YEAR ENDING 2007

# ANNUAL REPORT
OF

# MONTANA-DAKOTA UTILITIES CO.

## GAS UTILITY

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

# 2007 Gas Annual Report

Instructions

## General

1. A Microsoft EXCEL workbook of the annual report is provided on our website 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. You may also obtain these instructions and the report in both an Adobe Acrobat© format and as an EXCEL© file from our website at **http://psc.mt.gov**. Please be sure you use the 2006 report form.

2. The use of the EXCEL© file is optional.

3. 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"

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

5. 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.

6. 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).

7. 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.

8. All companies owned by another company shall attach a corporate structure chart of the holding company.

9. 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.

10. 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.

11. 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).

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

13. 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**

2. 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.)

3. 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.

3. 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.

**Schedule 36a**

1. Contracted or committed current year expenditures include those expenditures that derive from preexisting contracts or commitments related to current year program activity but which will actually occur in a year other than the current year.

2. Expected average annual bill savings from weatherization should reflect average household bill savings based on the total households weatherized and the combined savings of all weatherization measures installed.

# Gas Annual Report

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**Description** **Schedule**

## IDENTIFICATION

Year: 2007

| | | |
|---|---|---|
| 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 | Terry D. Hildestad, Bismarck, ND | - |
| 2 | Vernon A. Raile, Bismarck, ND | - |
| 3 | Paul K. Sandness, Bismarck, ND | - |
| 4 | Bruce T. Imsdahl, Bismarck, ND 2/ | - |
| 5 | David L. Goodin, Bismarck, ND 2/ | - |
| 6 | | |
| 7 | | |
| 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/ Bruce T. Imsdahl will retire effective June 5, 2008. David L. Goodin assumed | |
| 14 | a position on the Managing Committee effective March 1, 2008. | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |

## Officers

Year: 2007

| Title of Officer (a) | Department Supervised (b) | Name (c) |
|---|---|---|
| President and Chief Executive Officer | Executive | Bruce T. Imsdahl 1/ |
| President | Executive | David L. Goodin 1/ |
| Executive Vice President | Business Development and Gas Supply | Dennis L. Haider |
| Executive Vice President - Finance & Chief Accounting Officer | Accounting, Information Systems, Regulatory Affairs | John F. Renner |
| Vice President | Regulatory Affairs | Donald R. Ball |
| Vice President | Human Resources | Richard D. Spratt 2/ |
| Vice President | Electric Supply | Andrea L. Stomberg |
| Vice President | Operations, Fleet and Procurement | K. Frank Morehouse |
| Controller | Accounting | Garret Senger |

1/ Bruce T. Imsdahl will retire effective June 5, 2008. David L. Goodin assumed the position of President of Montana-Dakota Utilities Co. effective March 1, 2008.

2/ Richard D. Spratt left the company April 3, 2008.

## CORPORATE STRUCTURE

Year: 2007

| Subsidiary/Company Name | Line of Business | Earnings (000's) | Percent of Total |
|---|---|---|---|
| Montana-Dakota Utilities Co./ Great Plains Natural Gas Co. (Divisions of MDU Resources Group, Inc.) and Cascade Natural Gas Corp. | Electric and Natural Gas Distribution | $31,744 | 7.36% |
| WBI Holdings, Inc. | Pipeline and Energy Services and Natural Gas and Oil Production | 173,999 | 40.33% |
| Knife River Corporation | Construction Materials and Mining | 77,001 | 17.85% |
| MDU Construction Services Group, Inc. | Construction Services | 43,843 | 10.16% |
| Centennial Energy Resources LLC/ Centennial Holdings Capital Corp. | Other | 104,848 | 24.30% |
| **TOTAL** | | $431,435 | 100.00% |

# CORPORATE ALLOCATIONS - GAS

Year: 2007

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1 | Audit Costs | Administrative & General | Various Corporate Overhead Allocation Factors | $2,603 | 1.35% | $189,626 |
| 2 | | | | | | |
| 3 | Advertising | Administrative & General | Various Corporate Overhead Allocation Factors, | 1,593 | 1.35% | 116,135 |
| 4 | | | and/or Actual Costs Incurred | | | |
| 5 | | | | | | |
| 6 | Air Service | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 2,314 | 1.90% | 119,207 |
| 7 | | | Studies, and/or Actual Costs Incurred | | | |
| 8 | | | | | | |
| 9 | Automobile | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 655 | 2.32% | 27,559 |
| 10 | | | Studies, and/or Actual Costs Incurred | | | |
| 11 | | | | | | |
| 12 | Bank Services | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 5,630 | 1.35% | 410,041 |
| 13 | | | Actual Costs Incurred | | | |
| 14 | | | | | | |
| 15 | Computer Rental | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 30,873 | 9.86% | 282,340 |
| 16 | | | Studies, and/or Actual Costs Incurred | | | |
| 17 | | | | | | |
| 18 | Consultant Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 33,003 | 2.60% | 1,235,275 |
| 19 | | | Actual Costs Incurred | | | |
| 20 | | | | | | |
| 21 | Contract Services | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 45,554 | 1.99% | 2,248,040 |
| 22 | | | Actual Costs Incurred | | | |
| 23 | | | | | | |
| 24 | Corporate Aircraft | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 2,228 | 1.19% | 184,724 |
| 25 | | | Studies, and/or Actual Costs Incurred | | | |
| 26 | | | | | | |
| 27 | Directors Expenses | Administrative & General | Corporate Overhead Allocation Factor Based on a | 50,923 | 1.34% | 3,754,216 |
| 28 | | | Combination of Net Plant Investment and Number of | | | |
| 29 | | | Employees | | | |
| 30 | | | | | | |
| 31 | Employee Benefits | Administrative & General | Corporate Overhead Allocation Factor Based on | 4,617 | 1.52% | 299,581 |
| 32 | | | Number of Employees | | | |

# CORPORATE ALLOCATIONS - GAS

Year: 2007

| Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|
| Employee Meetings | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 2,960 | 1.37% | 213,796 |
| Employee Reimbursable Expenses | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 4,487 | 1.54% | 286,978 |
| Legal Retainers & Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 19,279 | 1.35% | 1,404,222 |
| Meal Allowance | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 73 | 1.43% | 5,039 |
| Meals & Entertainment | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 1,695 | 1.45% | 115,310 |
| Moving Expense | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 2,544 | 1.37% | 183,780 |
| Industry Dues & Licenses | Administrative & General | Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred | 1,897 | 1.39% | 134,959 |
| Office Expenses | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 14,898 | 2.48% | 585,258 |
| Prepaid Insurance | Administrative & General | Various Corporate Overhead Allocation Factors and Allocation Factors Based on Actual Experience | 21,509 | 1.24% | 1,710,990 |
| Permits and Filing Fees | Administrative & General | Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred | 563 | 1.78% | 31,039 |

# CORPORATE ALLOCATIONS - GAS

Year: 2007

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1 | Postage | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 598 | 1.36% | 43,366 |
| 2 | | | Actual Costs Incurred | | | |
| 3 | | | | | | |
| 4 | Payroll | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 426,003 | 1.82% | 23,010,908 |
| 5 | | | Studies, and/or Actual Costs Incurred | | | |
| 6 | | | | | | |
| 7 | Reimbursements and | Administrative & General | Various Corporate Overhead Allocation Factors and/or | (6,632) | 25.55% | (19,321) |
| 8 | Warranty Credits | | Actual Costs Incurred | | | |
| 9 | | | | | | |
| 10 | Rental | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 305 | 1.36% | 22,195 |
| 11 | | | Actual Costs Incurred | | | |
| 12 | | | | | | |
| 13 | Reference Materials | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 2,477 | 1.40% | 174,992 |
| 14 | | | Actual Costs Incurred | | | |
| 15 | | | | | | |
| 16 | Seminars & Meeting | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 3,767 | 2.25% | 163,592 |
| 17 | Registrations | | Studies, and/or Actual Costs Incurred | | | |
| 18 | | | | | | |
| 19 | Software Maintenance | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 54,344 | 2.64% | 2,005,338 |
| 20 | | | Studies, and/or Actual Costs Incurred | | | |
| 21 | | | | | | |
| 22 | Supplemental Insurance | Administrative & General | Various Corporate Overhead Allocation Factors | 22,797 | 1.35% | 1,671,686 |
| 23 | | | | | | |
| 24 | Telephone | Administrative & General | Various Corporate Overhead Allocation Factors and/or | 22,746 | 5.08% | 424,869 |
| 25 | | | Actual Costs Incurred | | | |
| 26 | | | | | | |
| 27 | Training Material | Administrative & General | Various Corporate Overhead Allocation Factors, Time | 5,714 | 2.35% | 236,989 |
| 28 | | | Studies, and/or Actual Costs Incurred | | | |
| 29 | | | | | | |
| 30 | **TOTAL** | | | $782,017 | 1.86% | $41,272,729 |

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

Year: 2007

| 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 | | $1,054 | | $846 |
| 3 | | Contract Services | | 195 | | 181 |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | Capital | Actual Costs Incurred | | | |
| 9 | | Contract Services | | 1,086 | | 35 |
| 10 | | Materials | | 8,926 | | 8,837 |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | Total Knife River Corporation Operating Revenues for the Year 2007 | | | $1,761,473,000 | |
| 20 | | Excludes Intersegment Eliminations | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | **TOTAL** | **Grand Total Affiliate Transactions** | | $11,261 | 0.0006% | $9,899 |

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

Year: 2007

| 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 | | $59,035,089 | | $17,692,774 |
| 3 | | | | | | |
| 4 | | Expense | Actual Costs Incurred | | | |
| 5 | | Contract Services | | 18,069 | | 5,276 |
| 6 | | Legal Fees | | 16,936 | | 4,380 |
| 7 | | Materials | | 4,108 | | 27 |
| 8 | | Easements | | 10 | | |
| 10 | | Reference Materials | | 13,645 | | 3,320 |
| 11 | | Public Info Mtgs | | 554 | | 1 |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | Capital | Actual Costs Incurred | | | |
| 17 | | Contract Services | | 64,433 | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | Total WBI Operating Revenues for the Year 2007 | | | $961,917,000 | |
| 28 | | Excludes Intersegment Eliminations | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | **TOTAL** | **Grand Total Affiliate Transactions** | | $59,152,844 | 6.1495% | $17,705,778 |

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

Year: 2007

| 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 | **MDU CONSTRUCTION** | | | | | |
| 2 | **SERVICES GROUP, INC** | Expense | Actual Costs Incurred | | | |
| 3 | | Materials | | $10 | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
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| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | Total MDU Construction Services Group, Inc Operating Revenues for the Year 2007 | | | $1,103,215,000 | |
| 23 | | Excludes Intersegment Eliminations | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | **TOTAL** | **Grand Total Affiliate Transactions** | | $10 | 0.0000% | $0 |

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

Year: 2007

| 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** | Office Supplies | Allocation Factors and/or | $83 | | $21 |
| 3 | | | Actual Costs Incurred | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | Capital | | | | |
| 8 | | Materials | | 1,037 | | 304 |
| 9 | | Office Supplies | | 629 | | 185 |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | Total Centennial Energy Resources Operating Revenues for the Year 2007 | | | $0 | |
| 22 | | Excludes Intersegment Eliminations | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | **TOTAL** | **Grand Total Affiliate Transactions** | | $1,749 | 0.0000% | $510 |

**Company Name: Montana-Dakota Utilities Co.** **SCHEDULE 6**

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

Year: 2007

| 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 | **CHCC** | Expense | * Various Corporate Overhead | | | |
| 2 | | Corporate Aircraft | Allocation Factors and/or | $118,659 | | $29,336 |
| 3 | | Rent | Actual Costs Incurred | 135,367 | | 35,009 |
| 4 | | Cost of Service | | 100,732 | | 26,052 |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | Capital | | | | |
| 8 | | Corporate Aircraft | Actual Costs Incurred | 31,372 | | 1,418 |
| 9 | | Subcontract Labor | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
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| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | Total CHCC Operating Revenues for the Year 2007 | | | $10,061,000 | |
| 23 | | Excludes Intersegment Eliminations | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | **TOTAL** | **Grand Total Affiliate Transactions** | | $386,130 | 3.8379% | $91,815 |

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

Year: 2007

| 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 | **CASCADE NATURAL GAS** | | | | | |
| 2 | **COMPANY** | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
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| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | Total Cascade Natural Gas Company Operating Revenues for the Year 2007 | | | $214,834,000 | |
| 23 | | Grand Total Affiliate Transactions | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | **TOTAL** | **Grand Total Affiliate Transactions** | | $0 | 0.0000% | $0 |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MDU RESOURCES GROUP, INC. | | | | |
| 2 | CORPORATION | Corporate Overhead | * Various Corporate Overhead Allocation | | | |
| 3 | | Audit Costs | Factors, Time Studies and/or Actual | $68,626 | | |
| 4 | | Advertising | Costs Incurred | 41,993 | | |
| 5 | | Air Service | | 47,031 | | |
| 6 | | Automobile | | 9,758 | | |
| 7 | | Bank Services | | 148,394 | | |
| 8 | | Corporate Aircraft | | 73,187 | | |
| 9 | | Consultant Fees | | 483,524 | | |
| 10 | | Contract Services | | 801,810 | | |
| 11 | | Computer Rental | | 1,224 | | |
| 12 | | Directors Expenses | | 1,363,418 | | |
| 13 | | Employee Benefits | | 108,602 | | |
| 14 | | Employee Meeting | | 77,296 | | |
| 15 | | Employee Reimbursable Expense | | 108,993 | | |
| 16 | | Express Mail | | 193 | | |
| 17 | | Insurance | | 649,847 | | |
| 18 | | Legal Retainers & Fees | | 508,190 | | |
| 19 | | Moving Allowance | | 66,430 | | |
| 20 | | Meal Allowance | | 1,835 | | |
| 21 | | Cash Donations | | 26,839 | | |
| 22 | | Meal & Entertainment | | 41,928 | | |
| 23 | | Industry Dues & Licenses | | 47,300 | | |
| 24 | | Office Expenses | | 252,599 | | |
| 25 | | Supplemental Insurance | | 604,931 | | |
| 26 | | Permits & Filing Fees | | 10,810 | | |
| 27 | | Postage | | 15,494 | | |
| 28 | | Payroll | | 7,849,542 | | |
| 29 | | Reference Materials | | 63,953 | | |
| 30 | | Rental | | 8,033 | | |
| 31 | | Seminars & Meeting Registrations | | 62,714 | | |
| 32 | | Software Maintenance | | 1,107,385 | | |
| 33 | | Telephone Expenses | | 62,858 | | |
| 34 | | Training | | 91,977 | | |
| 35 | | **Total MDU Resources Group, Inc.** | | $14,806,714 | 0.9124% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | CORPORATION | Communications Department | * Various Corporate Overhead Allocation | | | |
| 3 | | Air Service | Factors, Cost of Service Factors, Time | $10 | | |
| 4 | | Employee Reimbursable Expense | Studies and /or Actual Costs Incurred | 7 | | |
| 5 | | Meals & Entertainment | | 3 | | |
| 6 | | Office Expenses | | 256 | | |
| 7 | | Network Circuit Charges | | 2,343 | | |
| 8 | | Payroll | | 1,510 | | |
| 9 | | Company Vehicles | | 12 | | |
| 10 | | | | | | |
| 11 | | Office Services | * General Office Complex and Office | | | |
| 12 | | Contract Services | Supplies Cost of Service Allocation | 1,026 | | |
| 13 | | Express Mail | Factors | 13,359 | | |
| 14 | | Rental of Office Equipment | | 346 | | |
| 15 | | Office Expenses | | 1,501 | | |
| 16 | | Postage | | 8,559 | | |
| 17 | | Cost of Service - General Office Buildings | | 393,303 | | $89,833 |
| 18 | | | | | | |
| 19 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 20 | | Office Expenses | Factors and /or Actual Costs Incurred | (86) | | |
| 21 | | Office Telephones | | 79 | | |
| 22 | | Payroll | | 29 | | |
| 23 | | | | | | |
| 24 | | Other Miscellaneous Departments | * Various Corporate Overhead Allocation | | | |
| 25 | | Automobile | Factors and /or Actual Costs Incurred | 1 | | |
| 26 | | Payroll | | 40 | | |
| 27 | | | | | | |
| 28 | | Transportation & Procurement | * Various Corporate Overhead Allocation | | | |
| 29 | | Air Service | Factors and /or Actual Costs Incurred | 14 | | |
| 30 | | Employee Reimbursable Expense | | 53 | | |
| 31 | | Meals & Entertainment | | 3 | | |
| 32 | | Office Expenses | | 20 | | |
| 33 | | Payroll | | 2,770 | | |
| 34 | | Automobile | | 82 | | |
| 35 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | Transportation & Procurement Cont | | | | |
| 2 | CORPORATION | Seminars | | 10 | | |
| 3 | | Telephone Expense | | 22 | | |
| 4 | | Utilities | | 341 | | |
| 5 | | | | | | |
| 6 | | Other Direct Charges | Actual Costs Incurred | | | |
| 7 | | Employee Discounts | | 50,536 | | 6,267 |
| 8 | | Corporate/Commercial Air Service | | 216,272 | | |
| 9 | | Electric Consumption | | 70,432 | | |
| 10 | | Gas Consumption | | 74,436 | | 61,788 |
| 11 | | Miscellaneous | | 162,562 | | 3,693 |
| 12 | | **Total Montana-Dakota Utilities Co.** | | $999,851 | 0.0616% | $161,581 |
| 13 | | | | | | |
| 14 | | OTHER TRANSACTIONS/REIMBURSEMENTS | | | | |
| 15 | | | | | | |
| 16 | | Insurance | | (9,109) | | |
| 17 | | Federal & State Tax Liability Payments | | 43,330,885 | | |
| 18 | | KESOP carrying costs | | 186,664 | | |
| 19 | | Tax Deferred Savings Plan | | 101,867 | | |
| 20 | | Miscellaneous Reimbursements | | (307,166) | | |
| 21 | | | | | | |
| 22 | | **Total Other Transactions/Reimbursements** | | $43,303,141 | 2.6684% | |
| 23 | | | | | | |
| 24 | | **Grand Total Affiliate Transactions** | | $59,109,706 | 2.7238% | $161,581 |
| 25 | | | | | | |
| 26 | | **Total Knife River Corporation Operating Expenses for 2007 - Excludes Intersegment Eliminations** | | | $1,622,838,000 | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | $58,438 | | |
| 4 | | Advertising | Costs Incurred | 35,860 | | |
| 5 | | Air Service | | 30,128 | | |
| 6 | | Automobile | | 7,586 | | |
| 7 | | Bank Services | | 126,364 | | |
| 8 | | Corporate Aircraft | | 53,062 | | |
| 9 | | Consultant Fees | | 282,648 | | |
| 10 | | Contract Services | | 638,101 | | |
| 11 | | Computer Rental | | 42,147 | | |
| 12 | | Directors Expenses | | 1,155,060 | | |
| 13 | | Employee Benefits | | 90,186 | | |
| 14 | | Employee Meeting | | 65,821 | | |
| 15 | | Employee Reimbursable Expense | | 80,656 | | |
| 16 | | Express Mail | | 125 | | |
| 17 | | Insurance | | 632,522 | | |
| 18 | | Legal Retainers & Fees | | 432,744 | | |
| 19 | | Meal Allowance | | 1,526 | | |
| 20 | | Cash Donations | | 22,855 | | |
| 21 | | Meal & Entertainment | | 33,990 | | |
| 22 | | Moving Expense | | 56,615 | | |
| 23 | | Industry Dues & Licenses | | 41,382 | | |
| 24 | | Office Expenses | | 110,050 | | |
| 25 | | Supplemental Insurance | | 515,123 | | |
| 26 | | Permits & Filing Fees | | 9,203 | | |
| 27 | | Postage | | 13,194 | | |
| 28 | | Payroll | | 6,568,264 | | |
| 29 | | Reference Materials | | 53,365 | | |
| 30 | | Rental | | 6,840 | | |
| 31 | | Seminars & Meeting Registrations | | 43,643 | | |
| 32 | | Software Maintenance | | 372,428 | | |
| 33 | | Telephone | | 158,563 | | |
| 34 | | Training Material | | 63,416 | | |
| 35 | | **Total MDU Resources Group, Inc.** | | $11,801,905 | 1.7454% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | | Air Service | Studies and /or Actual Costs Incurred | $8 | | |
| 5 | | Employee Reimbursable Expense | | 6 | | |
| 6 | | Meals & Entertainment | | 3 | | |
| 7 | | Office Expenses | | 218 | | |
| 8 | | Office Telephone | | 1,995 | | |
| 9 | | Payroll | | 1,286 | | |
| 10 | | Automobile | | 10 | | |
| 11 | | | | | | |
| 12 | | Office Services | * General Office Complex and Office | | | |
| 13 | | Expense | Supplies cost of Service Allocation | | | |
| 14 | | Contract Services | Factors | 870 | | |
| 15 | | Rental of Office Equipment | | 295 | | |
| 16 | | Express Mail | | 11,369 | | |
| 17 | | Office Expenses | | 4,690 | | |
| 18 | | Postage | | 7,264 | | |
| 19 | | Cost of Service - General Office Buildings | | 346,841 | | $79,221 |
| 20 | | | | | | |
| 21 | | GIS Department | * Various Corporate Overhead Allocation | | | |
| 22 | | Expense | Factors, Cost of Service Factors, Time | | | |
| 23 | | Payroll | Studies and /or Actual Costs Incurred | 140 | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | Information Systems | * Various Corporate Overhead Allocation | | | |
| 27 | | Expense | Factors and /or Actual Costs Incurred | | | |
| 28 | | Office Telephones | | 66 | | |
| 29 | | Payroll | | 2 | | |
| 30 | | | | | | |
| 31 | | | | | | |

# AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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. | Region Operations | * Various Corporate Overhead | | | |
| 2 | | Expense | Allocation Factors and/or | | | |
| 3 | | Automobile | Actual Costs Incurred | $4,764 | | |
| 4 | | Air Services | | 6 | | |
| 5 | | Contract Services | | 339 | | |
| 6 | | Custodial Services & Supplies | | 56 | | |
| 7 | | Materials | | 1,119 | | |
| 8 | | Meals & Entertainment | | 145 | | |
| 9 | | Other Reimbruseable Expenses | | 292 | | |
| 10 | | OfficeTelephone | | 6,671 | | |
| 11 | | Payroll | | 12,858 | | |
| 12 | | Photocopier | | 46 | | |
| 13 | | Office Supplies | | 525 | | |
| 14 | | Annual Easements | | 3,315 | | |
| 15 | | Freight | | 3 | | |
| 16 | | Utilities | | 2,141 | | |
| 17 | | General & Administrative Expenses | | 4,844 | | |
| 18 | | Permits | | 12 | | |
| 19 | | | | | | |
| 20 | | Transportation Department | * Various Corporate Overhead | | | |
| 21 | | Capital | Allocation Factors, Time | | | |
| 22 | | Payroll | Studies and/or Actual Costs | 664 | | |
| 23 | | Meals & Entertainment | Incurred | 3 | | |
| 24 | | Office Expenses | | 1 | | |
| 25 | | | | | | |
| 26 | | Clearing Accounts | | | | |
| 27 | | Automobile | | 132 | | |
| 28 | | Air Service | | 22 | | |
| 29 | | Custodial Services | | 39 | | |
| 30 | | Employee Reimbursable Expense | | 88 | | |
| 31 | | Meals & Entertainment | | 3 | | |
| 32 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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. | Office Expenses | | $32 | | |
| 2 | | Office Telephone | | 276 | | |
| 3 | | Seminars & Meeting Registration | | 19 | | |
| 4 | | Payroll | | 4,356 | | |
| 5 | | Permits & Filing Fees | | 3 | | |
| 6 | | Utilities | | 276 | | |
| 7 | | Expense | | | | |
| 8 | | Payroll | | 10,469 | | |
| 9 | | Automobile | | 276 | | |
| 10 | | Air Service | | 46 | | |
| 11 | | Employee Reimbursable Expense | | 185 | | |
| 12 | | Meals & Entertainment | | 11 | | |
| 13 | | Office Expenses | | 70 | | |
| 14 | | Telephone Expense | | 71 | | |
| 15 | | Utilities | | 1,093 | | |
| 16 | | Seminars & Meeting Registration | | 40 | | |
| 17 | | | | | | |
| 18 | | Other Direct Charges | Actual Costs Incurred | | | |
| 19 | | Utility/Merchandise Discounts | | 145,054 | | $85,375 |
| 20 | | Corporate Aircraft | | 295,504 | | |
| 21 | | Radio Maintenance | | 929 | | |
| 22 | | Vehicle Maintenance | | 40,517 | | |
| 23 | | Misc Employee Benefits | | 13,315 | | |
| 24 | | Computer/Software Support | | 14,157 | | |
| 25 | | Cathodic Protection | | 14,475 | | 5,324 |
| 26 | | Purchased Power for Compressor Stations | | 107,544 | | 94,488 |
| 27 | | Electric Compressor - Electricity Cost | | 648,679 | | 443,383 |
| 28 | | Office Building Utilities | | 268,356 | | 97,747 |
| 29 | | Legal Fees | | 60,464 | | |
| 30 | | Employee Reimbursable Exp | | 37,920 | | |
| 31 | | Miscellaneous | | 72,187 | | |
| 32 | | BitterCreek Projects | | 7,240 | | |
| 33 | | Total Montana-Dakota Utilities Co. 1/ | | $2,156,715 | 0.3190% | $805,538 |
| 34 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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. | | | | | |
| 2 | | 1/ Total Montana-Dakota Charges By Category | | | | |
| 3 | | Expense | | $2,150,801 | 0.3181% | $805,538 |
| 4 | | Capital | | 668 | 0.0001% | - |
| 5 | | Clearing | | 5,246 | 0.0008% | - |
| 6 | | Total | | 2,156,715 | 0.3190% | 805,538 |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | OTHER TRANSACTIONS/REIMBURSEMENTS | | | | |
| 10 | | Insurance | Actual Costs Incurred | ($11,360) | | |
| 11 | | Federal & State Tax Liability Payments | | 34,167,065 | | |
| 12 | | Tax Deferred Savings Plan | | 49,175 | | |
| 13 | | KESOP carrying costs | | 19,698 | | |
| 14 | | Miscellaneous Reimbursements | | (84,071) | | |
| 15 | | **Total Other Transactions/Reimbursements** | | $34,140,507 | 5.0492% | |
| 16 | | | | | | |
| 17 | | **Grand Total Affiliate Transactions** | | $48,099,127 | 7.1136% | $805,538 |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | **Total WBI Holdings Operating Expenses for 2007 - Excludes Intersegment Eliminations** | | | $676,162,000 | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, an the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MDU CONSTRUCTION | MDU RESOURCES GROUP, INC. | | | | |
| 2 | SERVICES GROUP INC | Corporate Overhead | * Various Corporate Overhead | | | |
| 3 | | Audit Costs | Allocation Factors, Time | $15,763 | | |
| 4 | | Advertising | Studies and/or Actual Costs | 9,645 | | |
| 5 | | Air Service | Incurred | 11,172 | | |
| 6 | | Automobile | | 1,410 | | |
| 7 | | Bank Services | | 34,085 | | |
| 8 | | Corporate Aircraft | | 12,757 | | |
| 9 | | Consultant Fees | | 89,029 | | |
| 10 | | Contract Services | | 178,341 | | |
| 11 | | Computer Rental | | 281 | | |
| 12 | | Directors Expenses | | 308,325 | | |
| 13 | | Employee Benefits | | 24,920 | | |
| 14 | | Employee Meeting | | 17,754 | | |
| 15 | | Employee Reimbursable Expense | | 23,546 | | |
| 16 | | Express Mail | | 102 | | |
| 17 | | Insurance | | 153,495 | | |
| 18 | | Legal Retainers & Fees | | 116,727 | | |
| 19 | | Moving Allowance | | 15,255 | | |
| 20 | | Meal Allowance | | 429 | | |
| 21 | | Cash Donations | | 6,165 | | |
| 22 | | Meal & Entertainment | | 9,150 | | |
| 23 | | Industry Dues & Licenses | | 10,834 | | |
| 24 | | Office Expenses | | 80,064 | | |
| 25 | | Supplemental Insurance | | 138,948 | | |
| 26 | | Permits & Filing Fees | | 2,482 | | |
| 27 | | Postage | | 3,559 | | |
| 28 | | Payroll | | 1,765,567 | | |
| 29 | | Reference Materials | | 14,386 | | |
| 30 | | Rent | | 1,845 | | |
| 31 | | Seminars & Meeting Registrations | | 11,809 | | |
| 32 | | Software Maintenance | | 50,932 | | |
| 33 | | Telephone | | 13,073 | | |
| 34 | | Training Material | | 16,114 | | |
| 35 | | **Total MDU Resources Group, Inc.** | | $3,137,964 | 0.3053% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MDU CONSTRUCTION | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | SERVICES GROUP INC | Communications Department | * Various Corporate Overhead | | | |
| 3 | | Air Service | Allocation Factors, Cost of | $25 | | |
| 4 | | Automobile | Service Factors, Time Studies | 28 | | |
| 5 | | Meals & Entertainment | and/or Actual Costs Incurred | 17 | | |
| 6 | | Office Expenses | | 66 | | |
| 7 | | Office Telephone | | 22,439 | | |
| 8 | | Payroll | | 6,729 | | |
| 9 | | Employee Reimbursable Expense | | 118 | | |
| 10 | | Materials | | 46 | | |
| 11 | | Annual Easements | | 4 | | |
| 12 | | | | | | |
| 13 | | Office Services | * General Office Complex and | | | |
| 14 | | Contract Services | Office Supplies Cost of Service | 233 | | |
| 15 | | Rental of Office Equip | Allocation | 80 | | |
| 16 | | Express Mail | | 3,064 | | |
| 17 | | Office Expenses | | 346 | | |
| 18 | | Postage | | 1,945 | | |
| 19 | | Cost of Service - General Office Buildings | | 124,141 | | $28,355 |
| 20 | | | | | | |
| 21 | | Information Systems | * Various Corporate Overhead | | | |
| 22 | | Office Expenses | Allocation | (43) | | |
| 23 | | Payroll | | 22 | | |
| 24 | | Office Telephones | | 19 | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MDU CONSTRUCTION | MONTANA-DAKOTA UTILITIES CO. | | | | |
| 2 | SERVICES GROUP INC | Business Development | * General Office Complex and | | | |
| 3 | | Air Service | Office Supplies Cost of Service | $170 | | |
| 4 | | Meals & Entertainment | Allocation | 302 | | |
| 5 | | Payroll | | 27,985 | | |
| 6 | | Employee Reimbursable Expense | | 361 | | |
| 7 | | Professional Organ. Dues | | 83 | | |
| 8 | | | | | | |
| 9 | | Transportation Department | * Various Corporate Overhead | | | |
| 10 | | Automobile | Allocation Factors, Time Studies | 155 | | |
| 11 | | Meals & Entertainment | and/or Actual Costs Incurred | 5 | | |
| 12 | | Other Reimbruseable Expenses | | 167 | | |
| 13 | | Payroll | | 14,021 | | |
| 14 | | Office Supplies | | 57 | | |
| 15 | | Seminars & Meeting Registration | | 118 | | |
| 16 | | Utilities | | 393 | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | MDU CONSTRUCTION | Other Direct Charges | Actual Costs Incurred | | | |
| 2 | SERVICES GROUP INC | Legal Fees | | $177 | | |
| 3 | | Air Service | | 97,830 | | |
| 4 | | Advertising | | 13,651 | | |
| 5 | | Computer/Software Support | | 2,749 | | |
| 6 | | Employee Reimbursable Expense | | 4,847 | | |
| 7 | | Meals & Entertainment | | 589 | | |
| 8 | | Misc Employee Benefits | | 165,264 | | |
| 9 | | Office Expenses | | 3,099 | | |
| 10 | | Permits and Filing fees | | 6,892 | | |
| 11 | | Telephone | | 20,413 | | |
| 12 | | Miscellaneous | | (77,236) | | |
| 13 | | Employee Discounts | | 2,925 | | |
| 14 | | Gas Consumption | | 3,185 | | $3,079 |
| 15 | | **Total Montana-Dakota Utilities Co.** | | $447,481 | 0.0435% | $31,433 |
| 16 | | | | | | |
| 17 | | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual Costs Incurred | | | |
| 18 | | Federal & State Tax Liability Payments | | $27,785,267 | | |
| 19 | | Insurance | | 15,623 | | |
| 20 | | Miscellaneous Reimbursements | | (165,583) | | |
| 21 | | KESOP Carrying Costs | | 2,045 | | |
| 22 | | | | | | |
| 23 | | **Total Other Transactions/Reimbursements** | | $27,637,352 | 2.6892% | |
| 24 | | **Grand Total Affiliate Transactions** | | $31,222,797 | 3.0381% | $31,433 |
| 25 | | | | | | |
| 26 | | **Total MDU Construction Services Group, Inc. Operating Expenses for 2007** | | | | |
| 27 | | **Excludes Intersegment Eliminations** | | | $ 1,027,704,000 | |
| 28 | | | | | | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | Corporate Overhead | * Various Corporate Overhead | | | |
| 3 | | Audit Costs | Allocation Factors, Time Studies | $26,912 | | |
| 4 | | Advertising | and/or Costs Incurred | 16,468 | | |
| 5 | | Air Service | | 9,617 | | |
| 6 | | Automobile | | 2,038 | | |
| 7 | | Bank Services | | 58,194 | | |
| 8 | | Corporate Aircraft | | 21,746 | | |
| 9 | | Consultant Fees | | 108,365 | | |
| 10 | | Contract Services | | 277,131 | | |
| 11 | | Computer Rental | | 480 | | |
| 12 | | Directors Expenses | | 538,409 | | |
| 13 | | Employee Benefits | | 40,546 | | |
| 14 | | Employee Meeting | | 30,312 | | |
| 15 | | Employee Reimbursable Expense | | 30,010 | | |
| 16 | | Express Mail | | 54 | | |
| 17 | | Insurance | | 70,516 | | |
| 18 | | Legal Retainers & Fees | | 199,290 | | |
| 19 | | Cash Donations | | 10,525 | | |
| 20 | | Meals & Entertainment | | 13,254 | | |
| 21 | | Meal Allowance | | 690 | | |
| 22 | | Moving | | 26,045 | | |
| 23 | | Industry Dues & Licenses | | 18,109 | | |
| 24 | | Office Expenses | | 27,847 | | |
| 25 | | Supplemental Insurance | | 237,228 | | |
| 26 | | Permits & Filing Fees | | 4,236 | | |
| 27 | | Postage | | 6,076 | | |
| 28 | | Payroll | | 3,559,069 | | |
| 29 | | Reference Materials | | 24,323 | | |
| 30 | | Rental | | 3,150 | | |
| 31 | | Seminars & Meeting Registrations | | 16,487 | | |
| 32 | | Software Maintenance | | 55,648 | | |
| 33 | | Telephone | | 14,981 | | |
| 34 | | Training | | 21,567 | | |
| 35 | | **Total MDU Resources Group, Inc.** | | $5,469,323 | 64.5958% | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | Communications Department | * Various Corporate Overhead | | | |
| 3 | | Air Service | Allocation Factors, Cost of Service | $4 | | |
| 4 | | Automobile | Factors, Time Studies and/or Actua | 5 | | |
| 5 | | Employee Reimbursable Expense | Costs Incurred | 3 | | |
| 6 | | Meals & Entertainment | | 1 | | |
| 7 | | Office Expenses | | 100 | | |
| 8 | | Office Telephone | | 919 | | |
| 9 | | Payroll | | 592 | | |
| 10 | | | | | | |
| 11 | | Office Services | * General Office Complex and Office | | | |
| 12 | | Contract Services | Supplies Cost of Service Allocation | 398 | | |
| 13 | | Express Mail | Factors | 5,233 | | |
| 14 | | Postage | | 3,331 | | |
| 15 | | Office Expenses | | 572 | | |
| 16 | | Rental of Office Equipment | | 136 | | |
| 17 | | Cost of Service - General Office Buildings | | 156,228 | | $35,684 |
| 18 | | | | | | |
| 19 | | Information Systems | * Various Corporate Overhead | | | |
| 20 | | Payroll | Allocation Factors and/or Actual | 7 | | |
| 21 | | Office Telephones | Costs Incurred | 30 | | |
| 22 | | | | | | |
| 23 | | Transportation Department | * Various Corporate Overhead | | | |
| 24 | | Office Supplies | Allocation Factors and/or Actual | 11 | | |
| 25 | | Payroll | Costs Incurred | 3,505 | | |
| 26 | | Automobile | | 129 | | |
| 27 | | Air Services | | 22 | | |
| 28 | | Employee Reimbursable Expense | | 85 | | |
| 29 | | Meals & Entertainment | | 1 | | |
| 30 | | Telephone Expenses | | 35 | | |
| 31 | | Seminars & Meeting Registration | | 15 | | |
| 32 | | Utilities | | 72 | | |
| 33 | | | | | | |
| 34 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | Other Direct Charges | Actual costs incurred | | | |
| 2 | RESOURCES | Employee Discounts | | $3,085 | | |
| 3 | | Employee Benefits | | 98,329 | | |
| 4 | | Corporate/Commercial Air Service | | 55,880 | | |
| 5 | | Employee Reimbursable Exp | | 9,766 | | |
| 6 | | Legal Fees | | 14,867 | | |
| 7 | | Miscellaneous | | 147,282 | | |
| 8 | | **Total Montana-Dakota Utilities Co.** | | $500,643 | 5.913% | $35,684 |
| 9 | | | | | | |
| 10 | | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual costs incurred | | | |
| 11 | | Payroll | | $5,081,542 | | |
| 12 | | Federal & State Tax Liability Payments | | 102,884,340 | | |
| 13 | | Miscellaneous | | (8,701) | | |
| 14 | | **Total Other Transactions/Reimbursements** | | 107,957,180 | | |
| 15 | | | | | | |
| 16 | | **Grand Total Affiliate Transactions** | | $113,927,146 | 1345.5432% | $35,684 |
| 17 | | | | | | |
| 18 | | **Total Centennial Energy Resources Operating Expenses for 2007** | | | $8,467,000 | |
| 19 | | **Excludes Intersegment Eliminations** | | | | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | | | | | |
| 3 | | Other Direct Charges | Actual costs incurred | | | |
| 4 | | Aircraft Sale | | $2,897,632 | | |
| 5 | | Computer/Software Costs | | 688,423 | | |
| 6 | | Employee Reimbursable Exp and Fuel | | 467,186 | | |
| 7 | | Telephone | | 376 | | |
| 8 | | Building Expenses | | 153,528 | | |
| 9 | | Office Expenses | | 23,771 | | |
| 10 | | Miscellaneous | | 31,507 | | |
| 11 | | **Total Montana-Dakota Utilities Co.** | | $4,262,423 | 47.7368% | - |
| 12 | | | | | | |
| 13 | | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual costs incurred | | | |
| 14 | | Payroll | | $414,399 | | |
| 15 | | Federal & State Tax Liability Payments | | 95,562 | | |
| 16 | | **Total Other Transactions/Reimbursements** | | 509,961 | | |
| 17 | | | | | | |
| 18 | | **Grand Total Affiliate Transactions** | | $4,772,384 | 53.4481% | |
| 19 | | | | | | |
| 20 | | **Total CHCC Operating Expenses for 2007** | | | $8,929,000 | |
| 21 | | **Excludes Intersegment Eliminations** | | | | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2007

