YEAR ENDING 2009

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

2009 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 2009 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 schednles 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 spousc 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 nsed, 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 sball 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 oecur iu 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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Company Name: **Montana-Dakota Utilities Co.** **SCHEDULE 1**

IDENTIFICATION

Year: 2009

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. 400 North Fourth Street Bismarck, ND 58501
5.	Person Responsible for This Report:	Rita A. Mulkern
5a.	Telephone Number:	(701) 222-7854

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 2/	-
3	Paul K. Sandness, Bismarck, ND	-
4	David L. Goodin, Bismarck, ND	-
5		-
6		
7		
8	1/ Montana-Dakota Utilities Co. is a division of MDU Resources Group, Inc.,	
9	and has no Board of Directors. The affairs of the Company are managed by	
10	a Managing Committee, the members of which are provided herein rather	
11	than the directors of MDU Resources Group, Inc.	
12	2/ Vernon Raile retired from the Managing Committee effective February 2, 2010.	
13	Doran N. Schwartz was elected on February 3, 2010.	
14		
15		
16		
17		
18		

Officers

Year: 2009

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1	President & Chief	Executive	David L. Goodin
2	Executive Officer		
3			
4	Executive Vice President	Regulatory, Gas Supply	Dennis L. Haider
5		and Business Development	
6			
7	Executive Vice President	Finance, Integration and Acquisitions	John F. Renner [1/]
8			
9	Executive Vice President	Utiility Operations Support	Mike Gardner
10			
11	Vice President	Regulatory Affairs	Donald R. Ball [2/]
12			
13	Vice President	Electric Supply	Andrea L. Stomberg
14			
15	Vice President	Operations	Jay Skabo
16			
17	Vice President	Controller and Chief Accounting	Garret Senger
18		Officer	
19			
20			
21	1/ John Renner retired on January 3, 2010.		
22	2/ Donald Ball retired on March 31, 2010.		
23			
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CORPORATE STRUCTURE

Year: 2009

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.) Cascade Natural Gas Corp. and Intermountain Gas Company	Electric and Natural Gas Distribution	$54,895	21.08%
WBI Holdings, Inc. *	Pipeline and Energy Services and Natural Gas and Oil Production	125,515	48.19%
Knife River Corp.	Construction Materials and Mining	47,085	18.08%
MDU Construction Services Group, Inc.	Construction Services	25,589	9.83%
Centennial Energy Resources LLC/ Centennial Holdings Capital Corp.	Other	7,357	2.82%
TOTAL		$260,441	100.00%

* Excludes the effect of a $384.4 million after-tax noncash write-down of natural gas and oil properties.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 5

CORPORATE ALLOCATIONS - GAS

Year: 2009

Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
Audit Costs	Administrative & General	Various Corporate Overhead Allocation Factors	$2,010	1.06%	$188,083
Advertising	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	1,312	1.07%	121,698
Air Service	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	644	0.93%	68,975
Automobile	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	401	1.84%	21,422
Bank Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	3,610	1.06%	338,301
Computer Rental	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	97	1.40%	6,842
Consultant Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	17,646	1.84%	942,637
Contract Services	Administrative & General	Various Corporate Overhead Allocation Factors and/or Actual Costs Incurred	34,010	1.55%	2,166,176
Corporate Aircraft	Administrative & General	Various Corporate Overhead Allocation Factors, Time Studies, and/or Actual Costs Incurred	1,313	1.02%	127,091
Directors Expenses	Administrative & General	Corporate Overhead Allocation Factor Based on a Combination of Net Plant Investment and Number of Employees	21,655	1.13%	1,897,434
Employee Benefits	Administrative & General	Corporate Overhead Allocation Factor Based on Number of Employees	1,659	1.10%	148,595

CORPORATE ALLOCATIONS - GAS

Year: 2009

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Employee Meetings	Administrative & General	Various Corporate Overhead Allocation Factors and/or	1,441	1.00%	142,239
2			Actual Costs Incurred			
3						
4	Employee Reimbursable	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,405	1.05%	131,989
5	Expenses		Studies, and/or Actual Costs Incurred			
6						
7	Legal Retainers & Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	14,218	1.06%	1,323,635
8			Actual Costs Incurred			
9						
10	Meal Allowance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	31	1.10%	2,780
11			Studies, and/or Actual Costs Incurred			
12						
13	Meals & Entertainment	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,015	1.00%	100,273
14			Studies, and/or Actual Costs Incurred			
15						
16	Industry Dues & Licenses	Administrative & General	Various Corporate Overhead Allocation Factors, Time	1,444	1.02%	140,426
17			Studies, and/or Actual Costs Incurred			
18						
19	Office Expenses	Administrative & General	Various Corporate Overhead Allocation Factors and/or	1,083	1.27%	84,270
20			Actual Costs Incurred			
21						
22	Prepaid Insurance	Administrative & General	Various Corporate Overhead Allocation Factors and	17,244	1.01%	1,686,463
23			Allocation Factors Based on Actual Experience			
24						
25	Permits and Filing Fees	Administrative & General	Various Corporate Overhead Allocation Factors and/or	482	1.37%	34,655
26			Actual Costs Incurred			
27						
28	Postage	Administrative & General	Various Corporate Overhead Allocation Factors and/or	241	1.11%	21,527
29			Actual Costs Incurred			
30						
31	Payroll	Administrative & General	Various Corporate Overhead Allocation Factors, Time	267,543	1.22%	21,604,408
32			Studies, and/or Actual Costs Incurred			

Company Name: Montana-Dakota Utilities Co.

CORPORATE ALLOCATIONS - GAS

Year: 2009

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1	Rental	Administrative & General	Various Corporate Overhead Allocation Factors and/or	225	1.39%	15,975
2			Actual Costs Incurred			
3						
4	Reference Materials	Administrative & General	Various Corporate Overhead Allocation Factors and/or	2,370	1.12%	208,508
5			Actual Costs Incurred			
6						
7	Seminars & Meeting	Administrative & General	Various Corporate Overhead Allocation Factors, Time	956	1.36%	69,524
8	Registrations		Studies, and/or Actual Costs Incurred			
9						
10	Software Maintenance	Administrative & General	Various Corporate Overhead Allocation Factors, Time	7,098	1.47%	474,466
11			Studies, and/or Actual Costs Incurred			
12						
13	Supplemental Insurance	Administrative & General	Various Corporate Overhead Factors	(10,106)	1.18%	(844,963)
14						
15	Telephone & Cell Phones	Administrative & General	Various Corporate Overhead Allocation Factors and/or	2,882	1.26%	226,258
16			Actual Costs Incurred			
17						
18	Training Material	Administrative & General	Various Corporate Overhead Allocation Factors, Time	720	1.46%	48,466
19			Studies, and/or Actual Costs Incurred			
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**			$394,649	1.24%	$31,498,153

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2009

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		Contract Services		$150		
3		Materials		1,107		$944
4		Office Expense		288		72
5		Training		88		22
6						
7		Capital	Actual Costs Incurred			
8		Contract Services		350		
9		Materials		8,070		6,826
10		Office Services		1,523		408
11						
12		Other				
13		Balance Sheet Accts	Actual Costs Incurred	1,372,680		
14		Resources Cost Centers		9,808		
15		Non Utiility		681		
16						
17						
18		Total Knife River Corporation Operating Revenues for the Year 2009			$1,515,122,000	
19		Excludes Intersegment Eliminations				
20						
21						
22	TOTAL	Grand Total Affiliate Transactions		$1,394,745	0.0921%	$8,272

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2009

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		$55,575,789		$17,144,844
3						
4		Expense	Actual Costs Incurred			
5		Contract Services		23,206		4,783
6		Materials		2,766		847
7		Easements		10		
8		Reference Materials		10,146		2,529
9						
10		Capital	Actual Costs Incurred			
11		Contract Services		135,583		7,040
12		Materials		5,000		
13						
14		Other	Actual Costs Incurred			
15		Auto Clearing		569		
16		Balance sheet accounts		2,446,354		
17		Non Utility		9,769		
18		Resource Cost Centers		22,953		
19						
20		Total WBI Holdings, Inc. Operating Revenues for the Year 2009				
21		Excludes Intersegment Eliminations			$747,482,000	
22						
23						
24	TOTAL	**Grand Total Affiliate Transactions**		$58,232,145	7.7904%	$17,160,043

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2009

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**	Expense	Actual Costs Incurred			
2	**SERVICES GROUP, INC**	Office Expense		$94		
3						
4		Capital	Actual Costs Incurred			
5		Materials		20,908		$5,677
6		Office Expense		9		3
7						
8		Other	Actual Costs Incurred			
9		Miscellaneous		201,731		
10						
11						
12		Total MDU Construction Services Group, Inc Operating Revenues for the Year 2009			$819,064,000	
13		Excludes Intersegment Eliminations				
14						
15						
16						
17						
18						
19						
20						
21						
22	TOTAL	**Grand Total Affiliate Transactions**		$222,742	0.0272%	$5,680

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2009

Line	(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 HOLDINGS**	Expense	* Various Corporate Overhead			
2	**CAPITAL, LLC**	Contract Services	Allocation Factors and/or	$96,559		$24,275
3		Corporate Aircraft	Actual Costs Incurred	23,309		5,347
4		Office Expense		105,783		26,594
5		Rent		164,158		41,270
6		Other		10		
7						
8		Capital	Actual Costs Incurred			
9		Contract Services		178,540		47,833
10		Corporate Aircraft		1,323		47
11						
12		Other	Actual Costs Incurred			
13		Resources		307,581		
14		Balance Sheet Accts		1,826,707		
15		Auto & Work Clearing		21,659		
16		Non Utility		3,295		
17						
18						
19		Total Centennial Holdings Capital, LLC Operating Revenues for the Year 2009			$9,487,000	
20		Excludes Intersegment Eliminations				
21						
25	**TOTAL**	**Grand Total Affiliate Transactions**		$2,728,924	28.7649%	$145,366

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY - GAS

Year: 2009

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 ENERGY CAPITAL**	Expense	Actual Costs Incurred			
2		Payroll		$267,277		$73,714
3		Contract Services		3,343		1,075
4		Travel		15,217		3,826
5		Software Maintenance		182		59
6						
7		Other	Actual Costs Incurred			
8		Miscellaneous		1,977		
9						
10						
11						
12						
13		Total MDU Energy Capital Operating Revenues for the Year 2009			$754,428,000	
14		Grand Total Affiliate Transactions				
15						
16						
17						
18						
19						
20						
21						
22	**TOTAL**	**Grand Total Affiliate Transactions**		$287,996	0.0382%	$78,674

* 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: 2009

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	$57,341		
4		Advertising	Costs Incurred	36,862		
5		Air Service		21,591		
6		Automobile		4,114		
7		Bank Services		103,265		
8		Corporate Aircraft		37,358		
9		Consultant Fees		314,254		
10		Contract Services		1,053,132		
11		Computer Rental		2,167		
12		Directors Expenses		550,053		
13		Employee Benefits		46,349		
14		Employee Meeting		45,064		
15		Employee Reimbursable Expense		42,884		
16		Express Mail		514		
17		Insurance		489,645		
18		Legal Retainers & Fees		402,136		
19		Meal Allowance		911		
20		Cash Donations		16,577		
21		Meals & Entertainment		30,080		
22		Industry Dues & Licenses		42,887		
23		Office Expenses		29,790		
24		Supplemental Insurance		(234,371)		
25		Permits & Filing Fees		10,749		
26		Postage		6,175		
27		Payroll		7,006,196		
28		Reference Materials		62,414		
29		Rental		3,464		
30		Seminars & Meeting Registrations		22,092		
31		Software Maintenance		190,714		
32		Telephone Expenses		103,918		
33		Training		16,509		
34						
35		**Total MDU Resources Group, Inc.**		$10,514,834	0.7395%	

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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**	Other Direct Charges	Actual Costs Incurred			
3		Employee Discounts		45,150		
4		Dues, Permits, and Filing Fees		1,541		
5		Electric Consumption		98,554		
6		Gas Consumption		122,191		74,346
7		Miscellaneous		80,567		
8		Computer/Software Support		977,465		
9						
10		Cost of Service		278,678		66,113
11						
12		Audit Costs		493,613		
13		Region Damage Billings		863		
14		Employee Reimbursable Exp		122,010		
15		Misc Employee Benefits		(16,412)		
16						
17						
18		**Total Montana-Dakota Utilities Co.**		2,204,220	0.1550%	140,459
19						
20		OTHER TRANSACTIONS/REIMBURSEMENTS				
21						
22						
23		Federal & State Tax Liability Payments		43,012,117		
24		Tax Deferred Savings Plan		73,188		
25		Miscellaneous Reimbursements		(228,321)		
26						
27		**Total Other Transactions/Reimbursements**		42,856,984	3.0142%	
28						
29		**Grand Total Affiliate Transactions**		$55,576,038	3.9087%	$140,459
30						
31		**Total Knife River Corporation Operating Expenses for 2009-Excludes Intersegment Eliminations**			$1,421,852,000	
32						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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			
3		Audit Costs	Allocation Factors, Time	$70,149		
4		Advertising	Studies and/or Actual Costs	45,409		
5		Air Service	Incurred	18,463		
6		Automobile		11,333		
7		Bank Services		126,164		
8		Corporate Aircraft		49,748		
9		Consultant Fees		280,234		
10		Contract Services		519,838		
11		Computer Rental		2,431		
12		Directors Expenses		709,988		
13		Employee Benefits		54,763		
14		Employee Meeting		52,900		
15		Employee Reimbursable Expense		42,313		
16		Express Mail		210		
17		Insurance		605,365		
18		Legal Retainers & Fees		493,786		
19		Meal Allowance		1,008		
20		Cash Donations		19,938		
21		Meals & Entertainment		37,534		
22		Moving Expense		3,750		
23		Industry Dues & Licenses		53,288		
24		Office Expenses		28,761		
25		Supplemental Insurance		(317,011)		
26		Permits & Filing Fees		12,465		
27		Postage		7,542		
28		Payroll		8,113,347		
29		Reference Materials		77,482		
30		Rental		7,813		
31		Seminars & Meeting Registrations		25,321		
32		Software Maintenance		147,458		
33		Telephone		75,781		
34		Training Material		16,533		
35		**Total MDU Resources Group, Inc.**		$11,394,104	0.9895%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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			
3		Expense	Allocation Factors, Cost of			
4		Network Circuit Charges	Service Factors, Time	$3,812		
5			Studies and /or Actual Costs			
6						
7		Region Operations	* Various Corporate Overhead			
8		Expense	Allocation Factors and/or			
9		Automobile	Actual Costs Incurred	4,036		
10		Contract Services		25		
11		Materials		4		
12		Office Telephone		37		
13		Payroll		9,322		
14		Photocopier		32		
15		Utilities		46		
16		General & Administrative Expenses		2,061		
17						
18		Clearing Accounts	* Various Corporate Overhead			
19		Office Telephone	Time Studies and/or Actual Costs	242		
20			Incurred			
21						
22		Other Direct Charges	Actual Costs Incurred			
23		Utility/Merchandise Discounts		153,243		
24		Audit Costs		325,581		
25		Radio Maintenance		1,095		
26		Vehicle Maintenance		14,571		
27		Dues, Permits, and Filing Fees		5,650		
28		Misc Employee Benefits		3,638		
29		Computer/Software Support		281,812		
30		Electric Consumption		1,288,089		$947,568
31		Gas Consumption		49,994		32,456
32		Cost of Service		313,654		74,411
33		Region Billings		5,849		
34		Legal Fees		11,184		
35		Employee Reimbursable Exp		36,250		

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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.**	Telephone Expense		7,315		
2		Miscellaneous		58,182		
3		BitterCreek Projects		90,060		
4						
5		Total Montana-Dakota Utilities Co. 1/		$2,665,784	0.2315%	$1,054,434
6						
7						
8						
9		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual Costs Incurred			
10		Federal & State Tax Liability Payments		(9,562,040)		
11		Tax Deferred Savings Plan		7,277		
12		Miscellaneous Reimbursements		(82,885)		
13		**Total Other Transactions/Reimbursements**		(9,637,648)	-0.8370%	
14						
15		**Grand Total Affiliate Transactions**		$4,422,240	0.3840%	$1,054,434
16						
17						
18						
19		**Total WBI Holdings Operating Expenses for 2009 - Excludes Intersegment Eliminations**			$1,151,493,000	
20						
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27						

* 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: 2009

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	$13,484		
4		Advertising	Studies and/or Actual Costs	8,680		
5		Air Service	Incurred	8,202		
6		Automobile		699		
7		Bank Services		24,277		
8		Corporate Aircraft		8,783		
9		Consultant Fees		42,043		
10		Contract Services		86,099		
11		Computer Rental		433		
12		Directors Expenses		130,723		
13		Employee Benefits		10,565		
14		Employee Meeting		10,514		
15		Employee Reimbursable Expense		11,070		
16		Express Mail		309		
17		Insurance		118,158		
18		Legal Retainers & Fees		94,632		
19		Meal Allowance		195		
20		Cash Donations		3,885		
21		Meals & Entertainment		7,182		
22		Industry Dues & Licenses		9,970		
23		Office Expenses		5,291		
24		Supplemental Insurance		(56,236)		
25		Permits & Filing Fees		2,455		
26		Postage		1,451		
27		Payroll		1,107,468		
28		Reference Materials		14,766		
29		Rent		822		
30		Seminars & Meeting Registrations		4,292		
31		Software Maintenance		23,765		
32		Telephone		7,098		
33		Training Material		3,042		
34						
35		**Total MDU Resources Group, Inc.**		$1,704,117	0.2199%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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	$17		
4		Automobile	Service Factors, Time Studies	6		
5		Meals & Entertainment	and/or Actual Costs Incurred	1		
6		Office Telephone		22,579		
7		Payroll		6,965		
8		Employee Reimbursable Expense		4		
9		Materials		135		
10		Industry Dues & Licenses		22		
11						
12		Other Miscellaneous Departments	* Various Corporate Overhead			
13		Payroll	Allocation Factors and/or Actual	56		
14		Other	Costs Incurred	(1)		
15						
16		Other Direct Charges	Actual Costs Incurred			
17		Legal Fees		989		
18		Audit		321,662		
19		Computer/Software Support		20,646		
20		Employee Reimbursable Expense		87		
21		Cost of Service		107,168		$25,425
22		Misc Employee Benefits		832,964		
23		Contract Services		2,981		
24		Dues, Permits, and Filing Fees		11,291		
25		Telephone Expense		9,941		
26		Miscellaneous		81,896		
27		Employee Discounts		6,508		
28		Gas Consumption		2,832		2,832
29						
30		**Total Montana-Dakota Utilities Co.**		$1,428,749	0.1844%	$28,257
31						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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 TRANSACTIONS/REIMBURSEMENTS				
2	**SERVICES GROUP INC**	Federal & State Tax Liability Payments		$4,874,937		
3		Tax Deferred Savings Plan		7,644		
4		Miscellaneous Reimbursements		(143,982)		
5						
6		**Total Other Transactions/Reimbursements**		$4,738,599	0.6116%	
7		**Grand Total Affiliate Transactions**		$7,871,465	1.0159%	$28,257
8						
9		**Total MDU Construction Services Group, Inc. Operating Expenses for 2009**				
10		**Excludes Intersegment Eliminations**			$774,809,000	
11						
12						
13						
14						
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* 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: 2009

