 11 | | | | | | |
| 12 | | **Grand Total Affiliate Transactions** | | $26,877,126 | 2.1743% | $165,364 |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | **Total Knife River Corporation Operating Expenses for 2004 - Excludes Intersegment Eliminations** | | | $1,236,130,820 | |



* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | MDU RESOURCES GROUP, INC. | | | | |
| 2 | | Corporate Overhead | * Various Corporate Overhead Allocation | | | |
| 3 | | Audit Costs | Factors, Time Studies and/or Actual | $30,062 | | |
| 4 | | Advertising | Costs Incurred | 25,233 | | |
| 5 | | Air Service | | 34,198 | | |
| 6 | | Automobile | | 13,154 | | |
| 7 | | Bank Services | | 112,338 | | |
| 8 | | Corporate Aircraft | | 32,107 | | |
| 9 | | Consultant Fees | | 217,434 | | |
| 10 | | Contract Services | | 325,825 | | |
| 11 | | Directors Expenses | | 477,003 | | |
| 12 | | Employee Benefits | | 46,347 | | |
| 13 | | Employee Meeting | | 36,508 | | |
| 14 | | Employee Reimbursable Expense | | 63,965 | | |
| 15 | | Express Mail | | 42 | | |
| 16 | | Insurance | | 488,154 | | |
| 17 | | Legal Retainers & Fees | | 298,537 | | |
| 18 | | Meal Allowance | | 1,229 | | |
| 19 | | Cash Donations | | 23,839 | | |
| 20 | | Meal & Entertainment | | 31,463 | | |
| 21 | | Moving Expense | | 74,334 | | |
| 22 | | Industry Dues & Licenses | | 29,917 | | |
| 23 | | Office Expenses | | 23,948 | | |
| 24 | | Supplemental Insurance | | 634,114 | | |
| 25 | | Permits & Filing Fees | | 4,654 | | |
| 26 | | Postage | | 9,323 | | |
| 27 | | Payroll | | 4,690,326 | | |
| 28 | | Reference Materials | | 24,224 | | |
| 29 | | Rental | | 2,169 | | |
| 30 | | Seminars & Meeting Registrations | | 22,824 | | |
| 31 | | Software Maintenance | | 53,206 | | |
| 32 | | Training Material | | 29,620 | | |
| 33 | | **Total MDU Resources Group, Inc.** | | $7,856,097 | 1.5824% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | | Communications Department | * Various Corporate Overhead Allocation | | | |
| 3 | | Expense | Factors, Cost of Service Factors, Time | | | |
| 4 | | Automobile | Studies and /or Actual Costs Incurred | $1,301 | | |
| 5 | | Air Service | | 77 | | |
| 6 | | Annual Easements | | 1,559 | | |
| 7 | | Contract Services | | 1,739 | | |
| 8 | | Custodial Services & Supplies | | 128 | | |
| 8 | | Employee Reimbursable Expense | | 369 | | |
| 9 | | Materials | | 812 | | |
| 10 | | Meals & Entertainment | | 178 | | |
| 11 | | Office Expenses | | 462 | | |
| 12 | | Office Telephone | | 64,366 | | |
| 13 | | Payroll | | 34,991 | | |
| 14 | | Permits & Filing Fees | | 518 | | |
| 15 | | Photocopier | | 159 | | |
| 16 | | Professional Organ Dues | | 22 | | |
| 17 | | Seminars & Meeting Registrations | | 72 | | |
| 18 | | Utilities | | 2,757 | | |
| 19 | | | | | | |
| 20 | | Office Services | * General Office Complex and Office | | | |
| 21 | | Expense | Supplies cost of Service Allocation | | | |
| 22 | | Automobile | Factors | 53 | | |
| 23 | | Employee Meetings | | 85 | | |
| 24 | | Express Mail | | 8,486 | | |
| 25 | | Office Expenses | | 32,991 | | |
| 26 | | Postage | | 5,864 | | |
| 27 | | Cost of Service - General Office Buildings | | 360,443 | | $86,282 |
| 28 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | Purchasing Department | * Various Corporate Overhead Allocation | | | |
| 2 | | Capital | Factors, Cost of Service Factors, Time | | | |
| 3 | | Payroll | Studies and /or Actual Costs Incurred | 37,739 | | |
| 4 | | Expense | | | | |
| 5 | | Office Expenses | | 183 | | |
| 6 | | | | | | |
| 7 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 8 | | Expense | Factors and /or Actual Costs Incurred | | | |
| 9 | | Automobile | | 12 | | |
| 10 | | Air Service | | 58 | | |
| 11 | | Contract Services | | 2,763 | | |
| 12 | | Employee Reimbursable Expense | | 46 | | |
| 13 | | Meals & Entertainment | | 23 | | |
| 14 | | Office Expenses | | 3,443 | | |
| 15 | | Payroll | | 35,502 | | |
| 16 | | Training Material | | 239 | | |
| 17 | | Seminars & Meeting Registrations | | (11) | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | Region Operations | Actual Costs Incurred | | | |
| 21 | | Expense | | | | |
| 22 | | Automobile | | 2,452 | | |
| 23 | | OfficeTelephone | | 68 | | |
| 24 | | Payroll | | 5,409 | | |
| 25 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | Transportation Department | * Various Corporate Overhead Allocation | | | |
| 2 | | Capital | Factors, Time Studies and /or Actual | | | |
| 3 | | Payroll | Costs incurred | 19,892 | | |
| 4 | | Clearing Accounts | | | | |
| 5 | | Automobile | | 58 | | |
| 6 | | Air Service | | 39 | | |
| 7 | | Contract Services | | 554 | | |
| 8 | | Corporate Aircraft | | 21 | | |
| 9 | | Employee Reimbursable Expense | | 232 | | |
| 10 | | Materials | | 3 | | |
| 11 | | Meals & Entertainment | | 83 | | |
| 12 | | Office Expenses | | 5 | | |
| 13 | | Office Telephone | | 282 | | |
| 14 | | Professional Organ. Dues | | 12 | | |
| 15 | | Payroll | | 5,676 | | |
| 16 | | Reference Material | | 12 | | |
| 17 | | Utilities | | 105 | | |
| 18 | | | | | | |
| 19 | | Other Miscellaneous Departments | * Various Corporate Overhead Allocation | | | |
| 20 | | Expense | Factors, Time Studies and /or Actual | | | |
| 21 | | Automobile | Costs incurred | 453 | | |
| 22 | | Moving Allowance | | 207 | | |
| 23 | | Office Expenses | | 963 | | |
| 24 | | Payroll | | 1,424 | | |
| 25 | | Moving Allowance | | 20 | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | Capital | | | | |
| 2 | | Automobile | | 204 | | |
| 3 | | Air Service | | 228 | | |
| 4 | | Contract Services | | 53 | | |
| 5 | | Corporate Aircraft | | 112 | | |
| 6 | | Professional Organ. Dues | | 33 | | |
| 7 | | Employee Reimbursable Expense | | 641 | | |
| 8 | | Meals & Entertainment | | 243 | | |
| 9 | | Office Expenses | | 43 | | |
| 10 | | Payroll | | 5,051 | | |
| 11 | | Reference Material | | 33 | | |
| 12 | | Seminars & Meeting Registrations | | 55 | | |
| 13 | | | | | | |
| 14 | | Other Direct Charges | Actual Costs Incurred | | | |
| 15 | | Utility/Merchandise Discounts | | 151,398 | | 83,824 |
| 16 | | Corporate Aircraft | | 150,316 | | |
| 17 | | Radio Maintenance | | 10,022 | | |
| 18 | | Vehicle Maintenance | | 29,854 | | |
| 19 | | Computer/Software Support | | 218,661 | | |
| 20 | | Cathodic Protection | | 13,998 | | 4,452 |
| 21 | | Purchased Power for Compressor Stations | | 78,390 | | 68,892 |
| 22 | | Electric Compressor - Electricity Cost | | 164,376 | | 107,547 |
| 23 | | Office Building Utilities | | 174,246 | | 84,329 |
| 24 | | Help Desk Services | | 302 | | |
| 25 | | Miscellaneous | | 96,163 | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | Total Montana-Dakota Utilities Co. 1/ | | 1,729,819 | 0.3484% | $435,325 |
| 29 | | | | | | |
| 30 | | 1/ Total Montana-Dakota Charges By Category | | | | |
| 31 | | Expense | | 1,658,409 | 0.3340% | |
| 32 | | Capital | | 64,326 | 0.0130% | |
| 33 | | Clearing | | 7,083 | 0.0014% | |
| 34 | | Total | | 1,729,819 | 0.3484% | |
| 35 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | WBI HOLDINGS, INC. | OTHER TRANSACTIONS/REIMBURSEMENTS | | | | |
| 2 | | Insurance | Actual Costs Incurred | $651,337 | | |
| 3 | | Federal & State Tax Liability Payments | | 50,648,487 | | |
| 4 | | Tax Deferred Savings Plan | | 17,512 | | |
| 5 | | KESOP carrying costs | | 48,975 | | |
| 6 | | Interest | | (17,298) | | |
| 7 | | Charges of Corp Development | | 93,593 | | |
| 8 | | **Total Other Transactions/Reimbursements** | | $51,442,605 | 10.3614% | |
| 9 | | | | | | |
| 10 | | **Grand Total Affiliate Transactions** | | $61,028,521 | 12.2922% | $435,325 |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | **Total WBI Holdings Operating Expenses for 2004 - Excludes Intersegment Eliminations** | | | $496,480,944 | |



* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utilit |
|---|---|---|---|---|---|---|
| 1 | UTILITY SERVICES, INC. | MDU RESOURCES GROUP, INC. | | | | |
| 2 | | Corporate Overhead | * Various Corporate Overhead Allocation | | | |
| 3 | | Audit Costs | Factors, Time Studies and/or Actual | $9,203 | | |
| 4 | | Advertising | Costs Incurred | 7,724 | | |
| 5 | | Air Service | | 21,744 | | |
| 6 | | Automobile | | 2,834 | | |
| 7 | | Bank Services | | 34,389 | | |
| 8 | | Corporate Aircraft | | 10,099 | | |
| 9 | | Consultant Fees | | 41,234 | | |
| 10 | | Contract Services | | 99,740 | | |
| 11 | | Directors Expenses | | 145,103 | | |
| 12 | | Employee Benefits | | 14,346 | | |
| 13 | | Employee Meeting | | 11,176 | | |
| 14 | | Employee Reimbursable Expense | | 28,359 | | |
| 15 | | Express Mail | | 11 | | |
| 16 | | Insurance | | 149,435 | | |
| 17 | | Legal Retainers & Fees | | 91,533 | | |
| 18 | | Moving Allowance | | 22,613 | | |
| 19 | | Meal Allowance | | 349 | | |
| 20 | | Cash Donations | | 7,298 | | |
| 21 | | Meal & Entertainment | | 10,787 | | |
| 22 | | Industry Dues & Licenses | | 8,590 | | |
| 23 | | Office Expenses | | 7,197 | | |
| 24 | | Supplemental Insurance | | 194,117 | | |
| 25 | | Permits & Filing Fees | | 1,405 | | |
| 26 | | Postage | | 2,851 | | |
| 27 | | Payroll | | 1,477,293 | | |
| 28 | | Reference Materials | | 7,447 | | |
| 29 | | Rent | | 240 | | |
| 30 | | Seminars & Meeting Registrations | | 7,044 | | |
| 31 | | Software Maintenance | | 17,876 | | |
| 32 | | Training Material | | 9,078 | | |
| 33 | | **Total MDU Resources Group, Inc.** | | $2,441,115 | 0.5643% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utilit |
|---|---|---|---|---|---|---|
| 1 | UTILITY SERVICES, INC. | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | | Communications Department | * Various Corporate Overhead Allocation | | | |
| 3 | | Air Service | Factors, Cost of Service Factors, Time | $13 | | |
| 4 | | Automobile | Studies and /or Actual Costs Incurred | 98 | | |
| 5 | | Contract Services | | 54 | | |
| 6 | | Professional Organ. Dues | | 7 | | |
| 7 | | Office Expenses | | 142 | | |
| 8 | | Office Telephone | | 18,727 | | |
| 9 | | Payroll | | 9,300 | | |
| 10 | | Employee Reimbursable Expense | | 43 | | |
| 11 | | Materials | | 37 | | |
| 12 | | Meal & Entertainment | | 7 | | |
| 13 | | Permits & Filing Fees | | 21 | | |
| 14 | | Seminars & Meeting Registrations | | 25 | | |
| 15 | | | | | | |
| 16 | | Office Services | * General Office Complex and Office | | | |
| 17 | | Automobile | Supplies Cost of Service Allocation | 10 | | |
| 18 | | Employee Meetings | | 18 | | |
| 19 | | Express Mail | | 2,598 | | |
| 20 | | Office Expenses | | 1,892 | | |
| 21 | | Postage | | 1,770 | | |
| 22 | | Cost of Service - General Office Buildings | | 1,045,317 | | $250,226 |
| 23 | | | | | | |
| 24 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 25 | | Contract Services | Factors and /or Actual Costs Incurred | 64 | | |
| 26 | | Employee Reimbursable Expense | | 31 | | |
| 27 | | Office Expenses | | 1,355 | | |
| 28 | | Payroll | | 3,730 | | |
| 29 | | Air Services | | 39 | | |
| 30 | | Training Material | | 162 | | |
| 31 | | Meal & Entertainment | | 5 | | |

Company Name: Montana-Dakota Utilities Co. SCHEDULE

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utilit |
|---|---|---|---|---|---|---|
| 1 | UTILITY SERVICES, INC. | USI President and COO | * Various Corporate Overhead Allocation | | | |
| 2 | | Office Supplies | Factors, Time Studies and/or | 1,639 | | |
| 3 | | Payroll | Actual Costs Incurred | 10,719 | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | Other Miscellaneous Departments | * Various Corporate Overhead Allocation | | | |
| 8 | | Air Services | Factors, Time Studies and/or | | | |
| 9 | | Automobile | Actual Costs Incurred | 61 | | |
| 10 | | Office Expenses | | 3,997 | | |
| 11 | | Meals and Entertainment | | 145 | | |
| 12 | | Employee Reimbursable Expense | | 779 | | |
| 13 | | Payroll | | (519) | | |
| 14 | | Moving Allowance | | 10 | | |
| 15 | | Reference Materials | | 1,646 | | |
| 16 | | | | | | |
| 17 | | Other Direct Charges | Actual Costs Incurred | | | |
| 18 | | Legal Fees | | 28,166 | | |
| 19 | | Contract Services | | 4,999 | | |
| 20 | | Air Service | | 127,010 | | |
| 21 | | Meals and Entertainment | | 14,474 | | |
| 22 | | Employee Reimbursable Expense | | 83,179 | | |
| 23 | | Telephone | | 73,071 | | |
| 24 | | Consulting Service | | 400,552 | | |
| 25 | | Computer/Software Support | | 18,234 | | |
| 26 | | Office Expenses | | 13,704 | | |
| 27 | | Filing fees | | 33,545 | | |
| 28 | | Miscellaneous | | 47,907 | | |
| 27 | | Seminars and Meeting Registration | | 36,216 | | |
| 28 | | Gas Consumption | | 2,608 | | 2,608 |
| 29 | | **Total Montana-Dakota Utilities Co.** | | $1,987,606 | 0.4595% | $252,834 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utilit |
|---|---|---|---|---|---|---|
| 1 | UTILITY SERVICES, INC. | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual Costs Incurred | | | |
| 2 | | Payroll | | 2,830,677 | | |
| 3 | | Federal & State Tax Liability Payments | | ($5,704,262) | | |
| 4 | | Audit fees | | 164,500 | | |
| 5 | | Supplemental Insurance | | 205,890 | | |
| 6 | | Insurance | | 520,998 | | |
| 7 | | Miscellaneous | | 180,863 | | |
| 8 | | KESOP/Deferred Comp carrying costs | | 13,435 | | |
| 9 | | | | | | |
| 10 | | **Total Other Transactions/Reimbursements** | | (1,787,899) | -0.4133% | |
| 11 | | | | | | |
| 12 | | **Grand Total Affiliate Transactions** | | $2,640,822 | 0.6105% | $252,834 |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | **Total Utility Services, Inc. Operating Expenses for 2004 - Excludes Intersegment Eliminations** | | | $ 432,578,014 | |



* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | CENTENNIAL ENERGY | MDU RESOURCES GROUP, INC. | | | | |
| 2 | RESOURCES/CHCC | Corporate Overhead | * Various Corporate Overhead Allocation | | | |
| 3 | | Audit Costs | Factors, Time Studies and/or Actual | $2,699 | | |
| 4 | | Advertising | Costs Incurred | 2,266 | | |
| 5 | | Air Service | | 32,214 | | |
| 6 | | Automobile | | 1,195 | | |
| 7 | | Bank Services | | 10,087 | | |
| 8 | | Corporate Aircraft | | 7,232 | | |
| 9 | | Consultant Fees | | 11,867 | | |
| 10 | | Contract Services | | 29,257 | | |
| 11 | | Directors Expenses | | 56,064 | | |
| 12 | | Employee Benefits | | 5,012 | | |
| 13 | | Employee Meeting | | 3,278 | | |
| 14 | | Employee Reimbursable Expense | | 15,482 | | |
| 15 | | Insurance | | 43,834 | | |
| 16 | | Legal Retainers & Fees | | 26,770 | | |
| 17 | | Cash Donations | | 2,141 | | |
| 18 | | Meals & Entertainment | | 4,455 | | |
| 19 | | Meal Allowance | | 181 | | |
| 20 | | Moving | | 7,422 | | |
| 21 | | Industry Dues & Licenses | | 2,801 | | |
| 22 | | Office Expenses | | 2,161 | | |
| 23 | | Supplemental Insurance | | 56,941 | | |
| 24 | | Permits & Filing Fees | | 527 | | |
| 25 | | Postage | | 840 | | |
| 26 | | Payroll | | 707,633 | | |
| 27 | | Reference Materials | | 2,170 | | |
| 28 | | Rental | | 227 | | |
| 29 | | Seminars & Meeting Registrations | | 2,828 | | |
| 30 | | Software Maintenance | | 5,163 | | |
| 31 | | Training | | 2,662 | | |
| 32 | | **Total MDU Resources Group, Inc.** | | $1,045,409 | 2.6655% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2004

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | CENTENNIAL ENERGY | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | RESOURCES/CHCC | Communications Department | * Various Corporate Overhead Allocation | | | |
| | | Automobile | Factors, Cost of Service Factors, Time | 27 | | |
| 3 | | Employee Reimbursable Expense | Studies and /or Actual Costs Incurred | 31 | | |
| 4 | | Contract Services | | 15 | | |
| 5 | | Materials | | 9 | | |
| 6 | | Office Expenses | | 41 | | |
| 7 | | Office Telephone | | 4,698 | | |
| 8 | | Payroll | | 5,383 | | |
| 9 | | Seminars & Meeting Registrations | | 6 | | |
| 10 | | | | | | |
| 11 | | Office Services | * General Office Complex and Office | | | |
| 12 | | Express Mail | Supplies Cost of Service Allocation | 765 | | |
| 13 | | Postage | Factors | 462 | | |
| 14 | | Office Expenses | | 202 | | |
| 15 | | Employee Meetings | | 5 | | |
| 16 | | Cost of Service - General Office Buildings | | 35,817 | | 8,574 |
| 17 | | | | | | |
| 18 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 19 | | Payroll | Factors and /or Actual Costs Incurred | 113 | | |
| 20 | | Office Expenses | | 309 | | |
| 21 | | Contract Services | | 10 | | |
| 22 | | | | | | |
| 23 | | Other Miscellaneous Departments | * Various Corporate Overhead Allocation | | | |
| 24 | | Office Supplies | Factors and /or Actual Costs Incurred | 33 | | |
| 25 | | Payroll | | 50 | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | Other Direct Charges | Actual costs incurred | | | |
| 29 | | Employee Discounts | | 1,115 | | |
| 30 | | Corporate/Commercial Air Service | | 235,667 | | |
| 31 | | Computer/Software Costs | | 327,331 | | |
| 32 | | Employee Reimbursable Exp and Fuel | | 401,559 | | |
| 33 | | Consulting Fees | | 1,076,209 | | |
| 34 | | Legal Fees | | 4,951 | | |
| 35 | | Telephone | | 8,024 | | |
| 36 | | Building Expenses | | 80,450 | | |
| 37 | | Miscellaneous | | 64,378 | | |
| 38 | | **Total Montana-Dakota Utilities Co.** | | 2,247,659 | 5.731% | 8,574 |
| 39 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 200

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenue to MT Utili |
|---|---|---|---|---|---|---|
| 1 | CENTENNIAL ENERGY | | | | | |
| 2 | RESOURCES/CHCC | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual costs incurred | | | |
| 3 | | Payroll | | 2,456,870 | | |
| 4 | | Federal & State Tax Liability Payments | | ($8,071,379) | | |
| 5 | | Interest | | (353) | | |
| 6 | | Insurance | | 1,175,324 | | |
| 7 | | Miscellaneous | | 222,737 | | |
| 8 | | **Total Other Transactions/Reimbursements** | | (4,216,802) | -10.752% | |
| 9 | | | | | | |
| 10 | | **Grand Total Affiliate Transactions** | | ($923,734) | -2.355% | 8,57 |
| 11 | | | | | | |
| 12 | | **Total Centennial Energy Resources/CHCC Operating Expenses for 2004** | | | $39,219,819 | |
| 13 | | **Excludes Intersegment Eliminations** | | | | |



* Corporate overhead allocation factors are derived from net plant investment and number of employees. A cost of service allocation factor for the general office complex is derived by the ratio of MDU Resources and Montana-Dakota Utilities payroll allocated to affiliated companies to the total payroll costs for employees located in the general office complex. Cost of service allocation factors are also derived for office supplies, computer facilities and fixed and mobile radios based on usage of such supplies/facilities by affiliated companies.

## MONTANA UTILITY INCOME STATEMENT

Year: 2004

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | 400 Operating Revenues | $68,459,367 | $78,142,776 | 14.14% |
| 2 | | | | |
| 3 | Operating Expenses | | | |
| 4 | 401 Operation Expenses | $59,831,434 | $71,845,630 | 20.08% |
| 5 | 402 Maintenance Expense | 710,432 | 731,121 | 2.91% |
| 6 | 403 Depreciation Expense | 2,226,161 | 1,873,413 | -15.85% |
| 7 | 404-405 Amort. & Depl. of Gas Plant | 165,482 | 251,449 | 51.95% |
| 8 | 406 Amort. of Gas Plant Acquisition Adjustments | | | |
| 9 | 407.1 Amort. of Property Losses, Unrecovered Plant | | | |
| 10 | & Regulatory Study Costs | | | |
| 11 | 407.2 Amort. of Conversion Expense | | | |
| 12 | 408.1 Taxes Other Than Income Taxes | 2,168,518 | 2,300,595 | 6.09% |
| 13 | 409.1 Income Taxes - Federal | (555,622) | (868,979) | -56.40% |
| 14 | - Other | (226,760) | (251,944) | -11.11% |
| 15 | 410.1 Provision for Deferred Income Taxes | 1,413,421 | 494,004 | -65.05% |
| 16 | 411.1 (Less) Provision for Def. Inc. Taxes - Cr. | 201,751 | 211,011 | 4.59% |
| 17 | 411.4 Investment Tax Credit Adjustments | | | |
| 18 | 411.6 (Less) Gains from Disposition of Utility Plant | | | |
| 19 | 411.7 Losses from Disposition of Utility Plant | | | |
| 20 | **TOTAL Utility Operating Expenses** | $65,934,817 | $76,586,300 | 16.15% |
| 21 | **NET UTILITY OPERATING INCOME** | $2,524,550 | $1,556,476 | -38.35% |

## MONTANA REVENUES

SCHEDULE 9

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Sales of Gas | | | |
| 2 | 480 Residential | $42,354,672 | $46,458,146 | 9.69% |
| 3 | 481 Commercial & Industrial - Small | 23,960,332 | 26,446,139 | 10.37% |
| 4 | Commercial & Industrial - Large | 512 | 28,507 | |
| 5 | 482 Other Sales to Public Authorities | | | |
| 6 | 484 Interdepartmental Sales | | | |
| 7 | 485 Intracompany Transfers | | | |
| 8 | Net Unbilled Revenue | 453,385 | 3,569,672 | 687.34% |
| 9 | **TOTAL Sales to Ultimate Consumers** | 66,768,901 | 76,502,464 | 14.58% |
| 10 | 483 Sales for Resale | | | |
| 11 | **TOTAL Sales of Gas** | $66,768,901 | $76,502,464 | 14.58% |
| 12 | Other Operating Revenues | | | |
| 13 | 487 Forfeited Discounts & Late Payment Revenues | | | |
| 14 | 488 Miscellaneous Service Revenues | $50,438 | $42,974 | -14.80% |
| 15 | 489 Revenues from Transp. of Gas for Others 1/ | 1,392,083 | 1,270,808 | -8.71% |
| 16 | 490 Sales of Products Extracted from Natural Gas | | | |
| 17 | 491 Revenues from Nat. Gas Processed by Others | | | |
| 18 | 492 Incidental Gasoline & Oil Sales | | | |
| 19 | 493 Rent From Gas Property | 197,853 | 232,898 | 17.71% |
| 20 | 494 Interdepartmental Rents | | | |
| 21 | 495 Other Gas Revenues | 50,092 | 93,632 | 86.92% |
| 22 | **TOTAL Other Operating Revenues** | 1,690,466 | 1,640,312 | -2.97% |
| 23 | **Total Gas Operating Revenues** | $68,459,367 | $78,142,776 | 14.14% |
| 24 | | | | |
| 25 | 496 (Less) Provision for Rate Refunds | | | |
| 26 | | | | |
| 27 | **TOTAL Oper. Revs. Net of Pro. for Refunds** | $68,459,367 | $78,142,776 | 14.14% |

1/ Includes unbilled revenue.