| 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 | CASCADE NATURAL | MDU RESOURCES GROUP, INC. | | | | |
| 2 | GAS COMPANY | Corporate Overhead | * Various Corporate Overhead | | | |
| 3 | | | Allocation Factors, Time Studies | | | |
| 4 | | Air Service | and/or Actual Costs Incurred | $3,105 | | |
| 5 | | Corporate Aircraft | | 6,549 | | |
| 6 | | Consultant Fees | | 660 | | |
| 7 | | Contract Services | | 58,776 | | |
| 8 | | Employee Reimbursable Expense | | 7,974 | | |
| 9 | | Insurance | | 141,945 | | |
| 10 | | Meals & Entertainment | | 1,254 | | |
| 11 | | **Total MDU Resources Group, Inc.** | | $220,263 | 0.1118% | |
| 12 | | | | | | |
| 13 | | Other Direct Charges | Actual costs incurred | | | |
| 14 | | Employee Benefits | | $102 | | |
| 15 | | Corporate/Commercial Air Service | | 99,904 | | |
| 16 | | Computer/Software Costs | | 721,248 | | |
| 17 | | Legal Fees | | 11,396 | | |
| 18 | | Consulting Fees | | 23,366 | | |
| 19 | | Contract Services | | 695 | | |
| 20 | | Meals & Entertainment | | 12,218 | | |
| 21 | | Employee Reimbursable Exp | | 30,769 | | |
| 22 | | Miscellaneous | | 6,392 | | |
| 23 | | **Total Montana-Dakota Utilities Co.** | | $906,090 | 0.4599% | - |
| 24 | | | | | | |

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

0

| 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 | CASCADE NATURAL | OTHER TRANSACTIONS/REIMBURSEMENTS | Actual costs incurred | | | |
| 2 | GAS COMPANY | Payroll | | $1,356,261 | | |
| 3 | | Federal & State Tax Liability Payments | | 885,000 | | |
| 4 | | Miscellaneous Reimbursements | | (2,225) | | |
| 5 | | **Total Other Transactions/Reimbursements** | | $2,239,036 | | |
| 6 | | | | | | |
| 7 | | **Grand Total Affiliate Transactions** | | $3,365,389 | 1.7080% | |
| 8 | | | | | | |
| 9 | | **Total Cascade Natural Gas Company Operating Expenses for 2007** | | | $197,040,000 | |
| 10 | | **Excludes Intersegment Eliminations** | | | | |



* Corporate overhead allocation factors are derived from the invested capital balance as a percentage of the total corporate invested capital. Montana-Dakota Utilities Co. cost of service amounts are calculated for the general office complex, the printing department, and the budget and forecast system. The general office complex amounts are payroll and floor space costs for employees that perform services for Corporate. These include A/P, general accounting, fixed asset accounting, and miscellaneous other services. The charges are based on the percentage of system users that are corporate employees. Both the general office complex and amounts for corporate are allo to affiliated companies and amounts for corporate are allocated to affiliated companies based on corporate overhead allocation factors. The printing department amount is allocated to affiliated companies based on the direct printing images processed for them and their percentage of the corporate overhead allocation for the corporate printed image amount.

## MONTANA UTILITY INCOME STATEMENT

Year: 2007

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | 400 | Operating Revenues | $80,305,939 | $69,617,491 | -13.31% |
| 2 | | | | | |
| 3 | | Operating Expenses | | | |
| 4 | 401 | Operation Expenses | $72,954,433 | $61,502,078 | -15.70% |
| 5 | 402 | Maintenance Expense | 838,584 | 884,997 | 5.53% |
| 6 | 403 | Depreciation Expense | 2,281,903 | 2,398,077 | 5.09% |
| 7 | 404-405 | Amort. & Depl. of Gas Plant | 184,633 | 179,882 | -2.57% |
| 8 | 406 | Amort. of Gas Plant Acquisition Adjustments | 0 | 0 | |
| 9 | 407.1 | Amort. of Property Losses, Unrecovered Plant | 0 | 0 | |
| 10 | | & Regulatory Study Costs | | | |
| 11 | 407.2 | Amort. of Conversion Expense | 0 | 0 | |
| 12 | 408.1 | Taxes Other Than Income Taxes | 2,362,155 | 2,433,268 | 3.01% |
| 13 | 409.1 | Income Taxes - Federal | 165,588 | 1,043,780 | 530.35% |
| 14 | | - Other | 76,810 | 186,286 | 142.53% |
| 15 | 410.1 | Provision for Deferred Income Taxes | (177,970) | (950,719) | -434.20% |
| 16 | 411.1 | (Less) Provision for Def. Inc. Taxes - Cr. | (743) | (196,923) | -26403.77% |
| 17 | 411.4 | Investment Tax Credit Adjustments | 0 | 0 | 0.00% |
| 18 | 411.6 | (Less) Gains from Disposition of Utility Plant | (302,635) | 0 | 100.00% |
| 19 | 411.7 | Losses from Disposition of Utility Plant | 0 | 0 | 0.00% |
| 20 | | **TOTAL Utility Operating Expenses** | $78,382,758 | $67,480,726 | -13.91% |
| 21 | | **NET UTILITY OPERATING INCOME** | $1,923,181 | $2,136,765 | 11.11% |

## MONTANA REVENUES

SCHEDULE 9

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | Sales of Gas | | | |
| 2 | 480 | Residential | $51,334,359 | $42,915,114 | -16.40% |
| 3 | 481 | Commercial & Industrial - Small | 29,300,355 | 24,450,646 | -16.55% |
| 4 | | Commercial & Industrial - Large | 0 | 16,402 | 100.00% |
| 5 | 482 | Other Sales to Public Authorities | | | |
| 6 | 484 | Interdepartmental Sales | | | |
| 7 | 485 | Intracompany Transfers | | | |
| 8 | | Net Unbilled Revenue | (1,825,360) | 678,237 | 137.16% |
| 9 | | **TOTAL Sales to Ultimate Consumers** | 78,809,354 | 68,060,399 | -13.64% |
| 10 | 483 | Sales for Resale | | | |
| 11 | | **TOTAL Sales of Gas** | $78,809,354 | $68,060,399 | -13.64% |
| 12 | | Other Operating Revenues | | | |
| 13 | 487 | Forfeited Discounts & Late Payment Revenues | | | |
| 14 | 488 | Miscellaneous Service Revenues | $73,619 | $73,788 | 0.23% |
| 15 | 489 | Revenues from Transp. of Gas for Others 1/ | 1,219,824 | 1,309,619 | 7.36% |
| 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 | 139,506 | 117,649 | -15.67% |
| 20 | 494 | Interdepartmental Rents | | | |
| 21 | 495 | Other Gas Revenues | 63,636 | 56,036 | -11.94% |
| 22 | | **TOTAL Other Operating Revenues** | 1,496,585 | 1,557,092 | 4.04% |
| 23 | | **Total Gas Operating Revenues** | $80,305,939 | $69,617,491 | -13.31% |
| 24 | | | | | |
| 25 | 496 | (Less) Provision for Rate Refunds | | | |
| 26 | | | | | |
| 27 | | **TOTAL Oper. Revs. Net of Pro. for Refunds** | $80,305,939 | $69,617,491 | -13.31% |

1/ Includes unbilled revenue.

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

| | 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 | |
| 8 | 755 Field Compressor Station Fuel & Power | | APPLICABLE | |
| 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 | |
| 21 | 766 Maintenance of Field Meas. & Reg. Sta. Equip. | | APPLICABLE | |
| 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 | |
| 35 | 777 Gas Processed by Others | | APPLICABLE | |
| 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 | | NOT | |
| 48 | 788 Maintenance of Extracted Prod. Storage Equip. | | 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: 2007

| | 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 | $62,015,050 | $50,407,723 | -18.72% |
| 17 | 805 Other Gas Purchases | | | |
| 18 | 805.1 Purchased Gas Cost Adjustments | 1,610,213 | (3,603,911) | -323.82% |
| 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. | 16,929,672 | 15,778,320 | -6.80% |
| 27 | 808.2 (Less) Gas Delivered to Storage -Cr. | (18,515,750) | (11,853,434) | 35.98% |
| 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 | 75,074 | 76,794 | 2.29% |
| 33 | **TOTAL Other Gas Supply Expenses** | $62,114,259 | $50,805,492 | -18.21% |
| 34 | | | | |
| 35 | **TOTAL PRODUCTION EXPENSES** | $62,114,259 | $50,805,492 | -18.21% |

## MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

| | 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

Year: 2007

| | 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 | $463,445 | $534,905 | 15.42% |
| 28 | 871 | Distribution Load Dispatching | 57,729 | 60,758 | 5.25% |
| 29 | 872 | Compressor Station Labor and Expenses | | | |
| 30 | 873 | Compressor Station Fuel and Power | | | |
| 31 | 874 | Mains and Services Expenses | 1,035,373 | 1,059,280 | 2.31% |
| 32 | 875 | Measuring & Reg. Station Exp.-General | 33,217 | 25,599 | -22.93% |
| 33 | 876 | Measuring & Reg. Station Exp.-Industrial | 12,023 | 11,408 | -5.12% |
| 34 | 877 | Meas. & Reg. Station Exp.-City Gate Ck. Sta. | 0 | 0 | 0.00% |
| 35 | 878 | Meter & House Regulator Expenses | 417,219 | 283,849 | -31.97% |
| 36 | 879 | Customer Installations Expenses | 635,374 | 746,562 | 17.50% |
| 37 | 880 | Other Expenses | 1,042,770 | 925,890 | -11.21% |
| 38 | 881 | Rents | 29,660 | 53,692 | 81.02% |
| 39 | | **Total Operation - Distribution** | $3,726,810 | $3,701,943 | -0.67% |
| 40 | Maintenance | | | | |
| 41 | 885 | Maintenance Supervision & Engineering | $159,493 | $166,558 | 4.43% |
| 42 | 886 | Maintenance of Structures & Improvements | 2,100 | 712 | -66.10% |
| 43 | 887 | Maintenance of Mains | 119,743 | 100,744 | -15.87% |
| 44 | 888 | Maint. of Compressor Station Equipment | | | |
| 45 | 889 | Maint. of Meas. & Reg. Station Exp.-General | 33,053 | 28,991 | -12.29% |
| 46 | 890 | Maint. of Meas. & Reg. Sta. Exp.-Industrial | 17,985 | 13,188 | -26.67% |
| 47 | 891 | Maint. of Meas. & Reg. Sta. Equip.-City Gate | | | |
| 48 | 892 | Maintenance of Services | 71,069 | 113,980 | 60.38% |
| 49 | 893 | Maintenance of Meters & House Regulators | 199,795 | 182,990 | -8.41% |
| 50 | 894 | Maintenance of Other Equipment | 68,231 | 104,886 | 53.72% |
| 51 | | **Total Maintenance - Distribution** | $671,469 | $712,049 | 6.04% |
| 52 | | **TOTAL Distribution Expenses** | $4,398,279 | $4,413,992 | 0.36% |

## MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2007

| | Account Number & Title | | | Last Year | This Year | % Change |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | | | **Customer Accounts Expenses** | | | |
| 3 | Operation | | | | | |
| 4 | | 901 | Supervision | $170,261 | $171,592 | 0.78% |
| 5 | | 902 | Meter Reading Expenses | 635,994 | 641,359 | 0.84% |
| 6 | | 903 | Customer Records & Collection Expenses | 1,203,544 | 1,204,033 | 0.04% |
| 7 | | 904 | Uncollectible Accounts Expenses | 255,133 | 117,648 | -53.89% |
| 8 | | 905 | Miscellaneous Customer Accounts Expenses | 140,958 | 137,923 | -2.15% |
| 9 | | | | | | |
| 10 | | | **TOTAL Customer Accounts Expenses** | $2,405,890 | $2,272,555 | -5.54% |
| 11 | | | | | | |
| 12 | | | **Customer Service & Informational Expenses** | | | |
| 13 | Operation | | | | | |
| 14 | | 907 | Supervision | $3,745 | $4,520 | 20.69% |
| 15 | | 908 | Customer Assistance Expenses | 16,606 | 10,044 | -39.52% |
| 16 | | 909 | Informational & Instructional Advertising Exp. | 37,607 | 47,465 | 26.21% |
| 17 | | 910 | Miscellaneous Customer Service & Info. Exp. | 403 | 237 | -41.19% |
| 18 | | | | | | |
| 19 | | | **TOTAL Customer Service & Info. Expenses** | $58,361 | $62,266 | 6.69% |
| 20 | | | | | | |
| 21 | | | **Sales Expenses** | | | |
| 22 | Operation | | | | | |
| 23 | | 911 | Supervision | $62,332 | $65,734 | 5.46% |
| 24 | | 912 | Demonstrating & Selling Expenses | 130,933 | 134,943 | 3.06% |
| 25 | | 913 | Advertising Expenses | 24,214 | 13,913 | -42.54% |
| 26 | | 916 | Miscellaneous Sales Expenses | 18,308 | 18,507 | 1.09% |
| 27 | | | | | | |
| 28 | | | **TOTAL Sales Expenses** | $235,787 | $233,097 | -1.14% |
| 29 | | | | | | |
| 30 | | | **Administrative & General Expenses** | | | |
| 31 | Operation | | | | | |
| 32 | | 920 | Administrative & General Salaries | $1,162,815 | $1,266,098 | 8.88% |
| 33 | | 921 | Office Supplies & Expenses | 687,505 | 506,502 | -26.33% |
| 34 | | 922 | (Less) Administrative Expenses Transferred - Cr. | | | |
| 35 | | 923 | Outside Services Employed | 112,383 | 128,361 | 14.22% |
| 36 | | 924 | Property Insurance | 100,550 | 86,558 | -13.92% |
| 37 | | 925 | Injuries & Damages | 405,863 | 604,570 | 48.96% |
| 38 | | 926 | Employee Pensions & Benefits | 1,607,178 | 1,596,587 | -0.66% |
| 39 | | 927 | Franchise Requirements | | | |
| 40 | | 928 | Regulatory Commission Expenses | 136,612 | 10,252 | -92.50% |
| 41 | | 929 | (Less) Duplicate Charges - Cr. | | | |
| 42 | | 930.1 | General Advertising Expenses | 59,767 | 54,296 | -9.15% |
| 43 | | 930.2 | Miscellaneous General Expenses | 96,056 | 85,540 | -10.95% |
| 44 | | 931 | Rents | 44,597 | 87,961 | 97.24% |
| 45 | | | | | | |
| 46 | | | **TOTAL Operation - Admin. & General** | $4,413,326 | $4,426,725 | 0.30% |
| 47 | Maintenance | | | | | |
| 48 | | 935 | Maintenance of General Plant | $167,115 | $172,948 | 3.49% |
| 49 | | | | | | |
| 50 | | | **TOTAL Administrative & General Expenses** | $4,580,441 | $4,599,673 | 0.42% |
| 51 | **TOTAL OPERATION & MAINTENANCE EXP.** | | | $73,793,017 | $62,387,075 | -15.46% |

# MONTANA TAXES OTHER THAN INCOME

Year: 2007

| | Description of Tax | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Payroll Taxes | $453,822 | $455,751 | 0.43% |
| 2 | Secretary of State | 317 | 327 | 3.15% |
| 3 | Highway Use Tax | 154 | 155 | 0.65% |
| 4 | Montana Consumer Counsel | 55,250 | 52,379 | -5.20% |
| 5 | Montana PSC | 198,444 | 163,343 | -17.69% |
| 6 | Delaware Franchise Taxes | 18,827 | 18,849 | 0.12% |
| 7 | Property Taxes | 1,630,759 | 1,737,728 | 6.56% |
| 8 | Tribal Taxes | 4,582 | 4,736 | 3.36% |
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| 49 | | | | |
| 50 | **TOTAL MT Taxes other than Income** | $2,362,155 | $2,433,268 | 3.01% |

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

Year: 2007

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Able Field Services | Plant update & repair | $79,794 | $0 | 0.00% |
| 2 | | | | | |
| 3 | Aerial Contractors Inc. | Contractor services | 378,301 | 0 | 0.00% |
| 4 | | | | | |
| 5 | Agri Industries, Inc. | Boring & pipe installation | 158,125 | 0 | 0.00% |
| 6 | | | | | |
| 7 | Ahern Fire Protection | Fire system installation | 433,570 | 0 | 0.00% |
| 8 | | | | | |
| 9 | Alliance Pipeline L. P. | Interconnection Dev. Agreement | 1,394,095 | 0 | 0.00% |
| 10 | | | | | |
| 11 | Atlantic Insulco Environ. Serv. | Environmental work | 83,853 | 0 | 0.00% |
| 12 | | | | | |
| 13 | Benco Equipment Co. | Vehicle Maintenance | 234,178 | 4,991 | 2.13% |
| 14 | | | | | |
| 15 | Berger Electric Inc. | Boring & pipe installation | 81,412 | 35 | 0.04% |
| 16 | | | | | |
| 17 | Big Horn Asphalt & More | Contractor services | 102,046 | 0 | 0.00% |
| 18 | | | | | |
| 19 | Big K Industries, Inc. | Contractor services | 275,781 | 0 | 0.00% |
| 20 | | | | | |
| 21 | Black & Veatch Corporation | Contractor services | 293,248 | 0 | 0.00% |
| 22 | | | | | |
| 23 | Blue Heron Consulting | Consulting services | 1,108,023 | 128,712 | 11.62% |
| 24 | | | | | |
| 25 | Broadridge | Contr serv-shareholder position proc. | 199,519 | 2,702 | 1.35% |
| 26 | | | | | |
| 27 | Bullinger Tree Service | Tree trimming services | 203,619 | 0 | 0.00% |
| 28 | | | | | |
| 29 | Burns & McDonnell Eng Co. Inc. | Consulting services | 294,454 | 0 | 0.00% |
| 30 | | | | | |
| 31 | CEDA Inc. | Boiler Maintenance | 168,861 | 3,924 | 2.32% |
| 32 | | | | | |
| 33 | Cemtek Environmental Inc. | Install Mercury CEMS equip. L&C | 236,433 | 0 | 0.00% |
| 34 | | | | | |
| 35 | Cessna Aircraft Company | Aircraft Maintenance & Repair | 193,288 | 0 | 0.00% |
| 36 | | | | | |
| 37 | Chief Construction, Inc. | Construction Services | 533,539 | 0 | 0.00% |
| 38 | | | | | |
| 39 | Christensen IR | Investor relations | 90,732 | 1,229 | 1.35% |
| 40 | | | | | |
| 41 | Clean Harbors Environ. Serv. Inc. | Environmental Serv. - Site cleanup | 251,620 | 1,871 | 0.74% |
| 42 | | | | | |
| 43 | Conduit Constructors, LLC | Contract Svcs. - Memorial bridge reloc. | 182,219 | 0 | 0.00% |
| 44 | | | | | |
| 45 | Connecting Point | Computer service & software maint. | 403,537 | 10,819 | 2.68% |
| 46 | | | | | |
| 47 | Continental Line Builders, Inc | Contract Services - Electric Trans. | 196,244 | 0 | 0.00% |
| 48 | | | | | |
| 49 | Corporate Technologies, LLC. | Software maintenance | 107,972 | 1,889 | 1.75% |
| 50 | | | | | |

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

Year: 2007

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Crownbutte Wind Power, LLC | Contract Services - Windfarm Const. | $400,000 | $0 | 0.00% |
| 2 | | | | | |
| 3 | Deloitte & Touche, LLP | Auditing and consulting services | 432,289 | 2,708 | 0.63% |
| 4 | | | | | |
| 5 | Dewey & LeBoeuf LLP | Legal Services | 759,199 | 10,282 | 1.35% |
| 6 | | | | | |
| 7 | Diversified Graphics Inc. | Annual report | 243,020 | 3,291 | 1.35% |
| 8 | | | | | |
| 9 | DWD LLC | Tree trimming services | 107,484 | 0 | 0.00% |
| 10 | | | | | |
| 11 | Edison Electric Institute | Membership fees | 83,205 | 0 | 0.00% |
| 12 | | | | | |
| 13 | Edling Electric Inc. | Contract Services - Fiber optic install. | 78,034 | 0 | 0.00% |
| 14 | | | | | |
| 15 | Energy & Environ. Research Cent. | Contract services - environmental | 101,000 | 14 | 0.01% |
| 16 | | | | | |
| 17 | Environmental Systems Corp, | Boiler maintenance | 76,893 | 0 | 0.00% |
| 18 | | | | | |
| 19 | Earnst & Young, LLP | Consulting Services | 106,839 | 12,291 | 11.50% |
| 20 | | | | | |
| 21 | Fischer Contracting | Contract services | 409,062 | 200 | 0.05% |
| 22 | | | | | |
| 23 | Franz Construction Inc. | Construction services | 140,944 | 0 | 0.00% |
| 24 | | | | | |
| 25 | GE Energy Services | Construction services | 243,012 | 0 | 0.00% |
| 26 | | | | | |
| 27 | Gabe's Construction Co, Inc | Contractor Svcs. - Mem bridge UG line | 1,032,758 | 0 | 0.00% |
| 28 | | | | | |
| 29 | Gagnon, Inc. | Refractory Repairs | 173,116 | 0 | 0.00% |
| 30 | | | | | |
| 31 | Gary Forrester | Consulting Services | 50,104 | 679 | 1.36% |
| 32 | | | | | |
| 33 | Hamilton Spray | Contract Svcs. - Wood Pole Treatment | 211,220 | 0 | 0.00% |
| 34 | | | | | |
| 35 | Hardy Construction | Const. Svc. - Billing office & wrhse | 3,081,644 | 2,342,493 | 76.01% |
| 36 | | | | | |
| 37 | HDR Inc. | Contractor Services - Diamond Willow | 2,035,277 | 0 | 0.00% |
| 38 | | | | | |
| 39 | Hughes Kellner Sullivan & Alke | Legal Fees | 78,975 | 28,936 | 36.64% |
| 40 | | | | | |
| 41 | Indoor Services, Inc | Janitorial services | 45,114 | 748 | 1.66% |
| 42 | | | | | |
| 43 | Industrial Contractors Inc. | Construction services | 392,212 | 0 | 0.00% |
| 44 | | | | | |
| 45 | InfraSource Underground | Underground gas line installment | 2,221,605 | 0 | 0.00% |
| 46 | | | | | |
| 47 | Int. Business Machines, Inc. | Contract svcs. - Computer Maint. | 156,518 | 12,329 | 7.88% |
| 48 | | | | | |
| 49 | Itron, Inc. | Contract services - AMR project | 2,196,967 | 340,098 | 15.48% |
| 50 | | | | | |

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

Year: 2007

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | JGA Architects | Contract Serv. - Billings office & wrhse | $259,831 | $121,904 | 46.92% |
| 2 | | | | | |
| 3 | JP Pipeline Construction, Inc | Underground gas line installment | 963,151 | 0 | 0.00% |
| 4 | | | | | |
| 5 | K & H Electric, Inc. | Contract Services - Install UG lines | 143,463 | 0 | 0.00% |
| 6 | | | | | |
| 7 | Kappel Tree Service LLC | Tree trimming service | 146,619 | 42 | 0.03% |
| 8 | | | | | |
| 9 | Larsen Design Office, Inc. | Contract Services | 100,330 | 1,359 | 1.35% |
| 10 | | | | | |
| 11 | Leading Edge Turbine Tech. | Turbine Maint. & Repair - Glendive | 312,401 | 0 | 0.00% |
| 12 | | | | | |
| 13 | Lignite Energy Council | Membership fees | 108,841 | 0 | 0.00% |
| 14 | | | | | |
| 15 | Lindquist & Vennum, PLLP | Contract Services - Const. Big Stone II | 94,031 | 0 | 0.00% |
| 16 | | | | | |
| 17 | Lufkin Industries, Inc. | Turbine Maint. & Repair - Glendive | 183,076 | 0 | 0.00% |
| 18 | | | | | |
| 19 | Lynn, Jackson Schultz & Lebrun | Legal services | 19,590 | 5 | 0.03% |
| 20 | | | | | |
| 21 | MCM General Contractors, Inc. | Boring and pipe installation | 245,167 | 0 | 0.00% |
| 22 | | | | | |
| 23 | McDermott, Will & Emery, LLP | Legal services | 227,203 | 2,849 | 1.25% |
| 24 | | | | | |
| 25 | Merrill Communications, LLC | Contract Services-Stockholder Mtg Mat. | 103,049 | 1,396 | 1.35% |
| 26 | | | | | |
| 27 | Merrill Lynch | Advisory Fee | 204,909 | 2,775 | 1.35% |
| 28 | | | | | |
| 29 | Micon, Inc. | Consulting Services - CIS | 394,389 | 45,889 | 11.64% |
| 30 | | | | | |
| 31 | Microsoft Licensing GP | Contract svcs. - Software maint. | 729,079 | 13,968 | 1.92% |
| 32 | | | | | |
| 33 | Midwest ISO | Prelim Studies, wind farm & others | 226,000 | 0 | 0.00% |
| 34 | | | | | |
| 35 | Mitchell's Oil Field | Turbine Maint. & Repair - Glendive | 209,228 | 0 | 0.00% |
| 36 | | | | | |
| 37 | Moody's Investors Service | Financial Services | 63,551 | 5,067 | 7.97% |
| 38 | | | | | |
| 39 | New York Life | Consulting Services | 349,188 | 13,394 | 3.84% |
| 40 | | | | | |
| 41 | North Dakota Newspaper Assoc | Advertising | 109,620 | 27,544 | 25.13% |
| 42 | | | | | |
| 43 | Northern Improvement Co. | Contractor Serv. - Ash Disp., Heskett | 394,341 | 0 | 0.00% |
| 44 | | | | | |
| 45 | NYSE Market Inc | Financial Services | 191,275 | 2,455 | 1.28% |
| 46 | | | | | |
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## PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2007