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		Insurance	Allocation Factors, Time Studies	$213		
4		Payroll	and/or Costs Incurred	338,200		
5		**Total MDU Resources Group, Inc.**		$338,413	21.0194%	
6						
7		MONTANA-DAKOTA UTIILITIES CO.	* Various Corporate Overhead			
8		Other Miscellaneous Departments	Allocation Factors and/or Actual			
9		Payroll	Costs Incurred	3,072		
10						
11		Other Direct Charges	Actual costs incurred			
12		Audit Costs		33,600		
13		Dues, Permits, and Filing Fees		626		
14		Miscellaneous Emp Benefits		7,339		
15		Employee Reimbursable Exp		843		
16		Miscellaneous		3,696		
17		**Total Montana-Dakota Utilities Co.**		$49,176	3.0540%	
18						
19		OTHER TRANSACTIONS/REIMBURSEMENTS				
20		Federal & State Tax Liability Payments	Actual costs incurred	(3,791,432)		
21		Miscellaneous Reimbursements		(200)		
22		**Total Other Transactions/Reimbursements**		(3,791,632)	-235.5051%	
23						
24		**Grand Total Affiliate Transactions**		($3,404,043)	-211.4312%	
25						
26		**Total Centennial Energy Resources Operating Expenses for 2009**			$1,610,000	
27		**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: 2009

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 HOLDINGS**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL CORP. AND**					
3	**FUTURESOURCE**	Other Direct Charges	Actual costs incurred			
4		Dues, Permits, and Filing Fees		$470		
5		Computer/Software Support		46,933		
6		Employee Reimbursable Exp		15,445		
7		Legal Fees		3,315		
8		Electric Consumption		137,807		
9		Gas Consumption		9,996		
10		Payroll		451,539		
11		Miscellaneous		60,644		
12		**Total Montana-Dakota Utilities Co.**		$726,149	8.9692%	
13						
14		OTHER TRANSACTIONS/REIMBURSEMENTS	Actual costs incurred			
15		Insurance		21,137		
16		Miscellaneous Reimbursements		(2,033)		
17		Federal & State Tax Liability Payments		2,316,751		
18		**Total Other Transactions/Reimbursements**		$2,335,855	28.8520%	
19						
20		**Grand Total Affiliate Transactions**		$3,062,004	37.8212%	
21						
22		**Total CHCC Operating Expenses for 2009**			$8,096,000	
23		**Excludes Intersegment Eliminations**				
24						
25						
26						

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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 ENERGY**	MDU RESOURCES GROUP, INC.				
2	**CAPITAL ****	Corporate Overhead	* Various Corporate Overhead			
3		Audit Costs	Allocation Factors, Time	$30,368		
4		Advertising	Studies and/or Actual Costs	19,827		
5		Air Service	Incurred	15,359		
6		Automobile		1,696		
7		Bank Services		54,529		
8		Corporate Aircraft		19,738		
9		Consultant Fees		154,361		
10		Contract Services		230,459		
11		Computer Rental		1,005		
12		Directors Expenses		327,306		
13		Employee Benefits		26,754		
14		Employee Meeting		21,702		
15		Employee Reimbursable Expense		23,816		
16		Express Mail		60		
17		Insurance		330,066		
18		Legal Retainers & Fees		214,750		
19		Meal Allowance		406		
20		Cash Donations		8,448		
21		Meals & Entertainment		16,910		
22		Industry Dues & Licenses		17,613		
23		Office Expenses		11,416		
24		Supplemental Insurance		(153,533)		
25		Permits & Filing Fees		4,959		
26		Postage		3,260		
27		Payroll		2,809,124		
28		Reference Materials		34,132		
29		Rental		2,029		
30		Seminars & Meeting Registrations		9,865		
31		Software Maintenance		53,528		
32		Telephone		15,553		
33		Training Material		6,377		
34						
35		**Total MDU Resources Group, Inc.**		$4,311,883	0.6184%	

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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 ENERGY**	MONTANA-DAKOTA UTILITIES CO.				
2	**CAPITAL ****	Communications Department	* Various Corporate Overhead			
3		Payroll	Allocation Factors, Cost of	$53,554		
4		Telephone	Service Factors, Time Studies	823		
5			and/or Actual Costs Incurred			
6						
7		Customer Service/Call Center	* General Office Complex and			
8		Payroll	Office Supplies Cost of Service	72,437		
9			Allocation			
10						
11		Information Systems	* Various Corporate Overhead			
12		Payroll	Allocation Factors, Cost of Service	80,716		
13			Factors, Time Studies and/or			
14			Actual Costs Incurred			
15						
16		Other Miscellaneous Departments	* Various Corporate Overhead			
17		Payroll	Allocation Factors, Cost of Service	8,803		
18		Other	Factors, Time Studies and/or	(779)		
19			Actual Costs Incurred			
20						
21		Payroll Accounting	* Various Corporate Overhead			
22		Payroll	Allocation Factors, Cost of Service	84,835		
23		Other	Factors, Time Studies and/or	3441		
24			Actual Costs Incurred			
25						
26		Executive Departments	* Various Corporate Overhead			
27		Payroll	Allocation Factors, Cost of Service	571,491		
28		Employee Reimbursable Expense	Factors, Time Studies and/or	7,555		
29		Meals & Entertainment	Actual Costs Incurred	5,548		
30		Reference Materials		51,826		
31						
32		Transportation Department	* Various Corporate Overhead			
33		Payroll	Allocation Factors, Cost of Service	136,802		
34		Employee Reimbursable Expense	Factors, Time Studies and/or	2,525		
35		Meals & Entertainment	Actual Costs Incurred	841		

Company Name: Montana-Dakota Utilities Co. SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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 ENERGY**	Automobile		3,928		
2	**CAPITAL ****	Other		2,309		
3						
4		OTHER TRANSACTIONS/REIMBURSEMENTS				
5		Other Direct Charges	Actual costs incurred			
6		Misc Employee Benefits		1,519,256		
7		Audit Costs		511,699		
8		Cost of Service		727,945		
9		Computer/Software Support		612,513		
10		Legal Fees		30,329		
11		Contract Services		4,492,216		
12		Employee Reimbursable Exp		54,938		
13		Dues, Permits, and Filing Fees		$206,568		
14		Telephone Expense		17,231		
15		Miscellaneous		2,457,215		
16		**Total Montana-Dakota Utiilities Co.**		$11,716,565	1.6805%	
17						
18		Federal & State Tax Liability Payments		11,650,061		
19		Miscellaneous Reimbursements		(64,469)		
20		**Total Other Transactions/Reimbursements**		11,585,592	1.6617%	
21						
22		**Grand Total Affiliate Transactions**		$27,614,040	3.9607%	
23					$697,209,000	
		Total MDU Energy Capital Operating Expenses for 2009				
25		**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 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.

** MDU Energy Capital is the parent company for Cascade Natural Gas Company and Intermountain Gas Company.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

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	**HOLDING INC**					
3		Other Direct Charges	Actual costs incurred			
4		Audit Costs		$98,600		
5		Employee Reimbursable Exp		2,774		
6		Miscellaneous		235,826		
7		**Total Montana-Dakota Utilities Co.**		$337,200		
8						
9		**Grand Total Affiliate Transactions**		$337,200		
10						
11						
12						
13						

MONTANA UTILITY INCOME STATEMENT

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	$93,910,680	$77,730,500	-17.23%
2				
3	Operating Expenses			
4	401 Operation Expenses	$85,519,863	$66,883,054	-21.79%
5	402 Maintenance Expense	1,033,997	974,066	-5.80%
6	403 Depreciation Expense	2,588,492	2,681,239	3.58%
7	404-405 Amort. & Depl. of Gas Plant	193,016	198,611	2.90%
8	406 Amort. of Gas Plant Acquisition Adjustments			
9	407.1 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs			
11	407.2 Amort. of Conversion Expense			
12	408.1 Taxes Other Than Income Taxes	3,034,380	2,928,948	-3.47%
13	409.1 Income Taxes - Federal	(2,769,498)	2,083,053	175.21%
14	- Other	(654,590)	544,140	183.13%
15	410.1 Provision for Deferred Income Taxes	2,836,323	(1,587,922)	-155.99%
16	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	490,834	(150,843)	-130.73%
17	411.4 Investment Tax Credit Adjustments			
18	411.6 (Less) Gains from Disposition of Utility Plant			
19	411.7 Losses from Disposition of Utility Plant			
20	**TOTAL Utility Operating Expenses**	$92,272,817	$74,554,346	-19.20%
21	**NET UTILITY OPERATING INCOME**	$1,637,863	$3,176,154	93.92%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Gas			
2	480 Residential	$56,330,800	$49,407,605	-12.29%
3	481 Commercial & Industrial - Small	33,413,793	29,035,049	-13.10%
4	Commercial & Industrial - Large	25,411	33,351	31.25%
5	482 Other Sales to Public Authorities			
6	484 Interdepartmental Sales			
7	485 Intracompany Transfers			
8	Net Unbilled Revenue	2,593,461	(2,129,813)	-182.12%
9	**TOTAL Sales to Ultimate Consumers**	92,363,465	76,346,192	-17.34%
10	483 Sales for Resale			
11	**TOTAL Sales of Gas**	$92,363,465	$76,346,192	-17.34%
12	Other Operating Revenues			
13	487 Forfeited Discounts & Late Payment Revenues			
14	488 Miscellaneous Service Revenues	$58,365	$46,652	-20.07%
15	489 Revenues from Transp. of Gas for Others 1/	1,200,720	1,124,810	-6.32%
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	92,242	155,385	68.45%
20	494 Interdepartmental Rents			
21	495 Other Gas Revenues	195,888	57,461	-70.67%
22	**TOTAL Other Operating Revenues**	1,547,215	1,384,308	-10.53%
23	**Total Gas Operating Revenues**	$93,910,680	$77,730,500	-17.23%
24				
25	496 (Less) Provision for Rate Refunds			
26				
27	**TOTAL Oper. Revs. Net of Pro. for Refunds**	$93,910,680	$77,730,500	-17.23%

1/ Includes unbilled revenue.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

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

Company Name: Montana-Dakota Utilities Co.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	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	$77,825,544	$51,596,958	-33.70%
17	805 Other Gas Purchases			
18	805.1 Purchased Gas Cost Adjustments	(6,193,019)	9,033,807	245.87%
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.	15,782,707	12,615,075	-20.07%
27	808.2 (Less) Gas Delivered to Storage -Cr.	(12,981,144)	(15,890,802)	-22.41%
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	79,239	70,111	-11.52%
33	**TOTAL Other Gas Supply Expenses**	$74,513,327	$57,425,149	-22.93%
34				
35	**TOTAL PRODUCTION EXPENSES**	$74,513,327	$57,425,149	-22.93%

Company Name: Montana-Dakota Utilities Co.

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	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: 2009

	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	$548,565	$392,079	-28.53%
28	871	Distribution Load Dispatching	63,883	63,895	0.02%
29	872	Compressor Station Labor and Expenses			
30	873	Compressor Station Fuel and Power			
31	874	Mains and Services Expenses	1,099,603	1,046,324	-4.85%
32	875	Measuring & Reg. Station Exp.-General	37,331	57,983	55.32%
33	876	Measuring & Reg. Station Exp.-Industrial	10,506	15,508	47.61%
34	877	Meas. & Reg. Station Exp.-City Gate Ck. Sta.	0	0	0.00%
35	878	Meter & House Regulator Expenses	289,540	343,353	18.59%
36	879	Customer Installations Expenses	836,606	507,304	-39.36%
37	880	Other Expenses	957,235	932,102	-2.63%
38	881	Rents	39,347	39,277	-0.18%
39		**Total Operation - Distribution**	$3,882,616	$3,397,825	-12.49%
40	Maintenance				
41	885	Maintenance Supervision & Engineering	$165,647	$98,657	-40.44%
42	886	Maintenance of Structures & Improvements	741	2,562	245.75%
43	887	Maintenance of Mains	104,600	95,168	-9.02%
44	888	Maint. of Compressor Station Equipment			
45	889	Maint. of Meas. & Reg. Station Exp.-General	21,578	14,264	-33.90%
46	890	Maint. of Meas. & Reg. Sta. Exp.-Industrial	17,357	15,739	-9.32%
47	891	Maint. of Meas. & Reg. Sta. Equip.-City Gate			
48	892	Maintenance of Services	183,513	191,693	4.46%
49	893	Maintenance of Meters & House Regulators	295,566	313,723	6.14%
50	894	Maintenance of Other Equipment	90,278	116,222	28.74%
51		**Total Maintenance - Distribution**	$879,280	$848,028	-3.55%
52		**TOTAL Distribution Expenses**	$4,761,896	$4,245,853	-10.84%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Customer Accounts Expenses**			
3	Operation			
4	901 Supervision	$187,513	$155,762	-16.93%
5	902 Meter Reading Expenses	454,619	283,679	-37.60%
6	903 Customer Records & Collection Expenses	1,212,362	1,233,627	1.75%
7	904 Uncollectible Accounts Expenses	338,064	258,714	-23.47%
8	905 Miscellaneous Customer Accounts Expenses	129,481	139,223	7.52%
9				
10	**TOTAL Customer Accounts Expenses**	$2,322,039	$2,071,005	-10.81%
11				
12	**Customer Service & Informational Expenses**			
13	Operation			
14	907 Supervision	$36,551	$45,526	24.55%
15	908 Customer Assistance Expenses	13,500	12,283	-9.01%
16	909 Informational & Instructional Advertising Exp.	50,339	13,276	-73.63%
17	910 Miscellaneous Customer Service & Info. Exp.	85	63	-25.88%
18				
19	**TOTAL Customer Service & Info. Expenses**	$100,475	$71,148	-29.19%
20				
21	**Sales Expenses**			
22	Operation			
23	911 Supervision	$56,954	$23,868	-58.09%
24	912 Demonstrating & Selling Expenses	141,586	116,326	-17.84%
25	913 Advertising Expenses	16,385	10,749	-34.40%
26	916 Miscellaneous Sales Expenses	20,653	17,801	-13.81%
27				
28	**TOTAL Sales Expenses**	$235,578	$168,744	-28.37%
29				
30	**Administrative & General Expenses**			
31	Operation			
32	920 Administrative & General Salaries	$1,079,791	$1,030,154	-4.60%
33	921 Office Supplies & Expenses	569,446	545,775	-4.16%
34	922 (Less) Administrative Expenses Transferred - Cr.			
35	923 Outside Services Employed	105,561	104,229	-1.26%
36	924 Property Insurance	62,738	80,013	27.54%
37	925 Injuries & Damages	431,892	364,850	-15.52%
38	926 Employee Pensions & Benefits	2,034,834	1,493,062	-26.62%
39	927 Franchise Requirements			
40	928 Regulatory Commission Expenses	25,690	11,313	-55.96%
41	929 (Less) Duplicate Charges - Cr.			
42	930.1 General Advertising Expenses	48,825	14,529	-70.24%
43	930.2 Miscellaneous General Expenses	44,638	58,899	31.95%
44	931 Rents	62,413	46,359	-25.72%
45				
46	**TOTAL Operation - Admin. & General**	$4,465,828	$3,749,183	-16.05%
47	Maintenance			
48	935 Maintenance of General Plant	$154,717	$126,038	-18.54%
49				
50	**TOTAL Administrative & General Expenses**	$4,620,545	$3,875,221	-16.13%
51	**TOTAL OPERATION & MAINTENANCE EXP.**	$86,553,860	$67,857,120	-21.60%

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

SCHEDULE 11

MONTANA TAXES OTHER THAN INCOME

Year: 2009

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes	$453,557	$406,772	-10.32%
2	Secretary of State	227	178	-21.59%
3	Highway Use Tax	210	207	-1.43%
4	Montana Consumer Counsel	114,964	54,733	-52.39%
5	Montana PSC	270,916	197,512	-27.09%
6	Delaware Franchise Taxes	18,263	19,241	5.36%
7	Property Taxes	2,170,886	2,244,794	3.40%
8	Tribal Taxes	5,357	5,511	2.87%
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50	**TOTAL MT Taxes other than Income**	$3,034,380	$2,928,948	-3.47%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Able Field Services	Plant Update & Repair	$91,948	$0	0.00%
2					
3	Aerial Contractors Inc.	Contractor Services	178,847	0	0.00%
4					
5	Agri Industries Inc.	Contractor Services	124,786	0	0.00%
6					
7	Aptech CST, LLC	Engineering Services - L&C	240,435	0	0.00%
8					
9	Barr Engineering Co.	Engineering Services - Heskett	90,380	0	0.00%
10					
11	Benco Equipment Co.	Vehicle Maintenance	233,213	1,073	0.46%
12					
13	BHCI	Contractor Services	104,205	0	0.00%
14					
15	Big K Industries, Inc.	Contractor Services	227,515	0	0.00%
16					
17	Blue Heron Consulting	Consulting Services	1,489,302	246,412	16.55%
18					
19	Broadridge	Shareholder Position Process	156,970	1,539	0.98%
20					
21	Bullinger Tree Service	Tree Trimming Service	370,175	0	0.00%
22					
23	Central Trenching Inc.	Boring & Trenching Services	121,356	0	0.00%
24					
25	Chief Construction	Contractor Services	679,637	0	0.00%
26					
27	Cisco Systems Capital Corp.	Software Maintenance	121,222	1,862	1.54%
28					
29	Connecting Point	Computer Srvcs & Software Maint.	134,166	10,261	7.65%
30					
31	Dell Marketing, LP	Software Maintenance	103,247	2,654	2.57%
32					
33	Deloitte & Touche LLP	Auditing & Consulting Services	351,701	17,638	5.02%
34					
35	Dewey & LeBoeuf	Legal Services	741,445	7,838	1.06%
36					
37	Edison Electric Institute	Membership Dues	65,857	70	0.11%
38					
39	Edling Electric Inc	Fiber Optic Installation	173,325	0	0.00%
40					
41	Fischer Contracting	Contract Services	304,454	0	0.00%
42					
43	Gary Forrester	Contract Services	90,885	962	1.06%
44					
45	Franz Construction Inc.	Construction Services	146,891	0	0.00%
46					
47	G E Energy Services	Construction Services	463,706	0	0.00%
48					
49	Gagnon, Inc.	Contractor Services	75,075	0	0.00%
50					

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

SCHEDULE 12

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	GE Energy Management Services	Testing at Power Plants	146,548	0	0.00%
2					
3	GLS Companies	Contract Service - Annual Report	125,446	1,230	0.98%
4					
5	Hewlett-Packard Co.	Consulting Services	89,610	14,826	16.55%
6					
7	Highmark, Inc.	Construction Services	339,100	0	0.00%
8					
9	Hughes, Keller, Sullivan & Alke, PLLP	Legal Services	88,936	53,252	59.88%
10					
11	Hydrochem Industrial Services	Boiler Cleaning	256,869	0	0.00%
12					
13	Impact Mechanical Inc.	Carbon Injection Sys - L&C	613,125	0	0.00%
14					
15	Industrial Contractors Inc.	Construction Services	604,953	0	0.00%
16					
17	Infrasource	Underground Gas Line Installment	1,323,875	0	0.00%
18					
19	International Buisiness Machines Inc.	Contractor Serv - Computer Maint.	150,757	23,089	15.32%
20					
21	Itron Inc.	Contract Services	287,835	70,123	24.36%
22					
23	M C M General Contractors, Inc.	Boring & Pipe Installation	262,096	0	0.00%
24					
25	Martin Construction Inc.	Contr Serv-Ash Disposal - Heskett	522,447	0	0.00%
26					
27	Marting Engineering	Contr Serv - Dust Control L&C Station	125,000	0	0.00%
28					
29	McDermott, Will & Emery, LLP	Legal Services	143,402	1,489	1.04%
30					
31	Microbeam Technologies Inc.	Contr Serv - Limestone Testing	140,019	0	0.00%
32					
33	Microsoft	Software Maintenance	131,893	10,338	7.84%
34					
35	Midwest ISO	Prelim Studies, Cedar Hills	125,000	0	0.00%
36					
37	Midwest Testing Laboratory	Test Serv - Cedar Hills	89,449	0	0.00%
38					
39	Minnesota Valley Testing	Testing Services	104,860	0	0.00%
40					
41	Moorhead Boiler & Machinery Co.	Contract Services	81,814	0	0.00%
42					
43	Morgan, Lewis & Bockius LLP	Legal Services	364,911	4,115	1.13%
44					
45	New York Life	Consulting Services	394,249	12,541	3.18%
46					
47	NYSE Market Inc.	Financial Services	190,707	1,779	0.93%
48					
49	One Call Locators Ltd. (ELM)	Line Location Services	1,084,581	299,888	27.65%
50					