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | **Production Expenses** | | | |
| 2 | Production & Gathering - Operation | | | |
| 3 | 750 Operation Supervision & Engineering | | | |
| 4 | 751 Production Maps & Records | | | |
| 5 | 752 Gas Wells Expenses | | | |
| 6 | 753 Field Lines Expenses | | | |
| 7 | 754 Field Compressor Station Expenses | | NOT APPLICABLE | |
| 8 | 755 Field Compressor Station Fuel & Power | | | |
| 9 | 756 Field Measuring & Regulating Station Expense | | | |
| 10 | 757 Purification Expenses | | | |
| 11 | 758 Gas Well Royalties | | | |
| 12 | 759 Other Expenses | | | |
| 13 | 760 Rents | | | |
| 14 | **Total Operation - Natural Gas Production** | | | |
| 15 | Production & Gathering - Maintenance | | | |
| 16 | 761 Maintenance Supervision & Engineering | | | |
| 17 | 762 Maintenance of Structures & Improvements | | | |
| 18 | 763 Maintenance of Producing Gas Wells | | | |
| 19 | 764 Maintenance of Field Lines | | | |
| 20 | 765 Maintenance of Field Compressor Sta. Equip. | | NOT APPLICABLE | |
| 21 | 766 Maintenance of Field Meas. & Reg. Sta. Equip. | | | |
| 22 | 767 Maintenance of Purification Equipment | | | |
| 23 | 768 Maintenance of Drilling & Cleaning Equip. | | | |
| 24 | 769 Maintenance of Other Equipment | | | |
| 25 | **Total Maintenance- Natural Gas Prod.** | | | |
| 26 | **TOTAL Natural Gas Production & Gathering** | | | |
| 27 | Products Extraction - Operation | | | |
| 28 | 770 Operation Supervision & Engineering | | | |
| 29 | 771 Operation Labor | | | |
| 30 | 772 Gas Shrinkage | | | |
| 31 | 773 Fuel | | | |
| 32 | 774 Power | | | |
| 33 | 775 Materials | | | |
| 34 | 776 Operation Supplies & Expenses | | NOT APPLICABLE | |
| 35 | 777 Gas Processed by Others | | | |
| 36 | 778 Royalties on Products Extracted | | | |
| 37 | 779 Marketing Expenses | | | |
| 38 | 780 Products Purchased for Resale | | | |
| 39 | 781 Variation in Products Inventory | | | |
| 40 | 782 (Less) Extracted Products Used by Utility - Cr. | | | |
| 41 | 783 Rents | | | |
| 42 | **Total Operation - Products Extraction** | | | |
| 43 | Products Extraction - Maintenance | | | |
| 44 | 784 Maintenance Supervision & Engineering | | | |
| 45 | 785 Maintenance of Structures & Improvements | | | |
| 46 | 786 Maintenance of Extraction & Refining Equip. | | | |
| 47 | 787 Maintenance of Pipe Lines | | | |
| 48 | 788 Maintenance of Extracted Prod. Storage Equip. | | NOT APPLICABLE | |
| 49 | 789 Maintenance of Compressor Equipment | | | |
| 50 | 790 Maintenance of Gas Meas. & Reg. Equip. | | | |
| 51 | 791 Maintenance of Other Equipment | | | |
| 52 | **Total Maintenance - Products Extraction** | | | |
| 53 | **TOTAL Products Extraction** | | | |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | **Production Expenses - continued** | | | |
| 2 | | | | |
| 3 | Exploration & Development - Operation | | | |
| 4 | 795 Delay Rentals | | | |
| 5 | 796 Nonproductive Well Drilling | | NOT | |
| 6 | 797 Abandoned Leases | | APPLICABLE | |
| 7 | 798 Other Exploration | | | |
| 8 | **TOTAL Exploration & Development** | | | |
| 9 | | | | |
| 10 | Other Gas Supply Expenses - Operation | | | |
| 11 | 800 Natural Gas Wellhead Purchases | | | |
| 12 | 800.1 Nat. Gas Wellhead Purch., Intracomp. Trans. | | | |
| 13 | 801 Natural Gas Field Line Purchases | | | |
| 14 | 802 Natural Gas Gasoline Plant Outlet Purchases | | | |
| 15 | 803 Natural Gas Transmission Line Purchases | | | |
| 16 | 804 Natural Gas City Gate Purchases | $54,304,850 | $61,750,430 | 13.71% |
| 17 | 805 Other Gas Purchases | | | |
| 18 | 805.1 Purchased Gas Cost Adjustments | (4,022,314) | (1,310,518) | 67.42% |
| 19 | 805.2 Incremental Gas Cost Adjustments | | | |
| 20 | 806 Exchange Gas | | | |
| 21 | 807.1 Well Expenses - Purchased Gas | | | |
| 22 | 807.2 Operation of Purch. Gas Measuring Stations | | | |
| 23 | 807.3 Maintenance of Purch. Gas Measuring Stations | | | |
| 24 | 807.4 Purchased Gas Calculations Expenses | | | |
| 25 | 807.5 Other Purchased Gas Expenses | | | |
| 26 | 808.1 Gas Withdrawn from Storage -Dr. | 10,773,196 | 11,380,492 | 5.64% |
| 27 | 808.2 (Less) Gas Delivered to Storage -Cr. | (11,212,989) | (11,557,090) | -3.07% |
| 28 | 809.2 (Less) Deliveries of Nat. Gas for Processing-Cr. | | | |
| 29 | 810 (Less) Gas Used for Compressor Sta. Fuel-Cr. | | | |
| 30 | 811 (Less) Gas Used for Products Extraction-Cr. | | | |
| 31 | 812 (Less) Gas Used for Other Utility Operations-Cr. | | | |
| 32 | 813 Other Gas Supply Expenses | 134,878 | 154,315 | 14.41% |
| 33 | **TOTAL Other Gas Supply Expenses** | $49,977,621 | $60,417,629 | 20.89% |
| 34 | | | | |
| 35 | **TOTAL PRODUCTION EXPENSES** | $49,977,621 | $60,417,629 | 20.89% |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | **Storage, Terminaling & Processing Expenses** | | | | |
| 2 | | | | | |
| 3 | Underground Storage Expenses - Operation | | | | |
| 4 | 814 | Operation Supervision & Engineering | | | |
| 5 | 815 | Maps & Records | | | |
| 6 | 816 | Wells Expenses | | | |
| 7 | 817 | Lines Expenses | | | |
| 8 | 818 | Compressor Station Expenses | | | |
| 9 | 819 | Compressor Station Fuel & Power | | NOT | |
| 10 | 820 | Measuring & Reg. Station Expenses | | APPLICABLE | |
| 11 | 821 | Purification Expenses | | | |
| 12 | 822 | Exploration & Development | | | |
| 13 | 823 | Gas Losses | | | |
| 14 | 824 | Other Expenses | | | |
| 15 | 825 | Storage Well Royalties | | | |
| 16 | 826 | Rents | | | |
| 17 | | **Total Operation - Underground Strg. Exp.** | | | |
| 18 | | | | | |
| 19 | Underground Storage Expenses - Maintenance | | | | |
| 20 | 830 | Maintenance Supervision & Engineering | | | |
| 21 | 831 | Maintenance of Structures & Improvements | | | |
| 22 | 832 | Maintenance of Reservoirs & Wells | | | |
| 23 | 833 | Maintenance of Lines | | | |
| 24 | 834 | Maintenance of Compressor Station Equip. | | NOT | |
| 25 | 835 | Maintenance of Meas. & Reg. Sta. Equip. | | APPLICABLE | |
| 26 | 836 | Maintenance of Purification Equipment | | | |
| 27 | 837 | Maintenance of Other Equipment | | | |
| 28 | | **Total Maintenance - Underground Storage** | | | |
| 29 | | **TOTAL Underground Storage Expenses** | | | |
| 30 | | | | | |
| 31 | Other Storage Expenses - Operation | | | | |
| 32 | 840 | Operation Supervision & Engineering | | | |
| 33 | 841 | Operation Labor and Expenses | | | |
| 34 | 842 | Rents | | NOT | |
| 35 | 842.1 | Fuel | | APPLICABLE | |
| 36 | 842.2 | Power | | | |
| 37 | 842.3 | Gas Losses | | | |
| 38 | | **Total Operation - Other Storage Expenses** | | | |
| 39 | | | | | |
| 40 | Other Storage Expenses - Maintenance | | | | |
| 41 | 843.1 | Maintenance Supervision & Engineering | | | |
| 42 | 843.2 | Maintenance of Structures & Improvements | | | |
| 43 | 843.3 | Maintenance of Gas Holders | | | |
| 44 | 843.4 | Maintenance of Purification Equipment | | NOT | |
| 45 | 843.6 | Maintenance of Vaporizing Equipment | | APPLICABLE | |
| 46 | 843.7 | Maintenance of Compressor Equipment | | | |
| 47 | 843.8 | Maintenance of Measuring & Reg. Equipment | | | |
| 48 | 843.9 | Maintenance of Other Equipment | | | |
| 49 | | **Total Maintenance - Other Storage Exp.** | | | |
| 50 | | **TOTAL - Other Storage Expenses** | | | |
| 51 | | | | | |
| 52 | **TOTAL - STORAGE, TERMINALING & PROC.** | | | | |

# MONTANA OPERATION & MAINTENANCE EXPENSES

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | **Transmission Expenses** | | | |
| 2 | Operation | | | | |
| 3 | 850 | Operation Supervision & Engineering | | | |
| 4 | 851 | System Control & Load Dispatching | | | |
| 5 | 852 | Communications System Expenses | | | |
| 6 | 853 | Compressor Station Labor & Expenses | | | |
| 7 | 854 | Gas for Compressor Station Fuel | | NOT | |
| 8 | 855 | Other Fuel & Power for Compressor Stations | | APPLICABLE | |
| 9 | 856 | Mains Expenses | | | |
| 10 | 857 | Measuring & Regulating Station Expenses | | | |
| 11 | 858 | Transmission & Compression of Gas by Others | | | |
| 12 | 859 | Other Expenses | | | |
| 13 | 860 | Rents | | | |
| 14 | | **Total Operation - Transmission** | | | |
| 15 | Maintenance | | | | |
| 16 | 861 | Maintenance Supervision & Engineering | | | |
| 17 | 862 | Maintenance of Structures & Improvements | | | |
| 18 | 863 | Maintenance of Mains | | | |
| 19 | 864 | Maintenance of Compressor Station Equip. | | NOT | |
| 20 | 865 | Maintenance of Measuring & Reg. Sta. Equip. | | APPLICABLE | |
| 21 | 866 | Maintenance of Communication Equipment | | | |
| 22 | 867 | Maintenance of Other Equipment | | | |
| 23 | | **Total Maintenance - Transmission** | | | |
| 24 | | **TOTAL Transmission Expenses** | | | |
| 25 | | **Distribution Expenses** | | | |
| 26 | Operation | | | | |
| 27 | 870 | Operation Supervision & Engineering | $367,051 | $539,030 | 46.85% |
| 28 | 871 | Distribution Load Dispatching | 52,070 | 57,284 | 10.01% |
| 29 | 872 | Compressor Station Labor and Expenses | | | |
| 30 | 873 | Compressor Station Fuel and Power | | | |
| 31 | 874 | Mains and Services Expenses | 709,924 | 847,419 | 19.37% |
| 32 | 875 | Measuring & Reg. Station Exp.-General | 18,784 | 82,034 | 336.72% |
| 33 | 876 | Measuring & Reg. Station Exp.-Industrial | 6,295 | 13,433 | 113.39% |
| 34 | 877 | Meas. & Reg. Station Exp.-City Gate Ck. Sta. | 4 | 48 | 1100.00% |
| 35 | 878 | Meter & House Regulator Expenses | 469,013 | 415,972 | -11.31% |
| 36 | 879 | Customer Installations Expenses | 763,290 | 775,449 | 1.59% |
| 37 | 880 | Other Expenses | 1,002,466 | 882,055 | -12.01% |
| 38 | 881 | Rents | 19,295 | 24,379 | 26.35% |
| 39 | | **Total Operation - Distribution** | $3,408,192 | $3,637,103 | 6.72% |
| 40 | Maintenance | | | | |
| 41 | 885 | Maintenance Supervision & Engineering | $169,457 | $192,462 | 13.58% |
| 42 | 886 | Maintenance of Structures & Improvements | 117 | 160 | 36.75% |
| 43 | 887 | Maintenance of Mains | 62,073 | 99,524 | 60.33% |
| 44 | 888 | Maint. of Compressor Station Equipment | | | |
| 45 | 889 | Maint. of Meas. & Reg. Station Exp.-General | 13,410 | 39,174 | 192.13% |
| 46 | 890 | Maint. of Meas. & Reg. Sta. Exp.-Industrial | 9,546 | 13,250 | 38.80% |
| 47 | 891 | Maint. of Meas. & Reg. Sta. Equip.-City Gate | | | |
| 48 | 892 | Maintenance of Services | 43,398 | 100,621 | 131.86% |
| 49 | 893 | Maintenance of Meters & House Regulators | 55,511 | 80,890 | 45.72% |
| 50 | 894 | Maintenance of Other Equipment | 199,463 | 64,502 | -67.66% |
| 51 | | **Total Maintenance - Distribution** | $552,975 | $590,583 | 6.80% |
| 52 | | **TOTAL Distribution Expenses** | $3,961,167 | $4,227,686 | 6.73% |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2004

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | **Customer Accounts Expenses** | | | |
| 3 | Operation | | | |
| 4 | 901 Supervision | $170,318 | $173,827 | 2.06% |
| 5 | 902 Meter Reading Expenses | 509,095 | 595,377 | 16.95% |
| 6 | 903 Customer Records & Collection Expenses | 1,191,971 | 1,308,588 | 9.78% |
| 7 | 904 Uncollectible Accounts Expenses | 231,718 | 267,713 | 15.53% |
| 8 | 905 Miscellaneous Customer Accounts Expenses | 166,119 | 103,860 | -37.48% |
| 9 | | | | |
| 10 | **TOTAL Customer Accounts Expenses** | $2,269,221 | $2,449,365 | 7.94% |
| 11 | | | | |
| 12 | **Customer Service & Informational Expenses** | | | |
| 13 | Operation | | | |
| 14 | 907 Supervision | $3,782 | $1,601 | -57.67% |
| 15 | 908 Customer Assistance Expenses | 21,407 | 26,853 | 25.44% |
| 16 | 909 Informational & Instructional Advertising Exp. | 16,159 | 27,774 | 71.88% |
| 17 | 910 Miscellaneous Customer Service & Info. Exp. | 185 | 127 | -31.35% |
| 18 | | | | |
| 19 | **TOTAL Customer Service & Info. Expenses** | $41,533 | $56,355 | 35.69% |
| 20 | | | | |
| 21 | **Sales Expenses** | | | |
| 22 | Operation | | | |
| 23 | 911 Supervision | $90,477 | $83,809 | -7.37% |
| 24 | 912 Demonstrating & Selling Expenses | 199,693 | 214,362 | 7.35% |
| 25 | 913 Advertising Expenses | 19,297 | 22,133 | 14.70% |
| 26 | 916 Miscellaneous Sales Expenses | 17,612 | 17,941 | 1.87% |
| 27 | | | | |
| 28 | **TOTAL Sales Expenses** | $327,079 | $338,245 | 3.41% |
| 29 | | | | |
| 30 | **Administrative & General Expenses** | | | |
| 31 | Operation | | | |
| 32 | 920 Administrative & General Salaries | $1,125,594 | $2,035,726 | 80.86% |
| 33 | 921 Office Supplies & Expenses | 629,862 | 613,955 | -2.53% |
| 34 | 922 (Less) Administrative Expenses Transferred - Cr. | | | |
| 35 | 923 Outside Services Employed | 175,709 | 159,669 | -9.13% |
| 36 | 924 Property Insurance | 118,978 | 91,432 | -23.15% |
| 37 | 925 Injuries & Damages | 369,481 | 390,620 | 5.72% |
| 38 | 926 Employee Pensions & Benefits | 1,160,161 | 1,418,721 | 22.29% |
| 39 | 927 Franchise Requirements | | | |
| 40 | 928 Regulatory Commission Expenses | 76,909 | 62,123 | -19.23% |
| 41 | 929 (Less) Duplicate Charges - Cr. | | | |
| 42 | 930.1 General Advertising Expenses | 29,088 | 46,535 | 59.98% |
| 43 | 930.2 Miscellaneous General Expenses | 73,737 | 78,376 | 6.29% |
| 44 | 931 Rents | 48,269 | 49,776 | 3.12% |
| 45 | | | | |
| 46 | **TOTAL Operation - Admin. & General** | $3,807,788 | $4,946,933 | 29.92% |
| 47 | Maintenance | | | |
| 48 | 935 Maintenance of General Plant | $157,457 | $140,538 | -10.75% |
| 49 | | | | |
| 50 | **TOTAL Administrative & General Expenses** | $3,965,245 | $5,087,471 | 28.30% |
| 51 | **TOTAL OPERATION & MAINTENANCE EXP.** | $60,541,866 | $72,576,751 | 19.88% |

# MONTANA TAXES OTHER THAN INCOME

Year: 2004

| | Description of Tax | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Payroll Taxes | $439,770 | $467,056 | 6.20% |
| 2 | Secretary of State | 196 | 248 | 26.53% |
| 3 | Highway Use Tax | 167 | 196 | 17.37% |
| 4 | Montana Consumer Counsel | 66,214 | 85,424 | 29.01% |
| 5 | Montana PSC | 163,884 | 218,098 | 33.08% |
| 6 | Franchise Taxes | 18,128 | 18,821 | 3.82% |
| 7 | Property Taxes | 1,475,359 | 1,506,272 | 2.10% |
| 8 | Tribal Taxes | 4,800 | 4,480 | -6.67% |
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| 47 | | | | |
| 48 | | | | |
| 49 | | | | |
| 50 | **TOTAL MT Taxes other than Income** | $2,168,518 | $2,300,595 | 6.09% |

## PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2004

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | ADP Proxy Service | Investor Communication Services | 204,793 | 5,222 | 2.55% |
| 2 | | | | | |
| 3 | API Construction Company | Construction Services | 86,878 | | 0.00% |
| 4 | | | | | |
| 5 | Benco Equipment Company | Vehicle Maintenance | 180,456 | 402 | 0.22% |
| 6 | | | | | |
| 7 | Braden Constructions Services | Construction Services | 89,890 | | 0.00% |
| 8 | | | | | |
| 9 | Bullinger Tree Service | Tree Trimming Service | 244,378 | 43 | 0.02% |
| 10 | | | | | |
| 11 | C. Fox Consulting | Consulting Services | 111,456 | 5,504 | 4.94% |
| 12 | | | | | |
| 13 | Ceda Inc. | Boiler Maintenance | 138,908 | | 0.00% |
| 14 | | | | | |
| 15 | Chief Construction | Construction Services | 363,695 | 470 | 0.13% |
| 16 | | | | | |
| 17 | Citigate Financial Intelligence | Investor Relations Services | 77,452 | 1,975 | 2.55% |
| 18 | | | | | |
| 19 | Deloitte & Touche, LLP | Auditing and Consulting Services | 247,793 | 329 | 0.13% |
| 20 | | | | | |
| 21 | Diversified Graphics Inc. | Annual Report | 325,237 | 8,294 | 2.55% |
| 22 | | | | | |
| 23 | DMVW Railroad | Construction Services | 223,964 | | 0.00% |
| 24 | | | | | |
| 25 | Duffield Construction Inc | Construction Services | 322,013 | | 0.00% |
| 26 | | | | | |
| 27 | DWD LLC | Tree Trimming Service | 166,334 | | 0.00% |
| 28 | (Intermountain Tree Expert Co) | | | | |
| 29 | | | | | |
| 30 | Edison Electric Institute | Membership Fees | 95,349 | | 0.00% |
| 31 | | | | | |
| 32 | Edling Electric, Inc | Construction Services-Electrical | 234,071 | | 0.00% |
| 33 | | | | | |
| 34 | Electro-Test & Maintenance | Contract Services - Replace Xfmr's | 120,885 | | 0.00% |
| 35 | | | | | |
| 36 | Ernst & Young, LLP | Consulting Services | 91,399 | 7,161 | 7.83% |
| 37 | | | | | |
| 38 | Fischer Contracting | Contract Services | 100,986 | | 0.00% |
| 39 | | | | | |
| 40 | Franz Construction | Construction Services | 90,307 | 1,001 | 1.11% |
| 41 | | | | | |
| 42 | GE Energy Services | Construction Services | 516,735 | | 0.00% |

Company Name: Montana-Dakota Utilities Co. SCHEDULE 12

## PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2004

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Great Place to Work Institute | Consulting Services | 116,606 | 1,981 | 1.70% |
| 2 | | | | | |
| 3 | H. Zinder & Associates | Consulting Services | 77,771 | 36,627 | 47.10% |
| 4 | | | | | |
| 5 | Hamilton Spray | Contract Services - Pole Spraying | 146,180 | | 0.00% |
| 6 | | | | | |
| 7 | Hughes, Kellner, Sullivan | Legal Services | 73,308 | 25,507 | 34.79% |
| 8 | | | | | |
| 9 | IBM | Contract Services - Computer Maintenance | 114,255 | 16,747 | 14.66% |
| 10 | | | | | |
| 11 | Image Integration Services | Consulting Services | 130,971 | 9,630 | 7.35% |
| 12 | | | | | |
| 13 | Industrial Contractors, Inc | Construction Services | 705,672 | | 0.00% |
| 14 | | | | | |
| 15 | J.D. Edwards | Contract Services - Software Maintenace | 563,480 | 20,088 | 3.56% |
| 16 | | | | | |
| 17 | James W. Sewall Company | Consulting Services | 311,928 | 40,765 | 13.07% |
| 18 | | | | | |
| 19 | Kappel Tree Service | Tree Trimming Service | 79,473 | | 0.00% |
| 20 | | | | | |
| 21 | Kringen Construction Inc. | Construction Services | 185,816 | | 0.00% |
| 22 | | | | | |
| 23 | Larson Design Office, Inc. | Contract Services - Office Design | 109,700 | 2,797 | 2.55% |
| 24 | | | | | |
| 25 | Leboeuf, Lamb, Greene & Macrae | Legal Services | 245,752 | 6,267 | 2.55% |
| 26 | | | | | |
| 27 | Lignite Energy Council | Membership Fees | 88,810 | | 0.00% |
| 28 | | | | | |
| 29 | Lindtech Commercial Htg & Air | Contract Services - Annex Bldg AC | 117,050 | 13,399 | 11.45% |
| 30 | | | | | |
| 31 | McDermott, Will & Emery | Legal Services | 189,579 | 4,959 | 2.62% |
| 32 | | | | | |
| 33 | Merril Communications | Contract Services - Stockholder Mtg Mat. | 97,079 | 1,779 | 1.83% |
| 34 | | | | | |
| 35 | Microsoft | Contract Services - Software Maintenace | 268,270 | 11,905 | 4.44% |
| 36 | | | | | |
| 37 | Moody's Investors Services | Financial Services | 176,500 | 15,283 | 8.66% |
| 38 | | | | | |
| 39 | New York Life | K-Plan Administrator | 199,827 | | 0.00% |
| 40 | | | | | |
| 41 | New York Stock Exchange | Financial Services | 116,306 | 2,761 | 2.37% |
| 42 | | | | | |
| 43 | One Call Locators, LTD | Line Location Service | 841,937 | 195,778 | 23.25% |

## PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2004

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Outdoor Services Inc. | Contract Services - Meter Reading | 658,473 | 111,746 | 16.97% |
| 2 | | | | | |
| 3 | Philip Services Corp. | Boiler Maintenance | 414,993 | | 0.00% |
| 4 | | | | | |
| 5 | Pole Maintenance Co. | Contract Services - Pole Treatment | 289,738 | | 0.00% |
| 6 | | | | | |
| 7 | Power Generation Service | Contract Services | 230,097 | | 0.00% |
| 8 | | | | | |
| 9 | Progressive Maintenance Co. | Custodial Services | 83,632 | 8,732 | 10.44% |
| 10 | | | | | |
| 11 | Rocky Mountain Line | Construction Services | 246,095 | 132,235 | 53.73% |
| 12 | | | | | |
| 13 | Rolta International, Inc | Contract Services | 981,612 | 128,285 | 13.07% |
| 14 | | | | | |
| 15 | Sargent & Lundy, LLC | Consulting Services | 150,739 | | 0.00% |
| 16 | | | | | |
| 17 | Southern Cross Corporation | Contract Services - Leak Detection | 228,067 | 74,434 | 32.64% |
| 18 | | | | | |
| 19 | Standard & Poor's | Financial Services | 153,893 | 5,846 | 3.80% |
| 20 | | | | | |
| 21 | State-Line Contractors, Inc | Construction Services | 276,253 | 161,867 | 58.59% |
| 22 | | | | | |
| 23 | Tetra Tech EM Inc. | Contract Services | 179,677 | | 0.00% |
| 24 | | | | | |
| 25 | Thelen Reid & Priest, LLP | Legal Services | 1,498,965 | 23,253 | 1.55% |
| 26 | | | | | |
| 27 | The Structure Group | Contract Serv. - Software Install & Maint. | 125,925 | | 0.00% |
| 28 | | | | | |
| 29 | Towers Perrin | Consultant - Compensation and Benefits | 522,096 | 41,823 | 8.01% |
| 30 | | | | | |
| 31 | Ulmer Tree Services | Tree Trimming Service | 106,223 | | 0.00% |
| 32 | | | | | |
| 33 | Underground Locators, LLC | Line Location Service | 112,353 | | 0.00% |
| 34 | | | | | |
| 35 | US Bank | Bank Services | 197,420 | 36,776 | 18.63% |
| 36 | | | | | |
| 37 | Utilities International, Inc. | Consulting Services | 775,303 | 88,632 | 11.43% |
| 38 | | | | | |
| 39 | Utility Partners, LC | Consultant - Mobile Service Computer | 120,593 | 13,804 | 11.45% |
| 40 | | | | | |
| 41 | Wells Fargo | Stock Transfer Agent and ESOP Admin | 318,812 | 8,130 | 2.55% |
| 42 | | | | | |
| 43 | | | | | 0.00% |
| 44 | | | | | |
| 45 | | | | | 0.00% |
| 46 | | | | | |
| 47 | **TOTAL Payments for Services** | | 16,660,206 | 1,272,235 | 7.64% |

## POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2004

| | Description | Total Company | Montana | % Montana |
|---|---|---|---|---|
| 1 | Contributions to Candidates by PAC | $53,515 | $8,375 | 15.65% |
| 2 | | | | |
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| 41 | | | | |
| 42 | | | | |
| 43 | **TOTAL Contributions** | $53,515 | $8,375 | 15.65% |