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | One Call Locaters, LTD | Line location service | $1,189,141 | $210,189 | 17.68% |
| 2 | | | | | |
| 3 | Oracle Corp. | Software maintenance | 452,321 | 13,249 | 2.93% |
| 4 | | | | | |
| 5 | Osmose Utilities Services Inc. | Contract services - Overhead line Maint. | 190,526 | 0 | 0.00% |
| 6 | | | | | |
| 7 | OTP Big Stone II - Trust Acct | Big Stone II Construction | 1,180,914 | 0 | 0.00% |
| 8 | | | | | |
| 9 | Outdoor Services Inc. | Contract services - Meter reading | 1,064,449 | 115,177 | 10.82% |
| 10 | | | | | |
| 11 | PA Consulting Services Inc. | Consulting services - Big Stone II | 234,060 | 0 | 0.00% |
| 12 | | | | | |
| 13 | Perkins Coie, LLP | Legal Services | 100,174 | 0 | 0.00% |
| 14 | | | | | |
| 15 | Philip Service Corp. | Gritblast services | 148,136 | 0 | 0.00% |
| 16 | | | | | |
| 17 | Pole Maintenance Co. | Contract services - Pole treatment | 150,224 | 0 | 0.00% |
| 18 | | | | | |
| 19 | Pond & Lucier, LLC | Turbine maintenance & Repair | 274,509 | 0 | 0.00% |
| 20 | | | | | |
| 21 | Presort Plus, Inc. | Contract services - mail services | 81,393 | 9,586 | 11.78% |
| 22 | | | | | |
| 23 | Progressive Maintenance Co. | Custodial Services | 113,403 | 10,591 | 9.34% |
| 24 | | | | | |
| 25 | Prosource Technologies Inc. | Gas line construction | 263,589 | 0 | 0.00% |
| 26 | | | | | |
| 27 | Quality Underground Services Inc | Contractor svcs. - gas lines & mains | 177,304 | 0 | 0.00% |
| 28 | | | | | |
| 29 | Sargent & Lundy, LLC | Consulting services | 106,078 | 0 | 0.00% |
| 30 | | | | | |
| 31 | Southern Cross Corp. | Contract services - Leak Detection | 184,513 | 61,726 | 33.45% |
| 32 | | | | | |
| 33 | Standard & Poors | Financial Services | 108,460 | 1,469 | 1.35% |
| 34 | | | | | |
| 35 | State-Line Contractors, Inc. | Construction services | 242,390 | 227,487 | 93.85% |
| 36 | | | | | |
| 37 | Sulzer Hickman, Inc. | Turbine maint. & Repair, Glendive | 340,403 | 0 | 0.00% |
| 38 | | | | | |
| 39 | Sundog | MDUR eSource proj. & web redesign | 78,650 | 1,065 | 1.35% |
| 40 | | | | | |
| 41 | T & K Inspection, Inc. | Gas Construction | 123,558 | 0 | 0.00% |
| 42 | | | | | |
| 43 | The Structure Group | Cont. Svcs. - Software install. & maint. | 90,100 | 0 | 0.00% |
| 44 | | | | | |
| 45 | Thelen Reid Brown Raysman & | Legal Services | 746,937 | 6,533 | 0.87% |
| 46 | Steiner, LLP. | | | | |
| 47 | Timberline Construction Inc. | Const. serv. - Cabin Creek Substation | 530,981 | 0 | 0.00% |
| 48 | | | | | |
| 49 | Trading Partners | Fully managed reverse auction. | 188,500 | 1,425 | 0.76% |
| 50 | | | | | |

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

Year: 2007

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Treasury Management Services | Banking Services | $251,370 | $46,659 | 18.56% |
| 2 | | | | | |
| 3 | Tulsa Inspection Resources, Inc | Gas line construction | 90,072 | 0 | 0.00% |
| 4 | | | | | |
| 5 | UBS Invesment Bank | Banking Services | 2,552,937 | 0 | 0.00% |
| 6 | | | | | |
| 7 | Ulmer Tree Service | Tree trimming service | 140,488 | 0 | 0.00% |
| 8 | | | | | |
| 9 | Upper Missouri-G&T Electric Coop | Expenses, breaker replacement - Tioga | 444,850 | 0 | 0.00% |
| 10 | | | | | |
| 11 | Utility Partners, LC | Consulting services | 168,220 | 18,700 | 11.12% |
| 12 | | | | | |
| 13 | Van Horn Media | Advertising | 158,017 | 23,265 | 14.72% |
| 14 | | | | | |
| 15 | Virtual Hold Technology, LLC | Software installation & maintenance | 174,017 | 31,413 | 18.05% |
| 16 | | | | | |
| 17 | Wanzek Construction, Inc. | Contractor services | 2,986,887 | 0 | 0.00% |
| 18 | | | | | |
| 19 | Weisz & Sons, Inc. | Contractor services | 440,962 | 0 | 0.00% |
| 20 | | | | | |
| 21 | Wells Fargo Shareowners Serv. | Stock transfer agent & ESOP Admin. | 327,708 | 4,438 | 1.35% |
| 22 | | | | | |
| 23 | Williams & Associates, LLC | Consulting services | 100,039 | 1,355 | 1.35% |
| 24 | | | | | |
| 25 | Xerox Corporation | Contract svcs. - Equip. Maintenance | 226,675 | 25,917 | 11.43% |
| 26 | | | | | |
| 27 | | | | | |
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| 48 | | | | | |
| 49 | | | | | |
| 50 | | | | | |
| 51 | **TOTAL Payments for Services** | | $44,742,241 | $3,959,132 | 8.85% |

## POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2007

| | Description | Total Company | Montana | % Montana |
|---|---|---|---|---|
| 1 | Contributions to Candidates by PAC | $21,557 | $3,300 | 15.31% |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
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| 7 | | | | |
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| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |
| 43 | **TOTAL Contributions** | $21,557 | $3,300 | 15.31% |

## 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 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |

PROPRIETARY SCHEDULE

## COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

| Line No. | Name/Title | Base Salary | Bonuses | Other 1/ | Total Compensation | Total Compensation Last Year 2/ | % Increase Total Compensation |
|---|---|---|---|---|---|---|---|
| 1 | Terry D. Hildestad - President & CEO | $625,000 | $1,250,000 | $2,031,260 | $3,906,260 | $2,864,038 | 36% |
| 2 | Vernon A. Raile Executive Vice President, Treasurer and CFO | 350,700 | 350,700 | 831,080 | 1,532,480 | 1,441,422 | 6% |
| 3 | William Schneider - President & CEO of Knife River Corporation | 422,000 | 206,780 | 840,564 | 1,469,344 | 1,669,738 | -12% |
| 4 | John G. Harp - President & CEO of MDU Construction Services Group | 341,000 | 341,000 | 348,343 | 1,030,343 | 1,626,865 | -37% |
| 5 | Bruce T. Imsdahl President and CEO of Montana-Dakota Utilities and Grat Plains Natural Gas | 322,400 | 322,400 | 488,688 | 1,133,488 | 1,055,970 | 7% |

1/ Includes stock awards, option awards, change in pension value and non qualified deferred compensation earnings and all other compensation. See Page 20a for detail.
2/ See Page 20a for 2006 Total Compensation detail.

## Summary Compensation Table for 2007

| Name and Principal Position (a) | Year (b) | Salary ($) (c) | Bonus ($) (d) | Stock Awards ($) (e)(1) | Option Awards ($) (f)(1) | Non-Equity Incentive Plan Compensation ($) (g) | Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)(2) | All Other Compensation ($) (i) | Total ($) (j) |
|---|---|---|---|---|---|---|---|---|---|
| Terry D. Hildestad..... President and CEO | 2007 | 625,000 | — | 661,821 | — | 1,250,000 | 1,362,413 | 7,026 | 3,906,260 |
| | 2006 | 562,500 | — | 376,394 | 25,084 | 1,125,000 | 768,184 | 6,876 | 2,864,038(3) |
| Vernon A. Raile......... Executive Vice President, Treasurer and CFO | 2007 | 350,700 | — | 268,806 | — | 350,700 | 555,248 | 7,026 | 1,532,480 |
| | 2006 | 318,750 | — | 161,690 | — | 318,750 | 635,356 | 6,876 | 1,441,422(3) |
| William E. Schneider.............. President and CEO of Knife River Corporation | 2007 | 422,000 | — | 383,191 | — | 206,780 | 450,347 | 7,026 | 1,469,344 |
| | 2006 | 392,000 | — | 248,217 | 20,729 | 392,000 | 609,916 | 6,876 | 1,669,738(3) |
| John G. Harp............. President and CEO of MDU Construction Services Group, Inc. | 2007 | 341,000 | — | 277,929 | — | 341,000 | 47,334(5) | 23,080(6) | 1,030,343 |
| | 2006 | 310,000 | — | 150,566 | — | 810,000(4) | 324,976(5) | 31,323(6) | 1,626,865(3) |
| Bruce T. Imsdahl........ President and CEO of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. | 2007 | 322,400 | — | 289,434 | — | 322,400 | 192,228 | 7,026 | 1,133,488 |
| | 2006 | — | — | — | — | — | — | — | — |

(1) Amounts in these columns represent the dollar amount recognized for financial statement reporting purposes for the 2007 and 2006 fiscal years for restricted stock awards, performance share awards and stock option awards granted in 2007 and prior years. These amounts reflect our accounting expense for these awards and do not correspond to the actual value that will be recognized by the named executive officers. Assumptions used to determine the amounts in these columns are the same as used in the calculation of compensation expense for our audited financial statements, except for the effect of estimated forfeitures. Statement of Financial Accounting Standards No. 123 (revised), "Share-Based Payment" requires us to estimate forfeitures when awards are granted and reduce estimated compensation expense accordingly. These columns were prepared assuming none of the awards will be forfeited. However, for both these columns and our audited financial statements, compensation expense is adjusted for actual forfeitures.

The grant date fair value of restricted stock awards was based on the market price of our stock on the grant date.

The grant date fair value for the performance shares granted in 2007 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 18.17% to 18.73% comprised of 50% historical volatility and 50% implied volatility and a risk-free interest rate term structure in the range of 4.75% to 5.21% based on the U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.25 per target share.

The grant date fair value for the performance shares granted in 2006 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 17.65% to 18.79% comprised of 50% historical volatility and 50% implied volatility and a risk-free interest rate term structure in the range of 4.66% to 4.79% based on the U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.37 per target share.

The grant date fair value for the performance share awards granted in 2005 was equal to the market value of our common stock on the grant date.

The fair value of stock options was estimated on the grant date using the Black-Scholes option-pricing model. The fair value of the options granted and the underlying assumptions were as follows:

| | |
|---|---|
| Fair value of options at grant date | $3.22 |
| Risk-free interest rate | 5.18% |
| Expected price volatility | 25.94% |
| Expected dividend yield | 3.53% |
| Expected life in years | 7 |
| Date of Grant | February 14, 2001 |

For additional information about these stock awards and option awards, refer to Note 14 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2007.

(2) Amounts shown represent the change in the actuarial present value for years ending December 31, 2006 and December 31, 2007 for the named executive officers' accumulated benefits under the pension plan, excess SISP and SISP and, for Mr. Harp, the additional retirement benefit, collectively referred to as the "accumulated pension change," plus above market earnings on deferred annual incentives, if any. The amounts shown for accumulated pension change on December 31, 2006 have been corrected from the amounts reported in the 2007 proxy statement due to an error by an actuary. The corrected amounts for 2006 and the amounts for 2007 are:

| | Accumulated Pension Change | | Above Market Earnings | |
|---|---|---|---|---|
| **Name** | **12/31/2006 ($)** | **12/31/2007 ($)** | **12/31/2006 ($)** | **12/31/2007 ($)** |
| Terry D. Hildestad | 752,265 | 1,336,815 | 15,919 | 25,598 |
| Vernon A. Raile | 608,295 | 508,987 | 27,061 | 46,261 |
| William E. Schneider | 593,820 | 411,123 | 16,096 | 39,224 |
| John G. Harp | 239,228 | 38,498 | — | — |
| *Additional Retirement (John G. Harp)** | 85,748 | 8,836 | — | — |
| Bruce T. Imsdahl | — | 179,790 | — | 12,438 |

*See footnote 5.

(3) Totals corrected from amounts reported in the 2007 proxy statement. See footnote 2.

(4) Includes one-time incentive payment of $500,000 in addition to his executive incentive compensation plan payment.

(5) In addition to the change in the actuarial present value of Mr. Harp's accumulated benefit under the pension plan, excess SISP and SISP, this amount also includes the following amounts attributable to Mr. Harp's additional retirement benefit:

| | 2006 | 2007 |
|---|---|---|
| Change in present value of additional years of service for pension plan | $77,447 | $6,033 |
| Change in present value of additional years of service for excess SISP | $ 8,301 | $2,803 |
| Change in present value of additional years of service for SISP | — | — |

Mr. Harp's additional retirement benefit is described in the narrative that follows the Pension Benefits for 2007 table. The additional retirement benefit provides Mr. Harp with additional retirement benefits equal to the additional benefit he would earn under the pension plan, excess SISP and the SISP if he had three additional years of service. The amounts in the table above reflect the change in present value of this additional benefit in 2006 and 2007. The additional retirement benefit was determined by calculating the actuarial present values of the accumulated benefits under the pension plan, excess SISP and SISP, with and without the three additional years of service, using the same assumptions used to determine the amounts disclosed in the Pension Benefits for 2007 table. Because Mr. Harp would be fully vested in his SISP benefit if he retired at age 65, the additional years of service provided by the additional retirement agreement would not increase that benefit. If Mr. Harp retires before becoming 100% vested in his SISP benefit, his SISP benefit would be less than the amount shown in the Pension Benefits for 2007 table, but the payments he would receive under the additional retirement benefit arrangement would increase, as would the amounts reflected in the table above and in the Summary Compensation Table. In the Summary Compensation Table in last year's proxy statement, we disclosed a change in pension value of $772,200 for Mr. Harp. This included $197,550 attributable to the increase in Mr. Harp's pension due to the additional years of service and $317,273 attributable to the increase in Mr. Harp's SISP benefits due to the additional years of service. To calculate these amounts, we assumed Mr. Harp met the vesting conditions necessary to earn the additional retirement benefit and terminated employment on January 2, 2008. Both the $197,550 and the $317,273 amounts were reflected in our financial statements for 2007. We have determined, however, that it is more appropriate and consistent with our other disclosures in column (h) of the Summary Compensation Table and in the Pension Benefits for 2007 table if the amounts in the Summary Compensation Table attributable to this additional retirement benefit are determined using the same assumed retirement ages used for these other disclosures.

(6) Includes a company contribution to Mr. Harp's 401(k) account, a matching contribution to a charity, payment of a life insurance premium, an additional premium for Mr. Harp's long-term disability insurance and Mr. Harp's office and automobile allowance.

## Grants of Plan-Based Awards in 2007

| Name (a) | Grant Date (b) | Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold ($) (c) | Target ($) (d) | Maximum ($) (e) | Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#) (f) | Target (#) (g) | Maximum (#) (h) | All Other Stock Awards: Number of Shares of Stock or Units (#) (i) | All Other Option Awards: Number of Securities Underlying Options (#) (j) | Exercise or Base Price of Option Awards ($/Sh) (k) | Grant Date Fair Value of Stock and Option Awards ($) (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Terry D. Hildestad . . . . | 2/15/07(1) | 156,250 | 625,000 | 1,250,000 | — | — | — | — | — | — | |
| | 2/15/07(2) | — | — | — | 3,309 | 33,091 | 66,182 | — | — | — | 779,293 |
| Vernon A. Raile . . . . . | 2/15/07(1) | 43,838 | 175,350 | 350,700 | — | — | — | — | — | — | |
| | 2/15/07(2) | — | — | — | 1,256 | 12,564 | 25,128 | — | — | — | 295,882 |
| William E. Schneider . . | 2/15/07(3) | 52,750 | 211,000 | 422,000 | — | — | — | — | — | — | |
| | 2/15/07(2) | — | — | — | 1,512 | 15,119 | 30,238 | — | — | — | 356,052 |
| John G. Harp . . . . . . . | 2/15/07(4) | 42,625 | 170,500 | 341,000 | — | — | — | — | — | — | |
| | 2/15/07(2) | — | — | — | 1,018 | 10,181 | 20,362 | — | — | — | 239,763 |
| Bruce T. Imsdahl . . . . . | 2/15/07(5) | 40,300 | 161,200 | 322,400 | — | — | — | — | — | — | |
| | 2/15/07(2) | — | — | — | 963 | 9,625 | 19,250 | — | — | — | 226,669 |

(1) Annual incentive for 2007 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(2) Performance shares for the 2007-2009 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(3) Annual incentive for 2007 granted pursuant to the Knife River Corporation Executive Incentive Compensation Plan.

(4) Annual incentive for 2007 granted pursuant to the MDU Construction Services Group, Inc. Executive Compensation Plan.

(5) Annual incentive for 2007 granted pursuant to the Montana-Dakota Utilities Co. Executive Incentive Compensation Plan.

## Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

### Incentive Awards

*Annual Incentive*

On February 14, 2007, the compensation committee recommended the 2007 annual award opportunities for our named executive officers, and the board approved these opportunities at its meeting on February 15, 2007. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 15, 2007 in columns (c), (d) and (e) and in the Summary Compensation Table as earned with respect to 2007 in column (g).

Executive officers may receive 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 a percent of the executive's base salary. Actual payment may range from zero to 200% of the target based upon achievement of corporate goals.

In order to be eligible to receive an annual incentive award under the Long-Term Performance-Based Incentive Plan, Messrs. Hildestad and Raile must have remained employed by the company through December 31, 2007, unless the compensation committee determines otherwise. 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 downward based upon individual performance. Unless the committee determines otherwise, performance measure targets shall be adjusted to take into account unusual or nonrecurring events affecting the company, a subsidiary or a division or business unit, or any of their financial statements, or changes in applicable laws, regulations or accounting principles to the extent such unusual or nonrecurring events or changes in applicable laws, regulations or accounting principles otherwise would result in dilution or enlargement of the annual incentive award intended to be provided. Such adjustments are made in a manner that will not cause the award to fail to qualify as performance-based compensation for purposes of Section 162(m) of the Internal Revenue Code.

With respect to annual incentive awards granted pursuant to an Executive Incentive Compensation Plan, participants who retire at age 65, die or become disabled during the year remain eligible to receive an award. Subject to the compensation committee's discretion, executives who terminate employment for other reasons are not eligible for an award. The committee has full discretion to determine the extent to which goals have been achieved, the payment level and whether any final payment will be made. Once performance goals are approved by the committee for executive incentive compensation plan awards, the committee generally does not modify the goals. However, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance goals, the committee, in consultation with the chief executive officer, may modify the performance goals. Such goal modifications will only be considered in years of unusually adverse or favorable external conditions.

For Messrs. Hildestad and Raile, the performance measures for annual incentive awards are our annual return on invested capital achieved compared to target and our annual earnings per share achieved compared to target. For Messrs. Schneider, Harp and Imsdahl, the performance measures for annual incentive awards are their respective business unit's annual return on invested capital achieved compared to target and their respective business unit's allocated earnings per share achieved compared to target.

For 2007, the compensation committee weighted the goals for annual return on invested capital compared to planned results and allocated earnings per share compared to planned results each at 50%.

In 2006 we began limiting the incentive compensation we will pay above the target amount. The after-tax incentives paid above target will be limited to 20% of earnings in excess of planned earnings. The earnings in excess of planned earnings are calculated without regard to the after-tax incentive amounts above target. The 20% limitation is measured at the major business unit level for business unit and operating company executives, which include Messrs. Schneider, Harp and Imsdahl, and at the corporate level for corporate executives, which include Messrs. Hildestad and Raile. The committee also considers annual improvement in the return on invested capital measure for incentive purposes to help ensure that return on invested capital equals or exceeds the weighted average cost of capital.

The award opportunities available to each named executive officer were:

| 2007 earnings per share results as a % of 2007 plan | Corresponding payment of earnings per share annual incentive target |
|---|---|
| less than 85% | 0% |
| 85% | 25% |
| 90% | 50% |
| 95% | 75% |
| 100% | 100% |
| 103% | 120% |
| 106% | 140% |
| 109% | 160% |
| 112% | 180% |
| 115% or more | 200% |

| 2007 return on invested capital results as a % of 2007 plan | Corresponding payment of return on invested capital annual incentive target |
|---|---|
| less than 85% | 0% |
| 85% | 25% |
| 90% | 50% |
| 95% | 75% |
| 100% | 100% |
| 103% | 120% |
| 106% | 140% |
| 109% | 160% |
| 112% | 180% |
| 115% or more | 200% |

For discussion of the specific incentive plan performance targets and results, please see the compensation discussion and analysis.

*Long-Term Incentive*

On February 14, 2007, the compensation committee recommended long-term incentive grants to the named executive officers in the form of performance shares, and the board approved these grants at its meeting on February 15, 2007. These grants are reflected in columns (f), (g), (h) and (l) of the Grants of Plan-Based Awards table.

From 0% to 200% of the target grant will be paid out in February 2010 depending on our 2007-2009 total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage is determined as follows:

| The Company's Percentile Rank | Payout Percentage of Feb. 15, 2007 Grant |
|---|---|
| 100th | 200% |
| 75th | 150% |
| 50th | 100% |
| 40th | 10% |
| Less than 40th | 0% |

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2010 at the same time as the performance awards are paid.

**Salary and Bonus in Proportion to Total Compensation**

The following table shows the proportion of salary to total compensation. We paid no bonuses in 2007.

| Name | Salary ($) | Total Compensation ($) | Salary as % of Total Compensation |
|---|---|---|---|
| Terry D. Hildestad | 625,000 | 3,906,260 | 16.0 |
| Vernon A. Raile | 350,700 | 1,532,480 | 22.9 |
| William E. Schneider | 422,000 | 1,469,344 | 28.7 |
| John G. Harp | 341,000 | 1,030,343 | 33.1 |
| Bruce T. Imsdahl | 322,400 | 1,133,488 | 28.4 |

## Outstanding Equity Awards at Fiscal Year-End 2007

| | Option Awards | | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|---|
| Name (a) | Number of Securities Underlying Unexercised Options Exercisable (#) (b)(1,2) | Number of Securities Underlying Unexercised Options Unexercisable (#) (c) | Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d) | Option Exercise Price ($) (e)(1) | Option Expiration Date (f) | Number of Shares or Units of Stock That Have Not Vested (#) (g)(1,3) | Market Value of Shares or Units of Stock That Have Not Vested ($) (h) | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)(4) | Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)(5) |
| Terry D. Hildestad | — | — | — | — | — | 3,712 | 102,488 | 128,309 | 3,542,611 |
| Vernon A. Raile | — | — | — | — | — | 1,114 | 30,758 | 50,037 | 1,381,522 |
| William E. Schneider | — | — | — | — | — | 2,970 | 82,002 | 71,365 | 1,970,388 |
| John G. Harp | — | — | — | — | — | — | — | 51,968 | 1,434,836 |
| Bruce T. Imsdahl | 25,896 | — | — | 13.2178 | 02/15/2011 | 1,485 | 41,001 | 53,870 | 1,487,351 |

(1) Adjusted for the 3-for-2 stock split effective July 26, 2006.

(2) These options were granted in 2001 and vested on February 15, 2007.

(3) These shares of restricted stock were granted in 2001 and vest on February 15, 2010. Vesting of some or all shares may be accelerated upon change of control or if the total stockholder return equals or exceeds the 50th percentile of the performance graph peer group during three-year performance cycles: 2001-2003, 2004-2006 and 2007-2009. Non-preferential dividends are paid on these shares.

(4)

| Named Executive Officer | Award | Shares | End of Performance Period |
|---|---|---|---|
| Terry D. Hildestad | 2005 | 38,244 | 12/31/07 |
| | 2006 | 23,883 | 12/31/08 |
| | 2007 | 66,182 | 12/31/09 |
| Vernon A. Raile | 2005 | 12,480 | 12/31/07 |
| | 2006 | 12,429 | 12/31/08 |
| | 2007 | 25,128 | 12/31/09 |
| William E. Schneider | 2005 | 25,842 | 12/31/07 |
| | 2006 | 15,285 | 12/31/08 |
| | 2007 | 30,238 | 12/31/09 |
| John G. Harp | 2005 | 21,534 | 12/31/07 |
| | 2006 | 10,072 | 12/31/08 |
| | 2007 | 20,362 | 12/31/09 |
| Bruce T. Imsdahl | 2005 | 24,548 | 12/31/07 |
| | 2006 | 10,072 | 12/31/08 |
| | 2007 | 19,250 | 12/31/09 |

Shares for the 2005 award are shown at the maximum level (200%) based on results for the 2005-2007 performance cycle above target.

Shares for the 2006 award are shown at the target level (100%) based on results for the first two years of the 2006-2008 performance cycle above threshold but below target.

Shares for the 2007 award are shown at the maximum level (200%) based on results for the first year of the 2007-2009 performance cycle above target.

(5) Value based on the number of performance shares reflected in column (i) multiplied by $27.61, the year-end closing price for 2007.

## Option Exercises and Stock Vested during 2007

| Name (a) | Option Awards: Number of Shares Acquired on Exercise (#) (b) | Option Awards: Value Realized on Exercise ($) (c) | Stock Awards: Number of Shares Acquired on Vesting (#) (d)(1,2) | Stock Awards: Value Realized on Vesting ($) (e)(3) |
|---|---|---|---|---|
| Terry D. Hildestad | 68,995 | 929,688 | 16,109 | 444,019 |
| Vernon A. Raile | — | — | 5,319 | 146,610 |
| William E. Schneider | 57,015 | 785,096 | 10,781 | 297,161 |
| John G. Harp | — | — | — | — |
| Bruce T. Imsdahl | — | — | 4,500 | 124,035 |

(1) Adjusted for the 3-for-2 stock split effective July 26, 2006.

(2) Reflects performance shares for the 2004-2006 performance period that vested on February 15, 2007.

(3) Reflects the value of performance shares based on our stock price of $26.08 on February 15, 2007 and the dividend equivalents that were paid on the vested shares.

## Pension Benefits for 2007

| Name (a) | Plan Name (b) | Number of Years Credited Service (#) (c) | Present Value of Accumulated Benefit ($) (d) | Payments During Last Fiscal Year ($) (e) |
|---|---|---|---|---|
| Terry D. Hildestad | Pension Plan | 34 | 1,086,843 | — |
| | SISP I(1) | 25 | 1,288,914 | — |
| | SISP II(2) | 25 | 1,631,344 | — |
| | SISP Excess | 25 | 459,960 | — |
| Vernon A. Raile | Pension Plan | 28 | 932,905 | — |
| | SISP I(1) | 25 | 781,593 | — |
| | SISP II(2) | 25 | 943,264 | — |
| | SISP Excess | 25 | 35,451 | — |
| William E. Schneider | Pension Plan | 14 | 478,062 | — |
| | SISP I(1) | 13 | 941,660 | — |
| | SISP II(2) | 13 | 813,558 | — |
| | SISP Excess | 13 | 70,086 | — |
| John G. Harp | Pension Plan | 3 | 87,997 | — |
| | SISP I(1) | 2 | — | — |
| | SISP II(2) | 2 | 815,846 | — |
| | SISP Excess | 2 | 11,538 | — |
| | Harp Additional Retirement Benefit | 3 | 94,584 | — |
| Bruce T. Imsdahl | Pension Plan | 35 | 1,246,277 | — |
| | SISP I(1) | 21 | 656,240 | — |
| | SISP II(2) | 21 | 435,546 | — |
| | SISP Excess | 21 | 123,974 | — |

(1) Grandfathered under Section 409A.

(2) Not grandfathered under Section 409A.

The amounts shown for the pension plan and excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2007, calculated using a 6.0% discount rate, the 1994 Group Annuity Mortality Table for post-retirement mortality and no recognition of future salary increases or pre-retirement mortality. The assumed retirement ages for these benefits was age 60 for Messrs. Hildestad, Harp and Imsdahl and age 62 for Mr. Schneider. These are the earliest ages at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2007 was assumed for Mr. Raile, who is currently age 63. The amounts shown for the SISP I and SISP II were determined using a 6.0% discount rate and assume benefits commenced at age 65. The assumptions used to calculate Mr. Harp's additional retirement benefit are described below.

*Pension Plans*

Messrs. Hildestad, Raile, Harp and Imsdahl participate in the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees, which we refer to as our pension plan. Mr. Schneider participates in the Knife River Corporation Salaried Employees' Pension Plan, which we refer to as the KR pension plan. Pension benefits under our pension plan are based upon the participant's average annual salary over the 60 consecutive month period in which the participant received the highest annual salary during the participant's final 10 years of service. For this purpose, only a participant's salary is considered; bonuses and other forms of compensation are not included. Benefits are determined by multiplying (1) the participant's years of credited service by (2) the sum of (a) the average annual salary up to the social security integration level times 1.1% and (b) the average annual salary over the social security integration level times 1.45%. The KR pension plan uses the same formula except that 1.2% and 1.6% are used instead of 1.1% and 1.45%. The maximum years of service recognized when determining benefits under the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

To receive unreduced retirement benefits under our plan, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Under the KR pension plan, participants must remain employed until age 62 or elect to defer commencement of benefits until age 62 to receive unreduced benefits. Mr. Raile is currently eligible for unreduced retirement benefits under our pension plan. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service, in our plan and between the ages of 55 and 62, with 5 years of service, in the KR pension plan are eligible for early retirement benefits. Early retirement benefits are determined by reducing the normal retirement benefit by 0.25% per month for each month before age 60 in our plan and age 62 in the KR pension plan. If a participant's employment terminates before age 55, the same reduction applies for each month the termination occurs before age 62, with the reduction capped at 21%. Messrs. Hildestad, Schneider and Imsdahl are currently eligible for early retirement benefits.

Benefits for single participants under the pension plans are paid as straight life amounts and benefits for married participants are paid as actuarially reduced pensions with a survivor benefit for spouses, unless participants choose otherwise.

The Internal Revenue Code places limitations on benefit amounts that may be paid under the pension plans and on the amount of compensation that may be recognized when determining benefits. In 2007, the maximum annual benefit payable under the pension plans was $180,000 and the maximum amount of compensation that could be recognized when determining benefits was $225,000.