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 12**

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES - GAS

2008

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	Oracle Corp.	Software Maintenance	539,635	83,805	15.53%
2					
3	Ormat Nevada Inc.	Install Energy Convertor - Glen Ullin	7,120,538	0	0.00%
4					
5	Otis Elevator Co.	Elevator Service - Office & Heskett	65,145	4,944	7.59%
6					
7	OTP Big Stone II - Trust Acct	Big Stone II Const	1,135,068	0	0.00%
8					
9	Presort Plus Inc.	Mail Services	117,426	10,679	9.09%
10					
11	Progressive Maintenance Co.	Custodial Services	131,331	11,841	9.02%
12					
13	Prosource Technologies Inc.	Pipeline Construction	237,095	0	0.00%
14					
15	PSC Industrial Outsourcing Inc.	Boiler Maintenance	619,202	0	0.00%
16					
17	Quality Underground Service Inc.	Gas Lines & Maint.	168,714	0	0.00%
18					
19	Salo, Bertha	Contr Serv - CIS Project	76,525	12,599	16.46%
20					
21	Sargent & Lundy, LLC	Consulting Services	455,089	0	0.00%
22					
23	Standard & Poors	Financial Services	110,487	2,933	2.65%
24					
25	Toyo Tires	Vehicle Maintenance	96,396	0	0.00%
26					
27	Treasury Management Service	Banking Services	342,788	60,947	17.78%
28					
29	Ulmer Tree Service	Tree Trimming Service	126,364	0	0.00%
30					
31	Utilities International Inc.	Consulting Services	389,888	10,209	2.62%
32					
33	Ventyx Energy, LLC	Software Maintenance	81,885	0	0.00%
34					
35	Vic's Crane & Heavy Haul Service	Contr Services - Tioga Transformer	110,683	0	0.00%
36					
37	Wanzek Construction Inc.	Contractor Services	3,599,814	0	0.00%
38					
39	Wells Fargo Shareholders Services	Stock transfer agent & ESOP Admin	307,911	3,213	1.04%
40					
41	Wenck	Contr Serv - Billings Landfill	288,200	82,072	28.48%
42					
43	Willis of Minnesota	Consulting Services	96,916	818	0.84%
44					
45	Workforce Services, Inc.	Vehicle Maintenance	106,694	0	0.00%
46					
47	Xerox Corp	Copier Maintenance	138,268	18,376	13.29%
48					
49	Yellowstone Electric Co.	Contract Services - Glendive Unit 2	89,100	0	0.00%
50					
51	**TOTAL Payments for Services**		$31,219,387	$1,085,415	3.48%

Company Name: Montana-Dakota Utilities Co. SCHEDULE 13

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2009

	Description	Total Company	Montana	% Montana
1	Contributions to Candidates by PAC	$15,784	$660	4.18%
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43	**TOTAL Contributions**	$15,784	$660	4.18%

Pension Costs

Year: 2009

1	Plan Name MDU Resources Group, Inc. Master Pension Plan Trust			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Traditional unit credit	IRS Code: 1A		
4	Annual Contribution by Employer: 8,347,434	Is the Plan Over Funded? No		
5				
	Item	Current Year	Last Year	% Change
6	**Change in Benefit Obligation**	(000's)	(000's)	
7	Benefit obligation at beginning of year	$213,539	$215,629	-0.97%
8	Service cost	5,036	5,349	-5.85%
9	Interest cost	13,169	12,767	3.15%
10	Plan participants' contributions	-	-	
11	Amendments	-	-	
12	Actuarial (Gain) Loss	17,651	(4,940)	457.31%
13	Curtailment gain	(24,085)	-	
14	Benefits paid	(15,689)	(15,266)	-2.77%
15	Benefit obligation at end of year	$209,621	$213,539	-1.83%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	$134,645	$201,282	-33.11%
18	Actual return on plan assets	24,853	(51,743)	148.03%
19	Interplan transfer (1)	270	372	-27.42%
20	Employer contribution	8,347	-	
21	Plan participants' contributions	-	-	
22	Benefits paid	(15,689)	(15,266)	-2.77%
23	Fair value of plan assets at end of year	$152,426	$134,645	13.21%
24	**Funded Status**	($57,195)	($78,894)	27.50%
25	Unrecognized net actuarial loss	-	-	
26	Unrecognized prior service cost	-	-	
27	Unrecognized net transition obligation	-	-	
28	Accrued benefit cost	($57,195)	($78,894)	27.50%
29				
30	**Weighted-Average Assumptions as of Year End**			
31	Discount rate	5.75	6.25	-8.00%
32	Expected return on plan assets	8.25	8.50	-2.94%
33	Rate of compensation increase	4.00	4.00	0.00%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	$5,036	$5,349	-5.85%
37	Interest cost	13,169	12,767	3.15%
38	Expected return on plan assets	(15,429)	(15,973)	3.41%
39	Amortization of prior service cost	604	659	-8.35%
40	Recognized net actuarial gain	236	23	926.09%
41	Curtailment loss	1,143	-	
42	Net periodic benefit cost	$4,759	$2,825	68.46%
43				
44	**Montana Intrastate Costs:**			
45	Pension costs	$4,759	$2,825	68.46%
46	Pension costs capitalized	656	415	58.07%
47	Accumulated pension asset (liability) at year end	($57,195)	($78,894)	27.50%
48	**Number of Company Employees:**			
49	Covered by the plan	1,883	1,917	-1.77%
50	Not covered by the plan	252	248	1.61%
51	Active	889	937	-5.12%
52	Retired	931	923	0.87%
53	Deferred vested terminated	63	57	10.53%

(1) The company transferred assets between plans for employees that moved to a different MDU Resources Group, Inc. sponsored plan.

Other Post Employment Benefits (OPEBS)

Year: 2009

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number:			
4	Order numbers:			
5	Amount recovered through rates -			
6	**Weighted-Average Assumptions as of Year End**			
7	Discount rate	5.75	6.25	-8.00%
8	Expected return on plan assets	7.25	7.50	-3.33%
9	Medical cost inflation rate	6.00	6.00	0.00%
10	Actuarial cost method	Projected unit credit	Projected unit credit	
11	Rate of compensation increase	N/A	N/A	
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13	**VEBA**			
14	**Describe any Changes to the Benefit Plan:**			
15				
16				
	TOTAL COMPANY			
17	**Change in Benefit Obligation**	(000's)	(000's)	
18	Benefit obligation at beginning of year	$50,698	$48,565	4.39%
19	Service cost	1,106	1,172	-5.63%
20	Interest cost	2,838	2,956	-3.99%
21	Plan participants' contributions	1,526	1,384	10.26%
22	Amendments	(5,439)	-	
23	Actuarial (Gain) Loss	(1,618)	848	-290.80%
24	Acquisition	-	-	
25	Benefits paid	(4,263)	(4,227)	-0.85%
26	Benefit obligation at end of year	$44,848	$50,698	-11.54%
27	**Change in Plan Assets**			
28	Fair value of plan assets at beginning of year	$35,466	$47,494	-25.33%
29	Actual return on plan assets	3,411	(11,253)	130.31%
30	Acquisition	-	-	
31	Employer contribution	1,833	2,068	-11.36%
32	Plan participants' contributions	1,526	1,384	10.26%
33	Benefits paid	(4,263)	(4,227)	-0.85%
34	Fair value of plan assets at end of year	$37,973	$35,466	7.07%
35	**Funded Status**	($6,875)	($15,232)	54.86%
36	Unrecognized net actuarial loss	-	-	
37	Unrecognized prior service cost	-	-	
38	Unrecognized transition obligation	-	-	
39	Accrued benefit cost	($6,875)	($15,232)	54.86%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	$1,106	$1,172	-5.63%
42	Interest cost	2,838	2,956	-3.99%
43	Expected return on plan assets	(3,565)	(3,692)	3.44%
44	Amortization of prior service cost	36	36	0.00%
45	Recognized net acturial gain	(198)	(116)	-70.69%
46	Transition amount amortization	1,678	1,694	-0.94%
47	Net periodic benefit cost	$1,895	$2,050	-7.56%
48	**Accumulated Post Retirement Benefit Obligation**			
49	Amount funded through VEBA	3,359	$3,452	-2.69%
50	Amount funded through 401(h)			
51	Amount funded through Other ____________			
52	TOTAL	$3,359	$3,452	-2.69%
53	Amount that was tax deductible - VEBA	1,833 (1)	2,068	-11.36%
54	Amount that was tax deductible - 401(h)			
55	Amount that was tax deductible - Other ________			
56	TOTAL	$1,833	$2,068	-11.36%

(1) Estimated

Other Post Employment Benefits (OPEBS) Continued

Year: 2009

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the plan	1,783	1,822	-2.14%
3	Not covered by the plan	37	36	2.78%
4	Active	1,029	1,034	-0.48%
5	Retired	607	605	0.33%
6	Spouses/dependants covered by the plan	142	183	-22.40%
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost	NOT APPLICABLE		
11	Interest cost			
12	Plan participants' contributions			
13	Amendments			
14	Actuarial gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition	NOT APPLICABLE		
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss	NOT APPLICABLE		
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	NOT APPLICABLE		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount funded through VEBA			
39	Amount funded through 401(h)	NOT APPLICABLE		
40	Amount funded through other ______________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension costs	NOT APPLICABLE		
48	Pension costs capitalized			
49	Accumulated pension asset (liability) at year end			
50	**Number of Montana Employees:**			
51	Covered by the plan			
52	Not covered by the plan	NOT APPLICABLE		
53	Active			
54	Retired			
55	Spouses/dependants covered by the plan			

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 16

Year: 2009

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

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

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 17

Year: 2009

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION 1/

Line No.	Name/Title	Base Salary	Bonuses	Other 2/	Total Compensation	Total Compensation Last Year 2/	% Increase Total Compensation
1	Terry D. Hildestad - President & CEO	$750,000	$1,500,000	$1,953,004	$4,203,004	$3,119,702	35%
2	William Schneider - President & CEO of Knife River Corporation	447,400	581,620	1,136,063	2,165,083	1,097,551	97%
3	Vernon A. Raile Executive Vice President, Treasurer and CFO	450,000	585,000	1,105,718	2,140,718	1,432,401	49%
4	John G. Harp - President & CEO of MDU Construction Services Group	450,000	392,500	1,187,359	2,029,859	1,893,579	7%
5	Steven L. Bietz President & CEO of WBI Holdings, Inc.	350,000	450,450	797,056	1,597,506	635,279	151%

1/ See Page 20a for Total Compensation detail.

2/ Amounts represent the aggregate grant date fair value of the performance share awards calculated in accordance with Fiinancial Accounting Standards Board Accounting Standards Codification Topic 718 - Share Based Payment.

Policy Regarding Hedging Stock Ownership

In our Executive Compensation Policy, we adopted a policy that prohibits executives from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Compensation Committee Report

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Reg. S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our proxy statement on Schedule 14A.

Thomas Everist, Chairman
Karen B. Fagg
Thomas C. Knudson
Patricia L. Moss

Summary Compensation Table for 2009

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)(1)	Option Awards ($) (f)	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	2009	750,000	–	1,117,861	–	1,500,000	825,319	9,824 (3)	4,203,004
President and CEO	2008	700,000	–	1,200,485	–	310,800	898,941	9,476	3,119,702
	2007	625,000	–	779,293	–	1,250,000	1,362,413	7,026	4,023,732
Vernon A. Raile	2009	450,000	–	402,417	–	585,000	695,177	8,124 (3)	2,140,718
Executive Vice President,	2008	400,000	–	411,575	–	115,440	498,210	7,176	1,432,401
Treasurer and CFO	2007	350,700	–	295,882	–	350,700	555,248	7,026	1,559,556
John G. Harp	2009	450,000	–	402,417	–	392,500 (4)	761,670 (6)	23,272 (7)	2,029,859
President and CEO of	2008	400,000	–	411,575	–	720,000 (5)	338,774 (6)	23,230 (7)	1,893,579
MDU Construction Services Group, Inc.	2007	341,000	–	239,763	–	341,000	47,334 (6)	23,080 (7)	992,177
William E. Schneider	2009	447,400	–	400,093	–	581,620	726,646	9,324 (3)	2,165,083
President and CEO of	2008	447,400	–	460,374	–	–	180,801	8,976	1,097,551
Knife River Corporation	2007	422,000	–	356,052	–	206,780	450,347	7,026	1,442,205
Steven L. Bietz	2009	350,000	–	312,987	–	450,450	475,985	8,084 (3)	1,597,506
President and CEO of	2008	–	–	–	–	–	–	–	–
WBI Holdings, Inc.	2007	–	–	–	–	–	–	–	–

(1) Amounts in this column represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 – Share-Based Payment. Amounts for 2008 and 2007 have been recalculated to comply with the new requirements. This column was prepared assuming none of the awards will be forfeited. The amounts were calculated using a Monte Carlo simulation, as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2009.

(2) Amounts shown represent the change in the actuarial present value for years ended December 31, 2007, 2008, and 2009 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 are based on accumulated pension change and above market earnings as of December 31, 2007, 2008, and 2009, as follows:

Name	Accumulated Pension Change 12/31/2007 ($)	12/31/2008 ($)	12/31/2009 ($)	Above Market Earnings 12/31/2007 ($)	12/31/2008 ($)	12/31/2009 ($)
Terry D. Hildestad	1,336,815	883,351	806,554	25,598	15,590	18,765
Vernon A. Raile	508,987	469,755	661,243	46,261	28,455	33,934
John G. Harp	38,498	331,558	743,334	–	–	–
Additional Retirement (John G. Harp)*	8,836	7,216	18,336	–	–	–
William E. Schneider	411,123	155,816	696,572	39,224	24,985	30,074
Steven L. Bietz	–	–	475,985	–	–	–

* See footnote 6.

(3) Includes company contributions to the 401(k), payment of a life insurance premium, and matching contributions to charitable organizations.

(4) Includes one-time incentive payment of $100,000 in addition to his annual incentive compensation.

(5) Includes one-time incentive payment of $200,000 in addition to his executive incentive compensation plan payment.

(6) 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:

	2007	2008	2009
Change in present value of additional years of service for pension plan	$6,033	$3,570	$13,077
Change in present value of additional years of service for excess SISP	2,803	3,646	5,259
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 2009 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 2007, 2008, and 2009. 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 2009 table. Because Mr. Harp would be fully vested in his SISP benefit if he retired at age 65, the assumed retirement age of these calculations, 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 2009 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.

(7) Includes a company contribution to Mr. Harp's 401(k), 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 2009

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	2/12/09(1)	187,500	750,000	1,500,000	–	–	–	–	–	–	
	2/12/09(2)	–	–	–	5,482	54,824	109,648	–	–	–	1,117,861
Vernon A. Raile	2/12/09(1)	73,125	292,500	585,000	–	–	–	–	–	–	
	2/12/09(2)	–	–	–	1,973	19,736	39,472	–	–	–	402,417
John G. Harp	2/12/09(1)	73,125	292,500	585,000	–	–	–	–	–	–	
	2/12/09(2)	–	–	–	1,973	19,736	39,472	–	–	–	402,417
	2/12/09(3)	100,000	200,000	–	–	–	–	–	–	–	
William E. Schneider	2/12/09(1)	72,703	290,810	581,620	–	–	–	–	–	–	
	2/12/09(2)	–	–	–	1,962	19,622	39,244	–	–	–	400,093
Steven L. Bietz	2/12/09(4)	56,875	227,500	455,000	–	–	–	–	–	–	
	2/12/09(2)	–	–	–	1,535	15,350	30,700	–	–	–	312,987

(1) Annual incentive for 2009 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(2) Performance shares for the 2009-2011 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(3) Mr. Harp's additional 2009 incentive opportunity.

(4) Annual incentive for 2009 granted pursuant to the WBI Holdings Inc. Executive Incentive Compensation Plan.

PROXY

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

Incentive Awards

Annual Incentive

On February 11, 2009, the compensation committee recommended the 2009 annual incentive award opportunities for our named executive officers, and the board approved these opportunities at its meeting on February 12, 2009. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on February 12, 2009 in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2009 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 on 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, Raile, Schneider, and Harp must have remained employed by the company through December 31, 2009, 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 the WBI Holdings, Inc. Executive Incentive Compensation Plan, which includes Mr. Bietz, participants who retire at age 65 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 Bietz, 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. In 2009, Mr. Bietz had five individual goals relating to WBI Holdings Inc.'s safety results, and each goal that was not met reduced his annual incentive award by 1%.

For 2009, the compensation committee weighted the goals for annual return on invested capital compared to target and allocated earnings per share compared to target each at 50%.

We limit the after-tax annual incentive compensation we will pay above the target amount to 20% of earnings in excess of planned earnings. We calculate the earnings in excess of planned earnings without regard to the after-tax annual incentive amounts above target. We measure the 20% limitation at the major business unit level for business unit and operating company executives, which include Messrs. Harp, Schneider, and Bietz, and at the corporate level for corporate executives, which include Messrs. Hildestad and Raile. In 2009, the 20% limitation was calculated without regard to the noncash ceiling test impairment charge and an associated depletion, depreciation and amortization benefit as discussed in the Compensation Discussion and Analysis.

PROXY

The award opportunities available to each named executive officer were:

2009 earnings per share results as a % of 2009 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

2009 return on invested capital results as a % of 2009 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

For discussion of the specific incentive plan performance targets and results, please see the Compensation Discussion and Analysis.

In addition to his 2009 annual incentive award opportunity under our Long-Term Performance-Based Incentive Plan, Mr. Harp had an opportunity to earn an additional incentive, which was structured as follows:

MDU Construction Services Group, Inc.'s 2009 Return on Invested Capital (ROIC) as compared to MDU Construction Services Group, Inc.'s 2009 Weighted Average Cost of Capital (WACC)	Additional Incentive Amount
2009 ROIC is less than 100 basis points above 2009 WACC	$0
2009 ROIC is 100 to 199 basis points above 2009 WACC	$100,000
2009 ROIC is 200 basis points or more above 2009 WACC	$200,000

For a specific discussion of this additional incentive opportunity and the compensation committee's determination with respect to payment, please refer to the Compensation Discussion and Analysis.