# Pension Costs

Year: 2004

| | | | | |
|---|---|---|---|---|
| 1 | Plan Name MDU Resources Group, Inc. Master Pension Plan Trust | | | |
| 2 | Defined Benefit Plan? Yes | Defined Contribution Plan? No | | |
| 3 | PROPRIETARY SCHEDULE | | | |
| 4 | PROPRIETARY SCHEDULE | | | |
| 5 | | | | |
| | Item | Current Year | Last Year | % Change |
| 6 | **Change in Benefit Obligation** | | | |
| 7 | Benefit obligation at beginning of year | | | |
| 8 | Service cost | | | |
| 9 | Interest Cost | | | |
| 10 | Plan participants' contributions | PROPRIETARY SCHEDULE | | |
| 11 | Amendments | | | |
| 12 | Actuarial (Gain) Loss | | | |
| 13 | Acquisition | | | |
| 14 | Benefits paid | | | |
| 15 | Benefit obligation at end of year | | | |
| 16 | **Change in Plan Assets** | | | |
| 17 | Fair value of plan assets at beginning of year | | | |
| 18 | Actual return on plan assets | | | |
| 19 | Acquisition | | | |
| 20 | Employer contribution | PROPRIETARY SCHEDULE | | |
| 21 | Plan participants' contributions | | | |
| 22 | Benefits paid | | | |
| 23 | Fair value of plan assets at end of year | | | |
| 24 | **Funded Status** | | | |
| 25 | Unrecognized net actuarial loss | | | |
| 26 | Unrecognized prior service cost | PROPRIETARY SCHEDULE | | |
| 27 | Unrecognized net transition obligation | | | |
| 28 | Accrued benefit cost | | | |
| 29 | | | | |
| 30 | **Weighted-average Assumptions as of Year End** | | | |
| 31 | Discount rate | 5.75 | 6.00 | -4.17% |
| 32 | Expected return on plan assets | 8.50 | 8.50 | 0.00% |
| 33 | Rate of compensation increase | 4.75 | 4.75 | 0.00% |
| 34 | | | | |
| 35 | **Components of Net Periodic Benefit Costs** | | | |
| 36 | Service cost | | | |
| 37 | Interest cost | | | |
| 38 | Expected return on plan assets | PROPRIETARY SCHEDULE | | |
| 39 | Amortization of prior service cost | | | |
| 40 | Recognized net actuarial gain | | | |
| 41 | Transition amount amortization | | | |
| 42 | Net periodic benefit cost | | | |
| 43 | | | | |
| 44 | **Montana Intrastate Costs:** | | | |
| 45 | Pension Costs | PROPRIETARY SCHEDULE | | |
| 46 | Pension Costs Capitalized | | | |
| 47 | Accumulated Pension Asset (Liability) at Year End | | | |
| 48 | **Number of Company Employees:** | | | |
| 49 | Covered by the Plan | | | |
| 50 | Not Covered by the Plan | PROPRIETARY SCHEDULE | | |
| 51 | Active | | | |
| 52 | Retired | | | |
| 53 | Deferred Vested Terminated | | | |

# Other Post Employment Benefits (OPEBS)

Year: 2004

| | Item | Current Year | Last Year | % Change |
|---|---|---|---|---|
| 1 | **Regulatory Treatment:** | | | |
| 2 | Commission authorized - most recent | | | |
| 3 | Docket number: | | | |
| 4 | Order numbers: | | | |
| 5 | Amount recovered through rates - | | | |
| 6 | **Weighted-average Assumptions as of Year End** | | | |
| 7 | Discount rate | 5.75 | 6.00 | -4.17% |
| 8 | Expected return on plan assets | 7.50 | 7.50 | 0.00% |
| 9 | Medical Cost Inflation Rate | 6.00 | 6.00 | 0.00% |
| 10 | Actuarial Cost Method | PROPRIETARY SCHEDULE | | |
| 11 | Rate of compensation increase | PROPRIETARY SCHEDULE | | |
| 12 | **List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:** | | | |
| 13 | **VEBA** | | | |
| 14 | **Describe any Changes to the Benefit Plan:** The Company adopted FASB Staff Position No. FAS 106-2 "Accounting and | | | |
| 15 | Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" during 2004. | | | |
| 16 | The accumulated benefit obligation and net periodic costs for 2004 reflect the adoption of this accounting standard. | | | |
| | **TOTAL COMPANY** | | | |
| 17 | **Change in Benefit Obligation** | | | |
| 18 | Benefit obligation at beginning of year | | | |
| 19 | Service cost | | | |
| 20 | Interest Cost | | | |
| 21 | Plan participants' contributions | | | |
| 22 | Amendments | | | |
| 23 | Actuarial (Gain) Loss | PROPRIETARY SCHEDULE | | |
| 24 | Acquisition | | | |
| 25 | Benefits paid | | | |
| 26 | Benefit obligation at end of year | | | |
| 27 | **Change in Plan Assets** | | | |
| 28 | Fair value of plan assets at beginning of year | | | |
| 29 | Actual return on plan assets | | | |
| 30 | Acquisition | | | |
| 31 | Employer contribution | PROPRIETARY SCHEDULE | | |
| 32 | Plan participants' contributions | | | |
| 33 | Benefits paid | | | |
| 34 | Fair value of plan assets at end of year | | | |
| 35 | **Funded Status** | | | |
| 36 | Unrecognized net actuarial loss | | | |
| 37 | Unrecognized prior service cost | PROPRIETARY SCHEDULE | | |
| 38 | Unrecognized transition obligation | | | |
| 39 | Accrued benefit cost | | | |
| 40 | **Components of Net Periodic Benefit Costs** | | | |
| 41 | Service cost | | | |
| 42 | Interest cost | | | |
| 43 | Expected return on plan assets | | | |
| 44 | Amortization of prior service cost | PROPRIETARY SCHEDULE | | |
| 45 | Recognized net acturial gain | | | |
| 46 | Transition amount amortization | | | |
| 47 | Net periodic benefit cost | | | |
| 48 | **Accumulated Post Retirement Benefit Obligation** | | | |
| 49 | Amount Funded through VEBA | | | |
| 50 | Amount Funded through 401(h) | | | |
| 51 | Amount Funded through Other ________________ | | | |
| 52 | TOTAL | PROPRIETARY SCHEDULE | | |
| 53 | Amount that was tax deductible - VEBA | | | |
| 54 | Amount that was tax deductible - 401(h) | | | |
| 55 | Amount that was tax deductible - Other ____________ | | | |
| 56 | TOTAL | | | |

## Other Post Employment Benefits (OPEBS) Continued

| | Item | Current Year | Last Year | % Change |
|---|---|---|---|---|
| 1 | **Number of Company Employees:** | | | |
| 2 | Covered by the Plan | | | |
| 3 | Not Covered by the Plan | | | |
| 4 | Active | PROPRIETARY SCHEDULE | | |
| 5 | Retired | | | |
| 6 | Spouses/Dependants covered by the Plan | | | |
| 7 | **Montana** | | | |
| 8 | **Change in Benefit Obligation** | | | |
| 9 | Benefit obligation at beginning of year | | | |
| 10 | Service cost | NOT APPLICABLE | | |
| 11 | Interest Cost | | | |
| 12 | Plan participants' contributions | | | |
| 13 | Amendments | | | |
| 14 | Actuarial Gain | | | |
| 15 | Acquisition | | | |
| 16 | Benefits paid | | | |
| 17 | Benefit obligation at end of year | | | |
| 18 | **Change in Plan Assets** | | | |
| 19 | Fair value of plan assets at beginning of year | | | |
| 20 | Actual return on plan assets | | | |
| 21 | Acquisition | | | |
| 22 | Employer contribution | | | |
| 23 | Plan participants' contributions | | | |
| 24 | Benefits paid | | | |
| 25 | Fair value of plan assets at end of year | | | |
| 26 | **Funded Status** | | | |
| 27 | Unrecognized net actuarial loss | | | |
| 28 | Unrecognized prior service cost | | | |
| 29 | Prepaid (accrued) benefit cost | | | |
| 30 | **Components of Net Periodic Benefit Costs** | | | |
| 31 | Service cost | | | |
| 32 | Interest cost | | | |
| 33 | Expected return on plan assets | | | |
| 34 | Amortization of prior service cost | | | |
| 35 | Recognized net actuarial loss | | | |
| 36 | Net periodic benefit cost | | | |
| 37 | **Accumulated Post Retirement Benefit Obligation** | | | |
| 38 | Amount Funded through VEBA | | | |
| 39 | Amount Funded through 401(h) | | | |
| 40 | Amount Funded through other ______________ | | | |
| 41 | TOTAL | | | |
| 42 | Amount that was tax deductible - VEBA | | | |
| 43 | Amount that was tax deductible - 401(h) | | | |
| 44 | Amount that was tax deductible - Other | | | |
| 45 | TOTAL | | | |
| 46 | **Montana Intrastate Costs:** | | | |
| 47 | Pension Costs | | | |
| 48 | Pension Costs Capitalized | | | |
| 49 | Accumulated Pension Asset (Liability) at Year End | | | |
| 50 | **Number of Montana Employees:** | | | |
| 51 | Covered by the Plan | | | |
| 52 | Not Covered by the Plan | | | |
| 53 | Active | | | |
| 54 | Retired | | | |
| 55 | Spouses/Dependants covered by the Plan | | | |

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16

Year: 2004

## TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

| Line No. | Name/Title | Base Salary | Bonuses | Other | Total Compensation | Total Compensation Last Year | % Increase Total Compensation |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | PROPRIETARY SCHEDULE | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

## COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

| Line No. | Name/Title | Base Salary | Bonuses | Other 1/ | Total Compensation | Total Compensation Last Year | % Increase Total Compensation |
|---|---|---|---|---|---|---|---|
| 1 | Martin A. White - Chairman of the Board, President & CEO | $647,500 | $1,265,550 | $443,058 | $2,356,108 | $2,575,040 | -9% |
| 2 | Ronald D. Tipton - CEO of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. 2/ | 348,516 | 152,460 | 2,391,218 | 2,892,194 | 629,923 | 359% |
| 3 | Warren L. Robinson - Executive Vice President, & Chief Financial Officer | 348,500 | 350,000 | 154,401 | 852,901 | 912,034 | -6% |
| 4 | John K. Castleberry - President & CEO of WBI Holdings, Inc. | 348,500 | 350,000 | 153,372 | 851,872 | 1,001,644 | -15% |
| 5 | Terry D. Hildestad - President & CEO of Knife River Corporation | 348,500 | 120,925 | 155,395 | 624,820 | 615,050 | 2% |

1/ See page 20a for details.
2/ Mr. Tipton retired as Chief Executive Officer on September 28, 2004.

# EXECUTIVE COMPENSATION

## SUMMARY COMPENSATION TABLE

| | Annual compensation | | | | Long-term compensation | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Awards | | Payouts | |
| (a) Name and principal position | (b) Year | (c) Salary ($) | (d) Bonus(1) ($) | (e) Other annual compen-sation(2) ($) | (f) Restricted stock awards ($)(3) | (g) Securities underlying Options/ SARs (#) | (h) LTIP payouts ($) | (i) All other compen-sation(6) ($) |
| Martin A. White —Chairman of the Board, President & CEO | 2004 | 647,500 | 1,265,550 | — | — | — | 416,724(4) | 26,334(6) |
| | 2003 | 596,308 | 1,200,000 | — | — | — | 772,732(5) | 6,000 |
| | 2002 | 517,038 | 509,340 | — | — | — | — | 5,500 |
| Ronald D. Tipton —CEO of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.(7) | 2004 | 348,516 | 152,460 | — | — | — | 141,831(4) | 2,249,387(8) |
| | 2003 | 319,751 | 211,464 | — | — | — | 92,708(5) | 6,000 |
| | 2002 | 306,815 | 111,958 | — | — | — | — | 5,500 |
| Warren L. Robinson —Executive Vice President and Chief Financial Officer | 2004 | 348,500 | 350,000 | — | — | — | 141,715(4) | 12,686(6) |
| | 2003 | 318,154 | 320,000 | — | — | — | 267,880(5) | 6,000 |
| | 2002 | 278,265 | 182,840 | — | — | — | — | 5,500 |
| John K. Castleberry —President & CEO of WBI Holdings, Inc. | 2004 | 348,500 | 350,000 | — | — | — | 141,715(4) | 11,657(6) |
| | 2003 | 319,077 | 320,000 | — | — | — | 356,567(5) | 6,000 |
| | 2002 | 296,827 | 300,000 | — | — | — | | 5,500 |
| Terry D. Hildestad —President & CEO of Knife River Corporation | 2004 | 348,500 | 120,925 | — | — | — | 141,715(4) | 13,680(6) |
| | 2003 | 319,077 | 252,960 | — | — | — | 37,013(5) | 6,000 |
| | 2002 | 298,731 | 165,600 | 229 | — | — | — | 5,500 |
| Paul Gatzemeier —President & CEO of Centennial Energy Resources LLC | 2004 | 244,250 | 257,250 | — | — | — | 71,903(4) | 6,150(6) |
| | 2003 | 226,654 | 261,869 | — | — | — | — | — |
| | 2002 | 157,183 | 298,463 | — | — | — | — | — |

(1) Granted pursuant to the annual executive incentive compensation plans.

(2) Above-market interest on deferred compensation.

(3) At December 31, 2004, the Named Officers held the following amounts of restricted stock: Mr. White—24,300 shares ($650,511); Mr. Tipton—3,750 shares ($100,388); Mr. Robinson—8,235 shares ($220,451); Mr. Castleberry—6,990 shares ($187,122); Mr. Hildestad—9,675 shares ($259,000); and Mr. Gatzemeier—0 shares ($0).

(4) Represents the value of performance shares granted under the 1997 Executive Long-Term Incentive Plan for the 2002-2004 performance period, which were paid in stock, and dividend equivalents, which were paid in cash.

(5) Dividend equivalents paid with respect to options granted pursuant to the 1992 KESOP or the 1997 Executive Long-Term Incentive Plan for the 2001-2003 performance cycle.

(6) Comprised of Company contributions to the Company 401(k) Retirement Plan of $6,150 for each Named Officer and non-preferential dividends on restricted stock, as follows: Mr. White—$20,184; Mr. Robinson—$6,536; Mr. Castleberry—$5,507; Mr. Hildestad—$7,530; and Mr. Gatzemeier—$0.

(7) Mr. Tipton retired as CEO of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., and Utility Services, Inc. on September 28, 2004.

(8) Comprised of Company contributions to the Company 401(k) Retirement Plan—$6,150; a severance payment in connection with retirement—$2,235,707; and non-preferential dividends on restricted stock—$7,530.

## AGGREGATED OPTION/SAR EXERCISES IN LAST FISCAL YEAR AND FISCAL YEAR-END OPTION/SAR VALUES

| (a) Name | (b) Shares acquired on exercise (#)(2) | (c) Value realized ($) | (d) Number of securities underlying unexercised options at fiscal year-end(1)(2) (#) | | (e) Value of unexercised, in-the-money options at fiscal year-end ($) | |
|---|---|---|---|---|---|---|
| | | | Exercisable | Unexercisable | Exercisable | Unexercisable |
| Martin A. White | 270,000 | 1,333,846 | 0 | 0 | 0 | 0 |
| Ronald D. Tipton | 49,140 | 225,469 | 0 | 0 | 0 | 0 |
| Warren L. Robinson | 93,600 | 384,201 | 0 | 0 | 0 | 0 |
| John K. Castleberry | 94,500 | 611,548 | 0 | 0 | 0 | 0 |
| Terry D. Hildestad | 15,936 | 156,120 | 3,683 | 45,997 | 25,572 | 319,371 |
| Paul Gatzemeier | 0 | 0 | 0 | 0 | 0 | 0 |

(1) Vesting is accelerated upon a change in control.

(2) Adjusted for the three-for-two stock split on October 29, 2003.

# LONG-TERM INCENTIVE PLANS—AWARDS IN LAST FISCAL YEAR

| | | | Estimated future payouts under non-stock price-based plans | | |
|---|---|---|---|---|---|
| (a)<br>Name | (b)<br>Number of shares, units or other rights (#)(1) | (c)<br>Performance or other period until maturation or payout | (d)<br>Threshold ($ or #) | (e)<br>Target ($ or #) | (f)<br>Maximum ($ or #) |
| Martin A. White | 50,000 | 2004-2006 | 5,000 shares<br>$10,700<br>Dividend Equivalents | 50,000 shares<br>$107,000<br>Dividend Equivalents | 100,000 shares<br>$214,000<br>Dividend Equivalents |
| Ronald D. Tipton | 4,729 | 2004-2006 | 473 shares<br>$1,012<br>Dividend Equivalents | 4,729 shares<br>$10,120<br>Dividend Equivalents | 9,458 shares<br>$20,240<br>Dividend Equivalents |
| Warren L. Robinson | 13,097 | 2004-2006 | 1,310 shares<br>$2,803<br>Dividend Equivalents | 13,097 shares<br>$28,028<br>Dividend Equivalents | 26,194 shares<br>$56,055<br>Dividend Equivalents |
| John K. Castleberry | 13,097 | 2004-2006 | 1,310 shares<br>$2,803<br>Dividend Equivalents | 13,097 shares<br>$28,028<br>Dividend Equivalents | 26,194 shares<br>$56,055<br>Dividend Equivalents |
| Terry D. Hildestad | 13,097 | 2004-2006 | 1,310 shares<br>$2,803<br>Dividend Equivalents | 13,097 shares<br>$28,028<br>Dividend Equivalents | 26,194 shares<br>$56,055<br>Dividend Equivalents |
| Paul Gatzemeier | 5,093 | 2004-2006 | 509 shares<br>$1,089<br>Dividend Equivalents | 5,093 shares<br>$10,899<br>Dividend Equivalents | 10,186 shares<br>$21,798<br>Dividend Equivalents |

(1) Performance shares were granted in 2004 under the 1997 Executive Long-Term Incentive Plan and represent the opportunity to receive Company Common Stock at the end of the performance period based upon the Company's total shareholder return relative to a peer group of companies. The performance shares shown in column (b) are at the target level. The payout ranges from 0% for a rank less than 40th percentile, to 10% at the 40th percentile, 100% at the 50th percentile and 200% at the 100th percentile. Dividend equivalents also were granted and will be paid out in cash in an amount equal to the total dividends declared during the performance period on any shares that are actually earned by the participant. Performance shares and dividend equivalents that are not earned are forfeited. Vesting is accelerated upon a change in control.

## PENSION PLAN TABLE

| Remuneration | Years of Service | | | | |
|---|---|---|---|---|---|
| | 15 | 20 | 25 | 30 | 35 |
| $125,000 | $ 79,175 | $ 87,686 | $ 96,198 | $104,709 | $113,221 |
| 150,000 | 95,292 | 105,616 | 115,940 | 126,264 | 136,588 |
| 175,000 | 111,410 | 123,546 | 135,683 | 147,819 | 159,956 |
| 200,000 | 129,447 | 143,396 | 157,345 | 171,294 | 185,243 |
| 225,000 | 141,515 | 155,826 | 170,138 | 184,449 | 198,761 |
| 250,000 | 152,435 | 166,746 | 181,058 | 195,369 | 209,681 |
| 300,000 | 188,675 | 202,986 | 217,298 | 231,609 | 245,921 |
| 350,000 | 236,255 | 250,566 | 264,878 | 279,189 | 293,501 |
| 400,000 | 277,235 | 291,546 | 305,858 | 320,169 | 334,481 |
| 450,000 | 317,135 | 331,446 | 345,758 | 360,069 | 374,381 |
| 500,000 | 388,535 | 402,846 | 417,158 | 431,469 | 445,781 |
| 550,000 | 388,535 | 402,846 | 417,158 | 431,469 | 445,781 |
| 600,000 | 480,935 | 495,246 | 509,558 | 523,869 | 538,181 |
| 650,000 | 480,935 | 495,246 | 509,558 | 523,869 | 538,181 |

The Table covers the amounts payable under the Salaried Pension Plan and non-qualified Supplemental Income Security Plan (SISP).

Pension benefits are determined by the step-rate formula that places emphasis on the highest consecutive 60 months of earnings within the final 10 years of service.

Benefits for single participants under the Salaried Pension Plan are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivorship benefit for spouses, unless participants choose otherwise.

The Salaried Pension Plan also permits pre-retirement survivorship benefits upon satisfaction of certain conditions. Additionally, certain reductions are made for employees electing early retirement.

The Internal Revenue Code places maximum limitations on benefit amounts that may be paid under the Salaried Pension Plan.

Mr. Hildestad, one of the named officers, is covered by the Knife River Corporation Salaried Pension Plan, which is similar to the Salaried Pension Plan.

The Company has adopted a non-qualified SISP for senior management personnel. As of December 31, 2004, 98 senior management personnel were participating in the SISP, including the Named Officers.

Both plans cover salary shown in column (c) of the Summary Compensation Table and exclude bonuses and other forms of compensation.

Upon retirement and reaching age 65, participants receive either a retirement benefit or a survivor's benefit with the benefits payable monthly for 15 years or as an equivalent life annuity.

As of December 31, 2004, the Named Officers were credited with the following years of service under the plans:

| Name | Pension Service Years | SISP Service Years |
|---|---|---|
| Martin A. White | 13 | 13 |
| Ronald D. Tipton | 21 | 21 |
| Warren L. Robinson | 16 | 16 |
| John K. Castleberry | 22 | 17 |
| Terry D. Hildestad | 31 | 23 |
| Paul Gatzemeier | 3 | 3 |

The maximum years of service for benefits under the Pension Plan is 35. Vesting under the SISP begins at 3 years and is complete after 10 years. Benefit amounts under both plans are not subject to reduction for offset amounts.

## CHANGE-OF-CONTROL AND SEVERANCE ARRANGEMENTS

The Company entered into Change of Control Employment Agreements with the Named Officers and other executives ("executives") in November 1998 and May 2004, which provide certain protections to the executives in the event there is a change of control of the Company.

If a change of control occurs, the agreements provide for a three-year employment period from the date of the change of control, during which the executive is entitled to receive a base salary not less than the highest amount paid within the preceding twelve months, and annual bonuses not less than the highest bonus paid within the three years before the change of control, and to participate in the Company's incentive, savings, retirement and welfare benefit plans.

The agreements also provide that specified severance payments and benefits would be provided if the executive's employment is terminated during the employment period (or if connected to the change of control, prior thereto) by the Company, other than for cause or disability, or by the executive for good reason, which includes for any reason during the 30-day period beginning on the first anniversary of the change of control.

In such event, the executive would receive an amount equal to three times his annual base pay plus three times his highest annual bonus (as defined). In addition, he would receive (i) an immediate pro-rated cash-out of his bonus for the year of termination based on the highest annual bonus and (ii) an amount equal to the excess of (a) the actuarial equivalent of the benefit under Company qualified and nonqualified retirement plans that he would receive if he continued employment with the Company for an additional three years over (b) the actual benefit paid or payable under these plans.

The executive and family would continue to be covered by the Company's welfare benefit plans for three years. The executive also would receive outplacement benefits. Finally, the executive would receive an additional payment if necessary to make him or her whole for any federal excise tax on excess parachute payments imposed upon the executive, unless the total parachute payments were not more than 110% of the safe harbor amount for that tax (in which event the executive's payments would be reduced to the safe harbor amount).

For these purposes, "cause" generally means the executive's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or misconduct materially injurious to the Company. "Good reason" generally includes the diminution of the executive's position, authority, duties or responsibilities, the reduction of the executive's pay or benefits, and relocation or increased travel obligations.

Subject to certain exceptions described in the agreements, a "change of control" is defined in general as (i) the acquisition by an individual, entity, or group of 20% or more of the Company's voting securities; (ii) a turnover in a majority of the Board of Directors without the approval of a majority of the members of the Board who were members of the Board as of the agreement date or whose election was approved by such Board members; (iii) a merger or similar transaction; or (iv) the stockholders' approval of the Company's liquidation or dissolution.

The Company entered into an agreement with Ronald D. Tipton on October 4, 2004 in connection with his retirement as Chief Executive Officer of Utility Services, Inc., Montana-Dakota Utilities Co., and Great Plains Natural Gas Co. effective September 28, 2004. Mr. Tipton agreed to continue as a special projects advisor for Montana-Dakota Utilities Co. through January 2, 2005. Mr. Tipton received a severance payment of $2,235,707. Other benefits to which Mr. Tipton is entitled are determined in accordance with the terms and provisions of the Company's plans and programs.

## COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

### Purpose

The Compensation Committee of the Board of Directors has direct responsibility for determining compensation of the Company's executive officers and for producing an annual report on executive compensation for inclusion in the Company's proxy statement. Composed entirely of independent Directors, the Committee meets quarterly to review and determine compensation for the executive officers, including the Chief Executive Officer.

### Executive Compensation

Based upon a study of the Company's executive compensation programs in 2002, the Committee made several changes to its approach to long-term incentive compensation, including the elimination of stock options and restricted stock grants effective in 2003.

The Committee believes that appropriate compensation levels succeed in both attracting and motivating high quality employees. To implement this philosophy, the Committee analyzes trends in compensation among comparable companies participating in the oil and gas industry, segments of the energy and mining industries, the peer group of companies used in the graph following this report, and similar companies from general industry. The Committee then sets compensation levels that it believes are competitive within the industry and structured in a manner that rewards successful job performance. There are three components of total executive compensation: base salary, annual incentive compensation, and long-term incentive compensation.

In setting base salaries, the Committee does not use a particular formula. In addition to the above data, other factors the Committee uses in its analysis include the executive's current salary in comparison to the competitive industry standard as well as individual performance. Mr. White, the Chairman, President and Chief Executive Officer, received an 8.3% increase in base salary for 2004. During 2004, only approximately 25.6% of Mr. White's compensation was base pay. The remainder was performance-based. This reflects the Committee's belief in the importance of having substantial at risk compensation to provide a direct and strong link between performance and executive pay. For the other Named Officers, the Committee targeted salaries at the midpoint of the competitive industry standard. The other Named Officers, except for Mr. Tipton who retired, received base salary increases averaging 8.68% for 2004.

In keeping with the Committee's belief that compensation should be directly linked to successful performance, the Company employs both annual and long-term incentive compensation plans. The annual incentive compensation is determined under the executive incentive compensation plans.

On February 15, 2005, the Committee approved the payment of annual awards under the existing executive incentive compensation plans with respect to 2004. On February 17, 2005, the Board approved the payments. These payments are included in the Bonus column of the Summary Compensation Table.

The terms of the executive incentive compensation plans provide for annual cash incentive awards based upon achievement of annual performance measures with a threshold, target and maximum level. A target incentive award is established based upon the position level and actual base salary, or in the Committee's discretion, the assigned salary grade market value. Actual payment may range from zero to 200% of the target based upon achievement of corporate goals and individual performance. The Committee has full discretion to determine the extent to which goals have been achieved, the payment level, whether any final payment will be made and whether to adjust awards.

The performance goals for 2004 under the MDU Resources Group, Inc. Executive Incentive Compensation Plan, which applies to Mr. White and Mr. Robinson, were (i) budgeted earnings per share achieved (weighted 75%) and (ii) budgeted return on invested capital achieved (weighted 25%). Achievement of budgeted levels of earnings per share and return on invested capital would result in a potential award of 100% of the target amount. Achievement of less than 85% would result in no payment, while achievement of 114% would result in a payment of 200% of the target amount. The goals were met at near maximum level ($1.76 EPS, 9.4% ROIC) and resulted in a potential payment of 194.7% of the target amount. The Committee determined that maximum incentive payment would have resulted for Mr. White and Mr. Robinson in the absence of the severance payments to certain executives. The Committee decided to adjust Mr. Robinson's incentive payment to 200% to exclude the effects of the severance payments on the EPS and ROIC, but not to adjust Mr. White's payment.