*Supplemental Income Security Plan*

We also offer key managers and executives, including all of our named executive officers, benefits under our non-qualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Benefits under the SISP consist of

- a supplemental retirement benefit intended to supplement the retirement income provided under our qualified pension plans - we refer to this benefit as the regular SISP benefit
- an excess retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under our qualified pension plans - we refer to this benefit as the excess SISP benefit and
- death benefits – we refer to these benefits as the SISP death benefit.

SISP benefits are forfeited if the participant's employment is terminated for cause.

*Regular SISP Benefits and Death Benefits*

Regular SISP benefits and death benefits are determined by reference to a schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedule. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary.

Participants can elect to receive (1) the regular SISP benefit only, (2) the SISP death benefit only or (3) a combination of both. Regardless of the participant's election, if the participant dies before the regular SISP benefit would commence, only the SISP death benefit is provided. If the participant elects to receive both a regular SISP benefit and a SISP death benefit, each of the benefits is reduced proportionately.

The regular SISP benefits reflected in the table above are based on the assumption that the participant elects to receive only the regular SISP benefit. The present values of the SISP death benefits that would be provided if the named executive officers were to die prior to the commencement of regular SISP benefits are reflected in the table that appears in the section entitled "Potential Payments Upon Termination or Change of Control."

We amended the SISP in 2005 to address changes in applicable tax laws resulting from the enactment of section 409A of the Internal Revenue Code. As amended, regular SISP benefits that were vested as of December 31, 2004 and were thereby grandfathered under section 409A remain subject to SISP provisions then in effect. We refer to these benefits as SISP I benefits. Regular SISP benefits that are subject to section 409A, which we refer to as SISP II benefits, are governed by amended provisions intended to comply with section 409A. Participants generally have more discretion with respect to the distributions of their SISP I benefits.

The time and manner in which the regular SISP benefits are paid depend on a variety of factors, including the time and form of benefit elected by the participant and whether the benefits are SISP I or SISP II benefits. Unless the participant elects otherwise, the SISP I benefits are paid over 180 months, with benefits commencing when the participant attains age 65 or, if later, when the participant retires. Distribution of SISP II benefits generally is deferred for six months and the benefits are paid over 173 months. If the participant dies after the regular SISP benefits have begun but before receipt of all of the regular SISP benefits, the remaining payments are made to the participant's designated beneficiary.

Rather than receiving their regular SISP benefits in equal monthly installments over 15 years commencing at age 65, participants can elect a different form and time of commencement of their SISP I benefits. Participants can elect to defer commencement of the regular SISP benefits. If this is elected, the participant retains the right to receive a monthly SISP death benefit if death occurs prior to the commencement of the regular SISP benefit. Alternatively, participants can elect to receive both a regular SISP benefit and a SISP death benefit. A similar, one-time election may be made with respect to SISP II benefits, provided the election is made sufficiently in advance of the date SISP retirement benefits start.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, one hundred percent joint and survivor annuity or a joint and two-thirds joint and survivor annuity, provided that the cost of providing these actuarial equivalent forms of benefits does not exceed the cost of providing the normal form of benefit. Additionally, the SISP's administrator may choose to pay the SISP I benefits in the form of an actuarial equivalent lump sum. Neither the election to receive an actuarial equivalent benefit nor the administrator's right to pay the regular SISP benefit in the form of an actuarially equivalent lump sum are available with respect to SISP II benefits.

To promote retention, the regular SISP benefits are subject to the following ten-year vesting schedule:

- 0% vesting for less than 3 years of participation
- 20% vesting for 3 years of participation
- 40% vesting for 4 years of participation and
- an additional 10% vesting for each additional year of participation up to 100% vesting for 10 years of participation.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedule as the regular SISP benefits.

*Excess SISP Benefits*

Excess SISP benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under our qualified pension plan absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the qualified pension plan. Participants are only eligible for the excess SISP benefits if (1) the participant is fully vested under the qualified pension plan, (2) the participant's employment terminates prior to age 65 and (3) benefits under the qualified pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation. With the exception of Mr. Harp, each of the named executive officers would be entitled to the excess SISP benefits if they were to terminate employment prior to age 65. Mr. Harp must remain employed until age 60 to become entitled to his excess SISP benefit.

Benefits generally commence six months after the participant's employment terminates and continue up to age 65 or until the death of the participant, if prior to age 65. If a participant who dies prior to age 65 elected a joint and survivor benefit, the survivor's excess SISP benefits are paid until the date the participant would have attained age 65.

*Mr. Harp's Additional Retirement Benefit*

To encourage Mr. Harp to remain with the company through 2007, on November 16, 2006, upon recommendation of our chief executive officer and the compensation committee, our board of directors approved an additional retirement benefit for Mr. Harp. The benefit provides for Mr. Harp to receive payments that represent the equivalent of an additional three years of service under the pension plan, excess SISP and the SISP if he did not resign or retire before January 2, 2008 and if he had acceptable successors in place prior to his departure. The additional three years of service recognize Mr. Harp's previous employment with a subsidiary of the company. To calculate payments Mr. Harp could receive due to his additional retirement benefit, we applied the additional years of service to each of the retirement arrangements and assumed that he remained employed until age 60, for purposes of calculating the additional benefit under the pension plan and excess SISP, and age 65, for purposes of calculating the additional benefit under the SISP II. Because Mr. Harp would be fully vested in the SISP II benefit if he retired at age 65, the additional years of service provided by the agreement would not increase his SISP II benefit. Consequently, the amount shown in the table does not include any additional benefit attributable to the SISP II. If Mr. Harp were to retire before achieving 10 years of service and becoming fully vested in his SISP II benefit, the additional years of service provided by the additional retirement benefit would increase his vesting percentage under the SISP II and therefore would result in an additional payment. For a description of the payments that could be provided under the additional retirement benefit if Mr. Harp's employment were to be terminated on December 31, 2007, refer to the table and related notes in "Potential Payment upon Termination or Change of Control" below.

The SISP also provides that if a participant becomes totally disabled, the participant will continue to receive credit for up to two additional years under the SISP as long as the participant is totally disabled during such time. Since the named executive officers other than Mr. Harp are fully vested in their SISP benefits, this would not result in any incremental benefit for the named executive officers other than Mr. Harp. The present value of these two additional years of service for Mr. Harp is reflected in the table that appears in the section entitled "Potential Payments Upon Termination or Change of Control."

## Nonqualified Deferred Compensation for 2007

| Name (a) | Executive Contributions in Last FY ($) (b) | Registrant Contributions in Last FY ($) (c) | Earnings in Aggregate Last FY ($) (d) | Aggregate Withdrawals/ Distributions ($) (e) | Aggregate Balance at Last FYE ($) (f) |
|---|---|---|---|---|---|
| Terry D. Hildestad ............ | — | — | 64,170 | — | 728,975 |
| Vernon A. Raile ............. | — | — | 115,965 | — | 1,317,207 |
| William E. Schneider ......... | 392,000(1) | — | 98,325 | — | 1,168,277 |
| John G. Harp ................ | — | — | — | — | — |
| Bruce T. Imsdahl ............. | 159,278 | — | 31,178 | — | 375,498 |

(1) This amount was reported in the Summary Compensation Table for 2006 in column (g). Amounts reported in the Summary Compensation Table for 2007 in column (g) that our named executive officers have elected to defer are credited in 2008 and will be reflected in this table for 2008.

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts will accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2007, commencing January 1, 2007 was 9.25% or prime rate plus one percent. In August 2007 the compensation committee reduced the interest rate on deferred compensation from the prime rate plus one percentage point to the prime rate, effective January 1, 2008. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was granted. The amounts will be paid in accordance with the participant's election in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

Under the executive incentive compensation plan, upon a change of control, deferred awards become immediately payable. In 2007, the plan's definition of change of control was amended to comply with Section 409A of the Internal Revenue Code. As amended, a change of control is defined as

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors or
- acquisition of our assets having a gross fair market value at least equal to 40% of the total gross fair market value of all of our assets.

## Potential Payments upon Termination or Change of Control

The following tables—Potential Payments upon Termination or Change of Control—show the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios and upon a change of control. The information assumes the terminations and the change of control occurred on December 31, 2007. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables do not include amounts such as base salary, annual incentives and stock awards the named executive officers earned due to employment through December 31, 2007 or compensation or benefits provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan, accrued vacation pay, continuation of health care benefits and life insurance benefits. The tables also do not include the named executive officers' benefits under our non-qualified account balance deferred compensation plan. See the Pension Benefits for 2007 table and the Nonqualified Deferred Compensation for 2007 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans and our non-qualified account balance deferred compensation plan.

We provide disability benefits to all of our salaried employees equal to 60% of their base salary, subject to a cap on the amount of base salary taken into account when calculating benefits. For executives, the limit on base salary is $200,000. For other salaried employees, the limit is $100,000. For all salaried employees, disability payments continue until age 65 if disability occurs at or before age 60 and for 5 years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The amounts in the tables reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. The present value of the disability benefits was determined using a discount rate of 6.0%. As the tables reflect, with the exception of Mr. Harp, the reduction for amounts paid as retirement benefits would eliminate disability benefits assuming a termination of employment on December 31, 2007.

Upon a change of control, share based awards granted under our Long-Term Performance-Based Incentive Plan vest and non-share based awards are paid in cash. All of the named executive officers' outstanding unvested stock options and all shares of restricted stock would vest in full upon a change of control. All performance share awards would vest at their target levels. For this purpose, the term change of control is defined as:

- the public announcement that another entity will acquire 20% or more of our voting stock
- commencement of a tender or exchange offer the consummation of which would result in the acquisition of 30% or more of our voting stock
- the announcement of a transaction that would constitute a change in control under Item 6(e) of Schedule 14A under the Securities Exchange Act of 1934, as amended
- a proposed change in a majority of our board of directors during any two consecutive years, unless the election or nomination of each new director was approved by a vote of at least two-thirds of the directors then still in office who were members of the board at the beginning of the period or
- any other event deemed by a majority of the compensation committee of our board to constitute a change of control.

Shares of restricted stock and associated dividends are forfeited upon termination of employment. Performance shares are forfeited if termination of employment occurs during the first year of the performance period. If a termination of employment occurs for a reason other than cause during the second year of the performance period, the executive receives a prorated portion of any performance shares earned based on the number of months employed during the performance period. If a termination of employment occurs for a reason other than cause during the third year of the performance period, the executive receives the full amount of any performance shares earned. Accordingly, if a December 31, 2007 termination is assumed, the 2007-2009 performance share awards would be forfeited, the 2006-2008 performance share awards would be reduced by 12/36ths and the 2005-2007 performance share awards would be earned. The number of performance shares earned depends on actual performance through the full performance period. To illustrate the potential vesting that could occur under different employment termination scenarios, we assumed target performance would be achieved. Although vesting would only occur after completion of the performance period, the amounts shown in the tables were not reduced to reflect the present value of the performance shares that could vest. Dividend equivalents attributable to earned performance shares would also be paid. Dividend equivalents accrued through December 31, 2007 are included in the amounts shown.

The value of the vesting of shares of restricted stock and performance shares shown in the tables was determined by multiplying the number of shares of restricted stock or performance shares that would vest upon termination or a change of control by the closing price of our stock on December 31, 2007.

We also have change of control employment agreements with our named executive officers and other executives, which provide certain protections to the executives in the event there is a change of control of the company.

For these purposes, we define "change of control" as:

- the acquisition by an individual, entity or group of 20% or more of our voting securities
- a turnover in a majority of our 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
- consummation of a merger or consolidation, unless our stockholders immediately prior to the merger beneficially own more than 60% of the outstanding shares and voting power of the resulting corporation after the merger or
- stockholder approval of our liquidation or dissolution.

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 named executive officer is entitled to receive:

- a base salary not less than twelve times the highest monthly salary paid within the preceding twelve months
- annual bonuses* not less than the highest annual bonus for any of the three years before the change of control and
- participation in our incentive, savings, retirement and welfare benefit plans.

Assuming a change of control occurred on December 31, 2007, the guaranteed minimum level of base salary provided over the three-year employment period would not result in an increase in any

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* "Bonus" for purposes of the change of control employment agreements refers to annual incentive compensation.

of the named executive officers' base salaries. The minimum annual bonus amounts Messrs. Hildestad, Raile, Schneider, Harp and Imsdahl would be entitled to over the three-year employment period would be $1,250,000, $350,700, $392,000, $341,000 and $322,400, respectively. The agreements also provide that severance payments and benefits will be provided:

- if the named executive officer's employment is terminated during the employment period, other than for cause or disability
- if the named executive officer's employment is terminated prior to the change of control, if connected to the change of control, other than for cause or disability or
- the named executive officer resigns for good reason, which includes for any reason during the 30-day period beginning on the first anniversary of the change of control.

"Cause" means the named executive officer's willful and continued failure to substantially perform his duties or willfully engaging in illegal conduct or gross misconduct materially injurious to the company. "Good reason" includes:

- the diminution of the named executive officer's position, authority, duties or responsibilities
- the reduction of the named executive officer's pay or benefits and
- relocation or increased travel obligations.

In such event, the named executive officer would receive:

- accrued but unpaid base salary, accrued but unused vacation and payment of deferred compensation
- a lump sum payment equal to three times his (a) annual salary using the higher of the then current annual salary or twelve times the highest monthly salary paid within the twelve months before the change of control and (b) annual bonus using the highest annual bonus for any of the three years before the change of control or, if higher, the annual bonus for the most recently completed fiscal year
- a pro-rated annual bonus for the year of termination
- an amount equal to the excess of (a) the actuarial equivalent of the benefit under our qualified pension plan and non-qualified defined benefit retirement plans that the executive would receive if employment continued for an additional three years over (b) the actuarial equivalent of the actual benefit paid or payable under these plans
- welfare benefit plan coverage for the executive and his family for three years and an additional three years of service for purposes of determining eligibility for retiree welfare benefits
- outplacement benefits and
- a modified tax gross-up. This is an additional payment to make the executive whole for any federal excise tax on excess parachute payments. The gross-up payment is not made if the total parachute payments are not more than 110% of the safe harbor amount for that tax. In that case, the executive's payments and benefits would be reduced to avoid the tax.

This description of severance payments and benefits reflects the current terms of the agreements. The agreements have not yet been amended to address changes in applicable tax laws under Section 409A of the Internal Revenue Code, but they would be operated in a manner that complies with Section 409A if a payment event were to occur before amendments have been made.

The compensation committee may also consider providing severance benefits on a case-by-case basis for employment terminations not related to a change of control. The compensation committee adopted a checklist of factors in February 2005 to consider when determining whether any such severance benefits should be made. The tables do not reflect any such severance benefits, as these benefits are made in the discretion of the committee on a case by case basis and it is not possible to estimate the severance benefits, if any, that would be made.

*Terry D. Hildestad*

| Executive Benefits and Payments Upon Termination or Change of Control | Voluntary Termination | Not for Cause Termination | For Cause Termination | Death | Disability | Not for Cause or Good Reason Termination (change of control) | Change of Control (without termination) |
|---|---|---|---|---|---|---|---|
| **Compensation:** | | | | | | | |
| Base Salary | | | | | | $ 1,875,000 | |
| Short-term Incentive(1) | | | | | | $ 5,000,000 | |
| 2005-2007 Performance Shares | $ 558,110 | $ 558,110 | | $ 558,110 | $ 558,110 | $ 558,110 | $ 558,110 |
| 2006-2008 Performance Shares | $ 456,856 | $ 456,856 | | $ 456,856 | $ 456,856 | $ 685,284 | $ 685,284 |
| 2007-2009 Performance Shares | | | | | | $ 932,173 | $ 932,173 |
| Restricted Stock | | | | | | $ 102,488 | $ 102,488 |
| **Benefits and Perquisites:** | | | | | | | |
| Incremental Pension | | | | | | | |
| Regular SISP(2) | $2,920,258 | $2,920,258 | | | $2,920,258 | $ 2,920,258 | |
| Excess SISP(3) | $ 649,661 | $ 649,661 | | | $ 649,661 | $ 649,661 | |
| SISP Death Benefits(4) | | | | $8,694,010 | | | |
| Post-Retirement Health Care | | | | | | | |
| Disability Benefits | | | | | | | |
| Continuation of Welfare Benefits | | | | | | $ 59,701 | |
| Outplacement Services | | | | | | $ 50,000 | |
| 280G Tax Gross-up(5) | | | | | | $ 4,465,009 | |
| **Total** | **$4,584,885** | **$4,584,885** | | **$9,708,976** | **$4,584,885** | **$17,297,684** | **$2,278,055** |

(1) Includes the pro-rated annual bonus for the year of termination, which is the full annual bonus since we assume termination occurred on December 31, 2007, and the additional severance payment of three times the annual bonus. For each of these, we used the higher of (1) the annual incentive earned in 2007 or (2) the highest annual incentive earned in 2004, 2005 and 2006.

(2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2007, which was $36,500 per month for 15 years, commencing at age 65. Present value was determined using a 6.0% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2007 table.

(3) Represents the present value of all excess SISP benefits Mr. Hildestad would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2007 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Hildestad's change of control agreement would not increase the actuarial present value of his qualified pension plan benefits or his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of $73,000 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.0% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2007 table.

(5) Assumes an incremental overall tax rate of 41.994%, increased by the Internal Revenue Code section 4999 excise tax of 20%.

*Vernon A. Raile*

| Executive Benefits and Payments Upon Termination or Change of Control | Voluntary Termination | Not for Cause Termination | For Cause Termination | Death | Disability | Not for Cause or Good Reason Termination (change of control) | Change of Control (without termination) |
|---|---|---|---|---|---|---|---|
| **Compensation:** | | | | | | | |
| Base Salary | | | | | | $1,052,100 | |
| Short-term Incentive(1) | | | | | | $1,402,800 | |
| 2005-2007 Performance Shares | $ 182,126 | $ 182,126 | | $ 182,126 | $ 182,126 | $ 182,126 | $182,126 |
| 2006-2008 Performance Shares | $ 237,754 | $ 237,754 | | $ 237,754 | $ 237,754 | $ 356,630 | $356,630 |
| 2007-2009 Performance Shares | | | | | | $ 353,928 | $353,928 |
| Restricted Stock | | | | | | $ 30,758 | $ 30,758 |
| **Benefits and Perquisites:** | | | | | | | |
| Incremental Pension | | | | | | | |
| Regular SISP(2) | $1,724,857 | $1,724,857 | | | $1,724,857 | $1,724,857 | |
| Excess SISP(3) | $ 35,448 | $ 35,448 | | | $ 35,448 | $ 35,448 | |
| SISP Death Benefits(4) | | | | $3,837,274 | | | |
| Post-Retirement Health Care | | | | | | | |
| Disability Benefits | | | | | | | |
| Continuation of Welfare Benefits | | | | | | $ 54,920 | |
| Outplacement Services | | | | | | $ 50,000 | |
| 280G Tax Gross-up(5) | | | | | | $1,632,294 | |
| **Total** | **$2,180,185** | **$2,180,185** | | **$4,257,154** | **$2,180,185** | **$6,875,861** | **$923,442** |

(1) Includes the pro-rated annual bonus for the year of termination, which is the full annual bonus since we assume termination occurred on December 31, 2007, and the additional severance payment of three times the annual bonus. For each of these, we used the higher of (1) the annual incentive earned in 2007 or (2) the highest annual incentive earned in 2004, 2005 and 2006.

(2) Represents the present value of Mr. Raile's vested regular SISP benefit as of December 31, 2007, which was $16,110 per month for 15 years, commencing at age 65. Present value was determined using a 6.0% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2007 table.

(3) Represents the present value of all excess SISP benefits Mr. Raile would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2007 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Raile's change of control agreement would not increase the actuarial present value of his qualified pension plan benefits or his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of $32,220 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.0% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2007 table.

(5) Assumes an incremental overall tax rate of 41.994%, increased by the Internal Revenue Code section 4999 excise tax of 20%.

*William E. Schneider*

| Executive Benefits and Payments Upon Termination or Change of Control | Voluntary Termination | Not for Cause Termination | For Cause Termination | Death | Disability | Not for Cause or Good Reason Termination (change of control) | Change of Control (without termination) |
|---|---|---|---|---|---|---|---|
| **Compensation:** | | | | | | | |
| Base Salary | | | | | | $1,266,000 | |
| Short-term Incentive(1) | | | | | | $1,568,000 | |
| 2005-2007 Performance Shares | $ 377,123 | $ 377,123 | | $ 377,123 | $ 377,123 | $ 377,123 | $ 377,123 |
| 2006-2008 Performance Shares | $ 292,386 | $ 292,386 | | $ 292,386 | $ 292,386 | $ 438,579 | $ 438,579 |
| 2007-2009 Performance Shares | | | | | | $ 425,902 | $ 425,902 |
| Restricted Stock | | | | | | $ 82,002 | $ 82,002 |
| **Benefits and Perquisites:** | | | | | | | |
| Incremental Pension(2) | | | | | | $ 46,868 | |
| Regular SISP(3) | $1,755,218 | $1,755,218 | | | $1,755,218 | $1,755,218 | |
| Excess SISP | $114,031(4) | $114,031(4) | | | $114,031(4) | $ 81,695(5) | |
| SISP Death Benefits(6) | | | | $4,650,700 | | | |
| Post-Retirement Health Care | | | | | | | |
| Disability Benefits | | | | | | | |
| Continuation of Welfare Benefits | | | | | | $ 41,943 | |
| Outplacement Services | | | | | | $ 50,000 | |
| 280G Tax Gross-up(7) | | | | | | $1,943,884 | |
| **Total** | **$2,538,758** | **$2,538,758** | | **$5,320,209** | **$2,538,758** | **$8,077,214** | **$1,323,606** |

(1) Includes the pro-rated annual bonus for the year of termination, which is the full annual bonus since we assume termination occurred on December 31, 2007, and the additional severance payment of three times the annual bonus. For each of these, we used the higher of (1) the annual incentive earned in 2007 or (2) the highest annual incentive earned in 2004, 2005 and 2006.

(2) Represents the payment that would be made under Mr. Schneider's change of control agreement based on the increase in the actuarial present value of his qualified pension plan benefit that would result if he continued employment for an additional three years.

(3) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2007, which was $19,525 per month for 15 years, commencing at age 65. Present value was determined using a 6.0% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2007 table.

(4) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2007 table.

(5) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to upon termination of employment under the SISP, plus the payment that would be made under Mr. Schneider's change of control agreement based on the increase in the actuarial present value of his excess SISP benefit that would result if he continued employment for an additional three years.

(6) Represents the present value of 180 monthly payments of $39,050 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.0% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2007 table.

(7) Assumes an incremental overall tax rate of 41.994%, increased by the Internal Revenue Code section 4999 excise tax of 20%.

*John G. Harp*

| Executive Benefits and Payments Upon Termination or Change of Control | Voluntary Termination | Not for Cause Termination | For Cause Termination | Death | Disability | Not for Cause or Good Reason Termination (change of control) | Change of Control (without termination) |
|---|---|---|---|---|---|---|---|
| **Compensation:** | | | | | | | |
| Base Salary | | | | | | $1,023,000 | |
| Short-term Incentive(1) | | | | | | $1,364,000 | |
| 2005-2007 Performance Shares | $314,254 | $314,254 | | $ 314,254 | $ 314,254 | $ 314,254 | $314,254 |
| 2006-2008 Performance Shares | $192,676 | $192,676 | | $ 192,676 | $ 192,676 | $ 289,000 | $289,000 |
| 2007-2009 Performance Shares | | | | | | $ 286,799 | $286,799 |
| Restricted Stock | | | | | | | |
| **Benefits and Perquisites:** | | | | | | | |
| Incremental Pension(2) | | | | | | $ 270,154 | |
| Regular SISP | | | | | $322,794(3) | $652,676(4) | |
| Excess SISP | | | | | | | |
| SISP Death Benefits(5) | | | | $2,892,843 | | | |
| Post-Retirement Health Care | | | | | | | |
| Disability Benefits | | | | | | $ 444,292 | |
| Continuation of Welfare Benefits | | | | | | $ 38,890 | |
| Outplacement Services | | | | | | $ 50,000 | |
| 280G Tax Gross-up(6) | | | | | | $1,694,778 | |
| **Total** | **$506,930** | **$506,930** | | **$3,399,773** | **$ 829,724** | **$6,427,843** | **$890,053** |

(1) Includes the pro-rated annual bonus for the year of termination, which is the full annual bonus since we assume termination occurred on December 31, 2007, and the additional severance payment of three times the annual bonus. For each of these, we used the higher of (1) the annual incentive earned in 2007 or (2) the highest annual incentive earned in 2004, 2005 and 2006.

(2) Represents the payment that would be made under Mr. Harp's change of control agreement based on the increase in the actuarial present value of his qualified pension plan benefit that would result if he continued employment for an additional three years. Also represents the equivalent of three additional years of service that would be provided under the retirement benefit agreement described following the Pension Benefits for 2007 table.

(3) Represents the present value of the additional SISP retirement benefit due to an additional two years vesting under our SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2007 table. Present value was determined using a 6.0% discount rate.

(4) Represents the payment that would be made under Mr. Harp's change of control agreement based on the increase in the actuarial present value of his regular SISP benefit that would result if he continued employment for an additional three years. Also includes the additional benefit attributable to three additional years of service that would be provided under the retirement benefit agreement described following the Pension Benefits for 2007 table.

(5) Represents the present value of 180 monthly payments of $24,290 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.0% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2007 table.

(6) Assumes an incremental overall tax rate of 36.45%, increased by the Internal Revenue Code section 4999 excise tax of 20%.

*Bruce T. Imsdahl*

| Executive Benefits and Payments Upon Termination or Change of Control | Voluntary Termination | Not for Cause Termination | For Cause Termination | Death | Disability | Not for Cause or Good Reason Termination (change of control) | Change of Control (without termination) |
|---|---|---|---|---|---|---|---|
| **Compensation:** | | | | | | | |
| Base Salary | | | | | | $ 967,200 | |
| Short-term Incentive(1) | | | | | | $1,289,600 | |
| 2005-2007 Performance Shares | $ 358,239 | $ 358,239 | | $ 358,239 | $ 358,239 | $ 358,239 | $358,239 |
| 2006-2008 Performance Shares | $ 192,676 | $ 192,676 | | $ 192,676 | $ 192,676 | $ 289,000 | $289,000 |
| 2007-2009 Performance Shares | | | | | | $ 271,136 | $271,136 |
| Restricted Stock | | | | | | $ 41,001 | $ 41,001 |
| **Benefits and Perquisites:** | | | | | | | |
| Incremental Pension | | | | | | | |
| Regular SISP(2) | $1,091,786 | $1,091,786 | | | $1,091,786 | $1,091,786 | |
| Excess SISP(3) | $ 123,362 | $ 123,362 | | | $ 123,362 | $ 123,362 | |
| SISP Death Benefits(4) | | | | $2,892,843 | | | |
| Post-Retirement Health Care | | | | | | | |
| Disability Benefits | | | | | | | |
| Continuation of Welfare Benefits | | | | | | $ 60,076 | |
| Outplacement Services | | | | | | $ 50,000 | |
| 280G Tax Gross-up(5) | | | | | | $1,436,776 | |
| **Total** | **$1,766,063** | **$1,766,063** | | **$3,443,758** | **$1,766,063** | **$5,978,176** | **$959,376** |

(1) Includes the pro-rated annual bonus for the year of termination, which is the full annual bonus since we assume termination occurred on December 31, 2007, and the additional severance payment of three times the annual bonus. For each of these, we used the higher of (1) the annual incentive earned in 2007 or (2) the highest annual incentive earned in 2004, 2005 and 2006.

(2) Represents the present value of Mr. Imsdahl's vested regular SISP benefit as of December 31, 2007, which was $12,145 per month for 15 years, commencing at age 65. Present value was determined using a 6.0% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2007 table.

(3) Represents the present value of all excess SISP benefits Mr. Imsdahl would be entitled to upon termination of employment under the SISP. The terms of the excess SISP benefit are described following the Pension Benefits for 2007 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Imsdahl's change of control agreement would not increase the actuarial present value of his qualified pension plan benefits or his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of $24,290 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 6.0% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2007 table.

(5) Assumes an incremental overall tax rate of 41.994%, increased by the Internal Revenue Code section 4999 excise tax of 20%.

## Director Compensation for 2007

| Name (a) | Fees Earned or Paid in Cash ($) (b)(1) | Stock Awards ($) (c)(2) | Option Awards ($) (d) | Non-Equity Incentive Plan Compensation ($) (e) | Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f) | All Other Compensation ($) (g)(3) | Total ($) (h) |
|---|---|---|---|---|---|---|---|
| Thomas Everist ......... | 57,500 | 125,825 | —(4) | — | — | 276 | 183,601 |
| Karen B. Fagg ........... | 57,000(5) | 125,825 | — | — | — | 276 | 183,101 |
| Dennis W. Johnson ...... | 65,500(6) | 125,825 | — | — | — | 276 | 191,601 |
| Richard H. Lewis ........ | 60,000 | 125,825 | — | — | — | 276 | 186,101 |
| Patricia L. Moss ......... | 52,500(7) | 125,825 | — | — | — | 276 | 178,601 |
| John L. Olson ........... | 65,000 | 125,825 | —(8) | — | — | 276 | 191,101 |
| Harry J. Pearce .......... | 80,000 | 175,825(9) | —(10) | — | — | 276 | 256,101 |
| Sister Thomas Welder, O.S.B. ................. | 45,000 | 125,825 | — | — | — | 276 | 171,101 |
| John K. Wilson .......... | 55,500(11) | 125,825 | — | — | — | 276 | 181,601 |

(1) Amounts rounded to exclude receipt of cash in lieu of fractional shares of common stock.

(2) Valued based on $31.07, the purchase price of the stock on the date of grant, April 27, 2007, which is the grant date fair value.

(3) Group life insurance premium.

(4) Mr. Everist had 28,686 stock options outstanding as of December 31, 2007.

(5) Includes $18,000 that Ms. Fagg received in our common stock in lieu of cash.

(6) Includes $65,500 that Mr. Johnson received in our common stock in lieu of cash.

(7) Includes $52,500 that Ms. Moss received in our common stock in lieu of cash.

(8) Mr. Olson had 23,624 stock options outstanding as of December 31, 2007.

(9) Includes $125,825 for the April 27, 2007 stock grant and $50,000 of stock as part of Mr. Pearce's retainer as chairman of the board.

(10) Mr. Pearce had 13,500 stock options outstanding as of December 31, 2007.

(11) Includes $30,000 that Mr. Wilson received in our common stock in lieu of cash.