Long-Term Incentive

On February 11, 2009, 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 12, 2009. These grants are reflected in columns (f), (g), (h), and (i) of the Grants of Plan-Based Awards table and in column (e) of the Summary Compensation Table.

From 0% to 200% of the target grant will be paid out in February 2012, depending on our 2009-2011 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 February 12, 2009 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 2012 at the same time as the performance awards are paid.

PROXY

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary to total compensation. We paid no bonuses to our named executive officers in 2009.

Name	Salary ($)	Total Compensation ($)	Salary as % of Total Compensation
Terry D. Hildestad	750,000	4,203,004	17.8
Vernon A. Raile	450,000	2,140,718	21.0
John G. Harp	450,000	2,029,859	22.2
William E. Schneider	447,400	2,165,083	20.7
Steven L. Bietz	350,000	1,597,506	21.9

Outstanding Equity Awards at Fiscal Year-End 2009

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)(1,2)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)(4)
Terry D. Hildestad	–	–	–	–	–	3,712	87,603	181,830	4,291,188
Vernon A. Raile	–	–	–	–	–	1,114	26,290	65,438	1,544,337
John G. Harp	–	–	–	–	–	–	–	63,055	1,488,098
William E. Schneider	–	–	–	–	–	2,970	70,092	69,354	1,636,754
Steven L. Bietz	–	–	–	–	–	558	13,169	51,545	1,216,462

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

(2) These shares of restricted stock were granted in 2001 and vest automatically 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 the final three-year performance cycle 2007-2009. Non-preferential dividends are paid on these shares.

(3) Below is a breakdown by year of the plan awards:

Named Executive Officer	*Award*	*Shares*	*End of Performance Period*
Terry D. Hildestad	*2007*	*33,091*	*12/31/09*
	2008	*39,091*	*12/31/10*
	2009	*109,648*	*12/31/11*
Vernon A. Raile	*2007*	*12,564*	*12/31/09*
	2008	*13,402*	*12/31/10*
	2009	*39,472*	*12/31/11*
John G. Harp	*2007*	*10,181*	*12/31/09*
	2008	*13,402*	*12/31/10*
	2009	*39,472*	*12/31/11*
William E. Schneider	*2007*	*15,119*	*12/31/09*
	2008	*14,991*	*12/31/10*
	2009	*39,244*	*12/31/11*
Steven L. Bietz	*2007*	*10,354*	*12/31/09*
	2008	*10,491*	*12/31/10*
	2009	*30,700*	*12/31/11*

Shares for the 2007 award are shown at the target level (100%) based on results for the 2007-2009 performance cycle at target.
Shares for the 2008 award are shown at the target level (100%) based on results for the first two years of the 2008-2010 performance cycle at target.
Shares for the 2009 award are shown at the maximum level (200%) based on results for the first year of the 2009-2011 performance cycle above target.

(4) Value based on the number of performance shares reflected in column (i) multiplied by $23.60, the year-end closing price for 2009.

Option Exercises and Stock Vested during 2009

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)(1,2)	Value Realized on Vesting ($) (e)(3)
Terry D. Hildestad	–	–	19,584	397,426
Vernon A. Raile	–	–	10,192	206,830
John G. Harp	–	–	8,259	167,603
William E. Schneider	–	–	12,534	254,358
Steven L. Bietz	–	–	5,755	116,789

(1) Adjusted for the 3-for-2 stock split effective July 26, 2006.
(2) Reflects performance shares for the 2006-2008 performance period that vested on February 12, 2009.
(3) Reflects the value of performance shares based on our stock price of $18.61 on February 12, 2009, and the dividend equivalents that were paid on the vested shares.

Pension Benefits for 2009

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	35	1,369,893	–
	SISP I(1)	27	1,487,740	–
	SISP II(2)	27	2,456,479	–
	SISP Excess	27	842,854	–
Vernon A. Raile	Pension Plan	30	1,033,470	–
	SISP I(1)	27	891,572	–
	SISP II(2)	27	1,899,169	–
	SISP Excess	27	–	–
John G. Harp	Pension Plan	5	172,100	–
	SISP I(1)	4	–	–
	SISP II(2)	4	1,784,336	–
	SISP Excess	4	33,837	–
	Harp Additional Retirement Benefit	4	120,136	–
William E. Schneider	Pension Plan	16	667,138	–
	SISP I(1)	15	1,081,798	–
	SISP II(2)	15	1,278,020	–
	SISP Excess	15	128,798	–
Steven L. Bietz	Pension Plan	28	675,382	–
	SISP I(1)	15	458,686	–
	SISP II(2)	15	440,819	–
	SISP Excess	15	72,082	–

(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, 2009, calculated using a 5.75% 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. Harp and Bietz and age 62 for Mr. Schneider. These are the earliest ages at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2009, was assumed for Messrs. Hildestad and Raile, who were age 60 and 64, respectively, on that date. The amounts shown for the SISP I and SISP II were determined using a 5.75% 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, and Harp 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. Mr. Bietz participates in the Williston Basin Interstate Pipeline Company Pension Plan, which we refer to as the WBI pension plan. Pension benefits under our pension plan and the WBI pension plan are based on 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; incentives 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 each of the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

Each of the pension plans was amended to cease benefit accruals as of December 31, 2009, meaning the normal retirement benefit will not change.

To receive unreduced retirement benefits under our pension plan and the WBI pension 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. Messrs. Hildestad and Raile were eligible for unreduced retirement benefits under our pension plan on December 31, 2009. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service, in our pension plan or the WBI pension 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 pension plan and the WBI pension 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. Harp and Schneider 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. Participants who terminate employment before age 55 may elect to receive their benefits in a lump sum. Mr. Bietz is currently eligible for a lump sum.

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 2009, the maximum annual benefit payable under the pension plans was $195,000 and the maximum amount of compensation that could be recognized when determining benefits was $245,000.

Supplemental Income Security Plan

We also offer key managers and executives, including all of our named executive officers, benefits under our nonqualified 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 augment 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.

Effective January 1, 2010, we amended the SISP to:

- reduce by 20% the regular SISP and.death benefit levels in the benefit schedule used to determine regular SISP and death benefits for new participants and participants whose benefit levels increase on or after January 1, 2010
- impose an additional vesting period applicable to any increased regular SISP benefit and SISP death benefit occurring on or after January 1, 2010
- eliminate the excess SISP benefit for new participants and current participants who were not already eligible for the excess SISP benefit, and
- freeze excess SISP benefit accruals.

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 one of two schedules attached to the SISP - the original schedule or the amended schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedules. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary. Benefit levels in the amended schedule which became effective on January 1, 2010, are 20% lower than the benefit levels in the original schedule. The amended schedule applies to new participants and participants who receive a benefit level increase on or after January 1, 2010.

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."

The SISP was amended to address changes in applicable tax laws resulting from the enactment of section 409A of the Internal Revenue Code. 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, which we refer to 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. The SISP II benefits commence when the participant attains age 65 or, if later, when the participant retires, subject to a six-month delay if the participant is subject to the provisions of section 409A of the Internal Revenue Code that require delayed commencement of these types of retirement benefits. The SISP II benefits are paid over 180 months or, if commencement of payments is delayed for six months, 173 months. If the commencement of benefits is delayed for six months, the first payment includes the payments that would have been paid during the six-month period. 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 I 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 I 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 I benefit.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, 100% 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. 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.

In 2009, the plan was amended to impose an additional vesting requirement on benefit level increases for the regular SISP benefit granted on or after January 1, 2010. The requirement applies only to the increased benefit level. The increased benefit vests after the later of three additional years of participation in the SISP or the end of the regular vesting schedule described above. The additional three-year vesting requirement for benefit level increases is pro-rated for participants who are officers, attain age 65, and are required to retire, pursuant to the company's bylaws, prior to the end of the additional vesting period as follows:

- 33% of the increase vests for participants required to retire at least one year but less than two years after the increase is granted, and
- 66% of the increase vests for participants required to retire at least two years but less than three years after the increase is granted.

The benefit level increases of participants who attain age 65 and are required to retire pursuant to the company's bylaws will be further reduced to the extent the participants are not fully vested in their regular SISP benefit under the 10-year vesting schedule described above. The additional vesting period associated with a benefit level increase may be waived by the compensation committee.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedules 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 the qualified pension plans 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. Effective January 1, 2005, participants who were not then vested in the excess SISP benefits were also required to remain actively employed by the company until age 60. In 2009, the plan was amended to limit eligibility of the excess SISP benefit to current SISP participants (1) who are already vested in the excess SISP benefit or (2) who will become vested in the excess SISP benefits if they remain employed with the company until age 60. The plan was further amended to freeze the excess SISP benefits to a maximum of the benefit level payable based on the participant's years of service and compensation level as of December 31, 2009. With the exception of Mr. Harp, each of the named executive officers would be entitled to the excess SISP benefit 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 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 benefit is 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, 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 our pension plan, the excess SISP, and the SISP. 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 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, 2009, 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 2009

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	–	–	52,314	–	835,932
Vernon A. Raile	–	–	94,556	–	1,510,791
John G. Harp	–	–	–	–	–
William E. Schneider	–	–	83,840	–	1,339,689(1)
Steven L. Bietz	–	–	–	–	–

(1) Includes $392,000, which was reported in the Summary Compensation Table for 2006 in column (g).

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2009 was 6.48% or the "Moody's Rate," which was defined by reference to the U.S. Long-Term Corporate Bond Yield Average for "A" rated companies. Effective January 1, 2009, "Moody's Rate" is the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last business day of each month for the 12-month period ending October 31, 2008, and dividing by 12. 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 a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

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 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, 2009. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude base salary, 2009 annual incentives, stock awards the named executive officers earned due to employment through December 31, 2009, and compensation and 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 nonqualified deferred compensation plans that are reported in the Nonqualified Deferred Compensation for 2009 table. See the Pension Benefits for 2009 table and the Nonqualified Deferred Compensation for 2009 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans and our nonqualified deferred compensation plans.

We provide disability benefits to some 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 officers, 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 5.75%. 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, 2009.

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 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 acquisition by an individual, entity, or group of 20% or more of our outstanding 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 plan's effective date or whose election was approved by such board members
- consummation of a merger or consolidation or sale or other disposition of all or substantially all of the company's assets, unless the company's stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding shares and voting power of the resulting corporation after the merger or the corporation that acquires the company's assets, as the case may be or
- stockholder approval of the company's liquidation or dissolution.

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, performance share awards granted prior to 2009 are prorated as follows:

- if the termination of employment occurs 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 and
- if the termination of employment occurs during the third year of the performance period, the executive receives the full amount of any performance shares earned.

Beginning with performance share awards granted in 2009, these awards will be forfeited if the participant's employment terminates for any reason before the participant has reached age 55 and completed 10 years of service. Performance shares and related dividend equivalents for those participants whose employment is terminated after the participant has reached age 55 and completed 10 years of service will be prorated as described above.

Accordingly, if a December 31, 2009 termination is assumed, the named executive officers' 2009-2011 performance share awards would be forfeited, any amounts earned under the 2008-2010 performance share awards would be reduced by one-third, and any amounts earned under the 2007-2009 performance share awards would not be reduced. The number of performance shares earned depends on actual performance through the full performance period. As actual performance for the 2007-2009 performance share awards has been determined, the amounts for these awards in the event of a non-change of control termination were based on actual performance, which resulted in vesting of 100% of the target award. Amounts for the 2008-2010 performance share awards are also shown at target, based upon assumed target performance. No amounts are shown for the 2009-2011 performance share awards because such awards would be forfeited. 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, 2009 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, 2009.

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 of not less than twelve times the highest monthly salary paid within the preceding twelve months
- annual incentive opportunity of not less than the highest annual incentive paid in any of the three years before the change of control
- participation in our incentive, savings, retirement, and welfare benefit plans
- reasonable vehicle allowance, home office allowance, and subsidized annual physical examinations and
- office and support staff, vacation, and expense reimbursement consistent with such benefits as they were provided before the change of control.

Assuming a change of control occurred on December 31, 2009, the guaranteed minimum level of base salary provided over the three-year employment period would not result in an increase in any of the named executive officers' base salaries. The minimum annual incentive amounts Messrs. Hildestad, Raile, Harp, Schneider, and Bietz would be entitled to over the three-year employment period would be $1,500,000, $585,000, $720,000, $581,620, and $450,450, respectively. The agreements also provide that severance payments and benefits will be provided:

- if we terminate the named executive officer's employment during the employment period, other than for cause or disability, or
- the named executive officer resigns for good reason.

"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:

- a material diminution of the named executive officer's authority, duties, or responsibilities
- a material change in the named executive officer's work location and
- our material breach of the agreement.

In such event, the named executive officer would receive:

- accrued but unpaid base salary and accrued but unused vacation
- 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 incentive using the highest annual incentive paid in any of the three years before the change of control or, if higher, the annual incentive for the most recently completed fiscal year
- a pro-rated annual incentive for the year of termination
- an amount equal to the actuarial equivalent of the additional benefit the named executive officer would receive under the SISP and any other supplemental or excess retirement plan if employment continued for an additional three years
- outplacement benefits and
- a payment equal to any federal excise tax on excess parachute payments if the total parachute payments exceed 110% of the safe harbor amount for that tax. If this 110% threshold is not exceeded, the named executive officer's payments and benefits would be reduced to avoid the tax. The named executive officers are not reimbursed for any taxes imposed on this tax reimbursement payment.

This description of severance payments and benefits reflects the terms of the agreements as in effect on December 31, 2009.

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 paid. 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 paid.

Terry D. Hildestad

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						2,250,000	
Short-term Incentive(1)						6,000,000	
2007-2009 Performance Shares	836,653	836,653		836,653	836,653	836,653	836,653
2008-2010 Performance Shares	645,270	645,270		645,270	645,270	967,893	967,893
2009-2011 Performance Shares						1,326,741	1,326,741
Restricted Stock						87,603	87,603
Benefits and Perquisites:							
Regular SISP(2)	3,944,219	3,944,219			3,944,219	3,944,219	
Excess SISP(3)	842,838	842,838			842,838	842,838	
SISP Death Benefits(4)				10,335,773			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						1,940,878	
Total	**6,268,980**	**6,268,980**		**11,817,696**	**6,268,980**	**18,246,825**	**3,218,890**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2009, which was $42,710 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Hildestad's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Hildestad would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 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 excess SISP benefits.

(4) Represents the present value of 180 monthly payments of $85,420 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

Vernon A. Raile

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,350,000	
Short-term Incentive(1)						2,340,000	
2007-2009 Performance Shares	317,661	317,661		317,661	317,661	317,661	317,661
2008-2010 Performance Shares	221,231	221,231		221,231	221,231	331,834	331,834
2009-2011 Performance Shares						477,611	477,611
Restricted Stock						26,290	26,290
Benefits and Perquisites:							
Regular SISP(2)	2,790,741	2,790,741			2,790,741	2,790,741	
SISP Death Benefits(3)				5,529,675			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(4)						856,992	
Total	**3,329,633**	**3,329,633**		**6,068,567**	**3,329,633**	**8,541,129**	**1,153,396**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Raile's vested regular SISP benefit as of December 31, 2009, which was $22,850 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Raile's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(4) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

PROXY

John G. Harp

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,350,000	
Short-term Incentive(1)						2,880,000	
2007-2009 Performance Shares	257,410	257,410		257,410	257,410	257,410	257,410
2008-2010 Performance Shares	221,231	221,231		221,231	221,231	331,834	331,834
2009-2011 Performance Shares						477,611	477,611
Restricted Stock							
Benefits and Perquisites:							
Incremental Pension(2)	107,307	107,307			107,307	107,307	
Regular SISP	1,249,035(3)	1,249,035(3)			1,603,546(4)	1,784,336(5)	
Excess SISP(6)						193,615	
SISP Death Benefits(7)				5,529,675			
Disability Benefits(8)					227,839		
Outplacement Services						50,000	
280G Tax(9)						1,068,156	
Total	**1,834,983**	**1,834,983**		**6,008,316**	**2,417,333**	**8,500,269**	**1,066,855**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the equivalent of three additional years of service that would be provided under the Harp additional retirement benefit described following the Pension Benefits for 2009 table. Present value was determined using a 5.75% discount rate.

(3) Represents the present value of Mr. Harp's vested regular SISP benefit as of December 31, 2009, which was $15,995 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. 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 2009 table.

(4) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 3, adjusted to reflect the increase in the present value of his regular SISP benefit that would result from an additional two years of vesting under the SISP. Present value was determined using a 5.75% discount rate.

(5) Represents the present value of Mr. Harp's vested SISP benefit described in footnote 3, adjusted to reflect the increase in the present value of his regular SISP benefit that would result if he continued employment for an additional three years. Present value was determined using a 5.75% discount rate.

(6) Represents the present value of all excess SISP benefits Mr. Harp would be entitled to, calculated with the assumption of three additional years of employment, as provided under Mr. Harp's change of control agreement. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(7) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(8) Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 5.75% discount rate.

(9) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

William E. Schneider

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,342,200	
Short-term Incentive(1)						2,326,480	
2007-2009 Performance Shares	382,260	382,260		382,260	382,260	382,260	382,260
2008-2010 Performance Shares	247,451	247,451		247,451	247,451	371,177	371,177
2009-2011 Performance Shares						474,852	474,852
Restricted Stock						70,092	70,092
Benefits and Perquisites:							
Regular SISP(2)	2,359,818	2,359,818			2,359,818	2,359,818	
Excess SISP(3)	126,868	126,868			126,868	126,868	
SISP Death Benefits(4)				5,529,675			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(5)						808,830	
Total	**3,116,397**	**3,116,397**		**6,159,386**	**3,116,397**	**8,312,577**	**1,298,381**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2009, which was $22,850 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Schneider's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Schneider would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of employment assumed for purposes of calculating the additional retirement plan payment under Mr. Schneider's change of control agreement would not increase the actuarial present value of his excess SISP benefits.

(4) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(5) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

Steven L. Bietz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Not for Cause or Good Reason Termination Following Change of Control ($)	Change of Control (Without Termination) ($)
Compensation:							
Base Salary						1,050,000	
Short-term Incentive(1)						1,801,800	
2007-2009 Performance Shares	261,784	261,784		261,784	261,784	261,784	261,784
2008-2010 Performance Shares	173,171	173,171		173,171	173,171	259,757	259,757
2009-2011 Performance Shares						371,470	371,470
Restricted Stock						13,169	13,169
Benefits and Perquisites:							
Regular SISP(2)	899,505	899,505			899,505	899,505	
Excess SISP	146,033(3)	146,033(3)			146,033(3)	388,504(4)	
SISP Death Benefits(5)				3,898,602			
Disability Benefits							
Outplacement Services						50,000	
280G Tax(6)						671,881	
Total	**1,480,493**	**1,480,493**		**4,333,557**	**1,480,493**	**5,767,870**	**906,180**

(1) Includes the prorated annual incentive for the year of termination, which is the full annual incentive since we assume termination occurred on December 31, 2009, and the additional severance payment of three times the annual incentive. For each of these, we used the higher of (1) the annual incentive earned in 2009 or (2) the highest annual incentive paid in 2007, 2008, and 2009.

(2) Represents the present value of Mr. Bietz's vested regular SISP benefit as of December 31, 2009, which was $16,110 per month for 15 years, commencing at age 65. Present value was determined using a 5.75% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2009 table. The three additional years of vesting credit assumed for purposes of calculating the additional SISP benefit under Mr. Bietz's change of control agreement would not increase the actuarial present value of his SISP amount.