Mr. Tipton, the retired Chief Executive Officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., and Utility Services, Inc., received his award pursuant to the Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, based upon (i) business units actual earnings per allocated share as a percentage of planned earnings per allocated share (weighted 75%) and (ii) business units actual return on invested capital as a percentage of planned return on invested capital (weighted 25%). The target amounts were: Montana-Dakota Utilities Co. ($0.61 EPS, 6.42% ROIC), weighted 66% and Utility Services, Inc. ($1.97 EPS and 7.27% ROIC), weighted 34%. Mr. Tipton's award was earned at 100.3% of target for the Montana-Dakota Utilities Co. portion and 0% of target for the Utility Services, Inc. portion and resulted in a potential payment of 67.3% of the target amount. For the same reasons as set forth above with respect to Mr. Robinson, the Committee adjusted Mr. Tipton's incentive payment to 87.1% to exclude the effects of such severance payments at Montana-Dakota Utilities Co. with respect to its effect on achieved allocated EPS and ROIC.

Mr. Castleberry received his award pursuant to the WBI Holdings, Inc. Executive Incentive Compensation Plan, based upon (i) actual earnings per allocated share as a percentage of planned earnings per allocated share (weighted 75%) and (ii) actual return on invested capital as a percentage of planned return on invested capital (weighted 25%) for WBI Holdings, Inc. ($2.37 EPS, 11.42% ROIC). Mr. Castleberry's award was earned at 114% of target on a weighted basis and resulted in a potential payment of 200% of the target amount. No adjustment was made by the Committee.

Mr. Hildestad received his award pursuant to the Knife River Corporation Executive Incentive Compensation Plan, based upon (i) actual earnings per allocated share as a percentage of planned earnings per allocated share (weighted 75%) and (ii) actual return on invested capital as a percentage of planned return on invested capital (weighted 25%) for Knife River Corporation. The target amounts were $1.21 EPS and 6.95% ROIC. His award was earned at 92.6% of target on a weighted basis and resulted in a potential payment of 69.1% of the target amount. No adjustment was made by the Committee.

Mr. Gatzemeier received his award based upon (i) actual return on invested capital (weighted 25%) and earnings per allocated share (weighted 37.5%), in each case compared to planned return on invested capital and planned earnings per allocated share for Centennial Power, Inc. and Centennial Energy Resources International, Inc. of 5.55% and $1.64, and 21.36% and $5.94, respectively; and (ii) corporate growth goals for acquisition of additional capacity in domestic projects (weighted 25%) and a feasibility study for international development projects (weighted 12.5%). Based on his performance with respect to these targets, the award was earned at 100% of target and resulted in a potential payment of 100% of the target amount. The Committee then used its discretion and increased Mr. Gatzemeier's payment percentage to 175%. The Committee determined that the excellent financial results in 2004 for the overall international independent power production operations (IPP) merited changing the separate weighting of domestic and international production figures to overall IPP financial results for 2004. The Committee also believed this would be more in line with the manner in which the incentives for the other named executive officers are measured.

Long-term incentive compensation serves to encourage successful strategic management and is awarded under the 1997 Executive Long-Term Incentive Plan.

Effective in 2003, several changes were made to the long-term incentive program as a result of the 2002 executive compensation program study discussed above. The Committee does not expect to make additional stock option or restricted stock grants under the 1997 Executive Long-Term Incentive Plan. Beginning with grants made in 2003, the Committee is using performance shares, with dividend equivalents, as the form of long-term incentive compensation. These awards are expected to be made annually. The performance goal is total shareholder return measured over three year periods and will compare Company performance against a peer group in specified areas. Performance shares and dividend equivalents will be paid out, if earned, between 10% and 200% of the target award. Performance shares will be paid out in stock and dividend equivalents in cash.

Awards for the 2004-2006 performance period were made to executive officers in 2004. The level of award for each executive officer was determined by using the Committee approved target incentive guidelines. Performance shares represent the opportunity to receive Company Common Stock at the end of the performance period based upon the Company's total shareholder return relative to a peer group of companies, which are not the same as the proxy peer group. The payout ranges from 0% for a rank less than the 40th percentile, to 10% at the 40th percentile, 100% at the 50th percentile and 200% at the 100th percentile. Dividend equivalents were also granted and will be paid out in cash in an amount equal to the total dividends declared during the performance period on any shares that are actually earned. This long-term award is designed to ensure the retention value and the motivation effect of the Company's long-term compensation program on the Company's executive officers.

Performance shares and dividend equivalents were granted to executive officers in 2003 for the 2002-2004 performance period. These awards were earned at the 126% level. As a result, Mr. White and the executive officers received a payment of Company Common Stock and cash equal to the dividend equivalents. These amounts are disclosed in the LTIP Payout column in the Summary Compensation Table.

The Committee granted shares of restricted stock to the executive officers in 1999. Vesting of 50 percent of these shares was accelerated after the first performance cycle (1999-2001). Company performance (total shareholder return) in comparison to the proxy peer group for the second performance cycle (2002-2004) resulted in acceleration of vesting of the remaining shares. The Named Officers received shares as follows: Mr. White—7,500 shares; Mr. Robinson—3,000 shares; Mr. Tipton—3,750 shares; Mr. Castleberry—2,250 shares; Mr. Hildestad—3,750 shares; and Mr. Gatzemeier—0 shares.

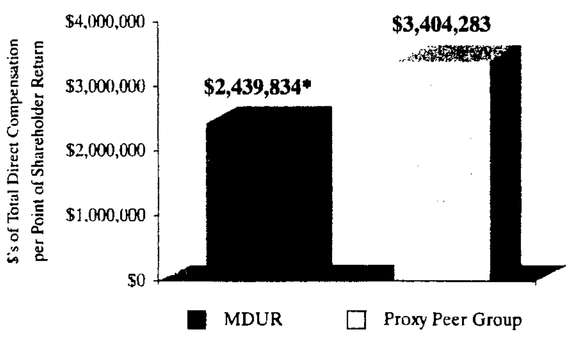
**2004 Analysis**

In 2004 the Compensation Committee requested an analysis by the Company's human resources department of the value of the Company's executive compensation program. Specifically, the Committee sought to determine whether or not the relationship between the level of compensation and shareholder return was more favorable than that of the proxy peer group.[1]

The analysis consisted of comparing what the Company paid its named executive officers for the years 1999 through 2003 to the Company's average annual total shareholder return over the same five-year period. The Company's pay ratio was compared to the ratios of companies in the proxy peer group.

All data used in the analysis, including the valuation of long-term incentives and calculation of shareholder return, were provided by Equilar, Inc.

**5 Year Total Direct Compensation to 5 Year Shareholder Return**




* A *smaller* number indicates *greater* value to shareholders.

The results of the analysis showed that the Company paid its named executive officers significantly less than what the peer group companies paid their named executive officers for comparable levels of shareholder return over the five-year period (see the above graph). **Specifically, the Company paid its named executives approximately $1,000,000 less per point of shareholder return than the proxy peer group. The Committee views these results as confirmation that MDU Resources Group, Inc.'s stockholders receive high value for the compensation paid to Company executives.**

The Committee adopted incentive repayment guidelines at its February 2005 meeting allowing the Committee to secure repayment of or to make additional incentive payments to senior officers if Company accounting restatements occur within three years after incentive payments have been made. The Committee may rescind award vesting, rescind vesting acceleration, require award forfeiture or require cash repayment. The Committee also adopted a checklist of factors that may be considered when determining whether to make severance payments to executive officers.

In 1993, the Board of Directors adopted Stock Ownership Guidelines under which executives are required to own Company Common Stock valued from one to four times their annual salary.

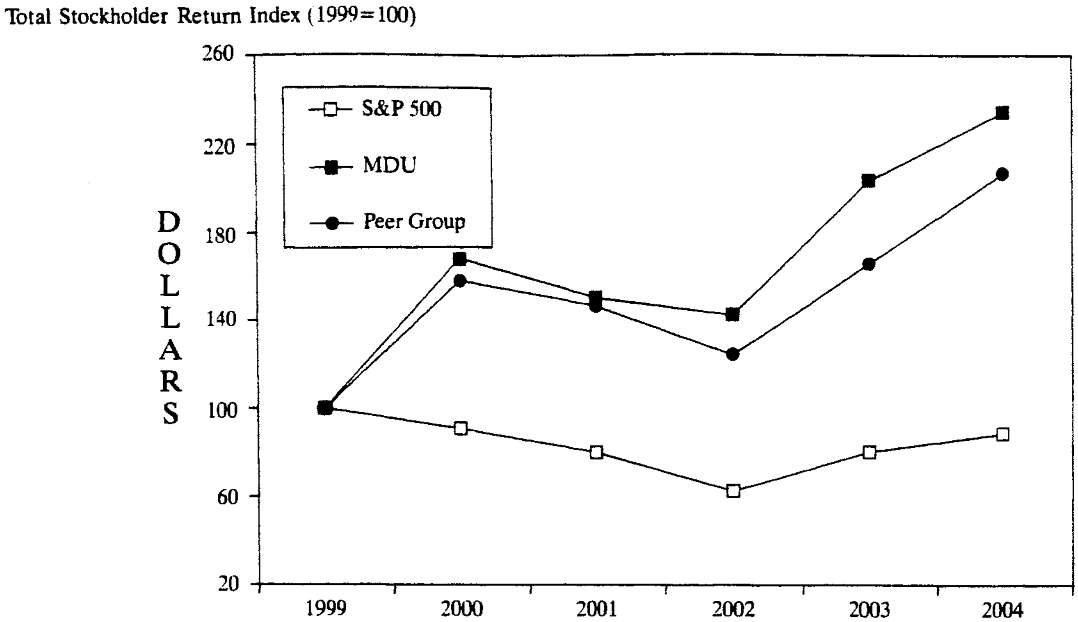
The Committee monitors the impact of federal tax laws on executive compensation, including Section 162(m) of the Internal Revenue Code. The deductibility of some types of compensation depends upon the timing of an executive's vesting or exercise of awards or on whether such awards qualify as "performance-based" under the provisions of Section 162(m). The Committee will consider the possible tax effect when structuring performance-based compensation but may pay compensation to its executive officers that is not fully deductible.

**Harry J. Pearce, Chairman**
**Thomas Everist, Member**
**Patricia L. Moss, Member**

(1) Louis Dreyfus Natural Gas Corp. and Vectren Corporation were not included because full five-year data was not available. Louis Dreyfus Natural Gas Corp. was acquired by Dominion Resources, Inc. in 2001 and shares in the company discontinued trading at that time. Vectren Corporation was formed in 2000 by a merger of Indiana Energy, Inc. and SIGCORP.

For purposes of this analysis, compensation data on Hanson PLC ADR executives were converted from British pounds to U.S. dollars. The rate of conversion was the average exchange rate for a given year, as reported by the currency site www.OANDA.com.

# MDU RESOURCES GROUP, INC.
# COMPARISON OF FIVE YEAR TOTAL STOCKHOLDER RETURN (1)




| | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|---|
| S&P 500 | 100.00 | 90.90 | 80.09 | 62.39 | 80.29 | 89.03 |
| MDU | 100.00 | 168.09 | 150.18 | 142.72 | 203.57 | 234.54 |
| Peer Group | 100.00 | 158.11 | 146.51 | 124.64 | 165.78 | 206.84 |

(1) All data is indexed to December 31, 1999, for the Company, the S&P 500, and the Peer Group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group is weighted according to the issuer's stock market capitalization at the beginning of the period.

Peer Group issuers are Allegheny Energy, Inc., Allete, Inc., Alliant Energy Corporation, Black Hills Corporation, Comstock Resources, Inc., Equitable Resources, Inc., Florida Rock Industries, Inc., Hanson PLC ADR, KeySpan Corporation, Kinder Morgan, Inc., Louis Dreyfus Natural Gas Corp. (returns included for the full years of trading for 1999 through 2000. Discontinued trading in 2001, the result of the acquisition by Dominion Resources, Inc.), Martin Marietta Materials, Inc., Newfield Exploration Company, NICOR, Inc., OGE Energy Corp., ONEOK, Inc., Peoples Energy Corporation, Pogo Producing Company, Quanta Services, Inc., Questar Corporation, SCANA Corporation, Stone Energy Corporation, TECO Energy, Inc., UGI Corporation, Vectren Corporation (formerly Indiana Energy, Inc.), Vulcan Materials Company, and XTO Energy, Inc.(formerly Cross Timbers Oil Company).

# BALANCE SHEET

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | **Assets and Other Debits** | | | |
| 2 | Utility Plant | | | | |
| 3 | 101 | Gas Plant in Service | $214,218,620 | $224,176,847 | 4.65% |
| 4 | 101.1 | Property Under Capital Leases | | | |
| 5 | 102 | Gas Plant Purchased or Sold | | | |
| 6 | 104 | Gas Plant Leased to Others | 25,772 | 25,772 | 0.00% |
| 7 | 105 | Gas Plant Held for Future Use | | | |
| 8 | 105.1 | Production Properties Held for Future Use | | | |
| 9 | 106 | Completed Constr. Not Classified - Gas | | | |
| 10 | 107 | Construction Work in Progress - Gas | 1,932,649 | 2,643,604 | 36.79% |
| 11 | 108 | (Less) Accumulated Depreciation | (135,226,064) | (141,061,279) | 4.32% |
| 12 | 111 | (Less) Accumulated Amortization & Depletion | (544,070) | (824,835) | 51.60% |
| 13 | 114 | Gas Plant Acquisition Adjustments | 13,942,794 | 12,606,238 | -9.59% |
| 14 | 115 | (Less) Accum. Amort. Gas Plant Acq. Adj. | (1,713,678) | (2,278,849) | 32.98% |
| 15 | 116 | Other Gas Plant Adjustments | | | |
| 16 | 117 | Gas Stored Underground - Noncurrent | 2,361,258 | 3,022,878 | 28.02% |
| 17 | 118 | Other Utility Plant | 662,364,228 | 674,433,879 | 1.82% |
| 18 | 119 | Accum. Depr. and Amort. - Other Utl. Plant | (375,000,947) | (389,289,705) | 3.81% |
| 19 | | **TOTAL Utility Plant** | $382,360,562 | $383,454,550 | 0.29% |
| 20 | **Other Property & Investments** | | | | |
| 21 | 121 | Nonutility Property | $1,036,084 | $1,511,061 | 45.84% |
| 22 | 122 | (Less) Accum. Depr. & Amort. of Nonutil. Prop. | (353,568) | (498,029) | 40.86% |
| 23 | 123 | Investments in Associated Companies | | | |
| 24 | 123.1 | Investments in Subsidiary Companies | 1,278,850,163 | 1,479,846,408 | 15.72% |
| 25 | 124 | Other Investments | 22,254,889 | 33,381,533 | 50.00% |
| 26 | 125 | Sinking Funds | | | |
| 27 | | **TOTAL Other Property & Investments** | $1,301,787,568 | $1,514,240,973 | 16.32% |
| 28 | **Current & Accrued Assets** | | | | |
| 29 | 131 | Cash | $861,378 | $1,593,384 | 84.98% |
| 30 | 132-134 | Special Deposits | 1,200 | 1,200 | 0.00% |
| 31 | 135 | Working Funds | 15,965 | 40,596 | 154.28% |
| 32 | 136 | Temporary Cash Investments | 8,529,412 | 7,142,665 | -16.26% |
| 33 | 141 | Notes Receivable | | | |
| 34 | 142 | Customer Accounts Receivable | 37,004,255 | 29,563,788 | -20.11% |
| 35 | 143 | Other Accounts Receivable | 3,987,038 | 4,471,664 | 12.16% |
| 36 | 144 | (Less) Accum. Provision for Uncollectible Accts. | (319,419) | (270,046) | -15.46% |
| 37 | 145 | Notes Receivable - Associated Companies | | | |
| 38 | 146 | Accounts Receivable - Associated Companies | 17,473,063 | 20,736,266 | 18.68% |
| 39 | 151 | Fuel Stock | 2,753,765 | 2,831,449 | 2.82% |
| 40 | 152 | Fuel Stock Expenses Undistributed | | | |
| 41 | 153 | Residuals and Extracted Products | | | |
| 42 | 154 | Plant Materials and Operating Supplies | 6,197,652 | 6,614,811 | 6.73% |
| 43 | 155 | Merchandise | 1,139,740 | 1,272,501 | 11.65% |
| 44 | 156 | Other Material & Supplies | | | |
| 45 | 163 | Stores Expense Undistributed | | 24,487 | 100.00% |
| 46 | 164.1 | Gas Stored Underground - Current | 18,438,454 | 21,773,200 | 18.09% |
| 47 | 165 | Prepayments | 8,839,446 | 7,074,369 | -19.97% |
| 48 | 166 | Advances for Gas Explor., Devl. & Production | | | |
| 49 | 171 | Interest & Dividends Receivable | | | |
| 50 | 172 | Rents Receivable | | | |
| 51 | 173 | Accrued Utility Revenues | 27,625,923 | 42,306,751 | 53.14% |
| 52 | 174 | Miscellaneous Current & Accrued Assets | 117,438 | 178,863 | 52.30% |
| 53 | | **TOTAL Current & Accrued Assets** | $132,665,310 | $145,355,948 | 9.57% |

# BALANCE SHEET

Year: 2004

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | **Assets and Other Debits (cont.)** | | | |
| 2 | | | | | |
| 3 | **Deferred Debits** | | | | |
| 4 | | | | | |
| 5 | 181 | Unamortized Debt Expense | $1,533,592 | $1,466,592 | -4.37% |
| 6 | 182.1 | Extraordinary Property Losses | | | |
| 7 | 182.2 | Unrecovered Plant & Regulatory Study Costs | | | |
| | 182.3 | Other Regulatory Assets | 4,744,491 | 3,333,602 | -29.74% |
| | 183 | Prelim. Electric Survey & Investigation Chrg. | 1,127,322 | 1,424,297 | 26.34% |
| 8 | 183.1 | Prelim. Nat. Gas Survey & Investigation Chrg. | | | |
| 9 | 183.2 | Other Prelim. Nat. Gas Survey & Invtg. Chrgs. | | | |
| 10 | 184 | Clearing Accounts | (124,215) | (149,815) | 20.61% |
| 11 | 185 | Temporary Facilities | | | |
| 12 | 186 | Miscellaneous Deferred Debits | 22,910,284 | 26,759,428 | 16.80% |
| 13 | 187 | Deferred Losses from Disposition of Util. Plant | | | |
| 14 | 188 | Research, Devel. & Demonstration Expend. | | | |
| 15 | 189 | Unamortized Loss on Reacquired Debt | 4,518,768 | 3,531,307 | -21.85% |
| 16 | 190 | Accumulated Deferred Income Taxes | 21,238,378 | 26,215,669 | 23.44% |
| 17 | 191 | Unrecovered Purchased Gas Costs | 10,518,527 | 15,533,707 | 47.68% |
| 18 | 192.1 | Unrecovered Incremental Gas Costs | | | |
| 19 | 192.2 | Unrecovered Incremental Surcharges | | | |
| 20 | | **TOTAL Deferred Debits** | $66,467,147 | $78,114,787 | 17.52% |
| 21 | | | | | |
| 22 | **TOTAL ASSETS & OTHER DEBITS** | | $1,883,280,587 | $2,121,166,258 | 12.63% |
| | Account Number & Title | | Last Year | This Year | % Change |
| 23 | | **Liabilities and Other Credits** | | | |
| 24 | | | | | |
| 25 | **Proprietary Capital** | | | | |
| 26 | | | | | |
| 27 | 201 | Common Stock Issued | $113,716,632 | $118,586,065 | 4.28% |
| 28 | 202 | Common Stock Subscribed | | | |
| 29 | 204 | Preferred Stock Issued | 15,000,000 | 15,000,000 | 0.00% |
| 30 | 205 | Preferred Stock Subscribed | | | |
| 31 | 207 | Premium on Capital Stock | 761,023,634 | 866,861,363 | 13.91% |
| 32 | 211 | Miscellaneous Paid-In Capital | | | |
| 33 | 213 | (Less) Discount on Capital Stock | | | |
| 34 | 214 | (Less) Capital Stock Expense | (3,236,160) | (3,412,569) | 5.45% |
| 35 | 216 | Appropriated Retained Earnings | 47,203,550 | 43,802,615 | -7.20% |
| 36 | 216.1 | Unappropriated Retained Earnings | 528,082,638 | 655,292,626 | 24.09% |
| 37 | 217 | (Less) Reacquired Capital Stock | | (3,625,813) | -100.00% |
| 38 | 219 | Accumulated Other Comprehensive Income | (7,528,653) | (11,491,485) | -52.64% |
| 39 | | **TOTAL Proprietary Capital** | $1,454,261,641 | $1,681,012,802 | 15.59% |
| 40 | | | | | |
| 41 | **Long Term Debt** | | | | |
| 42 | | | | | |
| 43 | 221 | Bonds | $160,850,000 | $145,850,000 | -9.33% |
| 44 | 222 | (Less) Reacquired Bonds | | | |
| 45 | 223 | Advances from Associated Companies | | | |
| 46 | 224 | Other Long Term Debt | 42,700,000 | 38,100,000 | -10.77% |
| 47 | 225 | Unamortized Premium on Long Term Debt | | | |
| 48 | 226 | (Less) Unamort. Discount on Long Term Debt-Dr. | (36,671) | (32,226) | -12.12% |
| 49 | | **TOTAL Long Term Debt** | $203,513,329 | $183,917,774 | -9.63% |

# BALANCE SHEET

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | **Total Liabilities and Other Credits (cont.)** | | | |
| 3 | | | | | |
| 4 | **Other Noncurrent Liabilities** | | | | |
| 5 | | | | | |
| 6 | 227 | Obligations Under Cap. Leases - Noncurrent | | | |
| 7 | 228.1 | Accumulated Provision for Property Insurance | | | |
| 8 | 228.2 | Accumulated Provision for Injuries & Damages | $1,017,175 | $1,046,120 | 2.85% |
| 9 | 228.3 | Accumulated Provision for Pensions & Benefits | 29,785,661 | 38,777,977 | 30.19% |
| 10 | 228.4 | Accumulated Misc. Operating Provisions | | | |
| 11 | 229 | Accumulated Provision for Rate Refunds | 299,228 | | -100.00% |
| 12 | 230 | Asset Retirement Obligations | 602,589 | 646,150 | 7.23% |
| 13 | | **TOTAL Other Noncurrent Liabilities** | $31,704,653 | $40,470,247 | 27.65% |
| 14 | | | | | |
| 15 | **Current & Accrued Liabilities** | | | | |
| 16 | | | | | |
| 17 | 231 | Notes Payable | $0 | $0 | 0.00% |
| 18 | 232 | Accounts Payable | 26,572,779 | 30,776,542 | 15.82% |
| 19 | 233 | Notes Payable to Associated Companies | | | |
| 20 | 234 | Accounts Payable to Associated Companies | 7,113,407 | 7,930,615 | 11.49% |
| 21 | 235 | Customer Deposits | 1,584,497 | 1,845,929 | 16.50% |
| 22 | 236 | Taxes Accrued | 10,323,491 | 9,081,392 | -12.03% |
| 23 | 237 | Interest Accrued | 2,324,244 | 2,047,469 | -11.91% |
| 24 | 238 | Dividends Declared | 19,441,745 | 21,449,171 | 10.33% |
| 25 | 239 | Matured Long Term Debt | | | |
| 26 | 240 | Matured Interest | | | |
| 27 | 241 | Tax Collections Payable | 1,662,094 | 1,618,279 | -2.64% |
| 28 | 242 | Miscellaneous Current & Accrued Liabilities | 10,665,144 | 22,696,729 | 112.81% |
| 29 | 243 | Obligations Under Capital Leases - Current | | | |
| 30 | | **TOTAL Current & Accrued Liabilities** | $79,687,401 | $97,446,126 | 22.29% |
| 31 | | | | | |
| 32 | **Deferred Credits** | | | | |
| 33 | | | | | |
| 34 | 252 | Customer Advances for Construction | $1,284,167 | $1,702,239 | 32.56% |
| 35 | 253 | Other Deferred Credits | 16,816,218 | 21,674,170 | 28.89% |
| 36 | 254 | Other Regulatory Liabilities | 15,633,652 | 12,186,926 | -22.05% |
| 37 | 255 | Accumulated Deferred Investment Tax Credits | 2,461,954 | 1,869,757 | -24.05% |
| 38 | 256 | Deferred Gains from Disposition Of Util. Plant | | | |
| 39 | 257 | Unamortized Gain on Reacquired Debt | | | |
| 40 | 281-283 | Accumulated Deferred Income Taxes | 77,917,572 | 80,886,217 | 3.81% |
| 41 | | **TOTAL Deferred Credits** | $114,113,563 | $118,319,309 | 3.69% |
| 42 | | | | | |
| 43 | **TOTAL LIABILITIES & OTHER CREDITS** | | $1,883,280,587 | $2,121,166,258 | 12.63% |

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1

Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining, independent power production, and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Utility services, natural gas and oil production, construction materials and mining, independent power production, and other are nonregulated. For further descriptions of the Company's businesses, see Note 13. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

The Company uses the equity method of accounting for certain investments. For more information on the Company's equity method investments, see Note 2.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2004 and 2003, was $6.8 million and $8.1 million, respectively.

Natural gas in underground storage

Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and was $24.9 million and $19.6 million at December 31, 2004 and 2003, respectively. The remainder of natural gas in underground storage was included in other assets and was $43.3 million and $42.6 million at December 31, 2004 and 2003, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $71.0 million and $54.7 million, materials and supplies of $31.0 million and $27.2 million, and other inventories of $17.0 million and $12.6 million, as of December 31, 2004 and 2003, respectively. These inventories were stated at the lower of average cost or market.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. Leased mineral rights at the Company's construction materials and mining

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|---|---|---|---|
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NOTES TO FINANCIAL STATEMENTS (Continued)

business were reclassified from other intangible assets, net, to property, plant and equipment, as discussed in new accounting standards in this note. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described in natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $6.2 million, $7.4 million and $7.6 million in 2004, 2003 and 2002, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units-of-production method based on recoverable deposits, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31, 2004 and 2003, was as follows:

| | 2004 | 2003 | Estimated Depreciable Life in Years |
|---|---|---|---|
| | (Dollars in thousands, as applicable) | | |
| Regulated: | | | |
| Electric: | | | |
| Electric generation, distribution and transmission plant | $ 650,902 | $ 639,893 | 4-50 |
| Natural gas distribution: | | | |
| Natural gas distribution plant | 264,496 | 252,591 | 4-40 |
| Pipeline and energy services: | | | |
| Natural gas transmission, gathering and storage facilities | 358,853 | 340,841 | 8-104 |
| Nonregulated: | | | |
| Utility services: | | | |
| Land | 2,533 | 2,505 | --- |
| Buildings and improvements | 10,257 | 10,123 | 3-40 |
| Machinery, vehicles and equipment | 63,586 | 58,843 | 2-10 |
| Other | 6,224 | 5,400 | 3-10 |
| Pipeline and energy services: | | | |
| Natural gas gathering and other facilities | 132,067 | 119,613 | 3-20 |
| Energy services | 1,480 | 1,339 | 3-15 |
| Natural gas and oil production: | | | |
| Natural gas and oil properties | 973,604 | 862,839 | * |
| Other | 9,021 | 8,518 | 3-7 |
| Construction materials and mining: | | | |
| Land | 91,610 | 89,545 | --- |
| Buildings and improvements | 51,309 | 48,907 | 3-40 |
| Machinery, vehicles and equipment | 658,355 | 569,295 | 1-23 |
| Construction in progress | 16,545 | 14,392 | --- |
| Aggregate reserves | 372,649 | 358,260 | ** |
| Independent power production: | | | |
| Electric generation | 154,631 | 153,944 | 10-30 |
| Construction in progress | 93,953 | 29,805 | --- |
| Land | 375 | 375 | --- |
| Other | 1,643 | 3 | 3-7 |

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NOTES TO FINANCIAL STATEMENTS (Continued)

| | | | |
|---|---|---|---|
| Other: | | | |
| Land | 3,044 | 1,626 | --- |
| Other | 14,291 | 15,381 | 3-20 |
| Less accumulated depreciation, depletion and amortization | 1,358,723 | 1,187,105 | |
| Net property, plant and equipment | $ 2,572,705 | $ 2,396,933 | |

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $.98, $.89, and $.80 for the years ended December 31, 2004, 2003 and 2002, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $69.0 million and $104.3 million were excluded from amortization at December 31, 2004 and 2003, respectively.