# BALANCE SHEET

Year: 2007

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | **Assets and Other Debits** | | | |
| 2 | Utility Plant | | | | |
| 3 | 101 | Gas Plant in Service | $245,828,420 | $261,025,044 | 6.18% |
| 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 | 2,377,127 | 9,441,802 | 297.19% |
| 11 | 108 | (Less) Accumulated Depreciation | (154,122,605) | (160,748,664) | 4.30% |
| 12 | 111 | (Less) Accumulated Amortization & Depletion | (828,529) | (886,959) | 7.05% |
| 13 | 114 | Gas Plant Acquisition Adjustments | 12,606,238 | 97,266 | -99.23% |
| 14 | 115 | (Less) Accum. Amort. Gas Plant Acq. Adj. | (3,236,143) | (41,114) | -98.73% |
| 15 | 116 | Other Gas Plant Adjustments | | | |
| 16 | 117 | Gas Stored Underground - Noncurrent | 3,893,518 | 2,757,982 | -29.16% |
| 17 | 118 | Other Utility Plant | 729,448,508 | 814,331,376 | 11.64% |
| 18 | 119 | Accum. Depr. and Amort. - Other Utl. Plant | (422,359,241) | (437,270,775) | 3.53% |
| 19 | | **TOTAL Utility Plant** | $413,633,065 | $488,731,730 | 18.16% |
| 20 | **Other Property & Investments** | | | | |
| 21 | 121 | Nonutility Property | $2,657,836 | $3,117,373 | 17.29% |
| 22 | 122 | (Less) Accum. Depr. & Amort. of Nonutil. Prop. | (910,813) | (1,013,133) | 11.23% |
| 23 | 123 | Investments in Associated Companies | | | |
| 24 | 123.1 | Investments in Subsidiary Companies | 1,950,702,048 | 2,284,551,173 | 17.11% |
| 25 | 124 | Other Investments | 37,506,147 | 40,972,687 | 9.24% |
| 26 | 125 | Sinking Funds | | | |
| 27 | | **TOTAL Other Property & Investments** | $1,989,955,218 | $2,327,628,100 | 16.97% |
| 28 | **Current & Accrued Assets** | | | | |
| 29 | 131 | Cash | $17,325,263 | $2,633,013 | -84.80% |
| 30 | 132-134 | Special Deposits | 1,200 | 1,200 | 0.00% |
| 31 | 135 | Working Funds | 80,790 | 163,690 | 102.61% |
| 32 | 136 | Temporary Cash Investments | 736,071 | 422,455 | -42.61% |
| 33 | 141 | Notes Receivable | | | |
| 34 | 142 | Customer Accounts Receivable | 33,082,491 | 27,981,262 | -15.42% |
| 35 | 143 | Other Accounts Receivable | 3,620,779 | 3,357,347 | -7.28% |
| 36 | 144 | (Less) Accum. Provision for Uncollectible Accts. | (284,641) | (230,059) | -19.18% |
| 37 | 145 | Notes Receivable - Associated Companies | | | |
| 38 | 146 | Accounts Receivable - Associated Companies | 23,870,580 | 30,629,676 | 28.32% |
| 39 | 151 | Fuel Stock | 4,006,441 | 4,055,099 | 1.21% |
| 40 | 152 | Fuel Stock Expenses Undistributed | | | |
| 41 | 153 | Residuals and Extracted Products | | | |
| 42 | 154 | Plant Materials and Operating Supplies | 7,733,344 | 9,128,932 | 18.05% |
| 43 | 155 | Merchandise | 1,445,448 | 1,470,096 | 1.71% |
| 44 | 156 | Other Material & Supplies | | | |
| 45 | 163 | Stores Expense Undistributed | | | |
| 46 | 164.1 | Gas Stored Underground - Current | 29,714,379 | 18,158,827 | -38.89% |
| 47 | 165 | Prepayments | 4,753,587 | 4,425,641 | -6.90% |
| 48 | 166 | Advances for Gas Explor., Devl. & Production | | | |
| 49 | 171 | Interest & Dividends Receivable | | | |
| 50 | 172 | Rents Receivable | | | |
| 51 | 173 | Accrued Utility Revenues | 35,632,536 | 39,762,227 | 11.59% |
| 52 | 174 | Miscellaneous Current & Accrued Assets | 1,774,615 | 184,014 | -89.63% |
| 53 | | **TOTAL Current & Accrued Assets** | $163,492,883 | $142,143,420 | -13.06% |

# BALANCE SHEET

Year: 2007

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | **Assets and Other Debits (cont.)** | | | |
| 2 | | | | |
| 3 | **Deferred Debits** | | | |
| 4 | | | | |
| 5 | 181 Unamortized Debt Expense | $955,806 | $893,195 | -6.55% |
| 6 | 182.1 Extraordinary Property Losses | | | |
| 7 | 182.2 Unrecovered Plant & Regulatory Study Costs | | | |
| | 182.3 Other Regulatory Assets | 25,546,923 | 20,474,249 | -19.86% |
| | 183 Prelim. Electric Survey & Investigation Chrg. | 449,996 | 766,627 | 70.36% |
| 8 | 183.1 Prelim. Nat. Gas Survey & Investigation Chrg. | 66,452 | 17,318 | -73.94% |
| 9 | 183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs. | | | |
| 10 | 184 Clearing Accounts | (142,924) | (49,436) | -65.41% |
| 11 | 185 Temporary Facilities | | | |
| 12 | 186 Miscellaneous Deferred Debits | 19,052,180 | 30,878,709 | 62.07% |
| 13 | 187 Deferred Losses from Disposition of Util. Plant | | | |
| 14 | 188 Research, Devel. & Demonstration Expend. | | | |
| 15 | 189 Unamortized Loss on Reacquired Debt | 11,231,577 | 10,604,809 | -5.58% |
| 16 | 190 Accumulated Deferred Income Taxes | 34,268,544 | 37,651,678 | 9.87% |
| 17 | 191 Unrecovered Purchased Gas Costs | (7,516,468) | 3,474,582 | -146.23% |
| 18 | 192.1 Unrecovered Incremental Gas Costs | | | |
| 19 | 192.2 Unrecovered Incremental Surcharges | | | |
| 20 | **TOTAL Deferred Debits** | $83,912,086 | $104,711,731 | 24.79% |
| 21 | | | | |
| 22 | **TOTAL ASSETS & OTHER DEBITS** | $2,650,993,252 | $3,063,214,981 | 15.55% |

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 23 | **Liabilities and Other Credits** | | | |
| 24 | | | | |
| 25 | **Proprietary Capital** | | | |
| 26 | | | | |
| 27 | 201 Common Stock Issued | $181,557,543 | $182,946,528 | 0.77% |
| 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 | 877,665,566 | 916,218,614 | 4.39% |
| 32 | 211 Miscellaneous Paid-In Capital | | | |
| 33 | 213 (Less) Discount on Capital Stock | | | |
| 34 | 214 (Less) Capital Stock Expense | (3,412,569) | (3,412,569) | 0.00% |
| 35 | 216 Appropriated Retained Earnings | 53,187,450 | 303,634,911 | 470.88% |
| 36 | 216.1 Unappropriated Retained Earnings | 1,051,023,038 | 1,129,950,735 | 7.51% |
| 37 | 217 (Less) Reacquired Capital Stock | (3,625,813) | (3,625,813) | 0.00% |
| 38 | 219 Accumulated Other Comprehensive Income | (6,482,400) | (9,393,173) | -44.90% |
| 39 | **TOTAL Proprietary Capital** | $2,164,912,815 | $2,531,319,233 | 16.92% |
| 40 | | | | |
| 41 | **Long Term Debt** | | | |
| 42 | | | | |
| 43 | 221 Bonds | $157,000,000 | $150,500,000 | -4.14% |
| 44 | 222 (Less) Reacquired Bonds | | | |
| 45 | 223 Advances from Associated Companies | | | |
| 46 | 224 Other Long Term Debt | 26,650,000 | 61,800,000 | 131.89% |
| 47 | 225 Unamortized Premium on Long Term Debt | | | |
| 48 | 226 (Less) Unamort. Discount on Long Term Debt-Dr. | (2,997) | (2,417) | -19.35% |
| 49 | **TOTAL Long Term Debt** | $183,647,003 | $212,297,583 | 15.60% |

# BALANCE SHEET

Year: 2007

| | 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 | $1,057,598 | $1,821,121 | 72.19% |
| 9 | 228.3 | Accumulated Provision for Pensions & Benefits | 41,940,504 | 45,052,837 | 7.42% |
| 10 | 228.4 | Accumulated Misc. Operating Provisions | | | |
| 11 | 229 | Accumulated Provision for Rate Refunds | 1,567,886 | 0 | -100.00% |
| 12 | 230 | Asset Retirement Obligations | 3,128,412 | 2,518,372 | -19.50% |
| 13 | | **TOTAL Other Noncurrent Liabilities** | $47,694,400 | $49,392,330 | 3.56% |
| 14 | | | | | |
| 15 | **Current & Accrued Liabilities** | | | | |
| 16 | | | | | |
| 17 | 231 | Notes Payable | $0 | $0 | 0.00% |
| 18 | 232 | Accounts Payable | 32,330,118 | 49,239,911 | 52.30% |
| 19 | 233 | Notes Payable to Associated Companies | | | |
| 20 | 234 | Accounts Payable to Associated Companies | 18,146,315 | 9,391,348 | -48.25% |
| 21 | 235 | Customer Deposits | 2,322,058 | 2,340,670 | 0.80% |
| 22 | 236 | Taxes Accrued | 15,637,578 | 19,382,784 | 23.95% |
| 23 | 237 | Interest Accrued | 2,800,536 | 2,664,504 | -4.86% |
| 24 | 238 | Dividends Declared | 24,606,427 | 26,619,224 | 8.18% |
| 25 | 239 | Matured Long Term Debt | | | |
| 26 | 240 | Matured Interest | | | |
| 27 | 241 | Tax Collections Payable | 1,824,219 | 1,525,151 | -16.39% |
| 28 | 242 | Miscellaneous Current & Accrued Liabilities | 21,263,357 | 25,405,080 | 19.48% |
| 29 | 243 | Obligations Under Capital Leases - Current | | | |
| 30 | | **TOTAL Current & Accrued Liabilities** | $118,930,608 | $136,568,672 | 14.83% |
| 31 | | | | | |
| 32 | **Deferred Credits** | | | | |
| 33 | | | | | |
| 34 | 252 | Customer Advances for Construction | $2,604,275 | $3,342,874 | 28.36% |
| 35 | 253 | Other Deferred Credits | 47,443,787 | 46,514,581 | -1.96% |
| 36 | 254 | Other Regulatory Liabilities | 11,145,347 | 10,023,560 | -10.07% |
| 37 | 255 | Accumulated Deferred Investment Tax Credits | 965,261 | 609,529 | -36.85% |
| 38 | 256 | Deferred Gains from Disposition Of Util. Plant | | | |
| 39 | 257 | Unamortized Gain on Reacquired Debt | | | |
| 40 | 281-283 | Accumulated Deferred Income Taxes | 73,649,756 | 73,146,619 | -0.68% |
| 41 | | **TOTAL Deferred Credits** | $135,808,426 | $133,637,163 | -1.60% |
| 42 | | | | | |
| 43 | **TOTAL LIABILITIES & OTHER CREDITS** | | $2,650,993,252 | $3,063,214,981 | 15.55% |

**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, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Construction services, natural gas and oil production, construction materials and contracting, and other are nonregulated. For further descriptions of the Company's businesses, see Note 16. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

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. 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 6 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, 2007 and 2006, was $14.6 million and $7.7 million, respectively.

**Natural gas in underground storage**

Natural gas in underground storage for the Company's regulated operations is generally 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 $28.8 million and $32.6 million at December 31, 2007 and 2006, respectively. The remainder of natural gas in underground storage, which represents the cost of the gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $43.0 million and $44.2 million at December 31, 2007 and 2006, respectively.

**Inventories**

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $102.2 million and $88.1 million, materials and supplies of $56.0 million and $54.1 million, and other inventories of $42.3 million and $29.6 million, as of December 31, 2007 and 2006, respectively. These inventories were stated at the lower of average cost or market value.

**Short-term investments**

The Company had auction rate securities of $91.6 million and $23.3 million at December 31, 2007 and 2006, respectively, which are long-term variable rate bonds tied to short-term interest rates that are reset through an auction process which typically occurs every 90 days or less. The Company accounts for these investments as available-for-sale in accordance with SFAS No. 115. Due to the short interest rate reset period, the fair value of the auction rate securities approximates cost and, as a result, there are no

| 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 | 12/31/2007 | 2007/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

accumulated unrealized gains or losses recorded in accumulated other comprehensive income on the Consolidated Balance Sheets related to these investments.

**Investments**

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, and investments in fixed-income and equity securities which are accounted for as available-for-sale investments in accordance with SFAS No. 115. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company's fixed-income and equity securities are recorded at fair value with any unrealized gains and losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. For more information, see comprehensive income in this note.

**Property, plant and equipment**

Additions to property, plant and equipment are recorded at cost. 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 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 $7.1 million, $5.8 million and $4.3 million in 2007, 2006 and 2005, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method based on recoverable aggregate reserves, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves.

| 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 | 12/31/2007 | 2007/Q4 |

NOTES TO FINANCIAL STATEMENTS (Continued)

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

| | 2007 | 2006 | Estimated Depreciable Life in Years |
|---|---|---|---|
| | *(Dollars in thousands, as applicable)* | | |
| Regulated: | | | |
| Electric: | | | |
| Electric generation, distribution and transmission plant | **$ 784,705** | $ 703,838 | 4-50 |
| Natural gas distribution: | | | |
| Natural gas distribution plant | **948,446** | 289,106 | 4-45 |
| Pipeline and energy services: | | | |
| Natural gas transmission, gathering and storage facilities | **403,459** | 384,354 | 8-104 |
| Nonregulated: | | | |
| Construction services: | | | |
| Land | **4,513** | 3,974 | - |
| Buildings and improvements | **11,987** | 11,288 | 3-40 |
| Machinery, vehicles and equipment | **76,937** | 70,687 | 2-10 |
| Other | **8,498** | 8,805 | 3-10 |
| Pipeline and energy services: | | | |
| Natural gas gathering and other facilities | **197,253** | 178,242 | 3-20 |
| Natural gas and oil production: | | | |
| Natural gas and oil properties | **1,892,757** | 1,606,508 | * |
| Other | **31,142** | 29,737 | 3-15 |
| Construction materials and contracting: | | | |
| Land | **115,935** | 95,294 | - |
| Buildings and improvements | **94,598** | 96,533 | 1-40 |
| Machinery, vehicles and equipment | **921,199** | 817,209 | 1-20 |
| Construction in progress | **22,253** | 23,968 | - |
| Aggregate reserves | **384,731** | 377,653 | ** |
| Other: | | | |
| Land | **3,022** | 3,079 | - |
| Other | **28,811** | 27,450 | 3-40 |
| Less accumulated depreciation, depletion and amortization | **2,270,691** | 1,735,302 | |
| Net property, plant and equipment | **$ 3,659,555** | $ 2,992,423 | |

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.59, $1.38 and $1.19 for the years ended December 31, 2007, 2006 and 2005, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $142.5 million and $164.0 million were excluded from amortization at December 31, 2007 and 2006, respectively.*

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

**Impairment of long-lived assets**

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, 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. No significant impairment losses were recorded in 2007, 2006 and 2005. 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, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. For more information on goodwill impairments and goodwill, see Notes 3 and 5.

**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, plus 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, 2007 and 2006, 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, 2007, 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, 2007, in total and by the year in which such costs were incurred:

| | | Year Costs Incurred | | | |
|---|---|---|---|---|---|
| | Total | 2007 | 2006 | 2005 | 2004 and prior |
| | | *(In thousands)* | | | |
| Acquisition | $ 62,619 | $15,632 | $ 19,135 | $ 8,812 | $19,040 |
| Development | 60,352 | 33,380 | 16,853 | 5,225 | 4,894 |
| Exploration | 15,643 | 13,771 | 812 | 1,060 | --- |
| Capitalized interest | 3,910 | 1,771 | 1,038 | 426 | 675 |
| Total costs not subject to amortization | $142,524 | $64,554 | $ 37,838 | $15,523 | $24,609 |

Costs not subject to amortization as of December 31, 2007, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with CBNG in the Powder River Basin of Montana and Wyoming; oil and gas development in the Big Horn Basin of Wyoming; an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana; oil and gas development in the Paradox Basin of Utah; a waterflood facility and injection project in southern Texas; and development of the Bakken play in western North Dakota. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

**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 reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota and Cascade was $66.6 million at December 31, 2007. Accrued unbilled revenue at Montana-Dakota was $35.6 million at December 31, 2006. 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 properties only on that portion of production sold and allocable to the Company's ownership interest in the related well. 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 $45.2 million and $41.3 million at December 31, 2007 and 2006, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $81.4 million and $84.2 million at December 31, 2007 and 2006, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $80.3 million and $81.8 million at December 31, 2007 and 2006, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $68.9 million and $81.8 million at December 31, 2007 and 2006, respectively. The long-term retainage which was included in deferred charges and other assets - other was $11.4 million at December 31, 2007.

**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 to derivative instruments in the event of nonperformance by counterparties. The Company's policy generally requires that natural gas and oil price derivative instruments at Fidelity 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 allows Cascade to maintain a portfolio of natural gas derivative instruments not to exceed a period of three years. 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. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

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**Asset retirement obligations**
The Company records 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 at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 11.

**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 14 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $11.6 million and $7.5 million at December 31, 2007 and 2006, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $3.9 million at December 31, 2007, 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 $750,000 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 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 the Brazilian Transmission Lines and its former investment in the Termoceara Generating Facility, as further discussed in Note 4, 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 are translated on a year-to-date basis using weighted average daily exchange rates. 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 would be recorded in income.

**Common stock split**
On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 13.

**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. In 2007, 2006 and 2005, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

**Stock-based compensation**
On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In accordance with the modified prospective method, the Company's consolidated financial statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123 (revised).

On January 1, 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 accounted for stock options granted prior to January 1, 2003, under APB Opinion No. 25 and no compensation expense was recognized 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 following table illustrates the effect on earnings and earnings per common share for the year ended December 31, 2005, 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:

| | 2005 |
|---|---|
| | *(In thousands, except per share amounts)* |
| Earnings on common stock, as reported | $ 274,398 |
| Stock-based compensation expense included in reported earnings, net of related tax effects of $1 | 2 |
| Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects | (471) |
| Pro forma earnings on common stock | $ 273,929 |
| Earnings per common share – basic – as reported | $ 1.54 |
| Earnings per common share – basic – pro forma | $ 1.54 |
| Earnings per common share – diluted – as reported | $ 1.53 |
| Earnings per common share – diluted – pro forma | $ 1.53 |

For more information on the Company's stock-based compensation, see Note 14.

**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, as well as 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; aggregate 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. 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, | **2007** | 2006 | 2005 |
|---|---|---|---|
| | | *(In thousands)* | |
| Interest, net of amount capitalized | **$ 74,404** | $ 65,850 | $ 47,902 |
| Income taxes | **$214,573** | $105,317 | $106,771 |

Income taxes paid for the year ended December 31, 2007, increased from the amount paid for the years ended December 31, 2006 and 2005, primarily due to higher estimated quarterly tax payments due in large part to the gain on the sale of the domestic independent power production assets as discussed in Note 3.

**New accounting standards**

***FIN 48*** In July 2006, the FASB issued FIN 48. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise's financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination. FIN 48 was effective for the Company on January 1, 2007. The adoption of FIN 48 did not have a material effect on the Company's financial position or results of operations. For more information on the implementation of FIN 48, see Note 15.

***SFAS No. 157*** In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions. SFAS No. 157 was effective for the Company on January 1, 2008. The adoption of SFAS No. 157 did not have a material effect on the Company's financial position or results of operations.

***SFAS No. 159*** In February 2007, the FASB issued SFAS No. 159. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. The standard also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 was effective for the Company on January 1, 2008, and at adoption, the Company elected to measure its investments in certain fixed-income and equity securities at fair value in accordance with SFAS No. 159. These investments prior to January 1, 2008, were accounted for as available-for-sale investments and recorded at fair value with any unrealized gains or losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. Upon the adoption of SFAS No. 159, the unrealized gain on the available-for-sale investments of $405,000 (after tax) was recorded as an increase to the January 1, 2008, balance of retained earnings. The adoption of SFAS No. 159 did not have a material effect on the Company's financial position or results of operations.

***SFAS No. 141 (revised)*** In December 2007, the FASB issued SFAS No. 141 (revised). SFAS No. 141 (revised) requires an acquirer to recognize and measure the assets acquired, liabilities assumed and any noncontrolling interests in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exception. In addition, SFAS No. 141 (revised) requires that acquisition-related costs will be generally expensed as incurred. SFAS No. 141 (revised) also expands the disclosure requirements for business combinations. SFAS No. 141 (revised) will be effective for the Company on January 1, 2009. The Company is evaluating the effects of the adoption of SFAS No. 141 (revised).

***SFAS No. 160*** In December 2007, the FASB issued SFAS No. 160. SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 will be effective for the Company on January 1, 2009. The Company is evaluating the effects of the adoption of SFAS No. 160.

**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, pension liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2007, 2006 and 2005, were as follows:

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | *(In thousands)* | | |
| Other comprehensive income (loss): | | | |
| Net unrealized gain (loss) on derivative instruments qualifying as hedges: | | | |
| Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $3,989, $12,359 and $(16,391) in 2007, 2006 and 2005, respectively | **$ 6,508** | $19,743 | $(26,167) |
| Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $12,504, $(16,194) and $(2,734) in 2007, 2006 and 2005, respectively | **20,013** | (25,867) | (4,367) |
| Net unrealized gain (loss) on derivative instruments qualifying as hedges | **(13,505)** | 45,610 | (21,800) |
| Pension liability adjustment, net of tax of $1,835, $1,122 and $353 in 2007, 2006 and 2005, respectively | **3,012** | 1,761 | 574 |
| Foreign currency translation adjustment, net of tax of $3,606 in 2007 | **7,177** | (1,585) | (1,099) |
| Net unrealized gain on available-for-sale investments, net of tax of $270 in 2007 | **405** | --- | --- |
| Total other comprehensive income (loss) | **$ (2,911)** | $45,786 | $(22,325) |

The after-tax components of accumulated other comprehensive loss as of December 31, 2007, 2006 and 2005, were as follows:

| | Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges | Pension Liability Adjustment | Foreign Currency Translation Adjustment | Net Unrealized Gain on Available-for-sale Investment | Total Accumulated Other Comprehensive Loss |
|---|---|---|---|---|---|
| | | *(In thousands)* | | | |
| Balance at December 31, 2005 | $ (26,167) | $ (7,651) | $ 2 | $ --- | $(33,816) |
| Balance at December 31, 2006 | $ 19,443 | $(24,342) | $ (1,583) | $ --- | $ (6,482) |
| **Balance at December 31, 2007** | **$ 5,938** | **$(21,330)** | **$ 5,594** | **$ 405** | **$ (9,393)** |

**NOTE 2 - ACQUISITIONS**

In 2007, the Company acquired construction materials and contracting businesses in North Dakota, Texas and Wyoming, a construction services business in Nevada, and Cascade, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain

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other acquisitions made prior to 2007, consisting of the Company's common stock and cash and the outstanding indebtedness of Cascade, was $526.3 million.

On July 2, 2007, the acquisition of Cascade was finalized and Cascade became an indirect wholly owned subsidiary of the Company. The acquisition of Cascade was funded with cash (largely proceeds from the sale of the domestic independent power production assets) and debt. Cascade's natural gas service areas are in Washington and Oregon.

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, and construction materials and contracting businesses in California and Washington, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was $120.6 million.

In 2005, the Company acquired construction services businesses in Nevada, natural gas and oil production properties in southern Texas and construction materials and contracting businesses in Idaho, Iowa and Oregon, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions acquired prior to 2005, consisting of the Company's common stock and cash, was $245.2 million.

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. On certain of the above acquisitions made in 2007, final fair market values are pending the completion of the review of the relevant assets and liabilities as of the acquisition date. The results of operations of the acquired businesses and properties 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 3 - DISCONTINUED OPERATIONS**

Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum because the Company determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company sold the remaining assets of Innovatum on January 23, 2008. The loss on disposal of Innovatum was not material.

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The results of operations of these assets were shown in continuing operations in the Company's financial statements in the Company's 2006 Annual Report on Form 10-K as the Company intended to have significant continuing involvement with these assets in the form of continuing existing operation and maintenance agreements between CEM and these assets after the sale.

The Company subsequently committed to a plan to sell CEM due to strong interest in the operations of CEM during the bidding process for the domestic independent power production assets in the first quarter of 2007. As a result of the Company's commitment to a plan to sell CEM, the Company would no longer have significant continuing involvement in the operations of the other domestic independent power production assets after the sale. Therefore, in accordance with SFAS No. 144, the results of operations of the domestic independent power production assets, including CEM, are presented as discontinued operations.

On July 10, 2007, Centennial Resources sold its domestic independent power production business consisting of Centennial Power and CEM to Bicent Power LLC (formerly known as Montana Acquisition Company LLC). The transaction was valued at $636 million, which included the assumption of approximately $36 million of project-related debt. The gain on the sale of the assets, excluding the gain on the sale of Hartwell as discussed in Note 4, was approximately $85.4 million (after tax). A portion of the proceeds from the sale was used to pay a dividend to the Company. This dividend was then used to prepay, in part, the outstanding term loan indebtedness that was incurred by the Company to fund the Cascade acquisition. The remaining proceeds of the sale provided additional cash for growth opportunities.

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for prior periods have been restated to present the results of operations of Innovatum and the domestic independent power production assets as discontinued operations. In addition, the assets and liabilities of these operations were treated as held for sale, and as a result, no depreciation, depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

In accordance with SFAS No. 142, at the time the Company committed to the plan to sell each of the assets, the Company was required to test the respective assets for goodwill impairment. The fair value of Innovatum, a reporting unit for goodwill impairment testing, was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment of $4.3 million (before tax) was recognized and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income in the third quarter of 2006. There were no goodwill impairments associated with the other assets held for sale.

Operating results related to Innovatum for the years ended December 31, 2007, 2006 and 2005, were as follows:

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | | *(In thousands)* | |
| Operating revenues | **$1,748** | $ 1,827 | $ 2,983 |
| Loss from discontinued operations before income tax benefit | **(210)** | (5,994) | (1,506) |
| Income tax benefit | **(316)** | (3,834) | (731) |
| Income (loss) from discontinued operations, net of tax | **$ 106** | $(2,160) | $ (775) |

The income tax benefit for the year ended December 31, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the $4.3 million and $4.0 million goodwill impairments in 2006 and 2004, respectively) resulting from the sale of the Innovatum stock.

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Operating results related to the domestic independent power production assets for the years ended December 31, 2007, 2006 and 2005, were as follows:

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | | *(In thousands)* | |
| Operating revenues | **$125,867** | $66,145 | $48,508 |
| Income from discontinued operations (including gain on disposal in 2007 of $142.4 million) before income tax expense (benefit) | **177,666** | 9,276 | 10,828 |
| Income tax expense (benefit) | **68,438** | (863) | 261 |
| Income from discontinued operations, net of tax | **$109,228** | $10,139 | $10,567 |

The income tax benefit for the year ended December 31, 2006, and the lower income tax expense for the year ended December 31, 2005, reflect a renewable electricity production tax credit of $4.4 million and $4.1 million, respectively.

Revenues at the former independent power production operations were recognized based on electricity delivered and capacity provided, pursuant to contractual commitments and, where applicable, revenues were recognized under EITF No. 91-6 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized under EITF No. 00-21 with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values.

The carrying amounts of the major assets and liabilities related to the domestic independent power production assets held for sale, as well as the major assets and liabilities related to Innovatum, at December 31, 2007 and 2006, were as follows:

| | **2007** | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Cash and cash equivalents | **$ ---** | $ 1,878 |
| Receivables, net | **---** | 8,307 |
| Inventories | **179** | 490 |
| Prepayments and other current assets | **---** | 1,981 |
| Total current assets held for sale | **$179** | $ 12,656 |
| Net property, plant and equipment | **$ ---** | $390,679 |
| Goodwill | **---** | 11,167 |
| Other intangible assets, net | **---** | 7,162 |
| Other | **---** | 2,257 |
| Total noncurrent assets held for sale | **$ ---** | $411,265 |
| Accounts payable | **$ ---** | $ 11,557 |
| Other accrued liabilities | **---** | 3,343 |
| Total current liabilities held for sale | **$ ---** | $ 14,900 |
| Deferred income taxes | **$ ---** | $ 27,956 |
| Other liabilities | **---** | 2,577 |
| Total noncurrent liabilities held for sale | **$ ---** | $ 30,533 |

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NOTES TO FINANCIAL STATEMENTS (Continued)

**NOTE 4 - EQUITY METHOD INVESTMENTS**

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2007, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning three electric transmission lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 23 and 25 years remaining under the contracts. Alusa, Brascan and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In February 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility in Trinidad and Tobago. On February 26, 2007, the Company sold its interest in Carib Power. The sale did not have a significant effect on the Company's results of operations.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. On July 10, 2007, the Company sold its ownership interest in Hartwell, and realized a gain of $10.1 million ($6.1 million after tax) from the sale which is recorded in earnings from equity method investments on the Consolidated Statements of Income.

In June 2005, the Company completed the sale of its 49 percent interest in MPX to Petrobras, the Brazilian state-controlled energy company. The Company realized a gain of $15.6 million from the sale in 2005.

At December 31, 2007 and 2006, the Company's equity method investments had total assets of $398.4 million and $583.6 million, respectively, and long-term debt of $211.2 million and $321.5 million, respectively. The Company's investment in its equity method investments was approximately $59.0 million and $102.0 million, including undistributed earnings of $6.9 million and $8.5 million, at December 31, 2007 and 2006, respectively.

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**NOTE 5 - GOODWILL AND OTHER INTANGIBLE ASSETS**

The changes in the carrying amount of goodwill for the year ended December 31, 2007, were as follows:

| | Balance as of January 1, 2007 | Goodwill Acquired During the Year* | Balance as of December 31, 2007 |
|---|---|---|---|
| | | *(In thousands)* | |
| Electric | $ --- | $ --- | $ --- |
| Natural gas distribution | --- | 171,129 | 171,129 |
| Construction services | 86,942 | 4,443 | 91,385 |
| Pipeline and energy services | 1,159 | --- | 1,159 |
| Natural gas and oil production | --- | --- | --- |
| Construction materials and contracting | 136,197 | 25,828 | 162,025 |
| Other | --- | --- | --- |
| Total | $224,298 | $201,400 | $425,698 |

** Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

The changes in the carrying amount of goodwill for the year ended December 31, 2006, were as follows:

| | Balance as of January 1, 2006 | Goodwill Acquired During the Year* | Balance as of December 31, 2006 |
|---|---|---|---|
| | | *(In thousands)* | |
| Electric | $ --- | $ --- | $ --- |
| Natural gas distribution | --- | --- | --- |
| Construction services | 80,970 | 5,972 | 86,942 |
| Pipeline and energy services | 1,159 | --- | 1,159 |
| Natural gas and oil production | --- | --- | --- |
| Construction materials and contracting | 133,264 | 2,933 | 136,197 |
| Other | --- | --- | --- |
| Total | $ 215,393 | $ 8,905 | $224,298 |

** Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

For more information on the goodwill impairment related to the discontinued operations at Innovatum in 2006, see Note 3.

Other amortizable intangible assets at December 31, 2007 and 2006, were as follows:

| | 2007 | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Customer relationships | **$ 21,834** | $13,030 |
| Accumulated amortization | **(4,444)** | (1,890) |
| | **17,390** | 11,140 |
| Noncompete agreements | **10,655** | 12,886 |
| Accumulated amortization | **(3,654)** | (8,540) |
| | **7,001** | 4,346 |
| Acquired contracts | **2,539** | 8,307 |
| Accumulated amortization | **(1,615)** | (4,646) |
| | **924** | 3,661 |
| Other | **3,404** | 5,062 |
| Accumulated amortization | **(927)** | (1,407) |
| | **2,477** | 3,655 |
| Total | **$27,792** | $22,802 |

Amortization expense for intangible assets for the years ended December 31, 2007, 2006 and 2005, was $4.4 million, $4.3 million and $3.5 million, respectively. Estimated amortization expense for intangible assets is $5.7 million in 2008, $4.4 million in 2009, $3.4 million in 2010, $2.9 million in 2011, $2.7 million in 2012 and $8.7 million thereafter.