(3) Represents the present value of all excess SISP benefits Mr. Bietz would be entitled to upon termination of employment under the SISP. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(4) Represents the present value of all excess SISP benefits Mr. Bietz would be entitled to, calculated with the assumption of three additional years of employment, as provided under Mr. Bietz's change of control agreement. Present value was determined using a 5.75% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2009 table.

(5) 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 5.75% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2009 table.

(6) Determined applying the Internal Revenue Code section 4999 excise tax of 20% only if 110% threshold is exceeded.

Director Compensation for 2009

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)(1)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)(2)	Total ($) (h)
Thomas Everist	57,083	69,445	–(3)	–	–	174	126,702
Karen B. Fagg	55,250(4)	69,445	–	–	–	174	124,869
A. Bart Holaday	50,583	69,445	–	–	–	174	120,202
Dennis W. Johnson	59,083	69,445	–	–	–	174	128,702
Thomas C. Knudson	52,083	69,445	–	–	–	174	121,702
Richard H. Lewis	55,083	69,445	–	–	–	174	124,702
Patricia L. Moss	52,083(5)	69,445	–	–	–	174	121,702
John L. Olson	40,083(6)	69,445	–(7)	–	–	563,060(9)	672,588
Harry J. Pearce	130,000	69,445	–(8)	–	–	174	199,619
Sister Thomas Welder	50,583	69,445	–	–	–	174	120,202
John K. Wilson	53,583(10)	69,445	–	–	–	174	123,202

(1) Valued based on $17.147, the purchase price of the stock on the date of grant, May 18, 2009, which is the grant date fair value.
(2) Group life insurance premiums, except for Mr. Olson.
(3) Mr. Everist had 18,562 stock options outstanding as of December 31, 2009.
(4) Includes $17,984 that Ms. Fagg received in our common stock in lieu of cash.
(5) Includes $52,064 that Ms. Moss received in our common stock in lieu of cash.
(6) Mr. Olson retired on August 13, 2009.
(7) Mr. Olson had 18,562 stock options outstanding as of December 31, 2009.
(8) Mr. Pearce had 13,500 stock options outstanding as of December 31, 2009.
(9) Comprised of a group life insurance premium of $116 and the value of Mr. Olson's deferred compensation at December 31, 2009, which is payable over five years in monthly installments.
(10) Includes $44,578 that Mr. Wilson received in our common stock in lieu of cash.

Effective June 1, 2009, the board approved changes to the MDU Resources Group, Inc. Directors' Compensation Policy, and the following table shows the cash and stock retainers payable to our non-employee directors.

	Effective June 1, 2009	Prior to June 1, 2009
Base Retainer	$55,000	$ 30,000
Additional Retainers:		
Non-Executive Chairman	75,000(2)	100,000(1)(2)
Lead Director, if any	33,000	33,000
Audit Committee Chairman	10,000	10,000
Compensation Committee Chairman	5,000	5,000
Nominating and Governance Committee Chairman	5,000	5,000
Meeting Fees:		
Board Meeting	–	1,500
Committee Meeting	–	1,500
Annual Stock Retainer	4,050 shares	4,050 shares

(1) $50,000 of this amount was paid in company common stock prior to January 1, 2009.
(2) The Non-Executive Chairman does not receive board or committee meeting fees.

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of each director's beneficiaries during the time each director serves on the board. The annual cost per director is $174.

Directors may defer all or any portion of the annual cash retainer, meeting fees, if any, and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Directors are reimbursed for all reasonable travel expenses including spousal expenses in connection with attendance at meetings of the board and its committees. All amounts together with any other perquisites were below the disclosure threshold for 2009.

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

The board adopted stock ownership guidelines for directors in November 2005. Each director is expected to own our common stock equal in value to five times the director's base retainer. A director, with good cause and with the knowledge of the board, may donate or assign all of the director's company common stock to a charitable, religious, or non-profit organization in lieu of ownership. Shares acquired through purchases on the open market and participation in our director stock plans will be considered in ownership calculations as will ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of that director's initial election to the board to meet the guideline requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. For stock ownership, please see "Security Ownership."

In our Director Compensation Policy, we prohibit our directors from hedging their ownership of company common stock. Directors may not enter into transactions that allow the director to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Narrative Disclosure of our Compensation Policies and Practices as They Relate to Risk Management

We have reviewed our compensation policies and practices for all employees and concluded that any risks arising from our policies and programs are not reasonably likely to have a material adverse effect on our company.

BALANCE SHEET

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1	**Assets and Other Debits**				
2	Utility Plant				
3	101	Gas Plant in Service	$288,109,384	$292,952,199	1.68%
4	101.1	Property Under Capital Leases			
5	102	Gas Plant Purchased or Sold			
6	104	Gas Plant Leased to Others	25,772	0	-100.00%
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	4,548,121	4,741,057	4.24%
11	108	(Less) Accumulated Depreciation	(167,643,439)	(171,361,313)	2.22%
12	111	(Less) Accumulated Amortization & Depletion	(967,784)	(1,089,620)	12.59%
13	114	Gas Plant Acquisition Adjustments	97,266	97,266	0.00%
14	115	(Less) Accum. Amort. Gas Plant Acq. Adj.	(43,934)	(46,753)	6.42%
15	116	Other Gas Plant Adjustments			
16	117	Gas Stored Underground - Noncurrent	3,166,622	3,865,481	22.07%
17	118	Other Utility Plant	883,115,046	975,345,216	10.44%
18	119	Accum. Depr. and Amort. - Other Utl. Plant	(454,745,730)	(473,668,639)	4.16%
19		**TOTAL Utility Plant**	$555,661,324	$630,834,894	13.53%
20	**Other Property & Investments**				
21	121	Nonutility Property	$3,707,024	$4,065,076	9.66%
22	122	(Less) Accum. Depr. & Amort. of Nonutil. Prop.	(1,117,112)	(1,207,227)	8.07%
23	123	Investments in Associated Companies			
24	123.1	Investments in Subsidiary Companies	2,478,164,341	2,240,332,380	-9.60%
25	124	Other Investments	35,032,098	41,701,031	19.04%
26	125	Sinking Funds			
27		**TOTAL Other Property & Investments**	$2,515,786,351	$2,284,891,260	-9.18%
28	**Current & Accrued Assets**				
29	131	Cash	$181,115	$5,039,802	2682.65%
30	132-134	Special Deposits	1,200	1,200	0.00%
31	135	Working Funds	113,921	63,569	-44.20%
32	136	Temporary Cash Investments	1,938,468	25,000,000	1189.68%
33	141	Notes Receivable			
34	142	Customer Accounts Receivable	29,930,415	26,120,425	-12.73%
35	143	Other Accounts Receivable	2,394,649	3,182,572	32.90%
36	144	(Less) Accum. Provision for Uncollectible Accts.	(285,809)	(233,779)	-18.20%
37	145	Notes Receivable - Associated Companies	57,000,000		-100.00%
38	146	Accounts Receivable - Associated Companies	26,427,125	33,121,406	25.33%
39	151	Fuel Stock	4,099,005	4,613,409	12.55%
40	152	Fuel Stock Expenses Undistributed			
41	153	Residuals and Extracted Products			
42	154	Plant Materials and Operating Supplies	10,225,093	9,812,475	-4.04%
43	155	Merchandise	1,742,091	974,586	-44.06%
44	156	Other Material & Supplies			
45	163	Stores Expense Undistributed		(1,699)	
46	164.1	Gas Stored Underground - Current	8,529,714	17,640,699	106.81%
47	165	Prepayments	4,865,549	4,950,903	1.75%
48	166	Advances for Gas Explor., Devl. & Production			
49	171	Interest & Dividends Receivable		139	
50	172	Rents Receivable			
51	173	Accrued Utility Revenues	46,729,484	35,878,909	-23.22%
52	174	Miscellaneous Current & Accrued Assets	2,560		-100.00%
53		**TOTAL Current & Accrued Assets**	$193,894,580	$166,164,616	-14.30%

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits (cont.)**			
2				
3	**Deferred Debits**			
4				
5	181 Unamortized Debt Expense	$1,191,582	$1,217,947	2.21%
6	182.1 Extraordinary Property Losses			
7	182.2 Unrecovered Plant & Regulatory Study Costs			
8	182.3 Other Regulatory Assets	88,196,422	80,661,452	-8.54%
9	183 Prelim. Electric Survey & Investigation Chrg.	579,901	283,502	-51.11%
10	183.1 Prelim. Nat. Gas Survey & Investigation Chrg.			
11	183.2 Other Prelim. Nat. Gas Survey & Invtg. Chrgs.	2,084	0	-100.00%
12	184 Clearing Accounts	(191,726)	(232,048)	21.03%
13	185 Temporary Facilities			
14	186 Miscellaneous Deferred Debits	26,229,986	22,623,810	-13.75%
15	187 Deferred Losses from Disposition of Util. Plant			
16	188 Research, Devel. & Demonstration Expend.			
17	189 Unamortized Loss on Reacquired Debt	9,990,648	10,285,123	2.95%
18	190 Accumulated Deferred Income Taxes	60,304,833	55,095,783	-8.64%
19	191 Unrecovered Purchased Gas Costs	24,225,488	(9,339,438)	-138.55%
20	192.1 Unrecovered Incremental Gas Costs			
21	192.2 Unrecovered Incremental Surcharges			
22	**TOTAL Deferred Debits**	$210,529,218	$160,596,131	-23.72%
23				
24	**TOTAL ASSETS & OTHER DEBITS**	$3,475,871,473	$3,242,486,901	-6.71%

	Account Number & Title	Last Year	This Year	% Change
25	**Liabilities and Other Credits**			
26				
27	**Proprietary Capital**			
28				
29	201 Common Stock Issued	$184,208,283	$188,389,265	2.27%
30	202 Common Stock Subscribed			
31	204 Preferred Stock Issued	15,000,000	15,000,000	0.00%
32	205 Preferred Stock Subscribed			
33	207 Premium on Capital Stock	941,909,202	1,019,788,138	8.27%
34	211 Miscellaneous Paid-In Capital			
35	213 (Less) Discount on Capital Stock			
36	214 (Less) Capital Stock Expense	(3,610,416)	(4,110,305)	13.85%
37	216 Appropriated Retained Earnings	436,608,753	472,482,478	8.22%
38	216.1 Unappropriated Retained Earnings	1,180,220,338	904,556,156	-23.36%
39	217 (Less) Reacquired Capital Stock	(3,625,813)	(3,625,813)	0.00%
40	219 Accumulated Other Comprehensive Income	10,365,311	(20,832,825)	-300.99%
41	**TOTAL Proprietary Capital**	$2,761,075,658	$2,571,647,094	-6.86%
42				
43	**Long Term Debt**			
44				
45	221 Bonds	$235,500,000	$280,000,000	18.90%
46	222 (Less) Reacquired Bonds			
47	223 Advances from Associated Companies			
48	224 Other Long Term Debt	80,708,867	1,102,591	-98.63%
49	225 Unamortized Premium on Long Term Debt			
50	226 (Less) Unamort. Discount on Long Term Debt-Dr.	(1,837)	0	-100.00%
51	**TOTAL Long Term Debt**	$316,207,030	$281,102,591	-11.10%

BALANCE SHEET

Year: 2009

	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	$1,582,142	$1,486,612	-6.04%
9	228.3	Accumulated Provision for Pensions & Benefits	59,371,415	54,313,944	-8.52%
10	228.4	Accumulated Misc. Operating Provisions			
11	229	Accumulated Provision for Rate Refunds			
12	230	Asset Retirement Obligations	2,691,414	3,302,103	22.69%
13		**TOTAL Other Noncurrent Liabilities**	$63,644,971	$59,102,659	-7.14%
14					
15	**Current & Accrued Liabilities**				
16					
17	231	Notes Payable		$0	
18	232	Accounts Payable	33,220,974	30,573,900	-7.97%
19	233	Notes Payable to Associated Companies			
20	234	Accounts Payable to Associated Companies	7,119,598	5,802,650	-18.50%
21	235	Customer Deposits	2,408,988	2,239,734	-7.03%
22	236	Taxes Accrued	(840,838)	14,803,275	1860.54%
23	237	Interest Accrued	4,206,271	5,058,554	20.26%
24	238	Dividends Declared	28,639,606	29,748,761	3.87%
25	239	Matured Long Term Debt			
26	240	Matured Interest			
27	241	Tax Collections Payable	1,578,001	1,986,880	25.91%
28	242	Miscellaneous Current & Accrued Liabilities	25,765,992	24,937,206	-3.22%
29	243	Obligations Under Capital Leases - Current			
30		**TOTAL Current & Accrued Liabilities**	$102,098,592	$115,150,960	12.78%
31					
32	**Deferred Credits**				
33					
34	252	Customer Advances for Construction	$5,289,755	$5,924,550	12.00%
35	253	Other Deferred Credits	101,962,554	81,150,481	-20.41%
36	254	Other Regulatory Liabilities	9,003,884	8,593,585	-4.56%
37	255	Accumulated Deferred Investment Tax Credits	361,334	162,069	-55.15%
38	256	Deferred Gains from Disposition Of Util. Plant			
39	257	Unamortized Gain on Reacquired Debt			
40	281-283	Accumulated Deferred Income Taxes	116,227,695	119,652,912	2.95%
41		**TOTAL Deferred Credits**	$232,845,222	$215,483,597	-7.46%
42					
43	**TOTAL LIABILITIES & OTHER CREDITS**		$3,475,871,473	$3,242,486,901	-6.71%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, 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 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The financial statements were prepared in accordance with the accounting requirements of the FERC 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. These requirements differ from generally accepted accounting principles (GAAP) related to the presentation of certain items including, but not limited to, the current portion of long-term debt, deferred income taxes, cost of removal liabilities, and current unrecovered purchased gas costs.

The Respondent owns two wholly owned subsidiaries, Centennial Energy Holdings, Inc. and MDU Energy Capital, LLC. As required by the FERC for Form 1 report purposes, MDU Resources Group, Inc. reports its subsidiary investments using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. If GAAP were followed, utility plant, other property and investments would increase by $1.1 billion; current and accrued assets would increase by $895.5 million; deferred debits would increase by $729.2 million; long-term debt would increase by $1.2 billion; other noncurrent liabilities and current and accrued liabilities would increase by $492.9 million; deferred credits would increase by $1.0 billion as of December 31, 2009. Furthermore, operating revenues would increase by $3.7 billion and operating expenses, excluding income taxes, would increase by $3.9 billion for the twelve months ended December 31, 2009. In addition, net cash provided by operating activities would increase by $623.3 million; net cash used in investing activities would increase by $322.8 million; net cash used in financing activities would increase by $205.8 million; the effect of exchange rate changes on cash would increase by $782,000; and the net change in cash and cash equivalents would be a increase of $95.5 million for the twelve months ended December 31, 2009. Reporting its subsidiary investments using the equity method rather than GAAP has no effect on net income or retained earnings.

The Company’s notes to the financial statements are presented consolidated with its subsidiary investments and prepared in conformity with GAAP. Accordingly, certain footnotes are not reflective of the Company’s FERC basis financial statements contained herein.

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 regulatory accounting, which 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

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the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

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, 2009 and 2008, was $16.6 million and $13.7 million, respectively.

Natural gas in storage
Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories and was $35.6 million and $27.6 million at December 31, 2009 and 2008, respectively. The remainder of natural gas in storage, which largely represents the cost of the gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $59.6 million and $43.4 million at December 31, 2009 and 2008, respectively.

Inventories
Inventories, other than natural gas in storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $80.1 million and $89.1 million, materials and supplies of $58.1 million and $70.3 million, asphalt oil of $23.0 million and $22.1 million, and other inventories of $53.0 million and $52.4 million, as of December 31, 2009 and 2008, respectively. These inventories were stated at the lower of average cost or market value.

Investments
The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, investments in fixed-income and equity securities and auction rate securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. On January 1, 2008, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. These investments had previously been accounted for as available-for-sale investments and were 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. The Company accounts for auction rate securities as available-for-sale. For more information, see Notes 8 and 16 and comprehensive income (loss) 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 $11.5 million, $9.0 million and $7.1 million in 2009, 2008 and 2007, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except

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for depletable aggregate reserves, which are depleted based on the units-of-production method, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

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

	2009	2008	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 486,710	$ 408,851	58
Distribution	230,795	219,501	36
Transmission	146,373	142,081	44
Other	77,913	78,292	12
Natural gas distribution:			
Distribution	1,218,124	1,260,651	39
Other	238,084	168,836	21
Pipeline and energy services:			
Transmission	351,019	322,276	52
Gathering	41,815	41,825	19
Storage	33,701	32,592	52
Other	33,283	31,925	27
Nonregulated:			
Construction services:			
Land	4,526	4,526	—
Buildings and improvements	15,110	12,913	23
Machinery, vehicles and equipment	87,462	84,042	7
Other	9,138	9,820	5
Pipeline and energy services:			
Gathering	202,467	201,323	17
Other	12,914	10,980	10
Natural gas and oil production:			
Natural gas and oil properties	1,993,594	2,443,946	*
Other	35,200	33,456	9
Construction materials and contracting:			
Land	127,928	127,279	—
Buildings and improvements	65,778	68,356	20
Machinery, vehicles and equipment	925,747	932,545	12
Construction in progress	3,733	11,488	—
Aggregate reserves	391,803	384,361	**
Other:			
Land	2,942	2,942	—
Other	30,423	27,430	19
Less accumulated depreciation, depletion and amortization	2,872,465	2,761,319	
Net property, plant and equipment	$ 3,894,117	$ 4,300,918	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.64, $2.00 and $1.59 for the years ended December 31, 2009, 2008 and 2007, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $178.2 million and $232.1 million were excluded from amortization at December 31, 2009 and 2008, respectively.*

** *Depleted on the units-of-production method.*

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 2009, 2008 and 2007. 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, see Note 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 cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, 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 regardless of subsequent price changes.

Due to low natural gas and oil prices that existed on March 31, 2009, and December 31, 2008, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009, and December 31, 2008. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-downs amounted to $620.0 million and $135.8 million ($384.4 million and $84.2 million after tax) for the years ended December 31, 2009 and 2008, respectively.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of $107.9 million ($66.9 million after tax) at March 31, 2009, and $79.2 million ($49.1 million after tax) at December 31, 2008, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

At December 31, 2009, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to

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December 31, 2009, 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, 2009, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2009	2008	2007	2006 and prior
			(In thousands)		
Acquisition	$122,806	$4,287	$81,954	$7,972	$28,593
Development	20,377	9,997	7,149	3,231	—
Exploration	28,216	19,311	8,093	811	1
Capitalized interest	6,815	1,336	3,865	478	1,136
Total costs not subject to amortization	$178,214	$34,931	$101,061	$12,492	$29,730

Costs not subject to amortization as of December 31, 2009, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with natural gas and oil development in the Paradox Basin in Utah; Big Horn Basin in Wyoming; east Texas properties; and CBNG in the Powder River Basin of Wyoming and Montana. 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, Cascade and Intermountain was $92.6 million and $123.2 million at December 31, 2009 and 2008, respectively. 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. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

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 and estimated earnings in excess of billings on uncompleted contracts of $28.8 million and $40.1 million at December 31, 2009 and 2008, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $49.3 million and $106.9 million at December 31, 2009 and 2008, 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 $45.4 million and $86.9 million at December 31, 2009 and 2008, respectively. The amounts expected to be paid within one year or less are included in

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receivables, net, and amounted to $44.0 million and $67.7 million at December 31, 2009 and 2008, respectively. The long-term retainage which was included in deferred charges and other assets - other was $1.4 million and $19.2 million at December 31, 2009 and 2008, respectively.