** Depleted on the units-of-production method based on recoverable deposits.

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the third quarter of 2004, the Company recognized a $2.1 million ($1.3 million after tax) adjustment reflecting the reduction in value of certain gathering facilities in the Gulf Coast region at the pipeline and energy services segment. No impairment losses were recorded in 2003 and 2002. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In the third quarter of 2004, the Company recognized a goodwill impairment at the pipeline and energy services segment. For more information on the goodwill impairment and goodwill, see Note 3.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point-in-time spot market prices, as mandated under the rules of the SEC, and the cost of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2004 and 2003, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2004, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2004, in total and by year in which such costs were incurred:

| | Total | 2004 | 2003 | 2002 | 2001 and prior |
|---|---|---|---|---|---|
| | | | Year Costs Incurred (In thousands) | | |
| Acquisition | $34,169 | $ 6,708 | $ 481 | $ 15,493 | $ 11,487 |
| Development | 22,582 | 16,259 | 4,559 | 1,764 | --- |
| Exploration | 5,228 | 4,681 | 547 | --- | --- |
| Capitalized interest | 7,005 | 2,252 | 1,839 | 2,914 | --- |
| Total costs not subject to amortization | $68,984 | $ 29,900 | $ 7,426 | $ 20,171 | $ 11,487 |

Costs not subject to amortization as of December 31, 2004, consisted primarily of lease acquisition costs, unevaluated drilling costs and capitalized interest associated with coalbed development in the Powder River Basin of Montana and Wyoming and an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana. The Company expects that the majority of these costs will be evaluated within the next five-year period and included in the amortization base as the properties are developed and evaluated and proved reserves are established or impairment is determined.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the Company's ownership interest in the related well. Revenues at the independent power production operations are recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues are recognized under Emerging Issues Task Force Issue No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts," ratably over the terms of the related contract. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of $31.9 million and $31.8 million at December 31, 2004 and 2003, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $32.2 million and $20.4 million at December 31, 2004 and 2003, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Also included in receivables, net, were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $40.9 million and $34.3 million at December 31, 2004 and 2003, respectively, which are expected to be paid within one year or less.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation

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NOTES TO FINANCIAL STATEMENTS (Continued)

to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires that natural gas and oil price derivative instruments and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial position or results of operations as a result of nonperformance by counterparties.

Asset retirement obligations

In 2003, the Company adopted SFAS No. 143, which requires the Company to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss. For more information on asset retirement obligations, see Note 8.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs recoverable through rate adjustments amounted to $15.5 million and $10.5 million at December 31, 2004 and 2003, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $500,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Foreign currency translation adjustment

The functional currency of the Company's investment in a 220-megawatt natural gas-fired electric generating facility in Brazil, as further discussed in Note 2, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses have been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity are recorded in income.

Common stock split

On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 10.

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. For the years ended December 31, 2004, 2003 and 2002, 36,000 shares, 209,805 shares and 3,674,925 shares, respectively, with an average exercise price of $25.70, $24.56 and $20.08, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the years ended December 31, 2004, 2003 and 2002, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the years ended December 31, 2004 and 2003, was $18,000 and $41,000, respectively (after tax).

As permitted by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123," the Company accounts for stock options granted prior to January 1, 2003, under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense has been recognized for stock options granted prior to January 1, 2003, as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

The Company adopted SFAS No. 123 effective January 1, 2003, for newly granted options only. The following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2004, 2003 and 2002, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | (In thousands, except per share amounts) | | |
| Earnings on common stock, as reported | $ 206,382 | $ 174,607 | $ 147,688 |
| Stock-based compensation expense included in reported earnings, net of related tax effects | 18 | 41 | --- |

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| | | | |
|---|---|---|---|
| Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects | (62) | (2,139) | (2,862) |
| Pro forma earnings on common stock | $ 206,338 | $ 172,509 | $ 144,826 |
| Earnings per common share -- basic -- as reported: | | | |
| Earnings before cumulative effect of accounting change | $ 1.77 | $ 1.64 | $ 1.39 |
| Cumulative effect of accounting change | --- | (.07) | --- |
| Earnings per common share -- basic | $ 1.77 | $ 1.57 | $ 1.39 |
| Earnings per common share -- basic -- pro forma: | | | |
| Earnings before cumulative effect of accounting change | $ 1.77 | $ 1.62 | $ 1.36 |
| Cumulative effect of accounting change | --- | (.07) | --- |
| Earnings per common share -- basic | $ 1.77 | $ 1.55 | $ 1.36 |
| Earnings per common share -- diluted -- as reported: | | | |
| Earnings before cumulative effect of accounting change | $ 1.76 | $ 1.62 | $ 1.38 |
| Cumulative effect of accounting change | --- | (.07) | --- |
| Earnings per common share -- diluted | $ 1.76 | $ 1.55 | $ 1.38 |
| Earnings per common share -- diluted -- pro forma: | | | |
| Earnings before cumulative effect of accounting change | $ 1.76 | $ 1.60 | $ 1.36 |
| Cumulative effect of accounting change | --- | (.07) | --- |
| Earnings per common share -- diluted | $ 1.76 | $ 1.53 | $ 1.36 |

For more information on the Company's stock-based compensation, see Note 11.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments, including the fair value of an embedded derivative in the electric power sales contract related to an equity method investment in Brazil, as discussed in Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

| Years ended December 31, | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In thousands) | |
| Interest, net of amount capitalized | $50,236 | $47,474 | $37,788 |
| Income taxes | $50,487 | $31,737 | $60,988 |

Reclassifications

Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting standards

FIN 46 (revised)

In December 2003, the FASB issued FIN 46 (revised), which replaced FIN 46. FIN 46 (revised) clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support. An enterprise shall consolidate a variable interest entity if that enterprise is the primary beneficiary. An enterprise is considered the primary beneficiary if it has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns or both. FIN 46 (revised) shall be applied to all entities subject to FIN 46 (revised) no later than the end of the first reporting period that ends after March 15, 2004.

The Company evaluated the provisions of FIN 46 (revised) and determined that the Company does not have any controlling financial interests in any variable interest entities and, therefore, is not required to consolidate any variable interest entities in its financial statements. The adoption of FIN 46 (revised) did not have an effect on the Company's financial position or results of operations.

FSP Nos. FAS 106-1 and FAS 106-2

In January 2004, the FASB issued FSP No. FAS 106-1. FSP No. FAS 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the 2003 Medicare Act.

In May 2004, the FASB issued FSP No. FAS 106-2. FSP No. FAS 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

The Company provides prescription drug benefits to certain eligible employees. The Company elected the one-time deferral of accounting for the effects of the 2003 Medicare Act in the quarter ended March 31, 2004, the first period in which the plan's accounting for the effects of the 2003 Medicare Act normally would have been reflected in the Company's financial statements.

During the second quarter of 2004, the Company adopted FSP No. FAS 106-2 retroactive to the beginning of the year. The Company and its actuarial advisors determined that benefits provided to certain participants are expected to be at least actuarially equivalent to Medicare Part D (the federal prescription drug benefit), and, accordingly, the Company expects to be entitled to a federal subsidy. The expected federal subsidy reduced the APBO at January 1, 2004, by approximately $3.2 million, and net periodic benefit cost for 2004 by approximately $285,000 (as compared with the amount calculated without considering the effects of the subsidy). In addition, the Company expects a reduction in future participation in the postretirement plans, which further reduced the APBO at January 1, 2004, by approximately $12.7 million and net periodic benefit cost for

2004 by approximately $1.3 million.

FSP Nos. FAS 141-1 and FAS 142-1
In April 2004, the FASB issued FSP Nos. FAS 141-1 and FAS 142-1. FSP Nos. FAS 141-1 and FAS 142-1 amend SFAS No. 141, "Business Combinations," and SFAS No. 142 to clarify that certain mineral rights held by mining entities that are not within the scope of SFAS No. 19 be classified as tangible assets rather than intangible assets. The Company adopted FSP Nos. FAS 141-1 and FAS 142-1 in the second quarter of 2004. FSP Nos. FAS 141-1 and FAS 142-1 required reclassification of the Company's leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment, as well as changes to Notes to Consolidated Financial Statements. FSP Nos. FAS 141-1 and FAS 142-1 affected the asset classification in the consolidated balance sheet and associated footnote disclosure only, so the reclassifications did not affect the Company's stockholders' equity, cash flows or results of operations.

FSP No. FAS 142-2
In September 2004, the FASB Staff issued FSP No. FAS 142-2. FSP No. FAS 142-2 indicates that the exception in SFAS No. 142 does not change the accounting prescribed in SFAS No. 19 including the balance sheet classification of drilling and mineral rights of oil and gas producing entities and, as a result, the contractual mineral rights should continue to be classified as part of property, plant and equipment. FSP No. FAS 142-2 did not have an effect on the Company's financial position, results of operations or cash flows.

SAB No. 106
In September 2004, the SEC issued SAB No. 106 which is an interpretation regarding the application of SFAS No. 143 by oil and gas producing companies following the full-cost accounting method. SAB No. 106 clarifies that the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full-cost ceiling calculation. SAB No. 106 also states that a company is expected to disclose in the financial statement footnotes and MD&A how the company's calculation of the ceiling test and depreciation, depletion and amortization are affected by the adoption of SFAS No. 143. SAB No. 106 shall be applied to all entities subject to SAB No. 106 as of the beginning of the first quarter after October 4, 2004. The adoption of SAB No. 106 is not expected to have a material effect on the Company's financial position or results of operations.

SFAS No. 123 (revised)
In December 2004, the FASB issued SFAS No. 123 (revised). SFAS No. 123 (revised) revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123 (revised) requires a company to record compensation expense for all awards granted after the date of adoption of SFAS No. 123 (revised) and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. SFAS No. 123 (revised) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is evaluating the effects of the adoption of SFAS No. 123 (revised).

Comprehensive income
Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, minimum pension liability adjustments and foreign currency translation adjustments. For more information on derivative instruments, see Note 5.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2004, 2003 and 2002, were as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In thousands) | |

| | | | |
|---|---|---|---|
| Other comprehensive income (loss): | | | |
| Net unrealized gain (loss) on derivative instruments qualifying as hedges: | | | |
| Net unrealized loss on derivative instruments arising during the period, net of tax of $2,734, $2,132 and $2,903 in 2004, 2003 and 2002, respectively | $ (4,367) | $ (3,335) | $ (4,541) |
| Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,132, $2,903 and $1,448 in 2004, 2003 and 2002, respectively | (3,335) | (4,541) | 2,218 |
| Net unrealized gain (loss) on derivative instruments qualifying as hedges | (1,032) | 1,206 | (6,759) |
| Minimum pension liability adjustment, net of tax of $2,406, $38 and $2,876 in 2004, 2003 and 2002, respectively | (3,782) | 21 | (4,464) |
| Foreign currency translation adjustment | 852 | 1,048 | (799) |
| Total other comprehensive income (loss) | $ (3,962) | $ 2,275 | $(12,022) |

The after-tax components of accumulated other comprehensive loss as of December 31, 2004, 2003 and 2002, were as follows:

| | Net Unrealized Loss on Derivative Instruments Qualifying as Hedges | Minimum Pension Liability Adjustment | Foreign Currency Translation Adjustment | Total Accumulated Other Comprehensive Loss |
|---|---|---|---|---|
| | | (In thousands) | | |
| Balance at December 31, 2002 | $(4,541) | $(4,464) | $ (799) | $ (9,804) |
| Balance at December 31, 2003 | $(3,335) | $(4,443) | $ 249 | $ (7,529) |
| Balance at December 31, 2004 | $(4,367) | $(8,225) | $1,101 | $(11,491) |

Note 2

Equity Method Investments

The Company has a number of equity method investments including MPX, Carib Power and Hartwell. The Company assesses its equity method investments for impairment whenever events or changes in circumstances indicate that such carrying values may not be recoverable. None of the Company's equity method investments have been impaired and, accordingly, no impairment losses have been recorded in the accompanying consolidated financial statements or related equity method investment balances.

MDU Brasil has a 49 percent interest in MPX, which was formed in August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm. MPX, through a wholly owned subsidiary, owns and operates the Termoceara Generating Facility in the Brazilian state of Ceara. Petrobras, the Brazilian state-controlled energy company, entered into a contract to purchase all of the capacity and market all of energy from the Termoceara Generating Facility. The first phase of the electric power sales contract with Petrobras for 110 megawatts expires in November 2007 and the portion of the contract for the remaining 110 megawatts expires in May 2008. Petrobras also is under contract to

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| MDU Resources Group, Inc. | (1) X An Original<br>(2) _ A Resubmission | 12/31/2004 | 2004/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

supply natural gas to the Termoceara Generating Facility during the term of the electric power sales contract. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years.

During 2004, Petrobras initiated discussions with a number of owners of thermoelectric plants, including MPX, regarding a possible renegotiation of their related power purchase agreements or buyout of the generating plants. On January 13, 2005, Petrobras obtained a Brazilian court order permitting it to cease making monthly capacity payments to MPX and to instead deposit the payments into a court account until the matter is resolved. On February 2, 2005, the court revoked its January 13, 2005, order and stated that MPX could withdraw the amounts deposited by Petrobras. This decision was upheld on appeal on February 17, 2005. Under the existing contract, Petrobras agreed to jointly market all of the facility's energy, and in the event that the facility's revenues are insufficient to cover its costs during certain periods, to make certain monthly contingency payments. Petrobras has stated that, because of structural changes in the Brazilian electric power markets since the contract was signed in 2001, the contingency payments had become permanent payment obligations entitling Petrobras to renegotiate the contract. The contract contains a dispute resolution provision which creates a 30-day period for accelerated negotiations. In the event that the parties do not reach agreement during the 30-day period, the dispute would be resolved in arbitration.

The Termoceara Generating Facility generates electricity based upon economic dispatch and available gas supplies. Under current conditions, including, in particular, existing constraints in the region's gas supply infrastructure, the Company does not expect the facility to generate a significant amount of energy at least through 2006.

The functional currency for the Termoceara Generating Facility is the Brazilian Real. The electric power sales contract with Petrobras contains an embedded derivative, which derives its value from an annual adjustment factor, which largely indexes the contract capacity payments to the U.S. dollar. The Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract and the Company's 49 percent share of the foreign currency gain (loss) resulting from an increase (decrease) in value of the Brazilian Real versus the U.S. dollar for the years ended December 31, were as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| | | (In thousands) | |
| Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract (after tax) | $2,451 | $(11,282) | $13,592 |
| Company's 49 percent share of the foreign currency gain (loss) resulting from the change in value of the Brazilian Real versus the U.S. dollar (after tax) | $1,871 | $ 2,757 | $(9,392) |

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX. For more information on this guarantee, see Note 18.

On February 26, 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-megawatt natural gas-fired electric generating facility located in Trinidad and Tobago. The Trinity Generating Facility sells its output to the T&TEC, the governmental entity responsible for the transmission, distribution and administration of electrical power to the national electrical grid of Trinidad and Tobago. The power purchase agreement expires in September

2029. T&TEC also is under contract to supply natural gas to the Trinity Generating Facility during the term of the power purchase contract. The functional currency for the Trinity Generating Facility is the U.S. dollar.

On September 28, 2004, Centennial Resources, through wholly owned subsidiaries, acquired a 50-percent ownership interest in a 310-megawatt natural gas-fired electric generating facility. This facility is located in Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe that expires in May 2019. American National Power, a wholly owned subsidiary of International Power of the United Kingdom, holds the remaining 50-percent ownership interest and is the operating partner for the facility.

At December 31, 2004, MPX, Carib Power and Hartwell had total assets of $334.2 million and long-term debt of $224.9 million. The Company's investment in the Termoceara, Trinity and Hartwell Generating Facilities was approximately $65.7 million, including undistributed earnings of $26.6 million at December 31, 2004. The Company's investment in the Termoceara Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003.

Note 3
Goodwill and Other Intangible Assets
The changes in the carrying amount of goodwill for the year ended December 31, 2004, were as follows:

| | Balance as of January 1, 2004 | Goodwill Acquired During the Year* | Goodwill Impaired During the Year | Balance as of December 31, 2004 |
|---|---|---|---|---|
| | | (In thousands) | | |
| Electric | $ --- | $ --- | $ --- | $ --- |
| Natural gas distribution | --- | --- | --- | --- |
| Utility services | 62,604 | 28 | --- | 62,632 |
| Pipeline and energy services | 9,494 | --- | (4,030) | 5,464 |
| Natural gas and oil production | --- | --- | --- | --- |
| Construction materials and mining | 120,198 | 254 | --- | 120,452 |
| Independent power production | 7,131 | 4,064 | --- | 11,195 |
| Other | --- | --- | --- | --- |
| Total | $199,427 | $ 4,346 | $ (4,030) | $ 199,743 |

* Includes purchase price adjustments related to acquisitions acquired in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2003, were as follows:

| | Balance as of January 1, 2003 | Goodwill Acquired During the Year* | Balance as of December 31, 2003 |
|---|---|---|---|
| | | (In thousands) | |
| Electric | $ --- | $ --- | $ --- |
| Natural gas | | | |

| | | | |
|---|---|---|---|
| distribution | --- | --- | --- |
| Utility services | 62,487 | 117 | 62,604 |
| Pipeline and energy services | 9,494 | --- | 9,494 |
| Natural gas and oil production | --- | --- | --- |
| Construction materials and mining | 111,887 | 8,311 | 120,198 |
| Independent power production | 7,131 | --- | 7,131 |
| Other | --- | --- | --- |
| Total | $190,999 | $8,428 | $199,427 |

* Includes purchase price adjustments related to acquisitions acquired in a prior period.

Innovatum, which specializes in cable and pipeline magnetization and location, developed a hand-held locating device that can detect both magnetic and plastic materials, including unexploded ordnance. Innovatum was working with, and had demonstrated the device to, a Department of Defense contractor and had also met with individuals from the Department of Defense, to discuss the possibility of using the hand-held locating device in their operations. In the third quarter of 2004, after communications with the Department of Defense, and delays in further testing resulting from a Department of Defense request to enhance the hand-held locating device, Innovatum decreased its expected future cash flows from the hand-held locating device. This decrease, coupled with the continued downturn in the telecommunications and energy industries, resulted in a revised earnings forecast for Innovatum, and as a result, a goodwill impairment loss of $4.0 million (before and after tax), which was included in asset impairments, was recognized in the third quarter of 2004. Innovatum, a reporting unit for goodwill impairment testing, is part of the pipeline and energy services segment. The fair value of Innovatum was estimated using the expected present value of future cash flows.

As discussed in Note 1, the Company reclassified its leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment.

Other intangible assets at December 31, 2004 and 2003 were as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Amortizable intangible assets: | | |
| Acquired contracts | $ 15,041 | $ 12,656 |
| Accumulated amortization | (5,013) | (1,944) |
| | 10,028 | 10,712 |
| Noncompete agreements | 10,575 | 12,075 |
| Accumulated amortization | (8,186) | (9,690) |
| | 2,389 | 2,385 |
| Other | 9,535 | 5,078 |
| Accumulated amortization | (534) | (321) |
| | 9,001 | 4,757 |
| Unamortizable intangible assets | 851 | 960 |
| Total | $ 22,269 | $18,814 |

The unamortizable intangible assets were recognized in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires that if an additional minimum liability is recognized an equal amount shall be recognized as an intangible asset, provided that the asset recognized shall not exceed the amount of unrecognized prior service cost. The unamortizable intangible asset will be eliminated or adjusted as necessary upon a new determination of the amount of additional liability.

Amortization expense for amortizable intangible assets for the years ended December 31, 2004, 2003 and 2002, was $3.8 million, $2.2 million and $757,000, respectively. Estimated amortization expense for amortizable intangible assets is $2.8 million in 2005, $2.0 million in 2006, 2007 and 2008, $1.9 million in 2009 and $10.7 million thereafter.

Note 4
Regulatory Assets and Liabilities
The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Regulatory assets: | | |
| Deferred income taxes | $ 39,212 | $ 37,072 |
| Natural gas costs recoverable through rate adjustments | 15,534 | 10,519 |
| Plant costs | 12,838 | 2,697 |
| Long-term debt refinancing costs | 3,531 | 4,519 |
| Postretirement benefit costs | 507 | 562 |
| Other | 7,225 | 7,159 |
| Total regulatory assets | 78,847 | 62,528 |
| Regulatory liabilities: | | |
| Plant removal and decommissioning costs | 78,525 | 76,176 |
| Liabilities for regulatory matters | 18,853 | 11,970 |
| Taxes refundable to customers | 15,660 | 18,973 |
| Deferred income taxes | 15,192 | 10,663 |
| Other | 3,676 | 658 |
| Total regulatory liabilities | 131,906 | 118,440 |
| Net regulatory position | $ (53,059) | $ (55,912) |

As of December 31, 2004, a large portion of the Company's regulatory assets, other than certain deferred income taxes, was being reflected in rates charged to customers and is being recovered over the next one to 18 years.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

Note 5
Derivative Instruments
Derivative instruments (including certain derivative instruments embedded in other contracts) are required to be recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

As of December 31, 2004, Fidelity held derivative instruments designated as cash flow hedging instruments.

Hedging activities

Fidelity utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on its forecasted sales of natural gas and oil production. Each of the natural gas and oil price swap and collar agreements was designated as a hedge of the forecasted sale of natural gas and oil production.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the years ended December 31, 2004, 2003 and 2002, the amount of hedge ineffectiveness, which was included in operating revenues, was immaterial. For the years ended December 31, 2004, 2003 and 2002, Fidelity did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2004, the maximum term of Fidelity's swap and collar agreements, in which Fidelity is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. Fidelity estimates that over the next 12 months, net losses of approximately $4.4 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Note 6

Fair Value of Other Financial Instruments

The estimated fair value of the Company's long-term debt is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilites at December 31, 2004 and 2003. The estimated fair values of the Company's natural gas and oil price swap and collar agreements reflect the estimated amounts the Company would receive or pay to terminate the contracts at the reporting date based upon quoted market prices of comparable contracts.

The estimated fair value of the Company's long-term debt and natural gas and oil price swap and collar agreements at December 31 was as follows:

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In thousands) | | | |

| | | | | |
|---|---|---|---|---|
| Long-term debt | $ 945,487 | $ 992,172 | $ 967,096 | $ 1,012,547 |
| Natural gas and oil price swap and collar agreements | $ (7,101) | $ (7,101) | $ (5,467) | $ (5,467) |

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities (excluding unsettled derivative instruments) approximate their fair values because of their short-term nature.

Note 7

Long-term Debt and Indenture Provisions

Long-term debt outstanding at December 31 was as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| First mortgage bonds and notes: | | |
| Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022 | $ 20,850 | $ 20,850 |
| Secured Medium-Term Notes, Series A, at a weighted average rate of 7.75%, due on dates ranging from April 1, 2007 to April 1, 2012 | 95,000 | 110,000 |
| Senior Note, 5.98%, due December 15, 2033 | 30,000 | 30,000 |
| Total first mortgage bonds and notes | 145,850 | 160,850 |
| Senior notes at a weighted average rate of 6.23%, due on dates ranging from January 18, 2005 to July 1, 2019 | 728,500 | 718,000 |
| Commercial paper at a weighted average rate of 2.28%, supported by revolving credit agreements | 63,000 | 72,500 |
| Term credit agreements at a weighted average rate of 6.68%, due on dates ranging from January 25, 2005 to December 1, 2013 | 8,172 | 14,286 |
| Pollution control note obligation, 6.20%, paid in 2004 | --- | 1,500 |
| Discount | (35) | (40) |
| Total long-term debt | 945,487 | 967,096 |
| Less current maturities | 72,046 | 27,646 |
| Net long-term debt | $ 873,441 | $ 939,450 |

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2004, aggregate $72.0 million in 2005; $138.8 million in 2006; $132.9 million in 2007; $161.3 million in 2008; $86.9 million in 2009 and $353.6 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2004.

MDU Resources Group, Inc.

The Company has a revolving credit agreement with various banks totaling $90 million at December 31, 2004. There were no amounts outstanding under the credit agreement at December 31, 2004 and 2003. The credit agreement supports the Company's $75 million commercial paper program. Under the Company's commercial paper program, $37.0 million and $40.0 million were outstanding at December 31, 2004 and 2003, respectively, which was classified as long-term debt. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2004.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2004, the Company could have issued approximately $343 million of additional first mortgage bonds.

Approximately $419.7 million of the Company's net electric and natural gas distribution properties at December 31, 2004, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustee, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

Centennial Energy Holdings, Inc.
Centennial has three revolving credit agreements with various banks and institutions that support $335 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2004 or 2003. Under the Centennial commercial paper program, $26.0 million and $32.5 million were outstanding at December 31, 2004 and 2003, respectively. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreements. One of these credit agreements is for $300 million and expires on August 17, 2007, and another agreement is for $25 million and expires on April 30, 2007. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities. The third agreement is an uncommitted line for $10 million, which was effective on January 25, 2005, and may be terminated by the bank at any time.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $384.0 million was outstanding at December 31, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on February 28, 2005. The Company is in discussion regarding potential renewal of this facility. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

In order to borrow under Centennial's credit agreements and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2004.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements, will be in default. Certain of Centennial's financing agreements and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company
Williston Basin has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $55.0 million was outstanding at December 31, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2005.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2004.