**NOTE 6 - REGULATORY ASSETS AND LIABILITIES**

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

| | 2007 | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Regulatory assets: | | |
| Deferred income taxes | **$ 43,866** | $ 35,978 |
| Pension and postretirement benefits | **21,613** | 19,075 |
| Natural gas supply derivatives | **16,324** | --- |
| Long-term debt refinancing costs | **10,605** | 11,232 |
| Plant costs | **4,930** | 13,254 |
| Other | **15,812** | 7,230 |
| Total regulatory assets | **113,150** | 86,769 |
| Regulatory liabilities: | | |
| Plant removal and decommissioning costs | **89,991** | 85,087 |
| Taxes refundable to customers | **22,580** | 14,229 |
| Deferred income taxes | **17,630** | 18,019 |
| Natural gas costs refundable through rate adjustments | **11,568** | 7,516 |
| Natural gas supply derivatives | **5,631** | --- |
| Other | **8,250** | 4,179 |
| Total regulatory liabilities | **155,650** | 129,030 |
| Net regulatory position | **$ (42,500)** | $ (42,261) |

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As of December 31, 2007, 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 1 to 15 years. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates.

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 7 - 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 fair value. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. 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; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would 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, 2007, the Company had no outstanding foreign currency or interest rate hedges.

Cascade core

At December 31, 2007, Cascade held natural gas swap agreements which were not designated as hedges.

Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Cascade applies SFAS No. 71 and records periodic changes in the fair market value of the derivative instruments on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract.

Fidelity and Cascade non-core

At December 31, 2007, Fidelity held natural gas and oil swap and collar derivative instruments designated as cash flow hedging instruments. Cascade held natural gas swap derivative instruments designated as cash flow hedging instruments.

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. Cascade utilizes natural gas swap agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas on its forecasted purchases of natural gas for non-core customers. Cascade's non-core customers, who are not covered by the purchased gas cost adjustment mechanism, are generally large industrial, electric generation and institutional customers. Each of the price swap and collar agreements was designated as a cash flow hedge of the forecasted sale of the related production or as a cash flow hedge of the forecasted purchase of the related commodity.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil quantities are settled, 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. The proceeds received for natural gas and oil production and the amount paid for natural gas purchases are also generally based on market prices.

For the years ended December 31, 2007 and 2005, the amount of hedge ineffectiveness was immaterial. In the second quarter of 2006, Fidelity's oil collar agreements became ineffective and no longer qualified for hedge accounting. The oil hedges became ineffective as the physical price received no longer correlated to the hedge price due to the widening of regional basis differentials on the price of the physical production received. The ineffectiveness related to these collar agreements resulted in a loss of approximately $138,000 (before tax) for the year ended December 31, 2006, that was recorded in operation and maintenance expense. The ineffective collar agreements expired by December 31, 2006. The amount of hedge ineffectiveness on Fidelity's remaining hedges was immaterial for the year ended December 31, 2006.

For the years ended December 31, 2007, 2006 and 2005, there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such 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, 2007, the maximum term of the swap and collar agreements, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 12 months. The Company estimates that over the next 12 months, net gains of approximately $6.2 million (after tax) 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.

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**NOTE 8 - 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 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 at December 31 was as follows:

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |
| | *(In thousands)* | | | |
| Long-term debt | **$1,308,463** | **$1,293,863** | $1,254,582 | $1,247,439 |
| Commodity derivative agreements – current asset | **$ 12,740** | **$ 12,740** | $ 32,101 | $ 32,101 |
| Commodity derivative agreements – current liability | **$ (14,799)** | **$ (14,799)** | $ --- | $ --- |
| Commodity derivative agreements – noncurrent asset | **$ 3,419** | **$ 3,419** | $ --- | $ --- |
| Commodity derivative agreements – noncurrent liability | **$ (2,570)** | **$ (2,570)** | $ --- | $ --- |

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

**NOTE 9 - SHORT-TERM BORROWINGS**

Cascade has a revolving credit agreement with various banks totaling $50 million with certain provisions allowing for increased borrowings, up to a maximum of $75 million. The $50 million credit agreement expires on December 28, 2012, with provisions allowing for an extension of up to two years upon consent of the banks. Cascade also has a $20 million uncommitted line of credit which may be terminated by the bank or Cascade at any time. There was $1.7 million outstanding under the Cascade credit agreements at December 31, 2007. The borrowings are classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2007, was 4.75 percent. As of December 31, 2007, there were outstanding letters of credit, as discussed in Note 20, of which $1.9 million reduced amounts available under the $50 million credit agreement.

In order to borrow under Cascade's $50 million credit agreement, Cascade must be in compliance with the applicable covenants and certain other conditions. This includes a covenant not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade was in compliance with these covenants and met the required conditions at December 31, 2007.

Cascade's $50 million credit agreement contains cross-default provisions. These provisions state that if Cascade 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 agreement will be in default. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

**NOTE 10 - LONG-TERM DEBT AND INDENTURE PROVISIONS**

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

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| | | 2007 | | 2006 |
|---|---|---|---|---|
| | | *(In thousands)* | | |
| First mortgage bonds and notes: | | | | |
| Secured Medium-Term Notes, Series A, at a weighted average rate of 6.48%, due on dates ranging from October 1, 2008 to April 1, 2012 | $ | **20,500** | $ | 27,000 |
| Senior Notes, 5.98%, due December 15, 2033 | | **30,000** | | 30,000 |
| Total first mortgage bonds and notes | | **50,500** | | 57,000 |
| Senior Notes at a weighted average rate of 5.64%, due on dates ranging from June 27, 2008 to March 8, 2037 | | **1,064,000** | | 1,064,500 |
| Medium-Term Notes, at a weighted average rate of 7.72% due on dates ranging from September 4, 2012 to March 16, 2029 | | **81,000** | | --- |
| Commercial paper at a weighted average rate of 4.95%, supported by revolving credit agreements | | **61,000** | | 122,850 |
| Other notes, at a weighted average rate of 5.24% due on dates ranging from September 1, 2020 to February 1, 2035 | | **43,679** | | --- |
| Term credit agreements at a weighted average rate of 5.88%, due on dates ranging from July 1, 2008 to August 31, 2015 | | **8,286** | | 10,290 |
| Discount | | **(2)** | | (58) |
| Total long-term debt | | **1,308,463** | | 1,254,582 |
| Less current maturities | | **161,682** | | 84,034 |
| Net long-term debt | | **$ 1,146,781** | $ | 1,170,548 |

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2007, aggregate $161.7 million in 2008; $73.4 million in 2009; $7.3 million in 2010; $128.0 million in 2011; $135.5 million in 2012 and $802.6 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, 2007.

***MDU Resources Group, Inc.*** The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at December 31, 2007 and 2006. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $61.0 million and $25.8 million were outstanding at December 31, 2007 and 2006, respectively. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2007. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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 Mortgage. Generally, those restrictions require the Company to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Mortgage and, in some cases, to certify to the trustee that annual earnings (pretax and before interest charges), as defined in the Mortgage, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the tests, as of December 31, 2007, the Company could have issued approximately $544 million of additional first mortgage bonds.

Approximately $549.8 million in net book value of the Company's electric and natural gas distribution properties at December 31, 2007, with certain exceptions, are subject to the lien of the Mortgage and to the junior lien of the Indenture.

***MDU Energy Capital, LLC*** On August 14, 2007, MDU Energy Capital entered into a $125 million master shelf agreement (dated as of August 9, 2007). Under the terms of the master shelf agreement, $85.0 million was outstanding at December 31, 2007.

The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (i) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (ii) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter (commencing with the fiscal quarter ended September 30, 2007), to be greater than 1.5 to 1. MDU Energy Capital was in compliance with these covenants and met the required conditions at December 31, 2007. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement). MDU Energy Capital may incur additional indebtedness under the master shelf agreement, up to a total of $125 million, until the earlier of August 14, 2010, or such time as the agreement is terminated by either of the parties thereto.

***Centennial Energy Holdings, Inc.*** Centennial has a revolving credit agreement and an uncommitted line of credit with various banks and institutions totaling $425 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2007 and 2006. Under the Centennial commercial paper program, there was no amount outstanding at December 31, 2007, and $97.1 million outstanding at December 31, 2006. Centennial commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued Centennial commercial paper borrowings (supported by Centennial credit agreements). The revolving credit agreement is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on December 13, 2012. The uncommitted line of credit for $25 million may be terminated by the bank at any time. As of December 31, 2007, $56.6 million of letters of credit were outstanding, as discussed in Note 20, of which $44.0 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $418.5 million and $539.5 million were outstanding at December 31, 2007 and 2006, respectively. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009.

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, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2007. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

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 practices 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 up to $100 million. Under the terms of the master shelf agreement, $80.0 million was outstanding at December 31, 2007 and 2006. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2007. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

**NOTE 11 - ASSET RETIREMENT OBLIGATIONS**

The Company records 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.

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

| | **2007** | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Balance at beginning of year | **$56,179** | $ 42,857 |
| Liabilities incurred | **4,149** | 4,878 |
| Liabilities acquired | **652** | 1,118 |
| Liabilities settled | **(5,896)** | (2,963) |
| Accretion expense | **3,081** | 3,093 |
| Revisions in estimates | **6,100** | 6,321 |
| Other | **188** | 875 |
| Balance at end of year | **$64,453** | $ 56,179 |

The Company believes that any expenses under SFAS No. 143 and FIN 47 as they relate to regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2007 and 2006, was $5.8 million and $5.5 million, respectively.

**NOTE 12 - PREFERRED STOCKS**

Preferred stocks at December 31 were as follows:

| | **2007** | 2006 |
|---|---|---|
| | *(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 per share and $102 per share, 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 bylaws 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 13 - COMMON STOCK**

On May 11, 2006, 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 July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally accepted in the United States of America to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

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 four-ninths 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 four-ninths of one one-thousandth of a share of 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 $.00444 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.

The 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 K-Plan is partially funded with the Company's common stock. From July 2006 through March 2007, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2005 through June 2006, and April 2007 through December 2007, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2007, there were 20.6 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

**NOTE 14 - STOCK-BASED COMPENSATION**

On January 1, 2006, the Company adopted SFAS No. 123 (revised) and on January 1, 2003, adopted SFAS No. 123. For a discussion of the adoption of SFAS No. 123 (revised) and SFAS No. 123, see Note 1.

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock of 6.9 million shares through December 31, 2007. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Total stock-based compensation expense for the year ended December 31, 2007, was $4.7 million, net of income taxes of $3.1 million. Total stock-based compensation for the year ended December 31, 2006, was $3.5 million, net of income taxes of $2.2 million.

As of December 31, 2007, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.7 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

**Stock options**

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. 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 the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2007, and changes during the year then ended was as follows:

| | Number of Shares | Weighted Average Exercise Price |
|---|---|---|
| Balance at beginning of year | 2,311,546 | $13.11 |
| Forfeited | (39,352) | 12.97 |
| Exercised | (776,286) | 13.15 |
| Balance at end of year | 1,495,908 | 13.09 |
| Exercisable at end of year | 1,468,940 | $13.08 |

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Summarized information about stock options outstanding and exercisable as of December 31, 2007, was as follows:

| | Options Outstanding | | | | Options Exercisable | | |
|---|---|---|---|---|---|---|---|
| Range of Exercisable Prices | Number Outstanding | Remaining Contractual Life in Years | Weighted Average Exercise Price | Aggregate Intrinsic Value (000's) | Number Exercisable | Weighted Average Exercise Price | Aggregate Intrinsic Value (000's) |
| $ 8.88 – 11.00 | 135,776 | .5 | $ 9.71 | $ 2,431 | 135,776 | $ 9.71 | $ 2,431 |
| 11.01 – 14.00 | 1,262,944 | 3.2 | 13.20 | 18,199 | 1,241,409 | 13.20 | 17,891 |
| 14.01 – 17.13 | 97,188 | 3.2 | 16.39 | 1,090 | 91,755 | 16.40 | 1,028 |
| Balance at end of year | 1,495,908 | 2.9 | $ 13.09 | $21,720 | 1,468,940 | $ 13.08 | $21,350 |

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2007, which would have been received by the option holders had all option holders exercised their options as of that date.

The weighted average remaining contractual life of options exercisable was 2.9 years at December 31, 2007.

The Company received cash of $10.2 million and $4.5 million from the exercise of stock options for the years ended December 31, 2007 and 2006, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2007 and 2006, was $11.2 million and $4.4 million, respectively.

**Restricted stock awards**
Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest at various times ranging from one year to nine years from the 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 grant-date fair value is the market price of the Company's stock on the grant date.

A summary of the status of the restricted stock awards for the year ended December 31, 2007, was as follows:

| | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at beginning of period | 32,117 | $ 13.22 |
| Vested | --- | --- |
| Forfeited | (5,384) | 13.22 |
| Nonvested at end of period | 26,733 | $ 13.22 |

The fair value of restricted stock awards that vested during the year ended December 31, 2006, was $1.8 million.

**Stock awards**
Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 48,228 shares with a fair value of $1.5 million and 50,627 shares with a fair value of $1.3 million issued under this plan during the years ended December 31, 2007 and 2006, respectively.

**Performance share awards**
Since 2003, key employees of the Company have been awarded performance share awards each year. 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 outstanding at December 31, 2007, were as follows:

| Grant Date | Performance Period | Target Grant of Shares |
|---|---|---|
| February 2005 | 2005-2007 | 256,081 |
| February 2006 | 2006-2008 | 184,000 |
| February 2007 | 2007-2009 | 184,418 |

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value. The grant-date fair value of performance share awards granted during the years ended December 31, 2007, 2006 and 2005, was $23.55, $25.22 and $18.36, per share, respectively. The grant-date fair value for the performance shares granted in 2007 and 2006 was determined by Monte Carlo simulation using a blended volatility term structure comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.25 and $1.37 per target share for the 2007 and 2006 awards, respectively. The grant-date fair value for the performance shares issued in 2005 was equal to the market value of the common stock on the grant date. The fair value of performance share awards that vested during the years ended December 31, 2007 and 2006, was $6.0 million and $2.2 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2007, was as follows:

| | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at beginning of period | 738,684 | $19.27 |
| Granted | 200,395 | 23.55 |
| Vested | (228,452) | 15.81 |
| Forfeited | (86,128) | 19.26 |
| Nonvested at end of period | 624,499 | $21.91 |

**NOTE 15 - INCOME TAXES**
The components of income before income taxes for each of the years ended December 31 were as follows:

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | | *(In thousands)* | |
| United States | **$508,210** | $469,741 | $397,703 |
| Foreign | **4,600** | 4,148 | 13,837 |
| Income before income taxes | **$512,810** | $473,889 | $411,540 |

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

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | *(In thousands)* | | |
| Current: | | | |
| Federal | **$106,399** | $108,843 | $102,736 |
| State | **15,135** | 18,487 | 20,449 |
| Foreign | **235** | 136 | (93) |
| | **121,769** | 127,466 | 123,092 |
| Deferred: | | | |
| Income taxes – | | | |
| Federal | **58,030** | 34,693 | 19,278 |
| State | **9,656** | 4,357 | 4,379 |
| Investment tax credit | **(414)** | (405) | (500) |
| | **67,272** | 38,645 | 23,157 |
| Change in uncertain tax benefits | **869** | --- | --- |
| Change in accrued interest | **114** | --- | --- |
| Total income tax expense | **$190,024** | $166,111 | $146,249 |

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

| | **2007** | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Deferred tax assets: | | |
| Accrued pension costs | **$ 44,002** | $ 43,433 |
| Regulatory matters | **43,866** | 35,978 |
| Asset retirement obligations | **15,163** | 14,789 |
| Deferred compensation | **13,677** | 13,286 |
| Other | **45,335** | 43,818 |
| Total deferred tax assets | **162,043** | 151,304 |
| Deferred tax liabilities: | | |
| Depreciation and basis differences on property, plant and equipment | **498,933** | 445,315 |
| Basis differences on natural gas and oil producing properties | **260,417** | 204,288 |
| Regulatory matters | **17,630** | 18,019 |
| Natural gas and oil price swap and collar agreements | **3,989** | 12,359 |
| Other | **42,044** | 23,894 |
| Total deferred tax liabilities | **823,013** | 703,875 |
| Net deferred income tax liability | **$(660,970)** | $ (552,571) |

As of December 31, 2007 and 2006, no valuation allowance has been recorded associated with

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the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2006, to December 31, 2007, to deferred income tax expense:

| | 2007 |
|---|---|
| | *(In thousands)* |
| Change in net deferred income tax liability from the preceding table | **$ 108,399** |
| Deferred taxes associated with other comprehensive loss | **2,804** |
| Deferred taxes associated with acquisitions | **(46,229)** |
| Other | **2,298** |
| Deferred income tax expense for the period | **$ 67,272** |

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, | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| | Amount | % | Amount | % | Amount | % |
| | *(Dollars in thousands)* | | | | | |
| Computed tax at federal statutory rate | **$ 179,484** | **35.0** | $165,861 | 35.0 | $144,039 | 35.0 |
| Increases (reductions) resulting from: | | | | | | |
| State income taxes, net of federal income tax benefit | **17,121** | **3.3** | 17,786 | 3.8 | 15,064 | 3.7 |
| Deferred taxes associated with unrepatriated foreign earnings | **9,368** | **1.8** | --- | --- | --- | --- |
| Domestic production activities deduction | **(4,787)** | **(.9)** | (2,324) | (.5) | (2,219) | (.5) |
| Depletion allowance | **(4,073)** | **(.8)** | (4,784) | (1.0) | (4,381) | (1.1) |
| Resolution of tax matters | **208** | **---** | (3,660) | (.8) | --- | --- |
| Foreign operations | **235** | **---** | 136 | --- | (4,225) | (1.0) |
| Other items | **(7,532)** | **(1.3)** | (6,904) | (1.4) | (2,029) | (.6) |
| Total income tax expense | **$ 190,024** | **37.1** | $166,111 | 35.1 | $146,249 | 35.5 |

Prior to the sale of the domestic independent power production assets on July 10, 2007, as discussed in Note 3, the Company considered earnings (including the gain from the sale of its foreign equity method investment in a natural gas-fired electric generating facility in Brazil in 2005) to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes were recorded with respect to such earnings. Following the sale of these assets, the Company reconsidered its long-term plans for future development and expansion of its foreign investment and has determined that it has no immediate plans to explore or invest in additional foreign investments at this time.

Therefore, in accordance with SFAS No. 109, in the third quarter of 2007, deferred income taxes were accrued with respect to the temporary differences which had not been previously recorded. The cumulative undistributed earnings at December 31, 2007, were approximately $36 million. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings and recognized during 2007 was approximately $9.4 million. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

On January 1, 2007, the Company adopted FIN 48 as discussed in Note 1. The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2004.

Upon the adoption of FIN 48, the Company recognized a decrease in the liability for unrecognized tax benefits, which was not material and was accounted for as an increase to the January 1, 2007, balance of retained earnings. At the date of adoption, the amount of unrecognized tax benefits was $4.5 million.

A reconciliation of the unrecognized tax benefits (excluding interest) for the year ended December 31, 2007, was as follows:

| | **2007** |
|---|---|
| | *(In thousands)* |
| Balance at beginning of year | **$ 4,241** |
| Additions based on tax positions related to the current year | **373** |
| Additions for tax positions of prior years | **588** |
| Lapse of statute of limitations | **(1,467)** |
| Balance at end of year | **$ 3,735** |

Included in the balance of unrecognized tax benefits at December 31, 2007, were $1.6 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2007, was $2.6 million, including approximately $441,000 for the payment of interest and penalties.

The Company does not anticipate the amount of unrecognized tax benefits to significantly increase or decrease within the next 12 months.

The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes. For the years ended December 31, 2007, 2006 and 2005, the Company recognized approximately $680,000, $7,100 and $7,300, respectively, in interest expense. Penalties were not material in 2007, 2006 and 2005. The Company recognized interest income of approximately $480,000, $1.5 million and $62,000 for the years ended December 31, 2007, 2006 and 2005, respectively. The Company had accrued liabilities of approximately $718,000 and $436,000 at December 31, 2007 and 2006, respectively, for the payment of interest.

**NOTE 16 - 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. 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 the Company's equity method investment in the Brazilian Transmission Lines.

Prior to the fourth quarter of 2007, the Company reported seven business segments consisting of electric, natural gas distribution, construction services, pipeline and energy services, natural gas and oil production, construction materials and contracting, and independent power production. As discussed in Note 3, the domestic independent power production assets were sold in the third quarter of 2007, and as a result, the remaining independent power production operations are no longer significant and do not meet the criteria to be considered a reportable segment. Therefore, the remaining operations of the independent power production segment, including the Company's equity method investment in the Brazilian Transmission Lines, are reported in the Other category. The other operations do not meet the criteria to be considered a reportable segment. The Company's operations are now conducted through six reportable segments and prior period information has been restated to reflect this change.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Minnesota, Oregon and Washington. These operations also supply related value-added products and services.

The construction services segment specializes in electric line construction, pipeline construction, utility excavation, inside electrical wiring, cabling and mechanical work, fire protection 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.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated construction services. The construction materials and contracting segment operates in the central, southern and western United States and Alaska and Hawaii.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes the Company's equity investment in the Brazilian Transmission Lines.

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:

| | **2007** | 2006 | 2005 |
|---|---|---|---|
| | | *(In thousands)* | |
| External operating revenues: | | | |
| Electric | **$ 193,367** | $ 187,301 | $ 181,238 |
| Natural gas distribution | **532,997** | 351,988 | 384,199 |
| Pipeline and energy services | **369,345** | 349,997 | 384,887 |
| | **1,095,709** | 889,286 | 950,324 |
| Construction services | **1,102,566** | 987,079 | 686,734 |
| Natural gas and oil production | **288,148** | 251,153 | 163,539 |
| Construction materials and contracting | **1,761,473** | 1,877,021 | 1,603,326 |
| Other | **---** | --- | --- |
| | **3,152,187** | 3,115,253 | 2,453,599 |
| Total external operating revenues | **$4,247,896** | $4,004,539 | $3,403,923 |
| Intersegment operating revenues: | | | |
| Electric | **$ ---** | $ --- | $ --- |
| Natural gas distribution | **---** | --- | --- |
| Construction services | **649** | 503 | 391 |
| Pipeline and energy services | **77,718** | 93,723 | 92,424 |
| Natural gas and oil production | **226,706** | 232,799 | 275,828 |
| Construction materials and contracting | **---** | --- | 1,284 |
| Other | **10,061** | 8,117 | 6,038 |
| Intersegment eliminations | **(315,134)** | (335,142) | (375,965) |
| Total intersegment operating revenues | **$ ---** | $ --- | $ --- |
| Depreciation, depletion and amortization: | | | |
| Electric | **$ 22,549** | $ 21,396 | $ 20,818 |
| Natural gas distribution | **19,054** | 9,776 | 9,534 |
| Construction services | **14,314** | 15,449 | 13,459 |
| Pipeline and energy services | **21,631** | 13,288 | 12,513 |
| Natural gas and oil production | **127,408** | 106,768 | 84,754 |
| Construction materials and contracting | **95,732** | 88,723 | 77,988 |
| Other | **1,244** | 1,131 | 374 |
| Total depreciation, depletion and amortization | **$ 301,932** | $ 256,531 | $ 219,440 |

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|---|---|---|---|
| Interest expense: | | | |
| Electric | $ **6,737** | $ 6,493 | $ 7,553 |
| Natural gas distribution | **13,566** | 3,885 | 3,973 |
| Construction services | **4,878** | 6,295 | 4,177 |
| Pipeline and energy services | **8,769** | 8,094 | 8,132 |
| Natural gas and oil production | **8,394** | 9,864 | 7,550 |
| Construction materials and contracting | **23,997** | 25,943 | 21,365 |
| Other | **10,717** | 11,775 | 1,861 |
| Intersegment eliminations | **(4,821)** | (254) | (227) |
| Total interest expense | $ **72,237** | $ 72,095 | $ 54,384 |
| Income taxes: | | | |
| Electric | $ **8,528** | $ 7,403 | $ 8,308 |
| Natural gas distribution | **6,477** | 2,108 | 2,240 |
| Construction services | **26,829** | 16,497 | 9,693 |
| Pipeline and energy services | **18,524** | 18,938 | 13,735 |
| Natural gas and oil production | **78,348** | 78,960 | 82,428 |
| Construction materials and contracting | **39,045** | 46,245 | 29,244 |
| Other | **12,273** | (4,040) | 601 |
| Total income taxes | $ **190,024** | $ 166,111 | $ 146,249 |
| Earnings on common stock: | | | |
| Electric | $ **17,700** | $ 14,401 | $ 13,940 |
| Natural gas distribution | **14,044** | 5,680 | 3,515 |
| Construction services | **43,843** | 27,851 | 14,558 |
| Pipeline and energy services | **31,408** | 32,126 | 22,867 |
| Natural gas and oil production | **142,485** | 145,657 | 141,625 |
| Construction materials and contracting | **77,001** | 85,702 | 55,040 |
| Other | **(4,380)** | (4,324) | 13,061 |
| Earnings on common stock before income from discontinued operations | **322,101** | 307,093 | 264,606 |
| Income from discontinued operations, net of tax | **109,334** | 7,979 | 9,792 |
| Total earnings on common stock | $ **431,435** | $ 315,072 | $ 274,398 |

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| | | | |
|---|---|---|---|
| Capital expenditures: | | | |
| Electric | **$ 91,548** | $ 39,055 | $ 27,036 |
| Natural gas distribution | **500,178** | 15,398 | 17,224 |
| Construction services | **18,241** | 31,354 | 50,900 |
| Pipeline and energy services | **39,162** | 42,749 | 36,318 |
| Natural gas and oil production | **283,589** | 328,979 | 329,773 |
| Construction materials and contracting | **189,727** | 141,088 | 161,977 |
| Other | **1,621** | 2,052 | 14,722 |
| Net proceeds from sale or disposition of property | **(24,983)** | (30,501) | (40,460) |
| Net capital expenditures before discontinued operations | **1,099,083** | 570,174 | 597,490 |
| Discontinued operations | **(548,216)** | 33,090 | 132,956 |
| Total net capital expenditures | **$ 550,867** | $ 603,264 | $ 730,446 |
| Assets: | | | |
| Electric* | **$ 428,200** | $ 353,593 | $ 330,327 |
| Natural gas distribution* | **942,454** | 264,102 | 271,653 |
| Construction services | **456,564** | 401,832 | 351,654 |
| Pipeline and energy services | **500,755** | 474,424 | 466,961 |
| Natural gas and oil production | **1,299,406** | 1,173,797 | 898,883 |
| Construction materials and contracting | **1,642,729** | 1,562,868 | 1,498,338 |
| Other** | **322,326** | 672,858 | 605,746 |
| Total assets | **$5,592,434** | $4,903,474 | $4,423,562 |
| Property, plant and equipment: | | | |
| Electric* | **$ 784,705** | $ 703,838 | $ 670,771 |
| Natural gas distribution* | **948,446** | 289,106 | 277,288 |
| Construction services | **101,935** | 94,754 | 90,110 |
| Pipeline and energy services | **600,712** | 562,596 | 521,495 |
| Natural gas and oil production | **1,923,899** | 1,636,245 | 1,303,447 |
| Construction materials and contracting | **1,538,716** | 1,410,657 | 1,310,426 |
| Other | **31,833** | 30,529 | 28,467 |
| Less accumulated depreciation, depletion and amortization | **2,270,691** | 1,735,302 | 1,523,887 |
| Net property, plant and equipment | **$3,659,555** | $2,992,423 | $2,678,117 |

* *Includes allocations of common utility property.*

** *Includes the domestic independent power production assets in 2006 and 2005 that were sold in 2007, and assets not directly assignable to a business (i.e. cash and cash equivalents, certain* *accounts receivable, certain investments and other miscellaneous current and deferred assets).*

The pipeline and energy services segment recognized income from discontinued operations, net of tax, of $106,000 for the year ended December 31, 2007, and a loss from discontinued operations, net of tax, of $2.1 million and $775,000 for the years ended December 31, 2006 and 2005, respectively. The Other category reflects income from discontinued operations, net of tax, of $109.2 million, $10.1 million and $10.6 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Excluding income (loss) from discontinued operations at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

Capital expenditures for 2007, 2006 and 2005 include noncash transactions, including the issuance of the Company's equity securities in connection with acquisitions and the outstanding indebtedness related to the 2007 Cascade acquisition. The noncash transactions were $217.3 million in 2007, immaterial in 2006 and $46.5 million in 2005.

**NOTE 17 - EMPLOYEE BENEFIT PLANS**

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

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Changes in benefit obligation and plan assets for the year ended December 31, 2007, and amounts recognized in the Consolidated Balance Sheets at December 31, 2007, were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2007** | 2006 | **2007** | 2006 |
| | *(In thousands)* | | | |
| Change in benefit obligation: | | | | |
| Benefit obligation at beginning of year | **$298,398** | $303,393 | **$ 67,724** | $ 69,811 |
| Service cost | **9,098** | 8,901 | **1,865** | 2,015 |
| Interest cost | **18,591** | 16,056 | **4,212** | 3,633 |
| Plan participants' contributions | **---** | --- | **1,790** | 1,533 |
| Actuarial (gain) loss | **(8,079)** | (14,363) | **482** | (4,019) |
| Acquisition | **63,556** | --- | **11,734** | --- |
| Benefits paid | **(21,641)** | (15,589) | **(6,226)** | (5,249) |
| Benefit obligation at end of year | **359,923** | 298,398 | **81,581** | 67,724 |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of year | **259,275** | 245,328 | **58,747** | 52,448 |
| Actual gain on plan assets | **28,393** | 27,047 | **2,357** | 6,440 |
| Employer contribution | **4,236** | 2,489 | **3,888** | 3,575 |
| Plan participants' contributions | **---** | --- | **1,790** | 1,533 |
| Acquisition | **60,703** | --- | **13,128** | --- |
| Benefits paid | **(21,641)** | (15,589) | **(6,226)** | (5,249) |
| Fair value of plan assets at end of year | **330,966** | 259,275 | **73,684** | 58,747 |
| Funded status – under | **$ (28,957)** | $ (39,123) | **$ (7,897)** | $ (8,977) |
| Amounts recognized in the Consolidated Balance Sheets at December 31: | | | | |
| Prepaid benefit cost (noncurrent) | **$ 10,253** | $ 4,368 | **$ 664** | $ --- |
| Accrued benefit liability (current) | **---** | --- | **(408)** | (364) |
| Accrued benefit liability (noncurrent) | **(39,210)** | (43,491) | **(8,153)** | (8,613) |
| Net amount recognized | **$ (28,957)** | $ (39,123) | **$ (7,897)** | $ (8,977) |
| Amounts recognized in accumulated other comprehensive loss consist of: | | | | |
| Actuarial (gain) loss | **$ 30,006** | $ 30,415 | **$ (2,466)** | $(13,718) |
| Prior service cost (credit) | **3,350** | 5,948 | **(10,524)** | 648 |
| Transition obligation | **---** | --- | **10,628** | 12,753 |
| Total | **$ 33,356** | $ 36,363 | **$ (2,362)** | $ (317) |

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

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets is amortized on a straight-line basis over the expected average remaining service lives of active participants. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $307.7 million and $245.6 million at December 31, 2007 and 2006, 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, 2007 and 2006, were as follows:

| | 2007 | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Projected benefit obligation | $106,236 | $187,638 |
| Accumulated benefit obligation | $ 95,435 | $151,850 |
| Fair value of plan assets | $ 94,845 | $148,261 |

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31, 2007 and 2006, were as follows:

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | | | *(In thousands)* | |
| Components of net periodic benefit cost: | | | | |
| Service cost | $ 9,098 | $ 8,901 | $ 1,865 | $ 2,015 |
| Interest cost | 18,591 | 16,056 | 4,212 | 3,633 |
| Expected return on assets | (22,524) | (19,913) | (4,776) | (4,119) |
| Amortization of prior service cost (credit) | 756 | 913 | (1,300) | 46 |
| Recognized net actuarial (gain) loss | 1,605 | 1,699 | 73 | (243) |
| Amortization of net transition obligation (asset) | --- | (3) | 2,125 | 2,125 |
| Net periodic benefit cost, including amount capitalized | 7,526 | 7,653 | 2,199 | 3,457 |
| Less amount capitalized | 991 | 689 | 373 | 261 |
| Net periodic benefit cost | 6,535 | 6,964 | 1,826 | 3,196 |
| Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive loss: | | | | |
| Net (gain) loss | (11,095) | (22,983) | 1,507 | (6,340) |
| Acquisition-related actuarial loss | 12,291 | --- | 9,818 | --- |
| Acquisition-related prior service credit | (1,842) | --- | (12,472) | --- |
| Amortization of actuarial gain (loss) | (1,605) | (1,699) | (73) | 243 |
| Amortization of prior service cost (credit) | (756) | (913) | 1,300 | (46) |
| Amortization of net transition (obligation) asset | --- | 3 | (2,125) | (2,125) |
| Total recognized in accumulated other comprehensive loss | (3,007) | (25,592) | (2,045) | (8,268) |
| Total recognized in net periodic benefit cost and accumulated other comprehensive loss | $ 3,528 | $(18,628) | $ (219) | $ (5,072) |

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the year ended December 31, 2005, was as follows:

| | Pension Benefits 2005 | Other Postretirement Benefits 2005 |
|---|---|---|
| | (In thousands) | |
| Components of net periodic benefit cost: | | |
| Service cost | $ 8,336 | $ 1,719 |
| Interest cost | 16,617 | 3,784 |
| Expected return on assets | (19,947) | (4,005) |
| Amortization of prior service cost | 1,025 | 45 |
| Recognized net actuarial (gain) loss | 1,385 | (549) |
| Amortization of net transition obligation (asset) | (45) | 2,126 |
| Net periodic benefit cost, including amount capitalized | 7,371 | 3,120 |
| Less amount capitalized | 730 | 313 |
| Net periodic benefit cost | $ 6,641 | $ 2,807 |

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2008 are $967,000 and $665,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2008 are $461,000, $2.8 million and $2.1 million, respectively.