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 allows the hedging of monthly forecasted natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that 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 the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value, with the unrealized gains or losses recognized as a component of accumulated other comprehensive income (loss). The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain 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.

The Company's swap and collar agreements are reflected at fair value, based upon futures prices, volatility and time to maturity, among other things.

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 10.

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 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $37.4 million and $64,000 at December 31, 2009 and 2008, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $982,000 and $51.7 million at December 31, 2009 and 2008, respectively, which is included in prepayments and other current assets.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported 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 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 regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Foreign currency translation adjustment
The functional currency of the Company's investment in the Brazilian Transmission Lines, 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.

Earnings (loss) per common share
Basic earnings (loss) per common share were computed by dividing earnings (loss) 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 2008 and 2007, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for 2009 was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for 2009, the effect of outstanding stock options, restricted stock grants and performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury.

Use of estimates
The preparation of financial statements in conformity with GAAP 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,	**2009**	2008	2007
		(In thousands)	
Interest, net of amount capitalized	**$ 81,267**	$ 77,152	$ 74,404
Income taxes	**$ 39,807**	$ 113,212	$ 214,573

Income taxes paid for the year ended December 31, 2007, were higher than the amount paid for the years ended December 31, 2009 and 2008, primarily due to higher estimated quarterly tax payments paid in 2007 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
Codification In June 2009, the FASB established the ASC as the source of authoritative generally accepted accounting principles recognized by the FASB. The ASC is a reorganization of GAAP into a topical format. It was effective for the Company in the third quarter of 2009. The adoption of the Codification required the Company to revise its disclosures when referencing generally accepted accounting principles.

Fair Value Measurements and Disclosures In September 2006, the FASB established guidance that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The guidance applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions and was effective for the Company on January 1, 2008. In February 2008, this guidance was revised to delay the effective date for certain nonfinancial assets and nonfinancial liabilities to January 1, 2009. The types of assets and liabilities that are recognized at fair value effective January 1, 2009, due to the delayed effective date, include nonfinancial assets and nonfinancial liabilities initially measured at fair value in a business combination or new basis event, certain fair value measurements associated with goodwill impairment testing, indefinite-lived intangible assets and nonfinancial

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long-lived assets measured at fair value for impairment assessment, and asset retirement obligations initially measured at fair value. The adoption of the fair value measurements and disclosure guidance, including the application to certain nonfinancial assets and nonfinancial liabilities with a delayed effective date of January 1, 2009, did not have a material effect on the Company's financial position or results of operations.

Business Combinations In December 2007, the FASB issued guidance related to business combinations that 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. The business combination guidance also requires that acquisition-related costs will be generally expensed as incurred, and expands the disclosure requirements for business combinations. In addition, the business combination guidance was amended and clarified to address application issues raised in regard to initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This guidance and its amendments were effective for the Company on January 1, 2009. The adoption of the business combination guidance and its amendments did not have a material effect on the Company's financial position or results of operations.

Noncontrolling Interests In December 2007, the FASB established accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance was effective for the Company on January 1, 2009. The adoption of the noncontrolling interest guidance did not have a material effect on the Company's financial position or results of operations.

Derivative Instruments and Hedging Activities In March 2008, the FASB released guidance related to derivative instruments and hedging activities that requires enhanced disclosures about an entity's derivative and hedging activities including how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. This guidance was effective for the Company on January 1, 2009. The adoption of the derivative instruments and hedging activities guidance requires additional disclosures regarding the Company's derivative instruments; however, it did not impact the Company's financial position or results of operations.

Pensions and Other Postretirement Benefits In December 2008, the FASB issued guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period and significant concentrations of risk within plan assets. This guidance was effective for the Company on January 1, 2009. The adoption of the pension and other postretirement benefits guidance required additional disclosures regarding the Company's defined benefit pension and other postretirement plans in the annual financial statements; however, it did not impact the Company's financial position or results of operations.

Modernization of Oil and Gas Reporting In January 2009, the SEC adopted final rules amending its oil and gas reporting requirements. The new rules include changes to the pricing used to estimate reserves, the ability to include nontraditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The final rules were effective on December 31, 2009. For information on the impacts of adopting the SEC's final rules for oil and gas reporting, see Supplementary Financial Information in the 2009 MDU Resources Group, Inc. Form 10-K.

Financial Instruments In April 2009, the FASB issued guidance that requires disclosures about the fair value of financial instruments for interim reporting periods of publicly

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traded companies as well as in annual financial statements, which was effective for the Company in the second quarter of 2009. The adoption of the financial instruments guidance required additional disclosures regarding the Company's fair value of financial instruments; however, it did not impact the Company's financial position or results of operations.

Subsequent Events In May 2009, the FASB issued subsequent events guidance which establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In addition it requires disclosure of the date through which the Company has evaluated subsequent events and whether it represents the date the financial statements were issued or were available to be issued. This guidance was effective for the Company on June 30, 2009. The adoption of the subsequent events guidance did not have a material effect on the Company's financial position or results of operations.

Variable Interest Entities In June 2009, the FASB issued guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance will require a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities was effective for the Company on January 1, 2010. The adoption of this guidance did not have a material effect on the Company's financial position or results of operations.

Oil and Gas Reserve Estimation and Disclosure In January 2010, the FASB issued guidance related to oil and gas reserve estimation and disclosure requirements, which aligned the current oil and gas reserve estimation and disclosures with those of the SEC's final rule, Modernization of Oil and Gas Reporting, and requires disclosure in the first annual period of the estimated effect of the initial application of the guidance. The guidance related to oil and gas reserve estimation and disclosure was effective for the Company on December 31, 2009. For more information on the effects of adopting the oil and gas reserve estimation and disclosure guidance, see Supplementary Financial Information in the 2009 MDU Resources Group, Inc. Form 10-K.

Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance will require additional disclosures but will not impact the Company's financial position or results of operations.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

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The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2009, 2008 and 2007, were as follows:

	2009	2008	2007
		(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 $(2,509), $30,414 and $3,989 in 2009, 2008 and 2007, respectively	**$(4,094)**	$ 49,623	$6,508
Less: Reclassification adjustment for gain on derivative instruments included in net income, net of tax of $29,170, $3,795 and $12,504 in 2009, 2008 and 2007, respectively	**47,590**	6,175	20,013
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**(51,684)**	43,448	(13,505)
Postretirement liability adjustment, net of tax of $6,291, $(8,750) and $1,835 in 2009, 2008 and 2007, respectively	**9,918**	(13,751)	3,012
Foreign currency translation adjustment, net of tax of $6,814, $(6,108) and $3,606 in 2009, 2008 and 2007, respectively	**10,568**	(9,534)	7,177
Net unrealized gain on available-for-sale investments, net of tax of $270 in 2007	—	—	405
Total other comprehensive income (loss)	**$(31,198)**	$20,163	$(2,911)

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2009, 2008 and 2007, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain on Available-for-sale Investments	Total Accumulated Other Comprehensive Income (Loss)
			(In thousands)		
Balance at December 31, 2007	$ 5,938	$(21,330)	$ 5,594	$405	$ (9,393)
Balance at December 31, 2008	$49,386	$(35,081)	$(3,940)	$ —	$ 10,365
Balance at December 31, 2009	**$ (2,298)**	**$(25,163)**	**$ 6,628**	**$ —**	**$(20,833)**

Note 2 - Acquisitions

In 2009, the Company acquired a pipeline and energy services business in Montana which was not material. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company's common stock and cash, was $22.0 million.

In 2008, the Company acquired a construction services business in Nevada; natural gas properties in Texas; construction materials and contracting businesses in Alaska, California, Idaho and Texas; and Intermountain, 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 other acquisitions made prior to 2008, consisting of the Company's common stock and cash and the outstanding indebtedness of Intermountain, was $624.5 million.

On October 1, 2008, the acquisition of Intermountain was finalized and Intermountain became an indirect wholly owned subsidiary of the Company. Intermountain's service area is in Idaho.

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 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. Cascade's natural gas service areas are in Washington and Oregon.

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 the above acquisition made in 2009, a final fair market value is 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 in January 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 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.

In July 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).

The Company's consolidated financial statements and accompanying notes for prior periods 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,

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depletion and amortization expense was recorded from the time each of the assets was classified as held for sale.

Operating results related to Innovatum for the year ended December 31, 2007, were as follows:

	2007
	(In thousands)
Operating revenues	$ 1,748
Loss from discontinued operations before income tax benefit	(210)
Income tax benefit	(316)
Income from discontinued operations, net of tax	$ 106

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

	2007
	(In thousands)
Operating revenues	$ 125,867
Income from discontinued operations (including gain on disposal in 2007 of $142.4 million) before income tax expense	177,666
Income tax expense	68,438
Income from discontinued operations, net of tax	$ 109,228

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 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities were recognized 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.

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, 2009 and 2008, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian 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 transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 21 and 23 years remaining under the contracts. Alusa 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 the fourth quarter of 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. This sale is pending regulatory approvals. One of the parties will purchase 15.6 percent of the Company's ownership interests over a four-year period. The other parties will purchase 84.4 percent of the Company's ownership interests at the financial close of the transaction.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries,

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acquired a 50 percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. In July 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.

At December 31, 2009 and 2008, the investments in which the Company held an equity method interest had total assets of $387.0 million and $294.7 million, respectively, and long-term debt of $176.7 million and $158.0 million, respectively. The Company's investment in its equity method investments was approximately $62.4 million and $44.4 million, including undistributed earnings of $9.3 million and $6.8 million, at December 31, 2009 and 2008, respectively.

Note 5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2009, were as follows:

	Balance as of January 1, 2009	Goodwill Acquired During the Year*	Balance as of December 31, 2009
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	344,952	784	345,736
Construction services	95,619	4,508	100,127
Pipeline and energy services	1,159	6,698	7,857
Natural gas and oil production	—	—	—
Construction materials and contracting	174,005	1,738	175,743
Other	—	—	—
Total	$ 615,735	$ 13,728	$ 629,463

* *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, 2008, were as follows:

	Balance as of January 1, 2008	Goodwill Acquired During the Year*	Balance as of December 31, 2008
		(In thousands)	
Electric	$ —	$ —	$ —
Natural gas distribution	171,129	173,823	344,952
Construction services	91,385	4,234	95,619
Pipeline and energy services	1,159	—	1,159
Natural gas and oil production	—	—	—
Construction materials and contracting	162,025	11,980	174,005
Other	—	—	—
Total	$ 425,698	$ 190,037	$ 615,735

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

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Other amortizable intangible assets at December 31 were as follows:

	2009	2008
	(In thousands)	
Customer relationships	$ 24,942	$ 21,842
Accumulated amortization	(9,500)	(6,985)
	15,442	14,857
Noncompete agreements	12,377	10,080
Accumulated amortization	(6,675)	(5,126)
	5,702	4,954
Other	10,859	10,949
Accumulated amortization	(3,026)	(2,368)
	7,833	8,581
Total	$ 28,977	$ 28,392

Amortization expense for intangible assets for the years ended December 31, 2009, 2008 and 2007, was $5.0 million, $5.1 million and $4.4 million, respectively. Estimated amortization expense for intangible assets is $4.5 million in 2010, $4.0 million in 2011, $3.9 million in 2012, $3.4 million in 2013, $3.0 million in 2014 and $10.2 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:

	2009	2008
	(In thousands)	
Regulatory assets:		
Pension and postretirement benefits (a)	$ 91,078	$ 119,868
Deferred income taxes*	85,712	46,855
Natural gas supply derivatives (a) (b)	27,900	89,813
Costs related to potential generation development (a)	15,499	—
Long-term debt refinancing costs (a)	12,089	9,991
Taxes recoverable from customers (a)	10,102	4,824
Plant costs (a)	7,775	8,534
Natural gas cost recoverable through rate adjustments (b)	982	51,699
Other (a) (b)	12,242	7,978
Total regulatory assets	263,379	339,562
Regulatory liabilities:		
Plant removal and decommissioning costs (c)	251,143	94,737
Deferred income taxes*	53,835	65,909
Natural gas costs refundable through rate adjustments (d)	37,356	64
Taxes refundable to customers (c)	34,571	25,642
Natural gas supply derivatives (c)	—	5,540
Other (c) (d)	17,767	7,460
Total regulatory liabilities	394,672	199,352
Net regulatory position	$ (131,293)	$ 140,210

* *Represents deferred income taxes related to regulatory assets and liabilities.*

(a) *Included in deferred charges and other assets on the Consolidated Balance Sheets.*

(b) *Included in prepayments and other current assets on the Consolidated Balance Sheets.*

(c) *Included in other liabilities on the Consolidated Balance Sheets.*

(d) *Included in other accrued liabilities on the Consolidated Balance Sheets.*

The regulatory assets are expected to be recovered in rates charged to customers. 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. In 2009, the Company determined that plant removal costs related to recent acquisitions should be reclassified from accumulated depreciation to a regulatory liability. This reclassification is reflected in the preceding table.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting 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 regulatory accounting 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. The Company's policy is to not offset fair value amounts for derivative instruments, and as a result the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. 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, 2009, the Company had no outstanding foreign currency or interest rate hedges.

Cascade and Intermountain

At December 31, 2009, Cascade and Intermountain held natural gas swap agreements, with total forward notional volumes of 12.1 million MMBtu, which were not designated as hedges. Cascade and Intermountain utilize natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, 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 and Intermountain record 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. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain 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. For the year ended December 31, 2009, Cascade and Intermountain recorded the decrease in the fair market value of the derivative instruments of $61.9 million in regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's and Intermountain's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade and Intermountain's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2009, was $27.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2009, was $27.9 million.

Fidelity

At December 31, 2009, Fidelity held natural gas swaps and collar agreements with total forward notional volumes of 26.5 million MMBtu, natural gas basis swaps with total forward notional volumes of 15.1 million MMBtu, and oil swaps and collar agreements with total forward notional volumes of 2.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or 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 and 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 are generally based on market prices.

For the years ended December 31, 2009, 2008 and 2007, the amount of hedge ineffectiveness was immaterial, and 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 operating revenues on the Consolidated Statements of Income. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

As of December 31, 2009, 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 24 months. The Company estimates that over the next 12 months net losses of approximately $3.8 million (after tax) will be reclassified from accumulated other

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comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2009, was $13.9 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2009, was $13.9 million.

The location and fair value of all of the Company's derivative instruments on the Consolidated Balance Sheets as of December 31, 2009, were as follows:

	Asset Derivatives		Liability Derivatives	
	Location on Consolidated Balance Sheets	Fair Value	Location on Consolidated Balance Sheets	Fair Value
		(In thousands)		
Commodity derivatives designated as hedges:				
	Commodity derivative instruments	$ 7,761	Commodity derivative instruments	$13,763
	Other assets - noncurrent	2,734	Other liabilities - noncurrent	114
Total derivatives designated as hedges		10,495		13,877
Commodity derivatives not designated as hedges:				
	Commodity derivative instruments	—	Commodity derivative instruments	23,144
	Other assets - noncurrent	—	Other liabilities - noncurrent	4,756
Total derivatives not designated as hedges		—		27,900
Total derivatives		$10,495		$41,777

Note 8 – Fair Value Measurements

On January 1, 2008, the Company elected to measure its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. These investments had previously been accounted for as available-for-sale investments. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $34.8 million and $27.7 million as of December 31, 2009 and 2008, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the year ended December 31, 2009, was $7.1 million (before tax). The decrease in the fair value of these investments for the year ended December 31, 2008, was $8.6 million (before tax). The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income. The Company did not elect the fair value option for its remaining available-for-sale securities, which are auction rate securities. The Company's auction rate securities, which totaled $11.4 million at December 31, 2009 and 2008, are

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accounted for as available-for-sale and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The statement establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2009, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at December 31, 2009
			(In thousands)		
Assets:					
Money market funds	$ 9,124	$ 151,000	$ —	$ —	$ 160,124
Available-for-sale securities	9,078	37,141	—	—	46,219
Commodity derivative instruments - current	—	7,761	—	—	7,761
Commodity derivative instruments - noncurrent	—	2,734	—	—	2,734
Total assets measured at fair value	$18,202	$ 198,636	$ —	$ —	$ 216,838
Liabilities:					
Commodity derivative instruments - current	$ —	$ 36,907	$ —	$ —	$ 36,907
Commodity derivative instruments - noncurrent	—	4,870	—	—	4,870
Total liabilities measured at fair value	$ —	$ 41,777	$ —	$ —	$ 41,777

	Fair Value Measurements at December 31, 2008, Using				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Collateral Provided to Counterparties	Balance at December 31, 2008
			(In thousands)		
Assets:					
Available-for-sale securities	$27,725	$ 11,400	$ —	$ —	$ 39,125
Commodity derivative instruments - current	—	78,164	—	—	78,164
Commodity derivative instruments - noncurrent	—	3,222	—	—	3,222
Total assets measured at fair value	$27,725	$ 92,786	$ —	$ —	$120,511
Liabilities:					
Commodity derivative instruments - current	$ —	$ 67,629	$ —	$ 11,100	$ 56,529
Commodity derivative instruments - noncurrent	—	23,534	—	—	23,534
Total liabilities measured at fair value	$ —	$ 91,163	$ —	$ 11,100	$ 80,063

The estimated fair value of the Company's Level 1 money market funds is valued at the net asset value of shares held by the Company, based on published market quotations in active markets. The estimated fair value of the Company's Level 1 available-for-sale securities is based on quoted market prices in active markets for identical equity and fixed-income securities. The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is based on comparable market transactions or underlying investments. The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The estimated fair value of the Company's long-term debt was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2009		2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$1,499,306**	**$1,566,331**	$1,647,302	$1,577,907

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

Note 9 – Debt
Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in

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compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2009. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2009	Amount Outstanding at December 31, 2008	Letters of Credit at December 31, 2009	Expiration Date
		(Dollars in millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0	$ — (b)	$ 22.5 (b)	$ —	6/21/11
MDU Energy Capital, LLC	Master shelf agreement	$175.0	$165.0	$165.0	$ —	8/14/10 (c)
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (d)	$ —	$ 48.1	$ 1.9 (e)	12/28/12 (f)
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (g)	$ 10.3	$ 36.5	$ —	8/31/10
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (h)	$400.0	$ — (b)	$150.0 (b)	$26.4 (e)	12/13/12
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0	$ 87.5	$ 72.5	$ —	12/23/10 (i)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, 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.
(b) Amount outstanding under commercial paper program.
(c) Or such time as the agreement is terminated by either of the parties thereto.
(d) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(e) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(f) Provisions allow for an extension of up to two years upon consent of the banks.
(g) Certain provisions allow for increased borrowings, up to a maximum of $70 million.
(h) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.
(i) Certain provisions allow for an extension to December 23, 2011.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

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Short-term borrowings
MDU Resources Group, Inc. The Company had $57.0 million outstanding under a $175 million term loan agreement at December 31, 2008. This agreement expired on March 24, 2009.

Cascade Natural Gas Corporation Any borrowings under the $50 million revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also 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, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Intermountain Gas Company The weighted average interest rate for borrowings outstanding under the credit agreement at December 31, 2009, was 3.25 percent. The credit agreement contains customary covenants and provisions, including covenants of Intermountain 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 Intermountain's earnings before interest, taxes, depreciation and amortization to interest expense (determined on a consolidated basis), for the 12-month period ended each fiscal quarter, to be less than 2 to 1. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of $5 million, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract, then Intermountain shall be in default under the revolving credit agreement.