Note 8
Asset Retirement Obligations
The Company adopted SFAS No. 143 on January 1, 2003. The Company recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties. Removal costs associated with certain natural gas distribution, transmission, storage and gathering facilities have not been recognized as these facilities have been determined to have indeterminate useful lives.

Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million). The Company believes that any expenses under SFAS No. 143 as they relate to regulated operations will be recovered in rates over time and accordingly, deferred such expenses as a regulatory asset upon adoption. The Company will continue to defer those SFAS No. 143 expenses that it believes will be recovered in rates over time. In addition to the $22.5 million liability recorded upon the adoption of SFAS No. 143, the Company had previously recorded a $7.5 million liability related to retirement obligations.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Balance at beginning of year | $ 34,633 | $ 29,997 |
| Liabilities incurred | 3,718 | 2,405 |
| Liabilities acquired | 178 | 1,803 |
| Liabilities settled | (2,286) | (1,555) |
| Accretion expense | 1,931 | 1,906 |
| Revisions in estimates | (824) | 77 |
| Balance at end of year | $ 37,350 | $ 34,633 |

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2004 and 2003, was $5.2 million and $5.1 million, respectively.

Note 9
Preferred Stocks
Preferred stocks at December 31 were as follows:

| | 2004 | 2003 |
|---|---|---|
| | (Dollars in thousands) | |
| Authorized: | | |
| Preferred -- | | |
| 500,000 shares, cumulative, par value $100, issuable in series | | |
| Preferred stock A -- | | |
| 1,000,000 shares, cumulative, without par value, issuable in series (none outstanding) | | |
| Preference -- | | |
| 500,000 shares, cumulative, without par value, issuable in series (none outstanding) | | |
| Outstanding: | | |
| 4.50% Series -- 100,000 shares | $10,000 | $ 10,000 |
| 4.70% Series -- 50,000 shares | 5,000 | 5,000 |
| Total preferred stocks | $ 15,000 | $ 15,000 |

The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 and $102, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or by-laws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 10
Common Stock
On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on October 29, 2003, to common stockholders of record on October 10, 2003. Common stock information appearing in the accompanying consolidated financial statements has been restated to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

The Company's Dividend Reinvestment and Direct Stock Purchase Plan (Stock Purchase Plan) provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The Company's 401(k) Retirement Plan (K-Plan) is partially funded with the Company's common stock. Since January 1, 2002, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2004, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for two-thirds of one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of two-thirds of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.00667 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

Note 11

Stock-based Compensation

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. As permitted by SFAS No. 148, the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25.

For a discussion of the adoption of SFAS No. 123 and the effect on earnings and earnings per common share for the years ended December 31, 2004, 2003 and 2002, as if the Company had applied SFAS No. 123, and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant, see Note 1.

Options granted to key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant.

A summary of the status of the stock option plans at December 31, 2004, 2003 and 2002, and changes during the years then ended were as follows:

| | 2004 | | 2003 | | 2002 | |
|---|---|---|---|---|---|---|
| | Shares | Weighted Average Exercise Price | Shares | Weighted Average Exercise Price | Shares | Weighted Average Exercise Price |
| Balance at beginning of year | 4,182,456 | $19.09 | 4,861,268 | $18.58 | 5,208,311 | $18.60 |
| Granted | --- | --- | 27,015 | 17.29 | 160,605 | 19.15 |
| Forfeited | (382,942) | 19.64 | (188,486) | 20.05 | (453,840) | 19.77 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Exercised | (1,237,830) | 18.49 | (517,341) | 13.88 | (53,808) | 12.20 |
| Balance at end of year | 2,561,684 | 19.29 | 4,182,456 | 19.09 | 4,861,268 | 18.58 |
| Exercisable at end of year | 1,700,223 | $18.73 | 611,404 | $15.06 | 1,135,050 | $14.56 |

Summarized information about stock options outstanding and exercisable as of December 31, 2004, was as follows:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercisable Prices | Number Outstanding | Remaining Contractual Life in Years | Weighted Average Exercise Price | Number Exercisable | Weighted Average Exercise Price |
| $ 8.22 - 13.00 | 11,076 | 2.3 | $ 10.69 | 11,076 | $ 10.69 |
| 13.01 - 17.00 | 374,050 | 3.4 | 14.20 | 371,404 | 14.19 |
| 17.01 - 21.00 | 1,977,433 | 6.2 | 19.77 | 1,243,108 | 19.78 |
| 21.01 - 25.70 | 199,125 | 6.2 | 24.55 | 74,635 | 24.97 |
| Balance at end of year | 2,561,684 | 5.8 | 19.29 | 1,700,223 | 18.73 |

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options were as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Weighted average fair value of options at grant date | --- | $4.67 | $5.38 |
| Weighted average risk-free interest rate | --- | 3.91% | 5.14% |
| Weighted average expected price volatility | --- | 32.28% | 30.80% |
| Weighted average expected dividend yield | --- | 3.43% | 3.43% |
| Expected life in years | --- | 7 | 7 |

In addition, prior to 2002 the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements. The restricted stock awards granted vest to the participants at various times ranging from one year to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The Company also has granted stock awards totaling 35,205 shares, 31,855 shares and 21,390 shares in 2004, 2003 and 2002, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $23.61, $21.40 and $19.20, in 2004, 2003 and 2002, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $3.4 million, $4.8 million and $5.2 million in 2004, 2003 and 2002, respectively.

In 2004 and 2003, key employees of the Company were awarded performance share awards. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. Target grants of performance shares were made for the following performance periods:

| Grant Date | Performance Period | Target Grant of Shares |
|---|---|---|
| February 2003 | 2003-2004 | 59,224 |
| February 2003 | 2003-2005 | 54,180 |
| February 2004 | 2004-2006 | 189,337 |

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. The final value of the performance units may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. Compensation expense recognized for the performance share awards for the years ended December 31, 2004 and 2003, was $2.5 million and $879,000, respectively.

The Company is authorized to grant options, restricted stock and stock for up to 14.7 million shares of common stock and has granted options, restricted stock and stock on 5.8 million shares through December 31, 2004.

Note 12
Income Taxes
The components of income before income taxes for each of the years ended December 31 were as follows:

| | 2004 | 2003 (In thousands) | 2002 |
|---|---|---|---|
| United States | $ 280,764 | $ 278,143 | $ 233,536 |
| Foreign | 20,277 | 3,342 | 1,138 |
| Income before income taxes | $ 301,041 | $ 281,485 | $ 234,674 |

Income tax expense for the years ended December 31 was as follows:

| | 2004 | 2003 (In thousands) | 2002 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 47,625 | $ 26,313 | $ 46,389 |
| State | 12,231 | 7,408 | 9,082 |
| Foreign | 955 | 264 | --- |
| | 60,811 | 33,985 | 55,471 |
| Deferred: | | | |
| Income taxes -- | | | |
| Federal | 28,556 | 55,660 | 26,373 |
| State | 5,422 | 9,861 | 4,632 |
| Foreign | (223) | (338) | 338 |
| Investment tax credit | (592) | (596) | (584) |
| | 33,163 | 64,587 | 30,759 |
| Total income tax expense | $ 93,974 | $ 98,572 | $ 86,230 |

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Deferred tax assets: | | |
| Regulatory matters | $ 39,212 | $ 37,072 |
| Accrued pension costs | 18,754 | 12,122 |
| Asset retirement obligations | 12,197 | 7,017 |
| Deferred compensation | 9,938 | 9,090 |
| Bad debts | 2,266 | 3,188 |
| Deferred investment tax credit | 724 | 954 |
| Other | 29,237 | 21,269 |
| Total deferred tax assets | 112,328 | 90,712 |
| Deferred tax liabilities: | | |
| Depreciation and basis differences on property, plant and equipment | 450,237 | 406,589 |
| Basis differences on natural gas and oil producing properties | 124,788 | 105,826 |
| Regulatory matters | 15,192 | 10,663 |

| | | |
|---|---|---|
| Other | 13,826 | 9,309 |
| Total deferred tax liabilities | 604,043 | 532,387 |
| Net deferred income tax liability | $ (491,715) | $ (441,675) |

As of December 31, 2004 and 2003, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2003, to December 31, 2004, to deferred income tax expense:

| | 2004 (In thousands) |
|---|---|
| Change in net deferred income tax liability from the preceding table | $ 50,040 |
| Deferred taxes associated with acquisitions | (16,189) |
| Other | (688) |
| Deferred income tax expense for the period | $ 33,163 |

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

| Years ended December 31, | 2004 Amount | 2004 % | 2003 Amount | 2003 % | 2002 Amount | 2002 % |
|---|---|---|---|---|---|---|
| | (Dollars in thousands) | | | | | |
| Computed tax at federal statutory rate | $105,364 | 35.0 | $ 98,520 | 35.0 | $ 82,136 | 35.0 |
| Increases (reductions) resulting from: | | | | | | |
| State income taxes, net of federal income tax benefit | 11,468 | 3.8 | 11,857 | 4.2 | 10,279 | 4.4 |
| Audit resolution | (8,818) | (2.9) | --- | --- | --- | --- |
| Foreign operations | (5,648) | (1.9) | (832) | (.3) | 177 | --- |
| Depletion allowance | (3,418) | (1.2) | (3,117) | (1.1) | (2,200) | (.9) |
| Renewable electricity production credit | (3,404) | (1.1) | (3,395) | (1.2) | --- | --- |
| Other items | (1,570) | (.5) | (4,461) | (1.6) | (4,162) | (1.8) |
| Total income tax expense | $ 93,974 | 31.2 | $ 98,572 | 35.0 | $ 86,230 | 36.7 |

In 2004, the Company resolved federal and related state income tax matters for the 1998 through 2000 tax years. The Company reflected the effects of this tax resolution and, in addition, reversed liabilities that had previously been provided and were deemed to be no longer required, which resulted in a benefit of $8.3 million (after tax), including interest.

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generating facility in Brazil to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits. The cumulative undistributed earnings at December 31, 2004, were approximately $22 million. The amount of unrecognized deferred tax liability associated with the undistributed earnings was approximately $5 million.

The Company has evaluated the repatriation provisions of the American Jobs Creation Act of 2004 (Act), which was enacted on October 22, 2004. The provisions of the Act permit corporations to elect an 85-percent deduction for certain qualifying dividends received during 2005 from controlled foreign corporations. The deduction is only available to the extent that the dividend is in excess of an historical base-period average and if the dividend is invested in the United States pursuant to a qualifying domestic investment plan. At this time, the Company does not anticipate that it will be receiving dividends qualifying for this election during 2005.

Note 13
Business Segment Data
The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. Prior to the fourth quarter of 2004, the Company reported six reportable segments consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production and construction materials and mining. The independent power production and other operations did not individually meet the criteria to be considered a reportable segment. In the fourth quarter of 2004, the Company separated independent power production as a reportable business segment due to the significance of its operations. The Company's operations are now conducted through seven reportable segments and all prior period information has been restated to reflect this change.

The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of investments in natural gas-fired electric generating facilities in Brazil and Trinidad and Tobago, as discussed in Note 2.

The electric segment generates, transmits and distributes electricity, and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, and the manufacture and distribution of specialty equipment. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities, primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performs integrated construction services, in the central and western United States and in the states of Alaska and Hawaii. The independent power production segment owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

| | 2004 | 2003<br>(In thousands) | 2002 |
|---|---|---|---|
| External operating revenues: | | | |
| Electric | $ 178,803 | $ 178,562 | $ 162,616 |
| Natural gas distribution | 316,120 | 274,608 | 186,569 |
| Pipeline and energy services | 281,913 | 187,892 | 110,224 |
| | 776,836 | 641,062 | 459,409 |
| Utility services | 425,250 | 434,177 | 458,660 |
| Natural gas and oil production | 152,486 | 140,281 | 148,158 |
| Construction materials and mining | 1,321,626 | 1,104,408 | 962,312 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| MDU Resources Group, Inc. | (1) X An Original<br>(2) _ A Resubmission | 12/31/2004 | 2004/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

| | | | |
|---|---|---|---|
| Independent power production | 43,059 | 32,261 | 2,998 |
| Other | --- | --- | --- |
| | 1,942,421 | 1,711,127 | 1,572,128 |
| Total external operating revenues | $ 2,719,257 | $ 2,352,189 | $ 2,031,537 |
| Intersegment operating revenues: | | | |
| Electric | $ --- | $ --- | $ --- |
| Natural gas distribution | --- | --- | --- |
| Utility services | 1,571 | --- | --- |
| Pipeline and energy services | 75,316 | 64,300 | 55,034 |
| Natural gas and oil production | 190,354 | 124,077 | 55,437 |
| Construction materials and mining | 535 | --- | --- |
| Independent power production | --- | --- | --- |
| Other | 4,423 | 2,728 | 3,778 |
| Intersegment eliminations | (272,199) | (191,105) | (114,249) |
| Total intersegment operating revenues | $ --- | $ --- | $ --- |
| Depreciation, depletion and amortization: | | | |
| Electric | $ 20,199 | $ 20,150 | $ 19,537 |
| Natural gas distribution | 9,329 | 10,044 | 9,940 |
| Utility services | 11,113 | 10,353 | 9,871 |
| Pipeline and energy services | 17,804 | 15,016 | 14,846 |
| Natural gas and oil production | 70,823 | 61,019 | 48,714 |
| Construction materials and mining | 69,644 | 63,601 | 54,334 |
| Independent power production | 9,587 | 7,860 | 444 |
| Other | 271 | 294 | 275 |
| Total depreciation, depletion and amortization | $ 208,770 | $ 188,337 | $ 157,961 |
| Interest expense: | | | |
| Electric | $ 9,116 | $ 8,013 | $ 7,621 |
| Natural gas distribution | 4,292 | 3,936 | 4,364 |
| Utility services | 3,442 | 3,668 | 3,568 |
| Pipeline and energy services | 9,262 | 7,952 | 7,670 |
| Natural gas and oil production | 7,552 | 4,767 | 2,464 |
| Construction materials and mining | 20,646 | 18,747 | 18,422 |
| Independent power production | 4,354 | 5,850 | 1,100 |
| Other | (70) | 15 | 22 |
| Intersegment eliminations | (1,157) | (154) | (216) |
| Total interest expense | $ 57,437 | $ 52,794 | $ 45,015 |
| Income taxes: | | | |
| Electric | $ 4,303 | $ 9,862 | $ 9,501 |
| Natural gas distribution | (3,883) | 1,823 | (1,325) |
| Utility services | (3,345) | 3,905 | 4,781 |
| Pipeline and energy services | 7,445 | 11,188 | 12,462 |
| Natural gas and oil production | 61,261 | 42,993 | 30,604 |
| Construction materials and mining | 26,674 | 28,168 | 29,415 |
| Independent power production | 1,249 | 257 | 406 |
| Other | 270 | 376 | 386 |
| Total income taxes | $ 93,974 | $ 98,572 | $ 86,230 |
| Cumulative effect of accounting change (Note 8): | | | |
| Electric | $ --- | $ --- | $ --- |
| Natural gas distribution | --- | --- | --- |
| Utility services | --- | --- | --- |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| MDU Resources Group, Inc. | (1) X An Original (2) _ A Resubmission | 12/31/2004 | 2004/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

| | | | |
|---|---|---|---|
| Pipeline and energy services | --- | --- | --- |
| Natural gas and oil production | --- | (7,740) | --- |
| Construction materials and mining | --- | 151 | --- |
| Independent power production | --- | --- | --- |
| Other | --- | --- | --- |
| Total cumulative effect of accounting change | $ --- | $ (7,589) | $ --- |
| Earnings on common stock: | | | |
| Electric | $ 12,790 | $ 16,950 | $ 15,780 |
| Natural gas distribution | 2,182 | 3,869 | 3,587 |
| Utility services | (5,650) | 6,170 | 6,371 |
| Pipeline and energy services | 8,944 | 18,158 | 19,097 |
| Natural gas and oil production | 110,779 | 63,027 | 53,192 |
| Construction materials and mining | 50,707 | 54,412 | 48,702 |
| Independent power production | 26,309 | 11,415 | 307 |
| Other | 321 | 606 | 652 |
| Total earnings on common stock | $ 206,382 | $ 174,607 | $ 147,688 |
| Capital expenditures: | | | |
| Electric | $ 18,767 | $ 28,537 | $ 27,795 |
| Natural gas distribution | 17,384 | 15,672 | 11,044 |
| Utility services | 8,470 | 7,820 | 17,242 |
| Pipeline and energy services | 38,282 | 93,004 | 21,449 |
| Natural gas and oil production | 111,506 | 101,698 | 136,424 |
| Construction materials and mining | 133,080 | 128,487 | 106,893 |
| Independent power production | 76,246 | 110,963 | 89,621 |
| Other | 4,215 | 1,895 | 6,127 |
| Net proceeds from sale or disposition of property | (20,518) | (14,439) | (16,217) |
| Total net capital expenditures | $ 387,432 | $ 473,637 | $ 400,378 |
| Identifiable assets: | | | |
| Electric* | $ 323,819 | $ 327,899 | $ 322,475 |
| Natural gas distribution* | 252,582 | 234,948 | 208,502 |
| Utility services | 230,955 | 221,824 | 230,888 |
| Pipeline and energy services | 447,302 | 405,904 | 312,858 |
| Natural gas and oil production | 685,610 | 602,389 | 554,420 |
| Construction materials and mining | 1,345,547 | 1,248,607 | 1,137,697 |
| Independent power production | 349,752 | 241,918 | 130,867 |
| Other** | 97,954 | 97,103 | 99,214 |
| Total identifiable assets | $ 3,733,521 | $ 3,380,592 | $ 2,996,921 |
| Property, plant and equipment: | | | |
| Electric* | $ 650,902 | $ 639,893 | $ 619,230 |
| Natural gas distribution* | 264,496 | 252,591 | 244,930 |
| Utility services | 82,600 | 76,871 | 70,660 |
| Pipeline and energy services | 492,400 | 461,793 | 372,420 |
| Natural gas and oil production | 982,625 | 871,357 | 755,788 |
| Construction materials and mining | 1,190,468 | 1,080,399 | 976,751 |
| Independent power production | 250,602 | 184,127 | 79,373 |
| Other | 17,335 | 17,007 | 15,152 |
| Less accumulated depreciation, depletion and amortization | 1,358,723 | 1,187,105 | 1,026,932 |
| Net property, plant and equipment | $ 2,572,705 | $ 2,396,933 | $ 2,107,372 |

* Includes allocations of common utility property.

** Includes assets not directly assignable to a business (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Excluding the asset impairments at the pipeline and energy services segment of $5.3 million (after tax), earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from utility services, natural gas and oil production, construction materials and mining, independent power production, and other are all from nonregulated operations. Capital expenditures for 2004, 2003 and 2002, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $33.1 million, $42.4 million and $47.2 million in 2004, 2003 and 2002, respectively.

Note 14
Acquisitions
In 2004, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Idaho, Iowa and Minnesota and an independent power production operating and development company in Colorado. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired prior to 2004, consisting of the Company's common stock and cash, was $70.3 million.

In 2003, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Montana, North Dakota and Texas and a wind-powered electric generating facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, consisting of the Company's common stock and cash, was $175.0 million.

In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and natural gas-fired electric generating facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

In April 2000, Fidelity purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming. Pursuant to the asset purchase and sale agreement, Preston could, but was not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. Fidelity had the right, but not the obligation, to purchase the Seller's Option Interest from Preston for an amount as specified in the agreement. In July 2002, Fidelity purchased the Seller's Option Interest.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2004. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 15
Employee Benefit Plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. As discussed in Note 1, the Company recognized the effects of the 2003 Medicare Act during the second quarter of 2004. The net periodic benefit cost for 2004 reflects the effects of the 2003 Medicare Act. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| | (In thousands) | | | |
| Change in benefit obligation: | | | | |
| Benefit obligation at beginning of year | $261,335 | $224,766 | $ 88,381 | $ 74,917 |
| Service cost | 7,667 | 5,897 | 1,826 | 1,857 |
| Interest cost | 15,903 | 15,211 | 4,312 | 5,281 |
| Plan participants' contributions | --- | --- | 1,133 | 977 |
| Amendments | --- | 210 | (773) | 754 |
| Actuarial (gain) loss | 12,240 | 27,701 | (14,951) | 10,338 |
| Benefits paid | (12,389) | (12,450) | (4,437) | (5,743) |
| Benefit obligation at end of year | 284,756 | 261,335 | 75,491 | 88,381 |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of year | 223,043 | 189,143 | 47,234 | 40,889 |
| Actual gain on plan assets | 27,264 | 43,087 | 2,920 | 6,148 |
| Employer contribution | 1,604 | 3,263 | 4,127 | 4,963 |
| Plan participants' contributions | --- | --- | 1,134 | 977 |
| Benefits paid | (12,389) | (12,450) | (4,437) | (5,743) |
| Fair value of plan assets at end of year | 239,522 | 223,043 | 50,978 | 47,234 |
| Funded status - under | (45,234) | (38,292) | (24,513) | (41,147) |
| Unrecognized actuarial (gain) loss | 46,293 | 41,422 | (1,832) | 11,862 |
| Unrecognized prior service cost | 7,435 | 8,556 | --- | 706 |
| Unrecognized net transition obligation (asset) | (47) | (297) | 16,999 | 19,362 |
| Prepaid (accrued) benefit cost | $ 8,447 | $ 11,389 | $ (9,346) | $ (9,217) |
| Amounts recognized in the Consolidated Balance Sheets at December 31: | | | | |
| Prepaid benefit cost | $ 19,020 | $ 19,671 | $ 572 | $ 614 |
| Accrued benefit liability | (10,573) | (8,282) | (9,918) | (9,831) |
| Net amount recognized | $ 8,447 | $ 11,389 | $ (9,346) | $ (9,217) |

Employer contributions and benefits paid in the above table include only those amounts contributed directly to, or paid directly from, plan assets.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $227.3 million and $212.0 million at December 31, 2004 and 2003, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31, 2004 and 2003, were as follows:

| 2004 | 2003 |
|---|---|
| (In thousands) | |

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| | | |
|---|---|---|
| Projected benefit obligation | $ 174,983 | $ 38,845 |
| Accumulated benefit obligation | $ 136,012 | $ 28,840 |
| Fair value of plan assets | $ 132,280 | $ 24,508 |

Components of net periodic benefit cost (income) for the Company's pension and other postretirement benefit plans were as follows:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| Years ended December 31, | 2004 | 2003 | 2002 | 2004 | 2003 | 2002 |
| | (In thousands) | | | | | |
| Components of net periodic benefit cost: | | | | | | |
| Service cost | $ 7,667 | $ 5,897 | $ 5,135 | $ 1,826 | $ 1,857 | $ 1,460 |
| Interest cost | 15,903 | 15,211 | 14,877 | 4,312 | 5,281 | 4,915 |
| Expected return on assets | (20,375) | (20,730) | (21,110) | (3,943) | (3,933) | (3,843) |
| Amortization of prior service cost | 1,121 | 1,156 | 1,148 | 144 | 48 | --- |
| Recognized net actuarial (gain) loss | 480 | (417) | (1,855) | (233) | (255) | (566) |
| Amortization of net transition obligation (asset) | (250) | (950) | (947) | 2,151 | 2,151 | 2,151 |
| Net periodic benefit cost (income) | 4,546 | 167 | (2,752) | 4,257 | 5,149 | 4,117 |
| Less amount capitalized | 409 | 14 | (352) | 440 | 601 | 404 |
| Net periodic benefit cost (income) | $ 4,137 | $ 153 | $ (2,400) | $ 3,817 | $ 4,548 | $ 3,713 |

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Discount rate | 5.75% | 6.00% | 5.75% | 6.00% |
| Rate of compensation increase | 4.70% | 4.70% | 4.50% | 4.50% |

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Discount rate | 6.00% | 6.75% | 6.00% | 6.75% |
| Expected return on plan assets | 8.50% | 8.50% | 7.50% | 7.50% |
| Rate of compensation increase | 4.70% | 4.50% | 4.50% | 4.50% |

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 percent fixed income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

| | 2004 | 2003 |
|---|---|---|
| Health care trend rate assumed for next year | 6.0%-9.5% | 6.0%-9.5% |
| Health care cost trend rate - ultimate | 5.0%-6.0% | 5.0%-6.0% |

| | | |
|---|---|---|
| Year in which ultimate trend rate achieved | 1999-2013 | 1999-2012 |

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2004:

| | 1 Percentage Point Increase | 1 Percentage Point Decrease |
|---|---|---|
| | (In thousands) | |
| Effect on total of service and interest cost components | $ 218 | $ (872) |
| Effect on postretirement benefit obligation | $ 3,176 | $ (8,489) |

The Company's defined benefit pension plans' asset allocation at December 31, 2004 and 2003, and weighted average targeted asset allocations at December 31, 2004, were as follows:

| | Percentage of Plan Assets | | Weighted Average Targeted Asset Allocation Percentage |
|---|---|---|---|
| Asset Category | 2004 | 2003 | 2004 |
| Equity securities | 74% | 72% | 70% |
| Fixed income securities | 24 | 25 | 30* |
| Other | 2 | 3 | --- |
| Total | 100% | 100% | 100% |

*Includes target for both fixed income securities and other.

The Company's pension assets are managed by nine outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities and leveraged or derivative securities. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

The Company's other postretirement benefit plans' asset allocation at December 31, 2004 and 2003, and weighted average targeted asset allocation at December 31, 2004, were as follows:

| | Percentage of Plan Assets | | Weighted Average Targeted Asset Allocation Percentage |
|---|---|---|---|
| Asset Category | 2004 | 2003 | 2004 |
| Equity securities | 70% | 66% | 70% |

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| | | | |
|---|---|---|---|
| Fixed income securities | 28 | 30 | 30* |
| Other | 2 | 4 | --- |
| Total | 100% | 100% | 100% |

*Includes target for both fixed income securities and other.

The Company expects to contribute approximately $900,000 to its defined benefit pension plans and approximately $3.8 million to its postretirement benefit plans in 2005.

The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

| Years | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | (In thousands) | |
| 2005 | $ 12,403 | $ 5,908 |
| 2006 | 12,726 | 5,666 |
| 2007 | 13,248 | 5,941 |
| 2008 | 13,830 | 6,204 |
| 2009 | 14,720 | 6,493 |
| 2010-2014 | 89,922 | 38,302 |

The following Medicare Part D subsidies are expected: none in 2005; $436,000 in 2006; $439,000 in 2007; $440,000 in 2008; $438,000 in 2009 and $2.2 million during the years 2010 through 2014.