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

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | **2007** | 2006 | **2007** | 2006 |
| Discount rate | **6.00%** | 5.75% | **6.00%** | 5.75% |
| Rate of compensation increase | **4.20%** | 4.30% | **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 | |
|---|---|---|---|---|
| | **2007** | 2006 | **2007** | 2006 |
| Discount rate | **5.75%** | 5.50% | **5.75%** | 5.50% |
| Expected return on plan assets | **8.40%** | 8.50% | **7.50%** | 7.50% |
| Rate of compensation increase | **4.20%** | 4.30% | **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:

| | **2007** | 2006 |
|---|---|---|
| Health care trend rate assumed for next year | **6.0%-10.0%** | 6.0%-9.0% |
| Health care cost trend rate – ultimate | **5.0%-6.0%** | 5.0%-6.0% |
| Year in which ultimate trend rate achieved | **1999-2017** | 1999-2014 |

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, 2007:

| | 1 Percentage Point Increase | 1 Percentage Point Decrease |
|---|---|---|
| | *(In thousands)* | |
| Effect on total of service and interest cost components | $ (21) | $ (930) |
| Effect on postretirement benefit obligation | $1,335 | $ (9,796) |

The Company's defined benefit pension plans' asset allocation at December 31, 2007 and 2006, and weighted average targeted asset allocations at December 31, 2007, were as follows:

| | Percentage of Plan Assets | | Weighted Average Targeted Asset Allocation Percentage |
|---|---|---|---|
| Asset Category | **2007** | 2006 | **2007** |
| Equity securities | **66%** | 69% | **70%** |
| Fixed-income securities | **29** | 27 | **30*** |
| Other | **5** | 4 | --- |
| Total | **100%** | 100% | **100%** |

* *Includes target for both fixed-income securities and other.*

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by three outside investment managers. 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, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. 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, 2007 and 2006, and weighted average targeted asset allocation at December 31, 2007, were as follows:

| | Percentage of Plan Assets | | Weighted Average Targeted Asset Allocation Percentage |
|---|---|---|---|
| Asset Category | **2007** | 2006 | **2007** |
| Equity securities | **70%** | 70% | **70%** |
| Fixed-income securities | **27** | 27 | **30*** |
| Other | **3** | 3 | **---** |
| Total | **100%** | 100% | **100%** |

* *Includes target for both fixed-income securities and other.*

The Company expects to contribute approximately $5.6 million to its defined benefit pension plans and approximately $3.5 million to its postretirement benefit plans in 2008.

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

| Years | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| | *(In thousands)* | |
| 2008 | $18,199 | $5,229 |
| 2009 | 18,993 | 5,429 |
| 2010 | 20,144 | 5,630 |
| 2011 | 21,046 | 5,852 |
| 2012 | 22,388 | 6,067 |
| 2013-2017 | 130,377 | 33,643 |

The following Medicare Part D subsidies are expected: $736,000 in 2008; $786,000 in 2009; $841,000 in 2010; $889,000 in 2011; $948,000 in 2012; and $5.6 million during the years 2013 through 2017.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed to the multi-employer plans

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were $51.5 million, $57.6 million and $39.6 million in 2007, 2006 and 2005, 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. The Company had investments of $55.0 million at December 31, 2007, consisting of equity securities of $26.4 million, life insurance carried on plan participants (payable upon the employee's death) of $20.8 million, fixed-income securities of $4.0 million, and other investments of $3.8 million, which the Company anticipates using to satisfy obligations under this plan. The Company's net periodic benefit cost for this plan was $7.6 million, $7.5 million and $7.4 million in 2007, 2006 and 2005, respectively. The total projected benefit obligation for this plan was $80.6 million and $69.5 million at December 31, 2007 and 2006, respectively. The accumulated benefit obligation for this plan was $69.3 million and $57.4 million at December 31, 2007 and 2006, respectively. A discount rate of 6.00 percent and 5.75 percent at December 31, 2007 and 2006, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2007 and 2006, were used to determine benefit obligations. A discount rate of 5.75 percent and 5.50 percent at December 31, 2007 and 2006, respectively, and a rate of compensation increase of 4.25 percent at December 31, 2007 and 2006, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $3.5 million in 2008; $3.6 million in 2009; $4.1 million in 2010; $4.4 million in 2011; $4.8 million in 2012; and $31.1 million for the years 2013 through 2017.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $21.1 million in 2007, $17.3 million in 2006 and $17.0 million in 2005. The costs incurred in each year reflect additional participants as a result of business acquisitions.

SFAS No. 158 became effective for the Company as of December 31, 2006. The adoption resulted in a negative transition effect on accumulated other comprehensive loss of $18.5 million.

**NOTE 18 - 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:

| | **2007** | 2006 |
|---|---|---|
| | *(In thousands)* | |
| Big Stone Station: | | |
| Utility plant in service | **$ 61,568** | $ 55,659 |
| Less accumulated depreciation | **39,168** | 38,881 |
| | **$ 22,400** | $ 16,778 |
| Coyote Station: | | |
| Utility plant in service | **$125,826** | $125,950 |
| Less accumulated depreciation | **79,783** | 78,056 |
| | **$ 46,043** | $ 47,894 |

**NOTE 19 - REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND**

In August 2006, CMS, a competing gas marketer, filed a complaint against Cascade before the WUTC alleging Cascade had entered into gas supply sales contracts with its non-core, transportation-only customers in violation of state law by not filing tariffs and copies of the gas supply contracts with the WUTC. CMS's complaint additionally raised claims of undue preference and discrimination. On January 12, 2007, the WUTC entered an order allowing Cascade to continue to make gas supply sales to non-core, transportation-only customers but requiring Cascade to file its tariffs and sales contracts with the WUTC. On February 12, 2007, Cascade filed revisions to its tariffs reflecting gas supply service options available to non-core, transportation-only customers; however, on March 14, 2007, the WUTC suspended the tariff filing. On March 30, 2007, due to the lack of approved tariffs, Cascade filed notice with the WUTC that it was reactivating a nonregulated affiliate to make retail gas sales to non-core, transportation-only customers. The WUTC consolidated the tariff proceeding with Cascade's filing to re-establish an affiliate to make non-core, transportation-only customer gas supply sales. On December 7, 2007, the WUTC filed a complaint against Cascade alleging it is in violation of its most recent general rate case settlement by not sharing gas supply sales margins with core customers. Cascade filed an answer to the complaint on December 27, 2007. On February 6, 2008, Cascade and the other participant parties entered into an agreement settling the issues in all of the above proceedings. Under the settlement, Cascade and its subsidiaries will discontinue the unbundled retail sale of gas supply to non-core, transportation-only customers by November 1, 2008. Fifty percent of the net gas supply sales margins realized from non-core, transportation-only customers by Cascade and its subsidiaries from April 1, 2007, through October 31, 2008, and fifty percent of the net gain, if any, from the sale of such business, will be credited to Cascade’s core customers. Cascade will also revise its gas procurement strategy for core customers to enhance its ability to acquire gas supply from the Rocky Mountain region. The settlement is subject to approval by the WUTC. Cascade has reserved an amount for the crediting of the net gas supply sales margins generated from April 1, 2007, through December 31, 2007. Cascade does not consider the discontinuance of gas supply sales to non-core, transportation-only customers to have a material impact on its financial position or results of operations.

On July 12, 2007, Montana-Dakota filed an application with the MTPSC for an electric rate increase. Montana-Dakota requested a total of $7.8 million annually or approximately 22 percent above current rates. Montana-Dakota requested a fuel and purchased power tracking adjustment and an off-system sales margin sharing adjustment. Montana-Dakota also requested an interim increase of $3.9 million annually, subject to refund. On December 5, 2007, the MTPSC granted an interim increase of $3.4 million annually. On February 8, 2008, Montana-Dakota and the interveners reached a settlement stipulation (subject to MTPSC approval) applicable to this filing whereby the $3.4 million of interim rate relief will become final upon approval of the stipulation and an additional annual rate increase of $730,000 will become effective January 1, 2009. As part of the settlement, Montana-Dakota will be allowed to implement a fuel and purchased power tracking mechanism on a shared basis, a margin sharing mechanism for off-system sales, and modify certain decommissioning and net negative salvage cost accruals. Also, Montana-Dakota will agree to not implement new rates from any subsequent general rate filings before January 1, 2010.

In November 2006, Montana-Dakota filed an application with the NDPSC requesting an advance determination of prudence of Montana-Dakota's ownership interest in Big Stone Station II, which is expected to be completed in 2013. Hearings on the application were held in June 2007. In September 2007, Montana-Dakota informed the NDPSC that certain of the other participants in the project had withdrawn, that it was considering the impact of these withdrawals on the project and its options, and proposed that the NDPSC suspend the procedural schedule. In October 2007, Montana-Dakota proposed to supplement the record with additional resource planning analysis reflecting changes in plant configuration as a result of the participant withdrawals. On February 1, 2008, the NDPSC issued an order setting supplemental hearings to commence April 28, 2008. The MNPUC is expected to rule on the issuance of the related transmission Certificate of Need in April 2008 and the NDPSC is expected to rule on the advance determination of prudence in June 2008.

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. Currently, the only remaining issue outstanding related to this rate change application is in regard to certain service restrictions. In May 2004, the FERC remanded this issue to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding certain service and annual demand quantity restrictions. In April 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's Order on Initial Decision. In April 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision and its Order on Rehearing. The matter concerning the service restrictions is pending resolution by the D.C. Appeals Court.

**NOTE 20 - COMMITMENTS AND CONTINGENCIES**

**Litigation**

***Coalbed Natural Gas Operations*** 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 CBNG 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 January 2007 by a number of environmental organizations, including the NPRC and the Montana Environmental Information Center, as well as the TRWUA and the Northern Cheyenne Tribe. Portions of three of the lawsuits have been transferred to the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA, the Montana State Constitution, the Montana Environmental Policy Act and the Montana Water Quality Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural and substantive requirements. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. In addition, Fidelity has intervened or moved to intervene in three lawsuits filed by other gas producers between June and September 2006 that challenge rules adopted by the BER related to management of water associated with CBNG production. The state of Wyoming has filed a similar suit in September 2006 and Fidelity moved to intervene in that action. Fidelity is partly funding the Petroleum Association of Wyoming's intervention in two suits. The first was brought by two landowners against the Wyoming State Engineer and the Wyoming Board of Control challenging the state's CBNG groundwater permitting

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practices. The second suit was brought by the Wyoming Outdoor Council and Powder River Basin Resource Council appealing the Wyoming Environmental Quality Council's rules establishing water quality standards relating to discharges of water associated with CBNG production.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS analyzing CBNG development in southeastern Montana. The Montana Federal District Court, in February 2005, entered a ruling finding that the 2003 EIS was inadequate. The Montana Federal District Court later entered an order that would have allowed limited CBNG development in the Montana Powder River Basin pending the BLM's preparation of a SEIS. The plaintiffs appealed the decision to the Ninth Circuit because the Montana Federal District Court declined to enter an injunction enjoining all development pending completion of the SEIS. The Montana Federal District Court also declined to enter an injunction pending the appeal. In May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending appeal or further order from the Ninth Circuit, enjoined the BLM from approving any new CBNG development on federal lands in the Montana Powder River Basin. The Ninth Circuit also enjoined Fidelity from drilling any additional federally permitted wells associated with its Montana Coal Creek Project and from constructing infrastructure to produce and transport CBNG from the Coal Creek Project's existing federal wells. The matter was briefed and argued to the Ninth Circuit in September 2005. On September 11, 2007, the Ninth Circuit affirmed the Montana Federal District Court and ruled it had correctly issued an injunction allowing up to 500 CBNG wells to be drilled each year on private, state and federal land in the Montana Powder River Basin. On October 29, 2007, in response to a motion filed by Fidelity, the Ninth Circuit lifted the 2005 injunction it had earlier issued pending the appeal. On the same date, the Ninth Circuit ordered Fidelity to respond within 21 days to the Northern Cheyenne Tribe and the NPRC's October 16, 2007, petition to the Ninth Circuit to rehear the case. On January 15, 2008, the Ninth Circuit denied the petition for rehearing.

In December 2006, the BLM issued a draft SEIS that endorses a phased-development approach to CBNG production in the Montana Powder River Basin, whereby future projects would be reviewed against four screens or filters (relating to water quality, wildlife, Native American concerns and air quality). Fidelity filed written comments on the draft SEIS asking the BLM to reconsider its proposed phased-development approach and to make numerous other changes to the draft SEIS. The public comment period on the draft SEIS concluded on May 2, 2007. In response to comments, the BLM published an Air Quality Supplement to the draft SEIS with the public comment period ending March 13, 2008. The final SEIS is scheduled for release in July 2008 with a Record of Decision expected in December 2008. Fidelity cannot predict what the final terms of the SEIS will be.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NHPA and the NEPA. In June 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of the NHPA and a further environmental analysis under the NEPA. Fidelity sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity's Badger Hills Project continues. In September 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity's Badger Hills Project may continue pending preparation of a revised environmental analysis. In November 2005, the Montana Federal District Court entered an Order dismissing the Northern Cheyenne Tribe lawsuit based on the parties' stipulation that production from existing wells in Fidelity's Badger Hills Project could continue pending consultation with the Northern Cheyenne Tribe under the NHPA. In December 2005, Fidelity filed a Notice of Appeal of the NPRC lawsuit to the Ninth Circuit in connection with the Montana Federal District Court's decision insofar as it found the BLM's approval of Fidelity's applications did not comply with applicable law.

In May 2005, the NPRC and other petitioners filed a petition with the BER to promulgate rules related to the management of water produced in association with CBNG operations. Thereafter, the BER initiated related rulemaking proceedings to consider rules that would, if promulgated, require re-injection of water produced in connection with CBNG operations, treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with CBNG development to include additional limitations on factors deemed harmful, thereby restricting discharges even further than under the previous standards. In March 2006, the BER issued its decision on the rulemaking petition. The BER rejected the proposed requirement of re-injection of water produced in connection with CBNG and deferred action on the proposed treatment requirement. The BER adopted the proposed amendment to the non-degradation policy. While it is possible the BER's ruling could have an adverse impact on Fidelity's operations, Fidelity believes that two five-year water discharge permits issued by the Montana DEQ in February 2006 should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations at least through the expiration of the permits in March 2011. However, these permits are now under challenge in Montana state court by the Northern Cheyenne Tribe. Specifically, in April 2006, the Northern Cheyenne Tribe filed a complaint in the District Court of Big Horn County against the Montana DEQ seeking to set aside the two permits. The Northern Cheyenne Tribe asserted the Montana DEQ issued the permits in violation of various federal and state environmental laws. In particular, the Northern Cheyenne Tribe claimed the agency violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by failing to impose a non-degradation policy like the one the BER adopted soon after the permit was issued. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution's guarantee of a clean and healthful environment, that the Montana DEQ's related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that the Montana DEQ failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA have been granted leave to intervene in this proceeding. The parties have submitted cross motions for summary judgment. The motions were argued to the District Court of Big Horn County on February 28, 2007. Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG produced water. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

In a related proceeding, in July 2006, Fidelity filed a motion to intervene in a lawsuit filed in the District Court of Big Horn County by other producers. The lawsuit challenges the BER's 2006 rulemaking, which amended the non-degradation policy, as well as the BER's 2003 rulemaking procedure which first set numeric limits for certain parameters contained in water produced in connection with CBNG operations. Fidelity's motion for intervention was granted in August 2006. The parties have briefed cross motions for summary judgment and the District Court of Big Horn County heard oral argument on those motions on July 2, 2007. On October 17, 2007, the District Court of Big Horn County entered an order granting the motions filed by the BER and others and denying the motions filed by Fidelity and other producers. The other producers appealed the order on December 26, 2007. Fidelity is not participating in the appeal.

Similarly, industry members have filed two lawsuits, and the state of Wyoming has filed one lawsuit, in Wyoming Federal District Court. These lawsuits challenge the EPA's failure to timely disapprove the 2006 rules. All three Wyoming lawsuits were consolidated in September 2006. Fidelity has moved to intervene in these consolidated cases.

Fidelity has also intervened in a Wyoming State District Court case in support of the Governor of Wyoming's decision not to promulgate rules which were proposed by the Powder River Basin Resource Council that would have granted Wyoming's DEQ authority to regulate water quantity issues that are currently regulated by the Wyoming State Engineer. In November 2007, the Wyoming State District Court dismissed the suit. The Powder River Basin

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NOTES TO FINANCIAL STATEMENTS (Continued)

Resource Council did not appeal.

Fidelity is partly funding the Petroleum Association of Wyoming's intervention in two suits. In the first case, in which the Petroleum Association of Wyoming's motion to intervene has been conditionally granted, the Powder River Basin Resource Council is funding litigation on behalf of two surface owners against the Wyoming State Engineer and the Wyoming Board of Control. The plaintiffs in the action, filed in Wyoming State District Court on June 14, 2007, seek a declaratory judgment that current ground water permitting practices are unlawful; that would mandate that the state adopt rules and procedures to ensure that coalbed groundwater is managed in accordance with the Wyoming Constitution and other laws; and that would prohibit the Wyoming State Engineer from issuing permits to produce coalbed groundwater and permits to store coalbed groundwater in reservoirs until the Wyoming State Engineer adopts such rules. In the second case, the Wyoming Outdoor Council and Powder River Basin Resource Council filed a petition on May 25, 2007, in the Wyoming State District Court seeking to invalidate the Environmental Quality Council's approval of amendments to Chapter 1 of the Wyoming Water Quality Rules and Regulations that subject certain discharges of water produced in connection with CBNG development to stricter water quality standards. The plaintiffs contend that the Wyoming DEQ's actions were arbitrary and capricious and that the rules are not in accordance with the Clean Water Act.

Fidelity will continue to vigorously defend its interests in all CBNG-related lawsuits and related actions in which it is involved, including the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material adverse effect on Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

***Electric Operations*** Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it 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 ND 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 were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there were no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA defended against the DRC claim and filed a motion to dismiss the case. The Colorado Federal District Court has dismissed the case.

On June 6, 2007, the EPA noticed for public comment a proposed rule that would, among other things, adopt PSD increment modeling refinements that, if adopted, would operate to formally ratify the modeling techniques and conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. The public comment period on the proposed rule closed September 28, 2007. The dismissal of the case in Burleigh County District Court referenced above is dependant upon the outcome of the proposed rule.

In November 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. The suit would seek injunctive relief and monetary penalties based on the Sierra Club's claim that three projects conducted at the Big Stone Station between 1995 and 2005 were modifications of a major source and that the Big Stone Station failed to obtain a PSD permit, conduct best available control technology analyses, and comply with other regulatory requirements for those projects. The South Dakota Department of Environment and Natural Resources reviewed and approved the three projects and the co-owners of the Big Stone Station believe the Sierra Club's claims are without merit. The Big Stone Station co-owners intend to vigorously defend their interests if the suit is filed.

***Natural Gas Storage*** Based on reservoir and well pressure data and other information, Williston Basin believes that reservoir pressure (and therefore the amount of gas) in the EBSR, one of its natural gas storage reservoirs, has decreased as a result of Howell and Anadarko's drilling and production activities in areas within and near the boundaries of the EBSR. As of December 31, 2007, Williston Basin estimated that between 9.5 and 10 Bcf of storage gas had been diverted from the EBSR as a result of Howell and Anadarko's drilling and production.

Williston Basin filed suit in Montana Federal District Court in January 2006, seeking to recover unspecified damages from Howell and Anadarko, and to enjoin Howell and Anadarko's present and future production from specified wells in and near the EBSR. The Montana Federal District Court entered an Order in July 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit in July 2006. The parties have briefed the issues. Oral argument was held on February 5, 2008.

In related litigation, Howell filed suit in Wyoming State District Court against Williston Basin in February 2006 asserting that it is entitled to produce any gas that might escape from the EBSR. In August 2006, Williston Basin moved for a preliminary injunction to halt Howell and Anadarko's production in and near the EBSR. A district court-appointed special master conducted a hearing on the motion in December 2006, and recommended denial of the motion on February 15, 2007. The Wyoming State District Court adopted the special master's report on July 25, 2007, and denied Williston Basin's motion for a preliminary injunction. On June 25, 2007, the Wyoming State District Court filed a motion with the Wyoming Supreme Court requesting it to answer questions of law concerning the production of Williston Basin's storage gas by Howell and Anadarko. On July 10, 2007, the Wyoming Supreme Court issued an Order declining to answer those questions. The Wyoming State District Court has set the case for trial beginning September 29, 2008. On December 12, 2007, motions were argued to the special master concerning the application of certain legal principles to the production of Williston Basin's storage gas by Howell and Anadarko. The parties await a decision.

As noted above, Williston Basin estimates that as of December 31, 2007, Howell and Anadarko had diverted between 9.5 and 10 Bcf from the EBSR. Williston Basin believes Howell and Anadarko continue to divert gas from the EBSR and Williston Basin continues to monitor and analyze the situation. At trial, Williston Basin will seek recovery based on the amount of gas that has been and continues to be diverted as well as on the amount of gas that must be recovered as a result of the equalization of the pressures of various interconnected geological formations.

In expert reports filed with the Wyoming State District Court in January 2008, Williston Basin's experts are of the opinion that all of the gas produced by Howell and Anadarko is Williston Basin's gas and will have to be replaced. Williston Basin's experts estimate that the replacement cost of the gas produced by Howell and Anadarko through October 2007 is approximately $106 million if injection is completed by the end of the 2010 injection season. Williston Basin's experts also estimate that Williston Basin will expend $8.7 million to mitigate the damages that Williston Basin suffered during the period of Howell and Anadarko's production if the replacement gas is injected by the end of the 2010 injection season. Williston Basin believes that its experts' opinions are based on sound law, economics, reservoir engineering, geology and geochemistry. The expert reports filed

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by Howell and Anadarko claim that storage gas owned by Williston Basin has migrated outside the EBSR into areas in which Howell and Anadarko have oil and gas rights. They theorize that Williston Basin is accountable to Howell and Anadarko for the migration of such gas. Although Howell and Anadarko have not specified the amount of damages they seek to recover, Williston Basin believes Howell and Anadarko's proposed methodology for valuing their alleged injury, if any, is flawed, inconsistent and lacking in factual and legal support. Williston Basin continues to evaluate the Howell and Anadarko reports. The parties have until May 14, 2008, to file rebuttal reports with the Wyoming State District Court.

Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of these proceedings.

In light of the actions of Howell and Anadarko, Williston Basin installed temporary compression at the site in 2006 in order to maintain deliverability into the transmission system. Williston Basin has leased working gas for the 2007 - 2008 heating season to supplement its cushion gas. While installation of the additional compression has provided temporary relief and the addition of leased working gas is expected to provide additional temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the continued loss of storage gas, if left unchecked, could threaten the operation and viability of the EBSR, impair Williston Basin's ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin's ability to meet its contractual storage and transportation service commitments to customers.

The Company also is 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**

***Portland Harbor Site*** In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a riverbed site adjacent to a commercial property site, acquired by MBI in 1999. The riverbed site is 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 Oregon 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 or Georgia-Pacific West, Inc., the seller of the commercial property to MBI. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately $10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of $60 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 more years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2010, after which a cleanup plan will be undertaken. MBI also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., 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. MBI has entered into an agreement tolling the statute of limitation in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study.

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

***Manufactured Gas Plant Sites*** There are two claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are potentially responsible parties in addition to Cascade that are potentially liable for cleanup of the contamination. Some of these other parties have shared in the investigation costs. It is expected that these and other potentially responsible parties will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. It is not known at this time what share of the cleanup costs will actually be borne by Cascade. In November 2007, the Oregon Department of Environmental Quality provided notice that additional ecological risk assessment of the site was necessary. Completion of the assessment is anticipated by the end of 2008.

The second claim is for contamination at a site in Washington and was received in 1997. Although a preliminary investigation has concluded the site is contaminated, it appears that other property owners may have contributed to the contamination. There is currently not enough information available to estimate the potential liability associated with this claim and no formal investigation plan has been communicated to Cascade.

The Company believes that both these claims are covered by insurance. To the extent not covered by insurance, Cascade will seek recovery of contamination remediation costs through its rates.

**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, 2007, were $20.3 million in 2008, $16.0 million in 2009, $13.7 million in 2010, $10.3 million in 2011, $8.4 million in 2012 and $48.8 million thereafter. Rent expense was $35.6 million, $23.1 million and $33.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

**Purchase commitments**
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and construction materials supply contracts. These commitments range from one to 53 years. The commitments under these contracts as of December 31, 2007, were $479.2 million in 2008, $340.0 million in 2009, $233.4 million in 2010, $163.7 million in 2011, $105.6 million in 2012 and $323.1 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2007, 2006 and 2005, were approximately $857.0 million (including the acquisition of Cascade as discussed in Note 2), $265.8 million and $318.1 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

**Guarantees**
In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses which Petrobras may incur from certain contingent liabilities specified in the purchase

agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging up to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. As described in Note 3, Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which has provided a $10 million bank letter of credit to Centennial in support of that guarantee obligation. The guarantee, which has no fixed maximum, expires when CEM has completed its obligations under the construction contract. Construction is expected to be completed in 2008, and the warranty period associated with this project will expire one year after the date of substantial completion of the construction.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. 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, 2007, expire in 2008; 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. The amount outstanding by Fidelity was $1.4 million and was reflected on the Consolidated Balance Sheet at December 31, 2007. 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 construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2007, the fixed maximum amounts guaranteed under these agreements aggregated $472.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $86.3 million in 2008; $355.8 million in 2009; $400,000 in 2010; $23.0 million in 2011; $1.2 million in 2012; $1.2 million in 2017; $1.0 million 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 $1.9 million and was reflected on the Consolidated Balance Sheet at December 31, 2007. 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.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2007, the fixed maximum amounts guaranteed under these letters of credit, which expire in 2008, aggregated $58.4 million. There were no amounts outstanding under the above letters of credit at December 31, 2007.

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. At December 31, 2007, 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 2008 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 $1.9 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2007, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial and Knife River have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials and lease obligations 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 or lease obligations, Centennial or Knife River would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these maintenance items and materials were reflected on the Consolidated Balance Sheet at December 31, 2007.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds 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. As of December 31, 2007, approximately $455 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

**NOTE 21 - SUBSEQUENT EVENT**

On January 31, 2008, Fidelity completed the acquisition of natural gas properties located in Rusk County in eastern Texas, with a January 1, 2008, effective date. The acquisition includes the purchase of 97 Bcfe of proven reserves. The purchase price for these properties was approximately $235 million, subject to accounting and purchase price adjustments customary with acquisitions of this type.

**NOTE 22 - Investment in Subsidiaries**

The Respondent owns one wholly owned subsidiary, Centennial Energy Holdings, Inc.

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. 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 $961,796,721; current and accrued assets would increase by $1,072,188,116; deferred debits would increase by $495,233,727; long-term debt would increase by $934,483,774; other noncurrent liabilities and current and accrued liabilities would increase by $663,927,492; deferred credits would increase by $930,807,298 as of December 31, 2007. Furthermore, operating revenues would increase by $3,768,184,669 and operating expenses, excluding income taxes, would increase by $3,250,672,473 for the twelve months ended December 31, 2007. In addition, net cash provided by operating activities would increase by $498,382,000; net cash used by investing activities would increase by $296,445,000; net cash used in financing activities would increase by $154,272,000; and the net change in cash and cash equivalents would be an increase of $47,665,000 for the twelve months ended December 31, 2007. 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: 2007

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | **Intangible Plant** | | | |
| 2 | | | | | |
| 3 | 301 | Organization | | | |
| 4 | 302 | Franchises & Consents | | | |
| 5 | 303 | Miscellaneous Intangible Plant | $2,673,840 | $2,693,241 | 0.73% |
| 6 | | | | | |
| 7 | | **TOTAL Intangible Plant** | $2,673,840 | $2,693,241 | 0.73% |
| 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: 2007

| | 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: 2007

| | | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | **Distribution Plant** | | | |
| 3 | | | | | |
| 4 | 374 | Land & Land Rights | $36,193 | $37,059 | 2.39% |
| 5 | 375 | Structures & Improvements | 195,164 | 195,164 | 0.00% |
| 6 | 376 | Mains | 24,963,343 | 25,926,462 | 3.86% |
| 7 | 377 | Compressor Station Equipment | | | |
| 8 | 378 | Meas. & Reg. Station Equipment-General | 569,797 | 567,347 | -0.43% |
| 9 | 379 | Meas. & Reg. Station Equipment-City Gate | 128,221 | 128,221 | 0.00% |
| 10 | 380 | Services | 15,150,522 | 16,341,565 | 7.86% |
| 11 | 381 | Meters | 12,471,111 | 14,888,765 | 19.39% |
| 12 | 382 | Meter Installations | | | |
| 13 | 383 | House Regulators | 1,647,153 | 1,689,672 | 2.58% |
| 14 | 384 | House Regulator Installations | | | |
| 15 | 385 | Industrial Meas. & Reg. Station Equipment | 184,923 | 184,923 | 0.00% |
| 16 | 386 | Other Prop. on Customers' Premises 1/ | 161,799 | 161,799 | 0.00% |
| 17 | 387 | Other Equipment | 999,583 | 996,950 | -0.26% |
| 18 | | | | | |
| 19 | | **TOTAL Distribution Plant** | $56,507,809 | $61,117,927 | 8.16% |
| 20 | | | | | |
| 21 | | **General Plant** | | | |
| 22 | | | | | |
| 23 | 389 | Land & Land Rights | $26,744 | $26,165 | -2.16% |
| 24 | 390 | Structures & Improvements | 454,400 | 444,324 | -2.22% |
| 25 | 391 | Office Furniture & Equipment | 418,584 | 417,657 | -0.22% |
| 26 | 392 | Transportation Equipment | 2,607,809 | 2,604,331 | -0.13% |
| 27 | 393 | Stores Equipment | 43,786 | 43,786 | 0.00% |
| 28 | 394 | Tools, Shop & Garage Equipment | 663,124 | 685,620 | 3.39% |
| 29 | 395 | Laboratory Equipment | 17,973 | 17,960 | -0.07% |
| 30 | 396 | Power Operated Equipment | 1,660,620 | 1,812,365 | 9.14% |
| 31 | 397 | Communication Equipment | 295,046 | 165,385 | -43.95% |
| 32 | 398 | Miscellaneous Equipment | 15,099 | 15,104 | 0.03% |
| 33 | 399 | Other Tangible Property | | | |
| 34 | | | | | |
| 35 | | **TOTAL General Plant** | $6,203,185 | $6,232,697 | 0.48% |
| 36 | | | | | |
| 37 | | **Common Plant** | | | |
| 38 | | | | | |
| 39 | 389 | Land & Land Rights | $522,834 | $535,523 | 2.43% |
| 40 | 390 | Structures & Improvements | 2,247,610 | 4,507,041 | 100.53% |
| 41 | 391 | Office Furniture & Equipment | 973,940 | 1,030,579 | 5.82% |
| 42 | 392 | Transportation Equipment | 1,189,409 | 881,334 | -25.90% |
| 43 | 393 | Stores Equipment | 9,664 | 9,865 | 2.08% |
| 44 | 394 | Tools, Shop & Garage Equipment | 154,415 | 175,018 | 13.34% |
| 45 | 396 | Power Operated Equipment | 0 | 462 | 100.00% |
| 46 | 397 | Communication Equipment | 297,173 | 268,322 | -9.71% |
| 47 | 398 | Miscellaneous Equipment | 98,173 | 102,043 | 3.94% |
| 48 | | | | | |
| 49 | | **TOTAL Common Plant** | $5,493,218 | $7,510,187 | 36.72% |
| 50 | | | | | |
| 51 | | **TOTAL Gas Plant in Service** | $70,878,052 | $77,554,052 | 9.42% |

1/ Includes gas plant leased to others.