Long-term debt
MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. 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.

The Company's credit agreement contains customary covenants and provisions, including covenants of the Company 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.

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

In November 2009, the Company completed a defeasance of its outstanding 8.60% Secured Medium-Term Notes, Series A, due April 1, 2012 (8.60% Notes), by depositing approximately

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$5.5 million with the Mortgage trustee. The $5.5 million deposit will be used solely to satisfy the principal and remaining interest obligations on the 8.60% Notes. These securities are the only remaining first mortgage bonds outstanding under the Mortgage, other than $30.0 million of first mortgage bonds which were held by the Indenture trustee for the benefit of the senior note holders. In connection with the defeasance of the 8.60% Notes, the Mortgage was discharged and the lien of the Indenture was discharged so that the Company's 5.98% Senior Notes due 2033 are now unsecured.

MDU Energy Capital, LLC The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total 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, to be greater than 1.5 to 1. 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).

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. The Centennial commercial paper borrowings are classified as long-term debt as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings.

Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, 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.

Pursuant to a covenant under the credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. The write-down of the natural gas and oil properties in 2009 would have negatively affected Centennial's ability to make distributions to the Company in 2010, however, in November 2009, the lenders under the credit agreement consented to permit Centennial to make distributions during 2010 in an aggregate amount up to 100 percent of its consolidated net income after taxes during fiscal year 2009 without giving effect to the write-down.

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 The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin 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.

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

	2009	2008	
	(In thousands)		
First mortgage bonds and notes:			
Secured Medium-Term Notes, Series A, 8.60%	$ —	$ 5,500	
Senior Notes, 5.98%, due December 15, 2033	—	30,000	(a)
Total first mortgage bonds and notes	—	35,500	
Senior Notes at a weighted average rate of 6.07%, due on dates ranging from October 30, 2010 to March 8, 2037	1,370,455	1,271,227	
Commercial paper supported by revolving credit agreements	—	172,500	
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	81,000	
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	42,070	42,971	
Credit agreements at a weighted average rate of 5.67%, due on dates ranging from April 1, 2010 to November 30, 2038	5,781	44,205	
Discount	—	(101)	
Total long-term debt	1,499,306	1,647,302	
Less current maturities	12,629	78,666	
Net long-term debt	$ 1,486,677	$ 1,568,636	

(a) The $30.0 million of 5.98% Senior Notes became unsecured upon the defeasance of the outstanding 8.60% Notes, as previously discussed.

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2009, aggregate $12.6 million in 2010; $72.3 million in 2011; $136.3 million in 2012; $258.8 million in 2013; $9.1 million in 2014 and $1,010.2 million thereafter.

Note 10 - 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, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution and transmission facilities and buildings, 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:

	2009	2008
	(In thousands)	
Balance at beginning of year	$ 70,147	$ 64,453
Liabilities incurred	2,418	2,943
Liabilities acquired	—	2,369
Liabilities settled	(9,319)	(3,188)
Accretion expense	3,385	3,191
Revisions in estimates	9,548	207
Other	180	172
Balance at end of year	$ 76,359	$ 70,147

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The Company believes that any expenses related to asset retirement obligations at the Company's 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, 2009 and 2008, was $5.9 million.

Note 11 - Preferred Stocks
Preferred stocks at December 31 were as follows:

	2009	2008
	(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.

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Note 12 - 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 January 2007 through March 2007 and October 1, 2008 through October 21, 2008, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From April 2007 through September 30, 2008, and October 22, 2008 through December 2009, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2009, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by state laws, applicable regulatory limitations, and compliance with the requirements of the Company's credit agreements. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 16.9 million shares of common stock and has granted options, restricted stock and stock of 7.3 million shares through December 31, 2009. 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 was $3.4 million, net of income taxes of $2.2 million in 2009; $3.7 million, net of income taxes of $2.3 million in 2008; and $4.7 million, net of income taxes of $3.1 million in 2007.

As of December 31, 2009, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 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, 2009, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	1,003,824	$13.39
Forfeited	(24,188)	13.22
Exercised	(154,765)	13.23
Balance at end of year	824,871	13.42
Exercisable at end of year	799,703	$13.41

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Summarized information about stock options outstanding and exercisable as of December 31, 2009, 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)
$ 9.61 – 12.00	12,131	.5	$ 9.93	$ 166	12,131	$ 9.93	$ 166
12.01 – 14.50	745,970	1.2	13.21	7,751	726,235	13.21	7,545
14.51 – 17.13	66,770	1.2	16.48	475	61,337	16.51	435
Balance at end of year	824,871	1.2	$13.42	$8,392	799,703	$13.41	$8,146

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, 2009, 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 1.2 years at December 31, 2009.

The Company received cash of $2.1 million, $5.9 million and $10.2 million from the exercise of stock options for the years ended December 31, 2009, 2008 and 2007, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007, was $1.3 million, $8.1 million and $11.2 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, 2009, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	20,606	$13.22
Vested	—	—
Forfeited	(2,970)	13.22
Nonvested at end of period	17,636	$13.22

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 49,649 shares with a fair value of $879,000, 45,675 shares with a fair value of $1.2 million and 48,228 shares with a fair value of $1.5 million issued under this plan during the years ended December 31, 2009, 2008 and 2007, respectively.

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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, 2009, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2007	2007-2009	175,596
February 2008	2008-2010	183,102
February 2009	2009-2011	275,807

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, 2009, 2008 and 2007, was $20.39, $30.71 and $23.55, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure in the range of 40.40 percent to 50.98 percent in 2009, 21.54 percent to 22.97 percent in 2008 and 18.17 percent to 18.73 percent in 2007 comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure in the range of .30 percent to 1.36 percent in 2009, 1.87 percent to 2.23 percent in 2008 and 4.75 percent to 5.21 percent in 2007 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 $1.79, $1.64 and $1.25 per target share for the 2009, 2008 and 2007 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2009, 2008 and 2007, was $2.8 million, $8.5 million and $6.0 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2009, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	546,867	$26.55
Granted	278,178	20.39
Vested	(151,848)	25.22
Forfeited	(38,692)	25.35
Nonvested at end of period	634,505	$24.24

Note 14 - Income Taxes

The components of income (loss) before income taxes for each of the years ended December 31 were as follows:

	2009	2008	2007
		(In thousands)	
United States	$(227,021)	$436,029	$508,210
Foreign	7,655	5,120	4,600
Income (loss) before income taxes	$(219,366)	$441,149	$512,810

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

	2009	2008	2007
	(In thousands)		
Current:			
Federal	$ 64,389	$ 82,279	$ 106,399
State	8,284	(184)	15,135
Foreign	254	(104)	235
	72,927	81,991	121,769
Deferred:			
Income taxes –			
Federal	(147,607)	59,963	58,030
State	(22,370)	5,332	9,656
Investment tax credit – net	213	(405)	(414)
	(169,764)	64,890	67,272
Change in uncertain tax benefits	562	422	869
Change in accrued interest	183	173	114
Total income tax expense (benefit)	$ (96,092)	$ 147,476	$ 190,024

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

	2009	2008
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 85,712	$ 46,855
Accrued pension costs	79,052	93,371
Asset retirement obligations	24,091	22,707
Deferred compensation	11,411	12,015
Other	59,763	62,456
Total deferred tax assets	260,029	237,404
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	601,426	562,326
Basis differences on natural gas and oil producing properties	116,521	284,231
Regulatory matters	53,835	65,909
Natural gas and oil price swap and collar agreements	—	30,414
Other	51,070	42,725
Total deferred tax liabilities	822,852	985,605
Net deferred income tax liability	$ (562,823)	$ (748,201)

As of December 31, 2009 and 2008, no valuation allowance has been recorded associated with the above deferred tax assets.

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The following table reconciles the change in the net deferred income tax liability from December 31, 2008, to December 31, 2009, to deferred income tax benefit:

	2009
	(In thousands)
Change in net deferred income tax liability from the preceding table	$(185,378)
Deferred taxes associated with other comprehensive loss	18,574
Deferred taxes associated with acquisitions	762
Other	(3,722)
Deferred income tax benefit for the period	$(169,764)

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

Years ended December 31,	2009		2008		2007	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ (76,778)	35.0	$ 154,402	35.0	$ 179,484	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	(7,280)	3.3	10,709	2.4	17,121	3.3
Deductible K-Plan dividends	(2,369)	1.1	(2,144)	(.5)	(2,134)	(.4)
Depletion allowance	(2,320)	1.0	(2,932)	(.7)	(4,073)	(.8)
Federal renewable energy credit	(1,452)	.7	(1,235)	(.3)	—	—
Foreign operations	(1,148)	.5	423	.1	9,603	1.8
Domestic production activities deduction	(856)	.4	(3,031)	(.7)	(4,787)	(.9)
Resolution of tax matters and uncertain tax positions	881	(.4)	595	.1	208	—
Other	(4,770)	2.2	(9,311)	(2.0)	(5,398)	(.9)
Total income tax expense (benefit)	$ (96,092)	43.8	$ 147,476	33.4	$ 190,024	37.1

The income tax benefit in 2009 resulted largely from the Company's write-down of natural gas and oil properties, as discussed in Note 1.

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 the third quarter of 2007, deferred income taxes were accrued with respect to the temporary differences which had not been previously recorded. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $36.8

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million at December 31, 2009. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2009, was approximately $10.5 million, which was largely recognized in 2007. Future earnings will also be subject to additional U.S. taxes, net of allowable foreign tax credits.

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.

On January 1, 2007, upon the adoption of accounting guidance related to uncertain tax positions, 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, including interest.

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

	2009	2008	2007
		(In thousands)	
Balance at beginning of year	$ 5,586	$ 3,735	$ 4,241
Additions based on tax positions related to the current year	—	1,102	373
Additions for tax positions of prior years	562	1,811	588
Reductions for tax positions of prior years	—	(1,062)	—
Lapse of statute of limitations	—	—	(1,467)
Balance at end of year	$ 6,148	$ 5,586	$ 3,735

Included in the balance of unrecognized tax benefits at December 31, 2009, were $540,000 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, 2009, was $6.4 million, including approximately $804,000 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.

For the years ended December 31, 2009, 2008 and 2007, the Company recognized approximately $190,000, $819,000 and $680,000, respectively, in interest expense. Penalties were not material in 2009, 2008 and 2007. The Company recognized interest income of approximately $165,000, $223,000 and $480,000 for the years ended December 31, 2009, 2008 and 2007, respectively. The Company had accrued liabilities of approximately $1.6 million, $1.4 million and $718,000 at December 31, 2009, 2008 and 2007, respectively, for the payment of interest.

Note 15 - 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 Centennial Resources' equity method investment in the Brazilian Transmission Lines.

The electric segment generates, transmits and distributes electricity in Montana, North

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

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes 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. This segment also provides cathodic protection and energy-related 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 contracting services. This 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 Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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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:

	2009	2008	2007
		(In thousands)	
External operating revenues:			
Electric	$ 196,171	$ 208,326	$ 193,367
Natural gas distribution	1,072,776	1,036,109	532,997
Pipeline and energy services	235,322	440,764	369,345
	1,504,269	1,685,199	1,095,709
Construction services	818,685	1,256,759	1,102,566
Natural gas and oil production	338,425	420,637	288,148
Construction materials and contracting	1,515,122	1,640,683	1,761,473
Other	—	—	—
	2,672,232	3,318,079	3,152,187
Total external operating revenues	$ 4,176,501	$ 5,003,278	$ 4,247,896
Intersegment operating revenues:			
Electric	$ —	$ —	$ —
Natural gas distribution	—	—	—
Construction services	379	560	649
Pipeline and energy services	72,505	91,389	77,718
Natural gas and oil production	101,230	291,642	226,706
Construction materials and contracting	—	—	—
Other	9,487	10,501	10,061
Intersegment eliminations	(183,601)	(394,092)	(315,134)
Total intersegment operating revenues	$ —	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ 24,637	$ 24,030	$ 22,549
Natural gas distribution	42,723	32,566	19,054
Construction services	12,760	13,398	14,314
Pipeline and energy services	25,581	23,654	21,631
Natural gas and oil production	129,922	170,236	127,408
Construction materials and contracting	93,615	100,853	95,732
Other	1,304	1,283	1,244
Total depreciation, depletion and amortization	$ 330,542	$ 366,020	$ 301,932
Interest expense:			
Electric	$ 9,577	$ 8,674	$ 6,737
Natural gas distribution	30,656	24,004	13,566
Construction services	4,490	4,893	4,878
Pipeline and energy services	8,896	8,314	8,769
Natural gas and oil production	10,621	12,428	8,394
Construction materials and contracting	20,495	24,291	23,997
Other	43	374	10,717
Intersegment eliminations	(679)	(1,451)	(4,821)
Total interest expense	$ 84,099	$ 81,527	$ 72,237

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	2009	2008	2007
		(In thousands)	
Income taxes:			
Electric	$ 8,205	$ 8,225	$ 8,528
Natural gas distribution	16,331	18,827	6,477
Construction services	15,189	26,952	26,829
Pipeline and energy services	22,982	15,427	18,524
Natural gas and oil production	(187,000)	68,701	78,348
Construction materials and contracting	25,940	8,947	39,045
Other	2,261	397	12,273
Total income taxes	$ (96,092)	$ 147,476	$ 190,024
Earnings (loss) on common stock:			
Electric	$ 24,099	$ 18,755	$ 17,700
Natural gas distribution	30,796	34,774	14,044
Construction services	25,589	49,782	43,843
Pipeline and energy services	37,845	26,367	31,408
Natural gas and oil production	(296,730)	122,326	142,485
Construction materials and contracting	47,085	30,172	77,001
Other	7,357	10,812	(4,380)
Earnings (loss) on common stock before income from discontinued operations	(123,959)	292,988	322,101
Income from discontinued operations, net of tax	—	—	109,334
Total earnings (loss) on common stock	$ (123,959)	$ 292,988	$ 431,435
Capital expenditures:			
Electric	$ 115,240	$ 72,989	$ 91,548
Natural gas distribution	43,820	398,116	500,178
Construction services	12,814	24,506	18,241
Pipeline and energy services	70,168	42,960	39,162
Natural gas and oil production	183,140	710,742	283,589
Construction materials and contracting	26,313	127,578	189,727
Other	3,196	774	1,621
Net proceeds from sale or disposition of property	(26,679)	(86,927)	(24,983)
Net capital expenditures before discontinued operations	428,012	1,290,738	1,099,083
Discontinued operations	—	—	(548,216)
Total net capital expenditures	$ 428,012	$ 1,290,738	$ 550,867
Assets:			
Electric*	$ 569,666	$ 479,639	$ 428,200
Natural gas distribution*	1,588,144	1,548,005	942,454
Construction services	328,895	476,092	456,564
Pipeline and energy services	538,230	506,872	500,755
Natural gas and oil production	1,137,628	1,792,792	1,299,406
Construction materials and contracting	1,449,469	1,552,296	1,642,729
Other**	378,920	232,149	322,326
Total assets	$ 5,990,952	$ 6,587,845	$ 5,592,434

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	2009	2008	2007
		(In thousands)	
Property, plant and equipment:			
Electric*	**$ 941,791**	$ 848,725	$ 784,705
Natural gas distribution*	**1,456,208**	1,429,487	948,446
Construction services	**116,236**	111,301	101,935
Pipeline and energy services	**675,199**	640,921	600,712
Natural gas and oil production	**2,028,794**	2,477,402	1,923,899
Construction materials and contracting	**1,514,989**	1,524,029	1,538,716
Other	**33,365**	30,372	31,833
Less accumulated depreciation, depletion and amortization	**2,872,465**	2,761,319	2,270,691
Net property, plant and equipment	**$ 3,894,117**	$ 4,300,918	$ 3,659,555

* *Includes allocations of common utility property.*

** *Includes 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).*

Note: *The results reflect a $620.0 million ($384.4 million after tax) and $135.8 million ($84.2 million after tax) noncash write-down of natural gas and oil properties in 2009 and 2008, respectively.*

The pipeline and energy services segment and the Other category recognized income from discontinued operations, net of tax, of $106,000 and $109.2 million, respectively for the year ended December 31, 2007.

Excluding income 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 2009, 2008 and 2007 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition and the 2007 Cascade acquisition. The net noncash transactions were immaterial in 2009, $97.6 million in 2008 and $217.3 million in 2007.

Note 16 - Employee Benefit Plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

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. In 2009, the Company evaluated several provisions of its employee defined benefit plans for nonunion and certain union employees. As a result of this evaluation, the Company determined that, effective January 1, 2010, all benefit and service accruals of these plans were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Current employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

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Changes in benefit obligation and plan assets for the year ended December 31, 2009 and 2008, and amounts recognized in the Consolidated Balance Sheets at December 31, 2009 and 2008, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	**2009**	2008
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 358,525**	$ 359,923	**$ 94,325**	$ 81,581
Service cost	**8,127**	8,812	**2,206**	1,977
Interest cost	**21,919**	21,264	**5,465**	5,079
Plan participants' contributions	**—**	—	**2,369**	2,120
Amendments	**—**	—	**(9,319)**	(382)
Actuarial (gain) loss	**26,188**	(8,336)	**813**	763
Curtailment gain	**(38,166)**	—	**—**	—
Acquisition	**—**	—	**—**	9,872
Benefits paid	**(23,678)**	(23,138)	**(7,708)**	(6,685)
Benefit obligation at end of year	**352,915**	358,525	**88,151**	94,325
Change in net plan assets:				
Fair value of plan assets at beginning of year	**226,214**	330,966	**60,085**	73,684
Actual gain (loss) on plan assets	**42,084**	(83,960)	**8,600**	(20,058)
Employer contribution	**10,707**	2,346	**3,638**	3,212
Plan participants' contributions	**—**	—	**2,369**	2,120
Acquisition	**—**	—	**—**	7,812
Benefits paid	**(23,678)**	(23,138)	**(7,708)**	(6,685)
Fair value of net plan assets at end of year	**255,327**	226,214	**66,984**	60,085
Funded status – under	**$ (97,588)**	$(132,311)	**$(21,167)**	$(34,240)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	**$ —**	$ —	**$ (459)**	$ (407)
Other liabilities (noncurrent)	**(97,588)**	(132,311)	**(20,708)**	(33,833)
Net amount recognized	**$ (97,588)**	$(132,311)	**$(21,167)**	$(34,240)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 99,985**	$ 131,081	**$ 20,134**	$ 23,418
Prior service cost (credit)	**430**	2,685	**(14,716)**	(8,151)
Transition obligation	**—**	—	**6,378**	8,503
Total	**$ 100,415**	$ 133,766	**$ 11,796**	$ 23,770

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time.

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.