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $28.2 million, $27.2 million and $27.8 million in 2004, 2003 and 2002, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments, at December 31, 2004, consisted of cash equivalents and life insurance carried on plan participants, which is payable to the Company upon the employee's death. The Company's net periodic benefit cost for this plan was $7.5 million, $5.3 million and $5.1 million in 2004, 2003 and 2002, respectively. The total projected obligation for this plan was $65.3 million and $51.1 million at December 31, 2004 and 2003, respectively. The accumulated benefit obligation for this plan was $52.3 million and $40.7 million at December 31, 2004 and 2003, respectively. The additional minimum liability relating to this plan was $14.3 million and $8.2 million at December 31, 2004 and 2003, respectively. The Company has a related intangible asset recognized as of December 31, 2004 and 2003, of $851,000 and $1.0 million, respectively. A discount rate of 5.75 percent and 6.0 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent at both December 31, 2004 and 2003, were used to determine benefit obligations.

A discount rate of 6.00 percent and 6.75 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2004 and 2003, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $3.8 million in 2004 and $2.6 million in 2003.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $2.5 million in 2005; $2.6 million in 2006; $3.1 million in 2007; $3.2 million in 2008; $3.3 million in 2009 and $20.0 million for the years 2010 through 2014.

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The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $13.8 million in 2004, $9.8 million in 2003 and $9.6 million in 2002. The costs incurred in each year reflect additional participants as a result of business acquisitions.

Note 16
Jointly Owned Facilities
The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

| | 2004 | 2003 |
|---|---|---|
| | (In thousands) | |
| Big Stone Station: | | |
| Utility plant in service | $ 52,157 | $ 52,154 |
| Less accumulated depreciation | 36,488 | 34,993 |
| | $ 15,669 | $ 17,161 |
| Coyote Station: | | |
| Utility plant in service | $ 124,388 | $ 124,086 |
| Less accumulated depreciation | 74,671 | 72,850 |
| | $ 49,717 | $ 51,236 |

Note 17
Regulatory Matters and Revenues Subject To Refund
On September 7, 2004, Great Plains filed an application with the MPUC for a natural gas rate increase. Great Plains had requested a total of $1.4 million annually or 4.0 percent above current rates. Great Plains also requested an interim increase of $1.4 million annually. On November 23, 2004, the MPUC issued an Order setting interim rates of $1.4 million annually effective with service rendered on or after January 10, 2005, subject to refund. A final order from the MPUC is expected in late 2005.

On June 7, 2004, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase for the Black Hills service area. Montana-Dakota requested a total of $1.3 million annually or 2.2 percent above current rates. On November 15, 2004, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $670,000 annually, or 1.4 percent. On November 30, 2004, the SDPUC approved the Settlement Stipulation effective with service rendered on or after December 1, 2004.

On April 1, 2004, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total of $1.5 million annually or 1.8 percent above current rates. On January 14, 2005, Montana-Dakota and the Montana Consumer Counsel filed a Stipulation with the MTPSC agreeing to an increase of $125,000 annually to be effective with service rendered on or after February 1, 2005. On January 25, 2005, the MTPSC passed a Motion approving the Stipulation.

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the ALJ issued an Initial Decision on Williston Basin's natural gas rate change application. The Initial Decision addressed numerous issues relating to the rate change application, including matters relating to allowable levels of rate base, return on common equity, and cost of service, as well as volumes established for purposes of cost recovery, and cost allocation and rate design. In July 2003, the FERC issued its

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Order on Initial Decision. The Order on Initial Decision affirmed the ALJ's Initial Decision on many of the issues including rate base and certain cost of service items as well as volumes to be used for purposes of cost recovery, and cost allocation and rate design. However, there are other issues as to which the FERC differed with the ALJ including return on common equity and the correct level of corporate overhead expense. In August 2003, Williston Basin requested rehearing of a number of issues including determinations associated with cost of service, throughput, and cost allocation and rate design, as discussed in the FERC's Order on Initial Decision. On May 11, 2004, the FERC issued an Order on Rehearing. The Order on Rehearing denied rehearing on all of the issues addressed by Williston Basin in its August 2003 request for rehearing except for the issue of the proper rate to utilize for transmission system negative salvage expenses. In addition, the FERC remanded the issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. On June 14, 2004, Williston Basin requested clarification of a few of the issues addressed in the Order on Rehearing including determinations associated with cost of service and cost allocation, as discussed in the FERC's Order on Rehearing. On June 14, 2004, Williston Basin also made its filing to comply with the requirements of the various FERC orders in this proceeding. Williston Basin is awaiting a decision from the FERC on Williston Basin's compliance filing and clarification request but is unable to predict the timing of the FERC's decision. Williston Basin participated in a hearing before the ALJ in early January 2005, regarding the matters remanded to the ALJ by the FERC in its Order on Rehearing and an order on these matters is expected in 2005.

A liability has been provided for a portion of the revenues that have been collected subject to refund with respect to Williston Basin's pending regulatory proceeding. Williston Basin believes that the liability is adequate based on its assessment of the ultimate outcome of the proceeding.

Note 18
Commitments and Contingencies
Litigation
In January 2002, Fidelity Oil Co. (FOC), one of the Company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment reflected a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

In June 1997, Grynberg filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota and filed over 70 similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming.

On June 4, 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the grounds that the information upon which Grynberg based his complaint was publicly disclosed prior to the filing of his complaint and further, that he is not the original source of such information. The Motion to Dismiss is additionally based on the grounds that Grynberg disclosed the filing of the complaint prior to the entry of a court order allowing such disclosure and that Grynberg failed to provide adequate information to the government prior to filing suit.

In the event the Motion to Dismiss is not granted, it is expected that further discovery will follow. Williston Basin and Montana-Dakota believe Grynberg will not prevail in the suit or recover damages from Williston Basin and/or Montana-Dakota because insufficient facts exist to support the allegations. Williston Basin and Montana-Dakota believe Grynberg's claims are without merit and intend to vigorously contest this suit.

Grynberg has not specified the amount he seeks to recover. Williston Basin and Montana-Dakota are unable to estimate their potential exposure and will be unable to do so until discovery is completed.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and November 2004 by a number of environmental organizations, including the Northern Plains Resource Council and the Montana Environmental Information Center, as well as the Tongue River Water Users' Association and the Northern Cheyenne Tribe. Portions of two of the lawsuits have been transferred to Federal District Court in Wyoming. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Federal Clean Water Act, the National Environmental Policy Act, the Federal Land Management Policy Act, the National Historic Preservation Act and the Montana Environmental Policy Act. The cases involving alleged violations of the Federal Clean Water Act have been resolved without a finding that Fidelity is in violation of the Federal Clean Water Act. There presently are no claims pending for penalties, fines or damages under the Federal Clean Water Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural requirements and the lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought in any of these cases, and will be unable to do so until after completion of discovery in these separate cases. Fidelity is vigorously defending all coalbed-related lawsuits in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

Montana-Dakota has joined with two electric generators in appealing a finding by the North Dakota Health Department in September 2003 that the North Dakota Health Department may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the North Dakota Health Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order in October 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the EPA, the North Dakota Health Department and the other electric generators.

In a related matter, the state of North Dakota and the EPA entered into a MOU on February 24, 2004, establishing the principles to be used by the state of North Dakota in completing dispersion modeling of air quality in Theodore Roosevelt National Park and other "Class I" areas in North Dakota and Montana. In April 2004, the Dakota Resource Council filed a petition for review of the MOU with the United States Eighth Circuit Court of Appeals. The petition was dismissed, without prejudice, in June 2004 upon stipulation of the EPA, the Dakota Resource Council and the state of North Dakota. The Company cannot predict the outcome of the North Dakota Health Department or Dakota Resource Council matters or their ultimate impact on its operations.

The Company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters
In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the DEQ are being recorded, and initially paid, through an administrative consent order by the LWG, a group of 10 entities, which does not include MBI. The LWG estimates the overall remedial investigation and feasibility study will cost approximately $10 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy, and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2006, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above administrative action.

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2004, were $14.7 million in 2005, $10.5 million in 2006, $6.6 million in 2007, $5.1 million in 2008, $3.5 million in 2009 and $25.2 million thereafter. Rent expense was $30.6 million, $27.2 million and $26.9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation, construction materials supply and electric generation construction contracts. These commitments range from one to 20 years. The commitments under these contracts as of December 31, 2004, were $223.6 million in 2005, $105.7 million in 2006, $65.4 million in 2007, $50.5 million in 2008, $46.9 million in 2009 and $236.4 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2004, 2003 and 2002, were approximately $318.3 million, $204.6 million and $152.1 million, respectively. These commitments are not reflected in the Company’s consolidated financial statements.

In addition to the above obligations, the Company has certain purchase obligations for natural gas connected to its gathering system. These purchases and the resale of the natural gas are at market-based prices. These obligations continue as long as natural gas is produced. However, if the purchase and resale of natural gas become uneconomical, the purchase commitments can be canceled by the Company with 60 days notice. These purchase obligations are currently estimated at approximately $10 million annually.

Guarantees

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| MDU Resources Group, Inc. | (1) X An Original<br>(2) _ A Resubmission | 12/31/2004 | 2004/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the Termoceara Generating Facility, as discussed in Note 2. The Company, through MDU Brasil, owns 49 percent of MPX. The main business purpose of Centennial extending the guarantee to MPX's creditors is to enable MPX to obtain lower borrowing costs. At December 31, 2004, the aggregate amount of borrowings outstanding subject to these guarantees was $34.9 million and the scheduled repayment of these borrowings is $11.0 million in 2005, $10.7 million in 2006 and 2007 and $2.5 million in 2008. The individual investor (who through EBX owns 51 percent of MPX) has also guaranteed these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees, which are joint and several obligations. Centennial and the individual investor have entered into reimbursement agreements under which they have agreed to reimburse each other to the extent they may be required to make any guarantee payments in excess of their proportionate ownership share in MPX. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity's obligations at December 31, 2004, were $4.9 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements at December 31, 2004, expire in 2005; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. At December 31, 2004, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to natural gas transportation and sales agreements, electric power supply agreements, insurance policies and certain other guarantees. At December 31, 2004, the fixed maximum amounts guaranteed under these agreements aggregated $88.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $40.1 million in 2005; $4.7 million in 2006; $2.1 million in 2007; $300,000 in 2008; $900,000 in 2009; $22.0 million in 2010; $12.0 million in 2012; $2.2 million in 2028; $500,000, which is subject to expiration 30 days after the receipt of written notice and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $561,000 and was reflected on the Consolidated Balance Sheets at December 31, 2004. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands Energy Marketing, Inc. (Prairielands), an indirect wholly owned subsidiary of the Company. At December 31, 2004, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2005 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $1.7 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2004, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees to third parties related to the Company's routine purchase of maintenance items for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items were reflected on the Consolidated Balance Sheet at December 31, 2004.

As of December 31, 2004, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $375 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

Note 19
Related Party Transactions
In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum Corporation (Nance Petroleum), a wholly owned subsidiary of St. Mary Land & Exploration Company (St. Mary). Robert L. Nance, an executive officer and shareholder of St. Mary, is also a member of the Board of Directors of the Company. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in mid-December 2004. Bitter Creek's capital expenditures related to the completion of the gathering lines and the expansion of its gathering facilities to accommodate the natural gas gathering agreements were $7.6 million in 2004 and are estimated for the next three years to be $2.5 million in 2005, $2.2 million in 2006 and $3.3 million in 2007. The natural gas gathering agreements are each for a term of 15 years and month-to-month thereafter. Bitter Creek's revenues from these contracts were $37,000 in 2004 and estimated revenues from these contracts for the next three years are $1.9 million in 2005, $3.8 million in 2006 and $5.8 million in 2007. The amount due from Nance Petroleum at December 31, 2004, was $37,000.

Note 20
Investment in Subsidiaries
The Respondent owns one wholly owned subsidiary, Centennial Energy Holdings, Inc.
As required by the Federal Energy Regulatory Commission for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investment using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary, as required by generally accepted accounting principles. If generally accepted accounting principles were followed, utility plant, other property and investments would increase by $795,563,998 and $757,759,059; current and accrued assets would increase by $582,821,865 and $480,874,653; deferred debits would increase by $233,968,821 and $258,677,208; long-term debt would increase by $689,523,614 and $735,936,753; other noncurrent liabilities and current and accrued liabilities would increase by $311,176,424 and $202,668,975; deferred credits would increase by $611,654,646 and $562,331,004 as of December 31, 2004 and 2003 (restated), respectively. Furthermore, operating revenues would increase by $2,224,333,861 and $1,899,020,074; and operating expenses, excluding income taxes, would increase by $1,932,210,801 and $1,629,210,888 for the year ended December 31, 2004 and 2003, respectively. In addition, net cash provided by operating activities would increase by $378,669,000; net cash used in investing activities would increase by $327,494,000; net cash provided by financing activities would decrease by $37,509,000; and the net change in cash and cash equivalents would be an increase of $13,666,000 for the year ended December 31, 2004. Reporting its subsidiary investment using the equity method rather than generally accepted accounting principles has no effect on net income or retained earnings.

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2004

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | **Intangible Plant** | | | | |
| 2 | | | | | |
| 3 | 301 | Organization | | | |
| 4 | 302 | Franchises & Consents | | | |
| 5 | 303 | Miscellaneous Intangible Plant | $1,742,955 | $2,522,804 | 44.74% |
| 6 | | | | | |
| 7 | **TOTAL Intangible Plant** | | $1,742,955 | $2,522,804 | 44.74% |
| 8 | | | | | |
| 9 | **Production Plant** | | | | |
| 10 | | | | | |
| 11 | Production & Gathering Plant | | | | |
| 12 | | | | | |
| 13 | 325.1 | Producing Lands | | | |
| 14 | 325.2 | Producing Leaseholds | | | |
| 15 | 325.3 | Gas Rights | | | |
| 16 | 325.4 | Rights-of-Way | | | |
| 17 | 325.5 | Other Land & Land Rights | | | |
| 18 | 326 | Gas Well Structures | | | |
| 19 | 327 | Field Compressor Station Structures | | | |
| 20 | 328 | Field Meas. & Reg. Station Structures | | | |
| 21 | 329 | Other Structures | | NOT | |
| 22 | 330 | Producing Gas Wells-Well Construction | | APPLICABLE | |
| 23 | 331 | Producing Gas Wells-Well Equipment | | | |
| 24 | 332 | Field Lines | | | |
| 25 | 333 | Field Compressor Station Equipment | | | |
| 26 | 334 | Field Meas. & Reg. Station Equipment | | | |
| 27 | 335 | Drilling & Cleaning Equipment | | | |
| 28 | 336 | Purification Equipment | | | |
| 29 | 337 | Other Equipment | | | |
| 30 | 338 | Unsuccessful Exploration & Dev. Costs | | | |
| 31 | | | | | |
| 32 | **Total Production & Gathering Plant** | | | | |
| 33 | | | | | |
| 34 | Products Extraction Plant | | | | |
| 35 | | | | | |
| 36 | 340 | Land & Land Rights | | | |
| 37 | 341 | Structures & Improvements | | | |
| 38 | 342 | Extraction & Refining Equipment | | | |
| 39 | 343 | Pipe Lines | | NOT | |
| 40 | 344 | Extracted Products Storage Equipment | | APPLICABLE | |
| 41 | 345 | Compressor Equipment | | | |
| 42 | 346 | Gas Measuring & Regulating Equipment | | | |
| 43 | 347 | Other Equipment | | | |
| 44 | | | | | |
| 45 | **Total Products Extraction Plant** | | | | |
| 46 | | | | | |
| 47 | **TOTAL Production Plant** | | | | |

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2004

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | **Natural Gas Storage and Processing Plant** | | | | |
| 3 | | | | | |
| 4 | Underground Storage Plant | | | | |
| 5 | | | | | |
| 6 | 350.1 | Land | | | |
| 7 | 350.2 | Rights-of-Way | | | |
| 8 | 351 | Structures & Improvements | | | |
| 9 | 352 | Wells | | | |
| 10 | 352.1 | Storage Leaseholds & Rights | | | |
| 11 | 352.2 | Reservoirs | | NOT | |
| 12 | 352.3 | Non-Recoverable Natural Gas | | APPLICABLE | |
| 13 | 353 | Lines | | | |
| 14 | 354 | Compressor Station Equipment | | | |
| 15 | 355 | Measuring & Regulating Equipment | | | |
| 16 | 356 | Purification Equipment | | | |
| 17 | 357 | Other Equipment | | | |
| 18 | | | | | |
| 19 | **Total Underground Storage Plant** | | | | |
| 20 | | | | | |
| 21 | Other Storage Plant | | | | |
| 22 | | | | | |
| 23 | 360 | Land & Land Rights | | | |
| 24 | 361 | Structures & Improvements | | | |
| 25 | 362 | Gas Holders | | | |
| 26 | 363 | Purification Equipment | | | |
| 27 | 363.1 | Liquification Equipment | | NOT | |
| 28 | 363.2 | Vaporizing Equipment | | APPLICABLE | |
| 29 | 363.3 | Compressor Equipment | | | |
| 30 | 363.4 | Measuring & Regulating Equipment | | | |
| 31 | 363.5 | Other Equipment | | | |
| 32 | | | | | |
| 33 | **Total Other Storage Plant** | | | | |
| 34 | | | | | |
| 35 | **TOTAL Natural Gas Storage and Processing Plant** | | | | |
| 36 | | | | | |
| 37 | **Transmission Plant** | | | | |
| 38 | | | | | |
| 39 | 365.1 | Land & Land Rights | | | |
| 40 | 365.2 | Rights-of-Way | | | |
| 41 | 366 | Structures & Improvements | | | |
| 42 | 367 | Mains | | NOT | |
| 43 | 368 | Compressor Station Equipment | | APPLICABLE | |
| 44 | 369 | Measuring & Reg. Station Equipment | | | |
| 45 | 370 | Communication Equipment | | | |
| 46 | 371 | Other Equipment | | | |
| 47 | | | | | |
| 48 | **TOTAL Transmission Plant** | | | | |

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2004

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | **Distribution Plant** | | | | |
| 3 | | | | | |
| 4 | 374 | Land & Land Rights | $36,193 | $36,193 | 0.00% |
| 5 | 375 | Structures & Improvements | 198,024 | 195,171 | -1.44% |
| 6 | 376 | Mains | 22,410,342 | 22,845,547 | 1.94% |
| 7 | 377 | Compressor Station Equipment | | | |
| 8 | 378 | Meas. & Reg. Station Equipment-General | 545,725 | 552,195 | 1.19% |
| 9 | 379 | Meas. & Reg. Station Equipment-City Gate | 128,221 | 128,221 | 0.00% |
| 10 | 380 | Services | 12,167,073 | 12,957,239 | 6.49% |
| 11 | 381 | Meters | 10,956,421 | 11,231,759 | 2.51% |
| 12 | 382 | Meter Installations | | | |
| 13 | 383 | House Regulators | 1,499,617 | 1,512,831 | 0.88% |
| 14 | 384 | House Regulator Installations | | | |
| 15 | 385 | Industrial Meas. & Reg. Station Equipment | 163,427 | 178,175 | 9.02% |
| 16 | 386 | Other Prop. on Customers' Premises 1/ | 161,799 | 161,799 | 0.00% |
| 17 | 387 | Other Equipment | 908,697 | 948,076 | 4.33% |
| 18 | | | | | |
| 19 | **TOTAL Distribution Plant** | | $49,175,539 | $50,747,206 | 3.20% |
| 20 | | | | | |
| 21 | **General Plant** | | | | |
| 22 | | | | | |
| 23 | 389 | Land & Land Rights | $26,744 | $26,745 | 0.00% |
| 24 | 390 | Structures & Improvements | 451,229 | 453,537 | 0.51% |
| 25 | 391 | Office Furniture & Equipment | 299,600 | 403,189 | 34.58% |
| 26 | 392 | Transportation Equipment | 2,095,172 | 2,399,189 | 14.51% |
| 27 | 393 | Stores Equipment | 43,786 | 43,786 | 0.00% |
| 28 | 394 | Tools, Shop & Garage Equipment | 517,755 | 557,911 | 7.76% |
| 29 | 395 | Laboratory Equipment | 40,694 | 19,727 | -51.52% |
| 30 | 396 | Power Operated Equipment | 1,318,760 | 1,572,543 | 19.24% |
| 31 | 397 | Communication Equipment | 291,546 | 292,484 | 0.32% |
| 32 | 398 | Miscellaneous Equipment | 14,311 | 14,312 | 0.01% |
| 33 | 399 | Other Tangible Property | | | |
| 34 | | | | | |
| 35 | **TOTAL General Plant** | | $5,099,597 | $5,783,423 | 13.41% |
| 36 | | | | | |
| 37 | **Common Plant** | | | | |
| 38 | | | | | |
| 39 | 389 | Land & Land Rights | $184,901 | $188,049 | 1.70% |
| 40 | 390 | Structures & Improvements | 2,134,622 | 2,197,417 | 2.94% |
| 41 | 391 | Office Furniture & Equipment | 823,344 | 847,937 | 2.99% |
| 42 | 392 | Transportation Equipment | 1,123,921 | 1,148,676 | 2.20% |
| 43 | 393 | Stores Equipment | 9,472 | 9,614 | 1.50% |
| 44 | 394 | Tools, Shop & Garage Equipment | 151,650 | 158,855 | 4.75% |
| 45 | 396 | Power Operated Equipment | 6,409 | 0 | -100.00% |
| 46 | 397 | Communication Equipment | 345,885 | 293,537 | -15.13% |
| 47 | 398 | Miscellaneous Equipment | 73,336 | 74,969 | 2.23% |
| 48 | | | | | |
| 49 | **TOTAL Common Plant** | | $4,853,540 | $4,919,054 | 1.35% |
| 50 | | | | | |
| 51 | **TOTAL Gas Plant in Service** | | $60,871,631 | $63,972,487 | 5.09% |

1/ Includes gas plant leased to others.

## MONTANA DEPRECIATION SUMMARY

Year: 2004

| | Functional Plant Classification | Plant Cost | Accumulated Depreciation Last Year Bal. | This Year Bal. | Current Avg. Rate |
|---|---|---|---|---|---|
| 1 | Production & Gathering | | | | |
| 2 | Products Extraction | | | | |
| 3 | Underground Storage | | | | |
| 4 | Other Storage | | | | |
| 5 | Transmission | | | | |
| 6 | Distribution | $50,747,206 | $32,307,322 | $33,380,517 | 3.80% |
| 7 | General | 5,837,196 | 1,883,401 | 2,334,343 | 1.74% |
| 8 | Common | 7,388,085 | 2,668,081 | 3,029,394 | 4.91% |
| 9 | **TOTAL** | $63,972,487 | $36,858,804 | $38,744,254 | 3.74% |

## MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

| | Account | | Last Year Bal. | This Year Bal. | %Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | 151 | Fuel Stock | | | |
| 3 | 152 | Fuel Stock Expenses - Undistributed | | | |
| 4 | 153 | Residuals & Extracted Products | | | |
| 5 | 154 | Plant Materials & Operating Supplies: | | | |
| 6 | | Assigned to Construction (Estimated) | | | |
| 7 | | Assigned to Operations & Maintenance | | | |
| 8 | | Production Plant (Estimated) | | | |
| 9 | | Transmission Plant (Estimated) | | | |
| 10 | | Distribution Plant (Estimated) | $314,475 | $402,977 | 28.14% |
| 11 | | Assigned to Other | | | |
| 12 | 155 | Merchandise | | | |
| 13 | 156 | Other Materials & Supplies | | | |
| 14 | 163 | Stores Expense Undistributed | | | |
| 15 | | | | | |
| 16 | **TOTAL Materials & Supplies** | | $314,475 | $402,977 | 28.14% |

## MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

| | Commission Accepted - Most Recent 1/ | | % Cap. Str. | % Cost Rate | Weighted Cost |
|---|---|---|---|---|---|
| 1 | Docket Number | D95.7.90 | | | |
| 2 | Order Number | 5856b | | | |
| 3 | | | | | |
| 4 | Common Equity | | 44.810% | 12.000% | 5.377% |
| 5 | Preferred Stock | | 1.810% | 4.653% | 0.084% |
| 6 | Long Term Debt | | 53.390% | 10.212% | 5.452% |
| 7 | Other | | | | |
| 8 | **TOTAL** | | | | 10.913% |
| 9 | | | | | |
| 10 | Actual at Year End | | | | |
| 11 | | | | | |
| 12 | Common Equity | | 51.638% | 12.000% | 6.197% |
| 13 | Preferred Stock | | 4.466% | 4.616% | 0.206% |
| 14 | Long Term Debt | | 40.455% | 8.644% | 3.497% |
| 15 | Short Term Debt | | 3.441% | 4.472% | 0.154% |
| 16 | **TOTAL** | | 100.000% | | 10.054% |

1/ Docket No. D2004.4.50, filed April 1, 2004, was settled pursuant to a Stipulation. A capital structure and costs were not specifically stipulated.