## MONTANA DEPRECIATION SUMMARY

Year: 2007

| | Functional Plant Classification | Plant Cost | Accumulated Depreciation Last Year Bal. | Accumulated Depreciation This Year Bal. | Current Avg. Rate |
|---|---|---|---|---|---|
| 1 | Production & Gathering | | | | |
| 2 | Products Extraction | | | | |
| 3 | Underground Storage | | | | |
| 4 | Other Storage | | | | |
| 5 | Transmission | | | | |
| 6 | Distribution | $61,117,927 | $35,989,542 | $37,471,927 | 3.14% |
| 7 | General | 6,286,958 | 3,191,516 | 3,626,851 | 2.74% |
| 8 | Common | 10,149,167 | 3,701,416 | 4,002,452 | 4.81% |
| 9 | **TOTAL** | $77,554,052 | $42,882,474 | $45,101,230 | 3.32% |

## 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) | $445,552 | $426,495 | -4.28% |
| 11 | Assigned to Other | | | |
| 12 | 155 Merchandise | | | |
| 13 | 156 Other Materials & Supplies | | | |
| 14 | 163 Stores Expense Undistributed | | | |
| 15 | | | | |
| 16 | **TOTAL Materials & Supplies** | $445,552 | $426,495 | -4.28% |

## MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

| | Commission Accepted - Most Recent | | % 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 | | 55.800% | 12.000% | 6.696% |
| 13 | Preferred Stock | | 3.804% | 4.603% | 0.175% |
| 14 | Long Term Debt | | 36.234% | 7.249% | 2.627% |
| 15 | Short Term Debt | | 4.162% | 6.512% | 0.271% |
| 16 | **TOTAL** | | 100.000% | | 9.769% |

## STATEMENT OF CASH FLOWS

Year: 2007

| | Description | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Increase/(decrease) in Cash & Cash Equivalents: | | | |
| 2 | | | | |
| 3 | **Cash Flows from Operating Activities:** | | | |
| 4 | Net Income | $315,757,473 | $432,120,349 | 36.85% |
| 5 | Depreciation | 31,171,213 | 32,223,579 | 3.38% |
| 6 | Amortization | 756,294 | 689,959 | -8.77% |
| 7 | Deferred Income Taxes - Net | (2,826,505) | 496,230 | -117.56% |
| 8 | Investment Tax Credit Adjustments - Net | (404,892) | (355,732) | -12.14% |
| 9 | Change in Operating Receivables - Net | 15,992,191 | (1,449,017) | -109.06% |
| 10 | Change in Materials, Supplies & Inventories - Net | (10,403,390) | 10,086,658 | 196.96% |
| 11 | Change in Operating Payables & Accrued Liabilities - Net | 7,285,432 | 17,597,389 | 141.54% |
| 12 | Change in Other Regulatory Assets | (4,072,255) | (4,000,748) | 1.76% |
| 13 | Change in Other Regulatory Liabilities | 505,037 | (1,329,929) | -363.33% |
| 14 | Allowance for Other Funds Used During Construction (AFUDC) | (413,791) | (1,230,086) | 197.27% |
| 15 | Change in Other Assets & Liabilities - Net | 38,004,249 | (2,304,527) | -106.06% |
| 16 | Less Undistributed Earnings from Subsidiary Companies | (294,990,232) | (405,457,963) | 37.45% |
| 17 | Other Operating Activities (explained on attached page) | | | |
| 18 | **Net Cash Provided by/(Used in) Operating Activities** | $96,360,824 | $77,086,162 | -20.00% |
| 19 | | | | |
| 20 | **Cash Inflows/Outflows From Investment Activities:** | | | |
| 21 | Construction/Acquisition of Property, Plant and Equipment | | | |
| 22 | (net of AFUDC & Capital Lease Related Acquisitions) | ($59,249,261) | ($404,720,296) | 583.08% |
| 23 | Acquisition of Other Noncurrent Assets | (95,820) | (3,097,384) | 3132.50% |
| 24 | Proceeds from Disposal of Noncurrent Assets | | | |
| 25 | Investments In and Advances to Affiliates | (27,820,669) | (27,876,935) | 0.20% |
| 26 | Contributions and Advances from Affiliates | 79,572,000 | 96,575,000 | 21.37% |
| 27 | Disposition of Investments in and Advances to Affiliates | 0 | 281,230,210 | 100.00% |
| 28 | Other Investing Activities: Depreciation & RWIP on Nonutility Plant | 89,364 | 102,657 | 14.88% |
| 29 | **Net Cash Provided by/(Used in) Investing Activities** | ($7,504,386) | ($57,786,748) | 670.04% |
| 30 | | | | |
| 31 | **Cash Flows from Financing Activities:** | | | |
| 32 | Proceeds from Issuance of: | | | |
| 33 | Long-Term Debt | $100,000,000 | $35,250,000 | -64.75% |
| 34 | Preferred Stock | | | |
| 35 | Common Stock | 20,932,376 | 39,942,033 | 90.81% |
| 36 | Other: | | | |
| 37 | Net Increase in Short-Term Debt | | | |
| 38 | Other: Commercial Paper | | | |
| 39 | Payment for Retirement of: | | | |
| 40 | Long-Term Debt | (102,350,000) | (6,600,000) | -93.55% |
| 41 | Preferred Stock | | | |
| 42 | Common Stock | | | |
| 43 | Other: Adjustment to Retained Earnings | (9,755,039) | (159,988) | 98.36% |
| 44 | Net Decrease in Short-Term Debt | | | |
| 45 | Dividends on Preferred Stock | (685,005) | (685,004) | 0.00% |
| 46 | Dividends on Common Stock | (94,421,992) | (101,969,421) | 7.99% |
| 47 | Other Financing Activities (explained on attached page) | | | |
| 48 | **Net Cash Provided by (Used in) Financing Activities** | ($86,279,660) | ($34,222,380) | 60.34% |
| 49 | | | | |
| 50 | **Net Increase/(Decrease) in Cash and Cash Equivalents** | $2,576,778 | ($14,922,966) | -679.13% |
| 51 | **Cash and Cash Equivalents at Beginning of Year** | $15,565,346 | $18,142,124 | 16.55% |
| 52 | **Cash and Cash Equivalents at End of Year** | $18,142,124 | $3,219,158 | -82.26% |

# LONG TERM DEBT

Year: 2007

| | 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 | 8.60 % Secured MTN, Series A | 04/92 | 04/12 | $35,000,000 | $28,906,532 | $4,500,000 | 8.60% | $495,900 | 11.02% |
| 2 | 6.71 % Secured MTN, Series A | 09/97 | 10/09 | 15,000,000 | 13,488,404 | 1,000,000 | 6.71% | 81,950 | 8.20% |
| 3 | 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% |
| 4 | 5.98 % Senior Notes | 12/03 | 12/33 | 30,000,000 | 29,456,832 | 30,000,000 | 5.98% | 1,861,500 | 6.21% |
| 5 | 6.33 % Senior Notes | 08/06 | 08/26 | 100,000,000 | 89,123,930 | 100,000,000 | 6.33% | 7,514,000 | 7.51% |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | | | | | | | | |
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| 21 | | | | | | | | | |
| 22 | | | | | | | | | |
| 23 | | | | | | | | | |
| 24 | | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | **TOTAL** | | | $195,000,000 | $175,789,612 | $150,500,000 | | $10,866,250 | 7.22% |

1/ Includes interest expense, bond discount expense, debt issuance expense and loss on bond reacquistion and redemption.

## PREFERRED STOCK

Year: 2007

| | 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 | 5.10 % Cumulative 2/ | 05/61 | 50,000 | 100 | 102 | 4,947,548 | 5.29% | 800,000 | 42,280 | 5.29% |
| 4 | | | | | | | | | | |
| 5 | | | | | | | | | | |
| 6 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
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| 21 | | | | | | | | | | |
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| 23 | | | | | | | | | | |
| 24 | | | | | | | | | | |
| 25 | | | | | | | | | | |
| 26 | | | | | | | | | | |
| 27 | | | | | | | | | | |
| 28 | | | | | | | | | | |
| 29 | | | | | | | | | | |
| 30 | | | | | | | | | | |
| 31 | | | | | | | | | | |
| 32 | **TOTAL** | | | | | $19,947,548 | | $15,800,000 | $727,280 | 4.60% |

1/ Plus accrued dividends.
2/ Mandatory annual redemption of $100,000.

## COMMON STOCK

Year: 2007

| | | 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 | 181,340,963 | $11.98 | $0.26 | $0.1350 | 48.08% | $29.00 | $24.39 | 16.9 X |
| 9 | | | | | | | | | |
| 10 | April | | | | | | | | |
| 11 | | | | | | | | | |
| 12 | May | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | June | 181,846,682 | 12.41 | 0.49 | 0.1350 | 72.45% | 31.79 | 27.40 | 15.7 X |
| 15 | | | | | | | | | |
| 16 | July | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | August | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | September | 182,192,021 | 13.42 | 1.10 | 0.1450 | 86.82% | 30.40 | 24.64 | 12.1 X |
| 21 | | | | | | | | | |
| 22 | October | | | | | | | | |
| 23 | | | | | | | | | |
| 24 | November | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | December | 182,390,928 | 13.80 | 0.52 | 0.1450 | 72.12% | 28.69 | 25.89 | 11.7 X |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |
| 30 | TOTAL Year End | 181,946,208 | $13.80 | $2.37 | 0.5600 | 76.37% | | | 11.7 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: 2007

| | | Description | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| | | Rate Base | | | |
| 1 | | | | | |
| 2 | 101 | Plant in Service | $70,878,052 | $77,554,052 | 9.42% |
| 3 | 108 | (Less) Accumulated Depreciation | 42,882,474 | 45,101,230 | 5.17% |
| 4 | | | | | |
| 5 | | **NET Plant in Service** | $27,995,578 | $32,452,822 | 15.92% |
| 6 | | | | | |
| 7 | | CWIP in Service Pending Reclassification | $349,235 | $494,745 | 41.67% |
| 8 | | | | | |
| 9 | | Additions | | | |
| 10 | 154, 156 | Materials & Supplies | $445,552 | $426,495 | -4.28% |
| 11 | 165 | Prepayments | 23,697 | 17,962 | -24.20% |
| 12 | | Prepaid Demand/Commodity Charges | 1,116,541 | 1,050,726 | -5.89% |
| 13 | | Gas in Underground Storage | 10,262,348 | 6,219,654 | -39.39% |
| 14 | | | | | |
| 15 | | | | | |
| 16 | | **TOTAL Additions** | $11,848,138 | $7,714,837 | -34.89% |
| 17 | | | | | |
| 18 | | Deductions | | | |
| 19 | 190 | Accumulated Deferred Income Taxes | $3,477,910 | $3,364,866 | -3.25% |
| 20 | 252 | Customer Advances for Construction | 465,720 | 543,734 | 16.75% |
| 21 | 255 | Accumulated Def. Investment Tax Credits | 111,105 | 80,900 | -27.19% |
| 22 | | | | | |
| 23 | | | | | |
| 24 | | **TOTAL Deductions** | $4,054,735 | $3,989,500 | -1.61% |
| 25 | | **TOTAL Rate Base** | $36,138,216 | $36,672,904 | 1.48% |
| 26 | | | | | |
| 27 | | **Net Earnings** | $1,923,181 | $2,136,765 | 11.11% |
| 28 | | | | | |
| 29 | | **Rate of Return on Average Rate Base** | 5.72% | 5.87% | 2.62% |
| 30 | | | | | |
| 31 | | **Rate of Return on Average Equity** | 4.27% | 4.88% | 14.29% |
| 32 | | | | | |
| 33 | Major Normalizing Adjustments & Commission | | | | |
| 34 | Ratemaking adjustments to Utility Operations 1/ | | | | |
| 35 | | | | | |
| 36 | Adjustment to Operating Revenues | | | | |
| 38 | Weather Normalization | | 644,663 | 451,840 | -29.91% |
| 39 | Late Payment Revenue | | 37,933 | 23,606 | -37.77% |
| 40 | Gain from Disposition of Utility Plant 2/ | | (146,748) | 43,180 | 129.42% |
| 41 | | | | | |
| 42 | Adjustment to Operating Expenses | | | | |
| 43 | Elimination of Promotional & Institutional Advertising | | (50,903) | (41,343) | 18.78% |
| 44 | Elimination of Supplemental Insurance | | (53,874) | (77,976) | -44.74% |
| 45 | | | | | |
| 46 | | Total Adjustments to Operating Income | $640,625 | $637,946 | -0.42% |
| 47 | | | | | |
| 48 | | **Adjusted Rate of Return on Average Rate Base** | 7.62% | 7.62% | 0.00% |
| 49 | | | | | |
| 50 | | **Adjusted Rate of Return on Average Equity** | 8.20% | 8.15% | -0.61% |

1/ Updated amounts, net of taxes.

2/ Amortized over five years.

## MONTANA COMPOSITE STATISTICS

Year: 2007

| | | Description | Amount |
|---|---|---|---|
| 1 | | | |
| 2 | | Plant (Intrastate Only) (000 Omitted) | |
| 3 | | | |
| 4 | 101 | Plant in Service | $73,009 |
| 5 | 107 | Construction Work in Progress | 541 |
| 6 | 114 | Plant Acquisition Adjustments | |
| 7 | 104 | Plant Leased to Others | 13 |
| 8 | 105 | Plant Held for Future Use | |
| 9 | 154, 156 | Materials & Supplies | 426 |
| 10 | | (Less): | |
| 11 | 108, 111 | Depreciation & Amortization Reserves | 45,101 |
| 12 | 252 | Contributions in Aid of Construction | 544 |
| 13 | | | |
| 14 | | **NET BOOK COSTS** | $28,344 |
| 15 | | | |
| 16 | | Revenues & Expenses (000 Omitted) | |
| 17 | | | |
| 18 | 400 | Operating Revenues | $69,617 |
| 19 | | | |
| 20 | 403 - 407 | Depreciation & Amortization Expenses | $2,578 |
| 21 | | Federal & State Income Taxes | 82 |
| 22 | | Other Taxes | 2,433 |
| 23 | | Other Operating Expenses | 62,387 |
| 24 | | TOTAL Operating Expenses | $67,480 |
| 25 | | | |
| 26 | | Net Operating Income | $2,137 |
| 27 | | | |
| 28 | | Other Income | 1,187 |
| 29 | | Other Deductions | 1,462 |
| 30 | | | |
| 31 | | **NET INCOME** | $1,862 |
| 32 | | | |
| 33 | | Customers (Intrastate Only) | |
| 34 | | | |
| 35 | | Year End Average: | |
| 36 | | Residential | 67,294 |
| 37 | | Firm General | 8,151 |
| 38 | | Small Interruptible | 44 |
| 39 | | Large Interruptible | 5 |
| 40 | | | |
| 41 | | **TOTAL NUMBER OF CUSTOMERS** | 75,494 |
| 42 | | | |
| 43 | | Other Statistics (Intrastate Only) | |
| 44 | | | |
| 45 | | Average Annual Residential Use (Dkt)) | 82 |
| 46 | | Average Annual Residential Cost per (Dkt) ($) * 1/ | $6.77 |
| | | * Avg annual cost = [(cost per Dkt x annual use) + | |
| 47 | | (monthly service charge x 12)]/annual use | |
| 48 | | Average Residential Monthly Bill | $46.26 |
| 49 | | Gross Plant per Customer | $967 |

1/ Reflects cost per dk effective December 1, 2007.

## MONTANA CUSTOMER INFORMATION

Year: 2007

| | City/Town | Population (Includes Rural) 1/ | Residential Customers | Commercial Customers | Industrial & Other Customers | Total Customers |
|---|---|---|---|---|---|---|
| 1 | Belfry | 219 | 131 | 21 | | 152 |
| 2 | Billings | 89,847 | 43,604 | 4,230 | | 47,834 |
| 3 | Bridger | 745 | 405 | 64 | | 469 |
| 4 | Crow Agency | 1,552 | 309 | 71 | | 380 |
| 5 | Edgar | Not Available | 104 | 8 | | 112 |
| 6 | Fromberg | 486 | 281 | 18 | | 299 |
| 7 | Hardin | 3,384 | 1,263 | 202 | | 1,465 |
| 8 | Joliet | 575 | 352 | 40 | | 392 |
| 9 | Laurel | 6,255 | 3,683 | 274 | 1 | 3,958 |
| 10 | Park City | 870 | 528 | 23 | | 551 |
| 11 | Pryor | 628 | 90 | 13 | | 103 |
| 12 | Rockvale | Not Available | 61 | 4 | | 65 |
| 13 | Silesia | Not Available | 31 | 2 | | 33 |
| 14 | Warren | Not Available | | 2 | | 2 |
| 15 | Alzada | Not Available | 11 | 7 | | 18 |
| 16 | Baker | 1,695 | 793 | 174 | | 967 |
| 17 | Carlyle | Not Available | 7 | 1 | | 8 |
| 18 | Fort Peck | 240 | 128 | 11 | | 139 |
| 19 | Fairview | 709 | 359 | 53 | | 412 |
| 20 | Forsyth | 1,944 | 865 | 150 | | 1,015 |
| 21 | Frazer | 452 | 92 | 15 | | 107 |
| 22 | Glasgow | 3,253 | 1,618 | 307 | | 1,925 |
| 23 | Glendive | 4,729 | 2,982 | 412 | | 3,394 |
| 24 | Hinsdale | Not Available | 115 | 20 | | 135 |
| 25 | Ismay | 26 | 10 | 4 | | 14 |
| 26 | Malta | 2,120 | 993 | 200 | | 1,193 |
| 27 | Miles City | 8,487 | 3,872 | 547 | | 4,419 |
| 28 | Nashua | 325 | 171 | 18 | | 189 |
| 29 | Poplar | 911 | 843 | 134 | | 977 |
| 30 | Richey | 189 | 119 | 25 | | 144 |
| 31 | Rosebud | Not Available | 42 | 6 | | 48 |
| 32 | Saco | 224 | 40 | 6 | | 46 |
| 33 | Savage | Not Available | 147 | 18 | | 165 |
| 34 | Sidney | 4,774 | 2,313 | 404 | | 2,717 |
| 35 | Terry | 611 | 314 | 57 | | 371 |
| 36 | St. Marie | 183 | 167 | 11 | | 178 |
| 37 | Wibaux | 567 | 218 | 49 | | 267 |
| 38 | Whitewater | Not Available | 33 | 10 | | 43 |
| 39 | Wolf Point | 2,663 | 1,354 | 198 | | 1,552 |
| 40 | MT Oil Fields | Not Available | 1 | 3 | | 4 |
| 41 | **TOTAL Montana Customers** | 138,663 | 68,449 | 7,812 | 1 | 76,262 |

1/ 2000 Census.

## MONTANA EMPLOYEE COUNTS 1/

Year: 2007

| | Department | Year Beginning | Year End | Average |
|---|---|---|---|---|
| 1 | Electric | 20 | 19 | 19.5 |
| 2 | Gas | 43 | 40(2) | 41.5(1) |
| 3 | Accounting | 19 | 18 | 18.5 |
| 4 | Management | 7 | 7 | 7.0 |
| 5 | Service 2/ | 53(3) | 52(3) | 52.5(3) |
| 6 | Communications/Substation/Training | 5 | 5 | 5.0 |
| 7 | Power | 27 | 27 | 27.0 |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
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| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | **TOTAL Montana Employees** | 174(3) | 168(5) | 171(4) |

1/ Parentheses denotes part-time.
2/ Reflects service employees such as meter readers and servicemen.

## MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) — Year: 2007

| | Project Description | Total Company | Total Montana | |
|---|---|---|---|---|
| 1 | Projects>$1,000,000 | | | |
| 2 | Common-General | | | |
| 3 | Sell Bravo Aircraft | ($3,500,000) | ($846,975) | 1/ |
| 4 | Common-Intangible | | | |
| 5 | Replace Customer Information System | 5,120,163 | 1,239,042 | 1/ |
| 6 | Electric-Steam Production | | | |
| 7 | Purchase 25 MW of WYGEN III Power Plant | 23,629,955 | 0 | |
| 8 | Construct Big Stone II Power Plant | 11,707,137 | 2,891,275 | 1/ |
| 9 | Install Flue Gas Desulfurization Technology at Big Stone I | 1,399,389 | 345,603 | 1/ |
| 10 | Overhaul Unit #1 Turbine at Heskett Station | 1,149,546 | 283,900 | 1/ |
| 11 | Electric-Other Production | | | |
| 12 | Install Waste Heat Energy Converter near Glen Ullin, ND | 8,218,800 | 2,029,771 | 1/ |
| 13 | Electric-Distribution | | | |
| 14 | Install Automated Meter Reading System | 1,353,633 | 266,571 | 1/ |
| 15 | Electric-Transmission | | | |
| 16 | Replace Lines Crossing Memorial Bridge in Bismarck, ND | 5,364,050 | 1,324,742 | 1/ |
| 17 | Replace Line Between Beulah, ND and Heskett Station | 1,047,732 | 258,755 | 1/ |
| 18 | Gas-Distribution | | | |
| 19 | Install Automated Meter Reading System | 7,390,944 | 2,400,964 | 1/ |
| 20 | Gas-General | | | |
| 21 | Construct Service Center in Spearfish, SD | 1,717,396 | 0 | |
| 22 | | | | |
| 23 | Other Projects<$1,000,000 | | | |
| 24 | Electric | | | |
| 25 | Production | 12,825,996 | 3,167,594 | 1/ |
| 26 | Integrated Transmission | 3,033,577 | 670,347 | 1/ |
| 27 | Direct Transmission | 2,407,007 | 448,780 | 2/ |
| 28 | Distribution | 11,304,619 | 2,335,182 | 2/ |
| 29 | General | 2,836,975 | 665,164 | 2/ |
| 30 | Common: | | | |
| 31 | General Office | 1,671,907 | 380,645 | 1/ |
| 32 | Other Direct | 1,280,901 | 330,473 | 2/ |
| 33 | Total Electric | $35,360,982 | $7,998,185 | |
| 34 | Gas | | | |
| 35 | Direct Transmission | $120,505 | $0 | |
| 36 | Distribution | 15,718,295 | 4,076,014 | 2/ |
| 37 | General | 3,589,322 | 547,359 | 2/ |
| 38 | Common: | | | |
| 39 | General Office | 1,322,242 | 358,036 | 1/ |
| 40 | Other Direct | 641,894 | 299,384 | 2/ |
| 41 | Total Gas | $21,392,258 | $5,280,793 | |
| 42 | TOTAL | $121,351,985 | $23,472,626 | |

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2007

| | 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: 2007

| | Total Company | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Dkt | Total Monthly Volumes Dkt |
| 1 | January | 11 | 301,850 | 6,492,587 |
| 2 | February | 1 | 292,844 | 6,111,677 |
| 3 | March | 2 | 223,465 | 3,996,750 |
| 4 | April | 2 | 188,685 | 3,341,901 |
| 5 | May | 23 | 80,612 | 1,877,452 |
| 6 | June | 7 | 66,398 | 1,533,247 |
| 7 | July | 30 | 55,754 | 1,317,210 |
| 8 | August | 29 | 54,538 | 1,494,952 |
| 9 | September | 24 | 71,632 | 1,552,009 |
| 10 | October | 31 | 119,306 | 2,897,816 |
| 11 | November | 29 | 252,812 | 4,654,456 |
| 12 | December | 1 | 250,358 | 6,555,747 |
| 13 | **TOTAL** | | | 41,825,804 |

| | Montana | | | |
|---|---|---|---|---|
| | | Peak Day of Month | Peak Day Volumes Dkt | Total Monthly Volumes Dkt |
| 14 | January | 11 | 90,000 | 1,884,847 |
| 15 | February | 1 | 87,490 | 1,733,189 |
| 16 | March | 2 | 61,733 | 1,122,125 |
| 17 | April | 6 | 61,940 | 1,079,570 |
| 18 | May | 22 | 30,063 | 595,051 |
| 19 | June | 12 | 20,875 | 505,142 |
| 20 | July | 30 | 24,757 | 437,905 |
| 21 | August | 8 | 21,262 | 547,128 |
| 22 | September | 24 | 25,042 | 485,398 |
| 23 | October | 30 | 40,404 | 916,718 |
| 24 | November | 29 | 78,853 | 1,442,193 |
| 25 | December | 1 | 82,615 | 1,924,399 |
| 26 | **TOTAL** | | | 12,673,665 |

Year: 2007

## STORAGE SYSTEM - TOTAL COMPANY & MONTANA

| | | Total Company | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Peak Day of Month | | Peak Day Volumes (Dkt) | | Total Monthly Volumes (Dkt) | | |
| | | Injection | Withdrawal | Injection | Withdrawal | Injection | Withdrawal | Losses |
| 1 | January | 3 | 11 | 3,350 | 176,358 | 16,851 | 2,657,323 | |
| 2 | February | 5 | 1 | 3,212 | 165,575 | 12,126 | 2,587,492 | |
| 3 | March | 25 | 2 | 38,273 | 105,388 | 207,082 | 759,242 | |
| 4 | April | 28 | 6 | 52,373 | 88,069 | 478,357 | 687,442 | |
| 5 | May | 9 | 25 | 61,663 | 1,030 | 1,346,122 | 2,459 | |
| 6 | June | 22 | 14 | 58,083 | 284 | 1,451,461 | 898 | |
| 7 | July | 6 | 12 | 53,654 | 317 | 1,533,101 | 401 | |
| 8 | August | 18 | 9 | 54,230 | 435 | 1,517,362 | 1,420 | |
| 9 | September | 2 | 16 | 51,475 | 322 | 1,270,471 | 1,436 | |
| 10 | October | 1 | 30 | 34,621 | 25,912 | 364,092 | 216,361 | |
| 11 | November | 10 | 29 | 11,588 | 133,318 | 43,525 | 1,369,136 | |
| 12 | December | 8 | 1 | 2,781 | 115,381 | 20,697 | 2,344,170 | |
| 13 | **TOTAL** | | | | | 8,261,247 | 10,627,780 | |

| | | 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: 2007

| | 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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| 26 | | | | | |
| 27 | | | | | |
| 28 | | | | | |
| 29 | 1/ Supplier information is proprietary and confidential. | | | | |
| 30 | | | | | |
| 31 | | | | | |
| 32 | | | | | |
| 33 | **Total Gas Supply Volumes** | 32,141,281 | 31,093,670 | $5.744 | $4.447 |

## MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2007

| | Program Description | Current Year Expenditures | Last Year Expenditures | % Change | Planned Savings **(Mcf or Dkt)** | Achieved Savings **(Mcf or Dkt)** | Difference |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | MT Conservation & DSM Program | $41,180 | $38,006 | 8.35% | N/A | 3,518 | N/A |
| 3 | (As Detailed on Schedule 36B) | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
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| 10 | | | | | | | |
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| 23 | | | | | | | |
| 24 | | | | | | | |
| 25 | | | | | | | |
| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | | | | | | | |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | **TOTAL** | $41,180 | $38,006 | 8.35% | N/A | 3,518 | N/A |

## MONTANA CONSUMPTION AND REVENUES

Year: 2007

| | 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 | $42,915,114 | $51,334,359 | 5,487,526 | 5,249,591 | 67,294 | 66,361 |
| 2 | Firm General | 24,182,920 | 29,107,567 | 3,212,229 | 3,076,522 | 8,151 | 8,031 |
| 3 | Small Interruptible | 267,726 | 192,788 | 55,964 | 24,239 | 3 | 3 |
| 4 | Large Interruptible | 16,402 | | 2,522 | | 0 | 0 |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | | | | | | | |
| 11 | **TOTAL** | $67,382,162 | $80,634,714 | 8,758,241 | 8,350,352 | 75,448 | 74,395 |
| 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 | Small Interruptible | $816,027 | $826,970 | 1.0 | 0.9 | 41 | 41 |
| 20 | Large Interruptible | 487,122 | 429,568 | 3.2 | 4.6 | 5 | 5 |
| 21 | | | | | | | |
| 22 | | | | | | | |
| 23 | | | | | | | |
| 24 | **TOTAL** | $1,303,149 | $1,256,538 | 4.2 | 5.5 | 46 | 46 |

Company Name: Montana-Dakota Utilities Co. SCHEDULE 36A

## NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2007

| | Program Description | Actual Current Year Expenditures | Contracted or Committed Current Year Expenditures | Total Current Year Expenditures | Expected savings (Mcf or Dkt) | Most recent program evaluation |
|---|---|---|---|---|---|---|
| 1 | Local Conservation | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | Market Transformation | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | Research & Development | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | Low Income | | | | | |
| 23 | Discounts | $208,626 | $0 | $208,626 | | |
| 24 | Bill Assistance | 45,000 | 0 | 45,000 | | |
| 25 | Furnace Safety/Repair | 50,000 | 0 | 50,000 | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | Other | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | Total | $303,626 | $0 | $303,626 | | 2007 |
| 43 | Number of customers that received low income rate discounts | | | (Average) | 2,785 | |
| 44 | Average monthly bill discount amount ($/mo) | | | | $6.27 | |
| 45 | Average LIEAP-eligible household income | | | | N/A | |
| 46 | Number of customers that received weatherization assistance | | | | N/A | |
| 47 | Expected average annual bill savings from weatherization | | | | N/A | |
| 48 | Number of residential audits performed | | | | N/A | |

**Company Name: Montana-Dakota Utilities Co.** **SCHEDULE 36B**

## MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2007

| | Program Description | Actual Current Year Expenditures | Contracted or Committed Current Year Expenditures | Total Current Year Expenditures | Expected savings (Mcf or Dkt) | Most recent program evaluation |
|---|---|---|---|---|---|---|
| 1 | Local Conservation | | | | | |
| 2 | Furnace Incentive | $38,400 | $0 | $38,400 | 3,004 | |
| 3 | | | | | | |
| 4 | Thermostat Incentive | 2,780 | 0 | 2,780 | 514 | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | Demand Response | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | Market Transformation | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | Research & Development | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | Low Income | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | | | | | | |
| 36 | Other | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | | | | | | |
| 45 | | | | | | |
| 46 | | | | | | |
| 47 | Total | $41,180 | $0 | $41,180 | 3,518 | 2007 |