## STATEMENT OF CASH FLOWS

Year: 2004

| | Description | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Increase/(decrease) in Cash & Cash Equivalents: | | | |
| 2 | | | | |
| 3 | **Cash Flows from Operating Activities:** | | | |
| 4 | Net Income | $175,324,972 | $207,066,607 | 18.10% |
| 5 | Depreciation | 30,195,105 | 29,529,445 | -2.20% |
| 6 | Amortization | 1,252,461 | 1,140,203 | -8.96% |
| 7 | Deferred Income Taxes - Net | 4,469,701 | (2,008,646) | -144.94% |
| 8 | Investment Tax Credit Adjustments - Net | (596,333) | (592,197) | -0.69% |
| 9 | Change in Operating Receivables - Net | (11,474,034) | 3,643,265 | 131.75% |
| 10 | Change in Materials, Supplies & Inventories - Net | (4,067,492) | (3,986,837) | 1.98% |
| 11 | Change in Operating Payables & Accrued Liabilities - Net | 22,096,610 | 17,758,725 | -19.63% |
| 12 | Change in Other Regulatory Assets | (1,092,811) | 1,410,889 | 229.11% |
| 13 | Change in Other Regulatory Liabilities | 672,317 | (3,403,165) | -606.18% |
| 14 | Allowance for Funds Used During Construction (AFUDC) | (217,797) | (264,953) | 21.65% |
| 15 | Change in Other Assets & Liabilities - Net | (13,303,142) | (4,483,170) | 66.30% |
| 16 | Less Undistributed Earnings from Subsidiary Companies | (153,788,920) | (191,408,704) | 24.46% |
| 17 | Other Operating Activities (explained on attached page) | | | |
| 18 | **Net Cash Provided by/(Used in) Operating Activities** | $49,470,637 | $54,401,462 | 9.97% |
| 19 | | | | |
| 20 | **Cash Inflows/Outflows From Investment Activities:** | | | |
| 21 | Construction/Acquisition of Property, Plant and Equipment | | | |
| 22 | (net of AFUDC & Capital Lease Related Acquisitions) | ($45,338,342) | ($36,250,756) | -20.04% |
| 23 | Acquisition of Other Noncurrent Assets | 4,502,946 | (11,126,644) | -347.10% |
| 24 | Proceeds from Disposal of Noncurrent Assets | | | |
| 25 | Investments In and Advances to Affiliates | (50,630,421) | (75,952,020) | 50.01% |
| 26 | Contributions and Advances from Affiliates | 56,273,000 | 64,106,000 | 13.92% |
| 27 | Disposition of Investments in and Advances to Affiliates | | | |
| 28 | Other Investing Activities: Depreciation & RWIP on Nonutility Plant | 49,965 | 144,461 | 189.12% |
| 29 | **Net Cash Provided by/(Used in) Investing Activities** | ($35,142,852) | ($59,078,959) | 68.11% |
| 30 | | | | |
| 31 | **Cash Flows from Financing Activities:** | | | |
| 32 | Proceeds from Issuance of: | | | |
| 33 | Long-Term Debt | $30,000,000 | | -100.00% |
| 34 | Preferred Stock | | | |
| 35 | Common Stock | 49,126,951 | $106,904,941 | 117.61% |
| 36 | Other: | | | |
| 37 | Net Increase in Short-Term Debt | | | |
| 38 | Other: Commercial Paper | | | |
| 39 | Payment for Retirement of: | | | |
| 40 | Long-Term Debt | (10,500,000) | (19,600,000) | 86.67% |
| 41 | Preferred Stock | (100,000) | | 100.00% |
| 42 | Common Stock | | | |
| 43 | Other: Adjustment to Retained Earnings | | (231,602) | -100.00% |
| 44 | Net Decrease in Short-Term Debt | (8,000,000) | | 100.00% |
| 45 | Dividends on Preferred Stock | (718,155) | (685,004) | -4.62% |
| 46 | Dividends on Common Stock | (74,118,558) | (82,340,948) | 11.09% |
| 47 | Other Financing Activities (explained on attached page) | | | |
| 48 | **Net Cash Provided by (Used in) Financing Activities** | ($14,309,762) | $4,047,387 | 128.28% |
| 49 | | | | |
| 50 | **Net Increase/(Decrease) in Cash and Cash Equivalents** | $18,023 | ($630,110) | -3596.14% |
| 51 | **Cash and Cash Equivalents at Beginning of Year** | $9,388,732 | $9,406,755 | 0.19% |
| 52 | **Cash and Cash Equivalents at End of Year** | $9,406,755 | $8,776,645 | -6.70% |

## LONG TERM DEBT

Year: 2004

| | Description | Issue Date Mo./Yr. | Maturity Date Mo./Yr. | Principal Amount | Net Proceeds | Outstanding Per Balance Sheet | Yield to Maturity | Annual Net Cost Inc. Prem/Disc. | Total Cost % 1/ |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 8.25 % Secured MTN, Series A | 04/92 | 04/07 | $30,000,000 | $26,111,796 | $30,000,000 | 8.25% | $3,053,100 | 10.18% |
| 2 | 8.60 % Secured MTN, Series A | 04/92 | 04/12 | 35,000,000 | 28,906,532 | 35,000,000 | 8.60% | 3,857,000 | 11.02% |
| 3 | 6.71 % Secured MTN, Series A | 09/97 | 10/09 | 15,000,000 | 13,488,404 | 15,000,000 | 6.71% | 1,229,250 | 8.20% |
| 4 | 5.83 % Secured MTN, Series A | 09/98 | 10/08 | 15,000,000 | 14,813,914 | 15,000,000 | 5.83% | 912,900 | 6.09% |
| 5 | 5.98 % Senior Notes | 12/03 | 12/33 | 30,000,000 | 29,456,832 | 30,000,000 | 5.98% | 1,861,500 | 6.21% |
| 6 | Mercer County 6.65 % 2/ | 06/92 | 06/22 | 15,000,000 | 14,061,276 | 15,000,000 | 6.65% | 1,093,200 | 7.29% |
| 7 | Richland County 6.65 % 2/ | 06/92 | 06/22 | 3,250,000 | 3,063,677 | 3,250,000 | 6.65% | 235,398 | 7.24% |
| 8 | Morton County 6.65 % 2/ | 06/92 | 06/22 | 2,600,000 | 2,420,986 | 2,600,000 | 6.65% | 190,944 | 7.34% |
| 9 | 5.10 % Cummulative Preferred Stock 3/ 4/ | 05/61 | 12/14 | 5,000,000 | 4,947,548 | 1,100,000 | 5.10% | 58,135 | 5.29% |
| 10 | | | | | | | | | |
| 11 | | | | | | | | | |
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| 23 | | | | | | | | | |
| 24 | | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | **TOTAL** | | | $150,850,000 | $137,270,965 | $146,950,000 | | $12,491,427 | 8.50% |

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.
2/ Pollution Control Refunding Revenue Bonds.
3/ Classified as long-term debt upon adoption of SFAS No. 150 in 2003.
4/ Mandatory annual redemption of $100,000

# PREFERRED STOCK

Year: 2004

| | Series | Issue Date Mo./Yr. | Shares Issued | Par Value | Call Price 1/ | Net Proceeds | Cost of Money | Principal Outstanding | Annual Cost | Embed. Cost % |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 4.50 % Cumulative | 01/51 | 100,000 | $100 | $105 | $10,000,000 | 4.50% | $10,000,000 | $450,000 | 4.50% |
| 2 | 4.70 % Cumulative | 12/55 | 50,000 | 100 | 102 | 5,000,000 | 4.70% | 5,000,000 | 235,000 | 4.70% |
| 3 | | | | | | | | | | |
| 4 | | | | | | | | | | |
| 5 | | | | | | | | | | |
| 6 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 13 | | | | | | | | | | |
| 14 | | | | | | | | | | |
| 15 | | | | | | | | | | |
| 16 | | | | | | | | | | |
| 17 | | | | | | | | | | |
| 18 | | | | | | | | | | |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| 21 | | | | | | | | | | |
| 22 | | | | | | | | | | |
| 23 | | | | | | | | | | |
| 24 | | | | | | | | | | |
| 25 | | | | | | | | | | |
| 26 | | | | | | | | | | |
| 27 | | | | | | | | | | |
| 28 | | | | | | | | | | |
| 29 | | | | | | | | | | |
| 30 | | | | | | | | | | |
| 31 | | | | | | | | | | |
| 32 | **TOTAL** | | | | | $15,000,000 | | $15,000,000 | $685,000 | 4.57% |

1/ Plus accrued dividends.

## COMMON STOCK

Year: 2004

| | | Avg. Number of Shares Outstanding 1/ | Book Value Per Share | Earnings Per Share 2/ | Dividends Per Share | Retention Ratio | Market Price High | Market Price Low | Price/ Earnings Ratio 3/ |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | January | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | February | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | March | 114,658,130 | $12.93 | $0.20 | $0.17 | 15.00% | $24.35 | $22.67 | 15.0 X |
| 9 | | | | | | | | | |
| 10 | April | | | | | | | | |
| 11 | | | | | | | | | |
| 12 | May | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | June | 116,559,018 | 13.26 | 0.50 | 0.17 | 66.00% | 24.03 | 21.85 | 14.3 X |
| 15 | | | | | | | | | |
| 16 | July | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | August | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | September | 117,109,110 | 13.66 | 0.61 | 0.18 | 70.49% | 26.43 | 23.72 | 15.4 X |
| 21 | | | | | | | | | |
| 22 | October | | | | | | | | |
| 23 | | | | | | | | | |
| 24 | November | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | December | 117,582,021 | 14.09 | 0.45 | 0.18 | 60.00% | 27.70 | 25.20 | 15.2 X |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |
| 30 | TOTAL Year End | 116,481,816 | $14.09 | $1.76 | $0.70 | 60.23% | | | 15.2 X |

1/ Basic shares
2/ Basic earnings per share.
3/ Calculated on 12 months ended using closing stock price.

# MONTANA EARNED RATE OF RETURN

Year: 2004

| | | Description | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| | | Rate Base | | | |
| 1 | | | | | |
| 2 | 101 | Plant in Service | $60,871,631 | $63,972,487 | 5.09% |
| 3 | 108 | (Less) Accumulated Depreciation | 36,858,804 | 38,744,254 | 5.12% |
| 4 | | | | | |
| 5 | | **NET Plant in Service** | $24,012,827 | $25,228,233 | 5.06% |
| 6 | | | | | |
| 7 | | CWIP in Service Pending Reclassification | $278,637 | $548,987 | 97.03% |
| 8 | | | | | |
| 9 | | Additions | | | |
| 10 | 154, 156 | Materials & Supplies | $314,475 | $402,977 | 28.14% |
| 11 | 165 | Prepayments | 53,909 | 44,033 | -18.32% |
| 12 | | Prepaid Demand/Commodity Charges | 1,193,850 | 1,359,433 | 13.87% |
| 13 | | Gas in Underground Storage | 6,112,241 | 7,259,116 | 18.76% |
| 14 | | Unamoritzed Gas IRP | 54,000 | 18,291 | -66.13% |
| 15 | | | | | |
| 16 | | **TOTAL Additions** | $7,728,475 | $9,083,850 | 17.54% |
| 17 | | | | | |
| 18 | | Deductions | | | |
| 19 | 190 | Accumulated Deferred Income Taxes | $3,298,121 | $3,705,125 | 12.34% |
| 20 | 252 | Customer Advances for Construction | 181,917 | 177,056 | -2.67% |
| 21 | 255 | Accumulated Def. Investment Tax Credits | 212,180 | 349,329 | 64.64% |
| 22 | | Other Deductions | | | |
| 23 | | | | | |
| 24 | | **TOTAL Deductions** | $3,692,218 | $4,231,510 | 14.61% |
| 25 | | **TOTAL Rate Base** | $28,327,721 | $30,629,560 | 8.13% |
| 26 | | | | | |
| 27 | | **Net Earnings** | $2,524,550 | $1,556,476 | -38.35% |
| 28 | | | | | |
| 29 | | **Rate of Return on Average Rate Base** | 9.40% | 5.28% | -43.83% |
| 30 | | | | | |
| 31 | | **Rate of Return on Average Equity** | 10.69% | 2.76% | -74.22% |
| 32 | | | | | |
| 33 | | Major Normalizing Adjustments & Commission | | | |
| 34 | | Ratemaking adjustments to Utility Operations 1/ | | | |
| 35 | | | | | |
| 36 | | Adjustment to Operating Revenues | | | |
| 38 | | Weather Normalization | 180,758 | 544,074 | 201.00% |
| 39 | | Late Payment Revenue | 23,598 | 31,373 | 32.95% |
| 40 | | | | | |
| 41 | | Adjustment to Operating Expenses | | | |
| 42 | | Elimination of Promotional & Institutional Advertising | (29,327) | (41,621) | 41.92% |
| 43 | | | | | |
| 44 | | Total Adjustments to Operating Income | $233,683 | $617,068 | 164.06% |
| 45 | | | | | |
| 46 | | | | | |
| 47 | | **Adjusted Rate of Return on Average Rate Base** | 10.27% | 7.37% | -28.24% |
| 48 | | | | | |
| 49 | | **Adjusted Rate of Return on Average Equity** | 12.52% | 6.80% | -45.69% |

1/ Updated amounts, net of taxes.

# MONTANA COMPOSITE STATISTICS

Year: 2004

| | | Description | Amount |
|---|---|---|---|
| 2 | | Plant (Intrastate Only) (000 Omitted) | |
| 4 | 101 | Plant in Service | $58,910 |
| 5 | 107 | Construction Work in Progress | 675 |
| 6 | 114 | Plant Acquisition Adjustments | |
| 7 | 104 | Plant Leased to Others | 13 |
| 8 | 105 | Plant Held for Future Use | |
| 9 | 154, 156 | Materials & Supplies | 403 |
| 10 | | (Less): | |
| 11 | 108, 111 | Depreciation & Amortization Reserves | 38,744 |
| 12 | 252 | Contributions in Aid of Construction | 177 |
| 14 | | **NET BOOK COSTS** | $21,080 |
| 16 | | Revenues & Expenses (000 Omitted) | |
| 18 | 400 | Operating Revenues | $78,143 |
| 20 | 403 - 407 | Depreciation & Amortization Expenses | $2,125 |
| 21 | | Federal & State Income Taxes | (416) |
| 22 | | Other Taxes | 2,301 |
| 23 | | Other Operating Expenses | 72,577 |
| 24 | | TOTAL Operating Expenses | $76,587 |
| 26 | | Net Operating Income | $1,556 |
| 28 | | Other Income | 81 |
| 29 | | Other Deductions | 968 |
| 31 | | **NET INCOME** | $669 |
| 33 | | Customers (Intrastate Only) | |
| 35 | | Year End Average: | |
| 36 | | Residential | 64,390 |
| 37 | | Firm General | 7,828 |
| 38 | | Small Interruptible | 41 |
| 39 | | Large Interruptible | 5 |
| 41 | | **TOTAL NUMBER OF CUSTOMERS** | 72,264 |
| 43 | | Other Statistics (Intrastate Only) | |
| 45 | | Average Annual Residential Use (Dkt)) | 82 |
| 46 | | Average Annual Residential Cost per (Dkt) ($) * 1/ | $10.46 |
| 47 | | * Avg annual cost = [(cost per Dkt x annual use) + (mo. svc chrg x 12)]/annual use | |
| 48 | | Average Residential Monthly Bill | $60.13 |
| 49 | | Gross Plant per Customer | $815 |

1/ Reflects cost per dk effective December 1, 2004.

## MONTANA CUSTOMER INFORMATION

Year: 2004

| | City/Town | Population (Includes Rural) 1/ | Residential Customers | Commercial Customers | Industrial & Other Customers | Total Customers |
|---|---|---|---|---|---|---|
| 1 | Belfry | 219 | 136 | 19 | | 155 |
| 2 | Billings | 89,847 | 41,123 | 3,945 | | 45,068 |
| 3 | Bridger | 745 | 406 | 64 | | 470 |
| 4 | Crow Agency | 1,552 | 317 | 65 | | 382 |
| 5 | Edgar | Not Available | 103 | 8 | | 111 |
| 6 | Fromberg | 486 | 274 | 21 | | 295 |
| 7 | Hardin | 3,384 | 1,258 | 204 | | 1,462 |
| 8 | Joliet | 575 | 346 | 44 | | 390 |
| 9 | Laurel | 6,255 | 3,453 | 262 | | 3,715 |
| 10 | Park City | 870 | 484 | 23 | | 507 |
| 11 | Pryor | 628 | 89 | 13 | | 102 |
| 12 | Rockvale | Not Available | 61 | 4 | | 65 |
| 13 | Silesia | Not Available | 33 | 2 | | 35 |
| 14 | Warren | Not Available | | 2 | | 2 |
| 15 | Alzada | Not Available | 10 | 7 | | 17 |
| 16 | Baker | 1,695 | 793 | 171 | | 964 |
| 17 | Carlyle | Not Available | 8 | 1 | | 9 |
| 18 | Fort Peck | 240 | 127 | 10 | | 137 |
| 19 | Fairview | 709 | 350 | 47 | | 397 |
| 20 | Forsyth | 1,944 | 871 | 143 | | 1,014 |
| 21 | Frazer | 452 | 90 | 15 | | 105 |
| 22 | Glasgow | 3,253 | 1,641 | 298 | | 1,939 |
| 23 | Glendive | 4,729 | 2,943 | 400 | | 3,343 |
| 24 | Hinsdale | Not Available | 114 | 20 | | 134 |
| 25 | Ismay | 26 | 8 | 4 | | 12 |
| 26 | Malta | 2,120 | 986 | 194 | | 1,180 |
| 27 | Miles City | 8,487 | 3,873 | 532 | | 4,405 |
| 28 | Nashua | 325 | 178 | 19 | | 197 |
| 29 | Poplar | 911 | 857 | 133 | | 990 |
| 30 | Richey | 189 | 126 | 25 | | 151 |
| 31 | Rosebud | Not Available | 43 | 6 | | 49 |
| 32 | Saco | 224 | 42 | 6 | | 48 |
| 33 | Savage | Not Available | 148 | 18 | | 166 |
| 34 | Sidney | 4,774 | 2,249 | 393 | | 2,642 |
| 35 | Terry | 611 | 311 | 62 | | 373 |
| 36 | St. Marie | 183 | 145 | 10 | | 155 |
| 37 | Wibaux | 567 | 211 | 51 | | 262 |
| 38 | Whitewater | Not Available | 34 | 9 | | 43 |
| 39 | Wolf Point | 2,663 | 1,384 | 198 | | 1,582 |
| 40 | MT Oil Fields | Not Available | 2 | 3 | | 5 |
| 41 | **TOTAL Montana Customers** | 138,663 | 65,627 | 7,451 | | 73,078 |

1/ 2000 Census.

## MONTANA EMPLOYEE COUNTS 1/

Year: 2004

| | Department | Year Beginning | Year End | Average |
|---|---|---|---|---|
| 1 | Electric | 19 | 21 | 20 |
| 2 | Gas | 42 | 45(1) | 43(1) |
| 3 | Accounting | 20 | 19 | 20 |
| 5 | Management | 6 | 8 | 7 |
| 7 | Service 2/ | 58(3) | 55(3) | 57(3) |
| 4 | Marketing/Communications | 7 | 7 | 7 |
| 6 | Power | 27 | 26 | 26 |
| 10 | | | | |
| 11 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | **TOTAL Montana Employees** | 179(3) | 181(4) | 180(4) |

1/ Parentheses denotes part-time.

2/ Reflects service employees such as meter readers and servicemen.

## MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2004

| | Project Description | Total Company | Total Montana | |
|---|---|---|---|---|
| 1 | Projects>$1,000,000 | | | |
| 2 | | | | |
| 3 | Electric-Steam Production | | | |
| 4 | Upgrade Coal System at Heskett Station | $1,272,683 | $324,085 | 1/ |
| 5 | Install AHPC Resolution at Big Stone | 1,108,822 | 282,358 | 1/ |
| 6 | Replace HP-IP Turbine at Big Stone | 1,099,875 | 280,080 | 1/ |
| 7 | | | | |
| 8 | Other Projects<$1,000,000 | | | |
| 9 | | | | |
| 10 | Electric | | | |
| 11 | Production | 8,219,099 | 2,092,967 | 1/ |
| 12 | Transmission: | | | |
| 13 | Integrated | 2,028,142 | 774,951 | 1/ |
| 14 | Direct | 632,125 | 46,561 | 2/ |
| 15 | Distribution | 7,517,577 | 1,085,026 | 2/ |
| 16 | General | 1,505,962 | 320,806 | 2/ |
| 17 | Common: | | | |
| 18 | General Office | 979,559 | 228,725 | 1/ |
| 19 | Other Direct | 762,744 | 100,953 | 2/ |
| 20 | Total Electric | 21,645,208 | 4,649,989 | |
| 21 | | | | |
| 22 | Gas | | | |
| 25 | Distribution | 9,692,737 | 2,457,441 | 2/ |
| 26 | General | 3,029,008 | 452,988 | 2/ |
| 27 | Common: | | | |
| 28 | General Office | 807,711 | 207,769 | 1/ |
| 29 | Other Direct | 362,163 | 100,033 | 2/ |
| 30 | Total Gas | 13,891,619 | 3,218,231 | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | TOTAL | $39,018,207 | $8,754,743 | |

1/ Allocated to Montana.
2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA Year: 2004

| | Total Company | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Mcf or Dkt | Total Monthly Volumes Mcf or Dkt |
| 1 | January | | | |
| 2 | February | | | |
| 3 | March | | | |
| 4 | April | | | |
| 5 | May | | | |
| 6 | June | NOT APPLICABLE | | |
| 7 | July | | | |
| 8 | August | | | |
| 9 | September | | | |
| 10 | October | | | |
| 11 | November | | | |
| 12 | December | | | |
| 13 | **TOTAL** | | | |

| | Montana | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Mcf or Dkt | Total Monthly Volumes Mcf or Dkt |
| 14 | January | | | |
| 15 | February | | | |
| 16 | March | | | |
| 17 | April | | | |
| 18 | May | | | |
| 19 | June | NOT APPLICABLE | | |
| 20 | July | | | |
| 21 | August | | | |
| 22 | September | | | |
| 23 | October | | | |
| 24 | November | | | |
| 25 | December | | | |
| 26 | **TOTAL** | | | |

## DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2004

| | Total Company | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Dkt | Total Monthly Volumes Dkt |
| 1 | January | 27 | 327,632 | 7,558,378 |
| 2 | February | 3 | 272,119 | 5,801,542 |
| 3 | March | 10 | 190,180 | 4,286,309 |
| 4 | April | 11 | 132,096 | 2,820,598 |
| 5 | May | 12 | 129,276 | 2,363,516 |
| 6 | June | 17 | 69,081 | 1,692,602 |
| 7 | July | 26 | 57,716 | 1,559,534 |
| 8 | August | 10 | 58,425 | 1,587,908 |
| 9 | September | 30 | 75,197 | 1,677,685 |
| 10 | October | 24 | 143,986 | 3,492,010 |
| 11 | November | 28 | 211,897 | 4,673,023 |
| 12 | December | 23 | 280,001 | 6,214,271 |
| 13 | **TOTAL** | | | 43,727,376 |

| | Montana | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Dkt | Total Monthly Volumes Dkt |
| 14 | January | 27 | 109,764 | 2,371,853 |
| 15 | February | 11 | 86,595 | 1,811,298 |
| 16 | March | 1 | 58,647 | 1,204,528 |
| 17 | April | 2 | 38,036 | 816,933 |
| 18 | May | 12 | 38,885 | 720,828 |
| 19 | June | 18 | 26,011 | 584,096 |
| 20 | July | 20 | 24,345 | 566,682 |
| 21 | August | 4 | 23,470 | 579,446 |
| 22 | September | 20 | 27,678 | 567,398 |
| 23 | October | 31 | 48,366 | 1,158,629 |
| 24 | November | 28 | 66,695 | 1,520,858 |
| 25 | December | 23 | 88,285 | 1,899,673 |
| 26 | **TOTAL** | | | 13,802,222 |

## STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2004

| | | Total Company | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Peak Day of Month | | Peak Day Volumes (Dkt) | | Total Monthly Volumes (Dkt) | | |
| | | Injection | Withdrawal | Injection | Withdrawal | Injection | Withdrawal | Losses |
| 1 | January | 3 | 5 | 1,006 | 187,460 | 6,027 | 3,378,902 | |
| 2 | February | 27 | 3 | 784 | 141,709 | 6,637 | 2,130,102 | |
| 3 | March | 31 | 3 | 38,871 | 64,956 | 237,156 | 756,583 | |
| 4 | April | 27 | 11 | 34,728 | 37,345 | 317,513 | 211,468 | |
| 5 | May | 28 | 12 | 59,532 | 27,766 | 1,058,514 | 55,833 | |
| 6 | June | 22 | 3 | 67,042 | 140 | 1,820,708 | 881 | |
| 7 | July | 30 | 5 | 68,101 | 594 | 1,984,332 | 1,292 | |
| 8 | August | 21 | 9 | 72,135 | 364 | 2,012,385 | 1,240 | |
| 9 | September | 11 | 20 | 65,699 | 2,151 | 1,647,184 | 10,049 | |
| 10 | October | 9 | 17 | 77,909 | 25,789 | 757,882 | 152,366 | |
| 11 | November | 6 | 28 | 24,794 | 67,709 | 184,960 | 576,245 | |
| 12 | December | 23 | 23 | 3,993 | 153,810 | 17,137 | 2,047,931 | |
| 13 | **TOTAL** | | | | | 10,050,435 | 9,322,892 | |

| | | Montana | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Peak Day of Month | | Peak Day Volumes (Dkt) | | Total Monthly Volumes (Dkt) | | |
| | | Injection | Withdrawal | Injection | Withdrawal | Injection | Withdrawal | Losses |
| 14 | January | | | | | | | |
| 15 | February | | | | | | | |
| 16 | March | | | | | | | |
| 17 | April | | | | | | | |
| 18 | May | | | | | | | |
| 19 | June | NOT AVAILABLE | | | | | | |
| 20 | July | | | | | | | |
| 21 | August | | | | | | | |
| 22 | September | | | | | | | |
| 23 | October | | | | | | | |
| 24 | November | | | | | | | |
| 25 | December | | | | | | | |
| 26 | **TOTAL** | | | | | | | |

## SOURCES OF GAS SUPPLY

Year: 2004

| | Name of Supplier 1/ | Last Year Volumes Dkt | This Year Volumes Dkt | Last Year Avg. Commodity Cost | This Year Avg. Commodity Cost |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
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| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
| 28 | | | | | |
| 29 | 1/ Supplier information is proprietary and confidential. | | | | |
| 30 | | | | | |
| 31 | | | | | |
| 32 | | | | | |
| 33 | **Total Gas Supply Volumes** | 36,113,425 | 34,234,159 | $4.098 | $5.196 |

## MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2004

| | Program Description | Current Year Expenditures | Last Year Expenditures | % Change | Planned Savings **(Mcf or Dkt)** | Achieved Savings **(Mcf or Dkt)** | Difference |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | NONE | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |
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| 22 | | | | | | | |
| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | | | | | | | |
| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | | | | | | | |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | **TOTAL** | | | | | | |

## MONTANA CONSUMPTION AND REVENUES

Year: 2004

| | Sales of Gas | Operating Revenues Current Year | Operating Revenues Previous Year | DK Sold Current Year | DK Sold Previous Year | Avg. No. of Customers Current Year | Avg. No. of Customers Previous Year |
|---|---|---|---|---|---|---|---|
| 1 | Residential | $46,458,146 | $42,354,672 | 5,249,842 | 5,839,669 | 64,390 | 63,588 |
| 2 | Firm General | 25,788,978 | 23,491,982 | 3,013,007 | 3,350,883 | 7,828 | 7,728 |
| 3 | Small Interruptible | 657,161 | 468,350 | 84,128 | 82,703 | 4 | 4 |
| 4 | Large Interruptible | 28,507 | 512 | 4,647 | 83 | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |
| 11 | **TOTAL** | $72,932,792 | $66,315,516 | 8,351,624 | 9,273,338 | 72,222 | 71,320 |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | | **Operating Revenues** | | **BCF Transported** | | **Avg. No. of Customers** | |
| 15 | | | | | | | |
| 16 | | Current | Previous | Current | Previous | Current | Previous |
| 17 | **Transportation of Gas** | Year | Year | Year | Year | Year | Year |
| 18 | | | | | | | |
| 19 | Utilities | | | | | | |
| 20 | Small Interruptible | $725,181 | $709,098 | 0.9 | 0.9 | 37 | 37 |
| 21 | Large Interruptible | 582,924 | 613,539 | 4.2 | 4.4 | 5 | 5 |
| 22 | Firm | | | | | | |
| 23 | | | | | | | |
| 24 | **TOTAL** | $1,308,105 | $1,322,637 | 5.1 | 5.3 | 42 | 42 |