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The accumulated benefit obligation for the defined benefit pension plans reflected above was $340.3 million and $312.1 million at December 31, 2009 and 2008, 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 were as follows:

	2009	2008
	(In thousands)	
Projected benefit obligation	**$352,915**	$358,525
Accumulated benefit obligation	**$340,341**	$312,110
Fair value of plan assets	**$255,327**	$226,214

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

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	**2009**	2008	2007
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 8,127**	$ 8,812	$ 9,098	**$ 2,206**	$ 1,977	$ 1,865
Interest cost	**21,919**	21,264	18,591	**5,465**	5,079	4,212
Expected return on assets	**(25,062)**	(26,501)	(22,524)	**(5,471)**	(5,657)	(4,776)
Amortization of prior service cost (credit)	**605**	665	756	**(2,756)**	(2,755)	(1,300)
Recognized net actuarial loss	**2,096**	1,050	1,605	**970**	594	73
Curtailment loss	**1,650**	—	—	—	—	—
Amortization of net transition obligation	—	—	—	**2,125**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**9,335**	5,290	7,526	**2,539**	1,363	2,199
Less amount capitalized	**1,127**	642	991	**330**	307	373
Net periodic benefit cost	**8,208**	4,648	6,535	**2,209**	1,056	1,826
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**(29,000)**	102,125	(11,095)	**(2,314)**	26,478	1,507
Acquisition-related actuarial loss	—	—	12,291	—	—	9,818
Prior service credit	—	—	—	**(9,321)**	(382)	—
Acquisition-related prior service credit	—	—	(1,842)	—	—	(12,472)
Amortization of actuarial loss	**(2,096)**	(1,050)	(1,605)	**(970)**	(594)	(73)
Amortization of prior service (cost) credit	**(2,255)**	(665)	(756)	**2,756**	2,755	1,300
Amortization of net transition obligation	—	—	—	**(2,125)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**(33,351)**	100,410	(3,007)	**(11,974)**	26,132	(2,045)
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$ (25,143)**	$105,058	$ 3,528	**$ (9,765)**	$ 27,188	$ (219)

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 2010 are $2.4 million and $152,000, 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 2010 are $1.0 million, $3.5 million and $2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	5.75%	6.25%	5.75%	6.25%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	6.25%	6.00%	6.25%	6.00%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.00%	4.20%	4.00%	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:

	2009	2008
Health care trend rate assumed for next year	6.0%-9.0%	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	1999-2017

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, 2009:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 91	$ (922)
Effect on postretirement benefit obligation	$ 2,435	$ (9,679)

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make

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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 fair value of the Company's pension net plan assets by category is as follows:

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
		(In thousands)		
Assets:				
Common stocks (a)	$ 133,989	$ —	$ —	$ 133,989
Collective and mutual funds (b)	39,234	10,379	—	49,613
U.S. government and U.S. government-sponsored securities (c)	—	28,091	—	28,091
Corporate and municipal bonds (d)	—	27,968	—	27,968
Collateral held on loaned securities (e)	—	21,597	937	22,534
Cash and cash equivalents	17,958	—	—	17,958
Total assets measured at fair value	191,181	88,035	937	280,153
Liabilities:				
Obligation for collateral received	24,826	—	—	24,826
Net assets measured at fair value	$ 166,355	$ 88,035	$ 937	$ 255,327

(a) This category includes approximately 75 percent U.S. common stocks and 25 percent non-U.S. common stocks.

(b) Collective and mutual funds invest approximately 43 percent in common stock of large-cap U.S. companies, 21 percent in asset-backed securities, 17 percent in cash and cash equivalents, 8 percent in small-cap U.S. companies and 11 percent in other investments.

(c) This category includes approximately 69 percent U.S. government-sponsored securities (asset-backed securities) and 31 percent U.S. government securities.

(d) This category includes approximately 78 percent corporate bonds and 22 percent municipal bonds.

(e) This category includes collateral held at December 31, 2009, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, money market funds, corporate bonds, commercial paper, asset-backed securities and certificates of deposit.

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The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Collateral Held on Loaned Securities
	(In thousands)
Balance at beginning of year	$ 573
Total realized/unrealized losses	80
Purchases, issuances and settlements (net)	284
Balance at end of year	$ 937

The fair value of the Company's other postretirement benefit plan assets by asset category is as follows:

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Money market funds	$ 1,469	$ —	$ —	$ 1,469
Common stock	2,897	—	—	2,897
Insurance investment contract*	—	62,618	—	62,618
Total assets measured at fair value	$ 4,366	$ 62,618	$ —	$ 66,984

* *Invested in mutual funds.*

The Company expects to contribute approximately $10.2 million to its defined benefit pension plans and approximately $4.1 million to its postretirement benefit plans in 2010.

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

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2010	$ 20,431	$ 6,027
2011	20,744	6,244
2012	21,496	6,431
2013	22,151	6,686
2014	22,640	6,905
2015 - 2019	122,347	37,504

The following Medicare Part D subsidies are expected: $637,000 in 2010; $675,000 in 2011; $725,000 in 2012; $765,000 in 2013; $807,000 in 2014; and $4.7 million during the years 2015 through 2019.

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In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed in 2009 to defined benefit and defined contribution multi-employer plans were $32.5 million and $16.4 million, respectively. Amounts contributed to the multi-employer plans were $73.1 million and $51.5 million in 2008 and 2007, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide 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 $67.9 million at December 31, 2009, consisting of equity securities of $32.1 million, life insurance carried on plan participants (payable upon the employee's death) of $29.8 million, fixed-income securities of $2.7 million and other investments of $3.3 million, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.8 million, $9.0 million and $7.6 million in 2009, 2008 and 2007, respectively. The total projected benefit obligation for these plans was $93.0 million and $87.2 million at December 31, 2009 and 2008, respectively. The accumulated benefit obligation for these plans was $84.8 million and $77.3 million at December 31, 2009 and 2008, respectively. A discount rate of 5.75 percent and 6.25 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2009 and 2008, were used to determine benefit obligations. A discount rate of 6.25 percent and 6.00 percent at December 31, 2009 and 2008, respectively, and a rate of compensation increase of 4.00 percent and 4.25 percent at December 31, 2009 and 2008, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans, as appropriate, are expected to aggregate $4.6 million in 2010; $5.0 million in 2011; $5.3 million in 2012; $5.9 million in 2013; $5.9 million in 2014; and $36.3 million for the years 2015 through 2019.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $20.5 million in 2009, $23.8 million in 2008 and $21.1 million in 2007.

Note 17 - 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.

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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:

	2009	2008
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 60,220	$ 61,030
Less accumulated depreciation	39,940	39,473
	$ 20,280	$ 21,557
Coyote Station:		
Utility plant in service	$ 131,042	$ 127,151
Less accumulated depreciation	82,402	82,018
	$ 48,640	$ 45,133

In April 2009, the Company purchased a 25 MW ownership interest in the Wygen III electric generation facility, which is under construction near Gillette, Wyoming, and is expected to be online in the second quarter of 2010. The Company's balance of construction work in progress related to this facility that is included in property, plant and equipment on the Consolidated Balance Sheets at December 31, 2009, is $56.1 million.

Note 18 - Regulatory Matters and Revenues Subject to Refund

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. In August 2008, the NDPSC approved Montana-Dakota's request for advance determination of prudence for ownership in the proposed Big Stone Station II for a minimum of 121.8 MW up to a maximum of 133 MW and a proportionate ownership share of the associated transmission electric resources. The intervenors in the proceeding appealed the NDPSC order to the North Dakota District Court which affirmed the order of the NDPSC. The intervenors then appealed the North Dakota District Court order to the North Dakota Supreme Court. The Big Stone Station II participants subsequently decided not to proceed with the project and on December 2, 2009, Montana-Dakota filed an application with the NDPSC for a determination that Montana-Dakota's continued participation in the Big Stone Station II is no longer prudent. The parties have stipulated that the intervenors will move to dismiss their appeal to the North Dakota Supreme Court if the NDPSC grants Montana-Dakota's pending application for a determination that its participation in the Big Stone Station II is no longer prudent. On December 4, 17, and 23, 2009, Montana-Dakota filed an application with the NDPSC, SDPUC, and MTPSC, respectively, for authority to defer the costs incurred for securing new electric generation, primarily Big Stone Station II, until the next general rate case.

On August 14, 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase. Montana-Dakota requested a total increase of $6.2 million annually or approximately 31 percent above current rates. The rate increase request was necessitated by the Company's 25 MW ownership interest in the Wygen III power generation facility currently under construction near Gillette, Wyoming. The generation will replace a portion of the purchased power currently used to serve its Wyoming system. On January 14, 2010, Montana-Dakota filed a supplement to the application to reflect the inclusion of bonus tax depreciation on the Wygen III plant, reducing its request to a $5.1 million annual increase or approximately 25 percent above current rates. A hearing has been set for February 23, 2010.

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. There had been one remaining issue outstanding related to this rate change application regarding certain service restrictions. After various steps in this proceeding, including a Williston Basin Request for Rehearing, an appeal to the D.C. Appeals Court, and a remand to FERC, the FERC, on October 30, 2009, issued its Order on

Remand in which it upheld its previous decision. No party requested rehearing of the order, which is now final, and no issue is outstanding in this application.

Note 19 - Commitments and Contingencies

Litigation

Coalbed Natural Gas Operations Fidelity's CBNG operations are and have been the subject of numerous lawsuits in Montana and Wyoming. The current cases involve the permitting and use of water produced in connection with Fidelity's CBNG development in the Powder River Basin. Some of these cases challenge the issuance of discharge permits by the Montana DEQ and approval of other water management tools by the MBOGC.

In April 2006, the Northern Cheyenne Tribe filed a complaint in Montana Twenty-Second Judicial District Court against the Montana DEQ seeking to set aside Fidelity's renewed direct discharge and treatment permits. The Northern Cheyenne Tribe claimed the Montana DEQ 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 nondegradation 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 were granted leave to intervene in this proceeding. On January 12, 2009, the Montana Twenty-Second Judicial District Court decided the case in favor of Fidelity and the Montana DEQ in all respects, denying the motions of the Northern Cheyenne Tribe, TRWUA, and NPRC, and granting the cross-motions of the Montana DEQ and Fidelity in their entirety. As a result, Fidelity may continue to utilize its direct discharge and treatment permits. The NPRC, the TRWUA and the Northern Cheyenne Tribe appealed the decision to the Montana Supreme Court on March 9, 11, and 13, 2009, respectively.

Fidelity's discharge of water pursuant to its two permits is its primary means for managing CBNG-produced water. Fidelity believes that its discharge permits should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations through the expiration of the permits in March 2011. If its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

In October 2003, Tongue & Yellowstone Irrigation District, NPRC and MEIC filed a lawsuit in Montana First Judicial District Court challenging the MBOGC's ROD adopting the 2003 Final EIS which analyzed CBNG development in the State of Montana. Through the amendment of the plaintiffs' pleadings and as a result of discovery, the defendants have now determined that the primary legal issue before the Court is whether the ROD authorizes the "wasting" of ground water in violation of the Montana State Constitution and the public trust doctrine. Specifically, the plaintiffs contend that various water management tools, including Fidelity's direct discharge permits, allow for the waste of water. Should the Montana First Judicial District Court determine that Fidelity's direct discharge permits violate the Montana State Constitution, Fidelity's Montana CBNG operations could be significantly and adversely affected.

Fidelity will continue to vigorously defend its interests in all CBNG-related litigation in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could adversely impact Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. The complaint alleged certain violations of the PSD and NSPS provisions of the Clean Air Act and certain violation of the South Dakota SIP. The action further alleged

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that the Big Stone Station was modified and operated without obtaining the appropriate permits, without meeting certain emissions limits and NSPS requirements and without installing appropriate emission control technology, all allegedly in violation of the Clean Air Act and the South Dakota SIP. The Sierra Club alleged that these actions contributed to air pollution and visibility impairment and have increased the risk of adverse health effects and environmental damage. The Sierra Club sought declaratory and injunctive relief to bring the co-owners of the Big Stone Station into compliance with the Clean Air Act and the South Dakota SIP and to require them to remedy the alleged violations. The Sierra Club also sought unspecified civil penalties, including a beneficial mitigation project. The Company believes the claims are without merit and that Big Stone Station has been and is being operated in compliance with the Clean Air Act and the South Dakota SIP. On March 31, 2009, the District Court granted the motion of the co-owners to dismiss the complaint. The Sierra Club filed a motion requesting the District Court to reconsider its ruling on a portion of the order dismissing the complaint which was denied on July 22, 2009. On July 30, 2009, the Sierra Club appealed from the orders dismissing the case and denying the motion for reconsideration to the United States Court of Appeals for the Eighth Circuit. The United States has filed a brief as amicus curiae supporting the Sierra Club's position in the appeal and the State of South Dakota filed a brief as amicus curiae supporting the Big Stone Station owners' position in the appeal.

Construction Materials LTM is a third-party defendant in litigation pending in Oregon Circuit Court regarding the concrete floors in an industrial food processing facility located in Jackson County, Oregon. The complaint against the facility construction contractor alleges the concrete floors of the facility are defective and must be removed and replaced for suitable repair. Damages, including disruption of the food processing operations, have been estimated by the plaintiff to be in excess of $32 million. The construction contractor's answer and third-party complaint alleges the owner and third-party defendants, including LTM which supplied the concrete, are primarily responsible for any defects in the concrete surfaces. Discovery is currently being conducted by the parties. A trial date has not been set.

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 PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by MBI from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. 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 and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include MBI or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. 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. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

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

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addition, MBI has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for 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 limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter of March 2, 2009, LWG stated its intent to file suit against MBI and others to recover LWG's investigation costs to the extent MBI cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, MBI has agreed to participate in the alternative dispute resolution process.

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 three 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 PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs 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. An ecological risk assessment draft report was submitted to the Oregon DEQ in June 2009. The assessment showed no unacceptable risk to the aquatic ecological receptors present in the shoreline along the site and concluded that no further ecological investigation is necessary. The report is being reviewed by the Oregon DEQ. It is anticipated the Oregon DEQ will recommend a cleanup alternative for the site after it completes its review of the report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. There is currently not enough information to estimate the potential liability to Cascade associated with this claim.

The third claim is also for contamination at a site in Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade's predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2009, were $25.2 million in 2010, $20.3 million in 2011, $15.3 million in

2012, $12.6 million in 2013, $6.7 million in 2014 and $43.9 million thereafter. Rent expense was $43.4 million, $35.3 million and $35.6 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage and construction materials supply contracts. These commitments range from 1 to 51 years. The commitments under these contracts as of December 31, 2009, were $507.6 million in 2010, $288.3 million in 2011, $192.1 million in 2012, $105.7 million in 2013, $90.3 million in 2014 and $234.9 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2009, 2008 and 2007, were $723.1 million, approximately $1.0 billion (including the acquisition of Intermountain as discussed in Note 2) and $857.0 million (including the acquisition of Cascade as discussed in Note 2), respectively.

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 that 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 guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation. On February 27, 2009, Centennial received a Notice and Demand from LPP under the guaranty agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. On December 4, 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand seeks compensatory damages of $146 million plus damages for increased operating, capital and construction costs related to a water treatment facility for the generating facility. LPP's notice of demand for arbitration also demanded performance of the guarantee by Centennial. The Company believes the indemnification claims against Centennial are without merit and intends to vigorously defend against such claims.

In connection with the pending sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee the performance of certain of the Company's indirect wholly owned subsidiaries in three purchase and sale agreements. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations of the wholly owned subsidiary sellers for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas swap and collar agreements as the amount of the obligation is dependent upon natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas swap and collar agreements at December 31, 2009, expire in 2010 and 2011; 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. There were no amounts outstanding by Fidelity at December 31, 2009. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

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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, 2009, the fixed maximum amounts guaranteed under these agreements aggregated $234.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $65.3 million in 2010; $141.8 million in 2011; $16.7 million in 2012; $1.8 million in 2013; $200,000 in 2014; $1.0 million in 2018; $300,000 in 2019; $3.3 million, which is subject to expiration on a specified number of 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 $570,000 and was reflected on the Consolidated Balance Sheet at December 31, 2009. 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, materials obligations, natural gas transportation agreements and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2009, the fixed maximum amounts guaranteed under these letters of credit, aggregated $37.1 million, which are scheduled to expire in 2010. There were no amounts outstanding under the above letters of credit at December 31, 2009.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2009, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2011. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $870,000. Prairielands also had $650,000 outstanding under a guarantee with Fidelity that will expire when paid. The amounts outstanding under these guarantees were not reflected on the Consolidated Balance Sheet at December 31, 2009, 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, materials 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, 2009.

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, 2009, approximately $532 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Note 20 – Subsequent Events
The Company evaluated events or transactions between the balance sheet date and April 7, 2010, the date the financial statements were available for issuance, which would require recognition or disclosure in the financial statements.

Company Name: Montana-Dakota Utilities Co.

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1	**Intangible Plant**				
2					
3	301	Organization			
4	302	Franchises & Consents			
5	303	Miscellaneous Intangible Plant	$2,855,632	$2,896,441	1.43%
6					
7	**TOTAL Intangible Plant**		$2,855,632	$2,896,441	1.43%
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: 2009

	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: 2009

	Account Number & Title		Last Year	This Year	% Change
1					
2	**Distribution Plant**				
3					
4	374	Land & Land Rights	$37,059	$37,059	0.00%
5	375	Structures & Improvements	195,164	195,164	0.00%
6	376	Mains	27,058,926	27,961,133	3.33%
7	377	Compressor Station Equipment			
8	378	Meas. & Reg. Station Equipment-General	567,347	575,341	1.41%
9	379	Meas. & Reg. Station Equipment-City Gate	128,221	128,221	0.00%
10	380	Services	17,456,137	18,604,465	6.58%
11	381	Meters	17,434,491	17,323,923	-0.63%
12	382	Meter Installations			
13	383	House Regulators	1,752,012	1,822,687	4.03%
14	384	House Regulator Installations			
15	385	Industrial Meas. & Reg. Station Equipment	184,923	187,824	1.57%
16	386	Other Prop. on Customers' Premises 1/	161,799	148,674	-8.11%
17	387	Other Equipment	1,001,722	1,025,230	2.35%
18					
19	**TOTAL Distribution Plant**		$65,977,801	$68,009,721	3.08%
20					
21	**General Plant**				
22					
23	389	Land & Land Rights	$26,165	$7,131	-72.75%
24	390	Structures & Improvements	449,416	449,416	0.00%
25	391	Office Furniture & Equipment	245,535	228,799	-6.82%
26	392	Transportation Equipment	2,517,360	2,196,993	-12.73%
27	393	Stores Equipment	43,785	43,786	0.00%
28	394	Tools, Shop & Garage Equipment	765,269	779,752	1.89%
29	395	Laboratory Equipment	17,700	37,139	109.82%
30	396	Power Operated Equipment	1,744,201	1,773,883	1.70%
31	397	Communication Equipment	192,293	297,789	54.86%
32	398	Miscellaneous Equipment	15,117	15,111	-0.04%
33	399	Other Tangible Property			
34					
35	**TOTAL General Plant**		$6,016,841	$5,829,799	-3.11%
36					
37	**Common Plant**				
38					
39	389	Land & Land Rights	$950,022	$947,842	-0.23%
40	390	Structures & Improvements	6,851,933	6,911,414	0.87%
41	391	Office Furniture & Equipment	953,754	946,105	-0.80%
42	392	Transportation Equipment	1,044,507	893,920	-14.42%
43	393	Stores Equipment	9,742	10,924	12.13%
44	394	Tools, Shop & Garage Equipment	174,611	204,773	17.27%
45	396	Power Operated Equipment	455	6,680	1368.13%
46	397	Communication Equipment	347,458	443,150	27.54%
47	398	Miscellaneous Equipment	124,063	123,857	-0.17%
48					
49	**TOTAL Common Plant**		$10,456,545	$10,488,665	0.31%
50					
51	**TOTAL Gas Plant in Service**		$85,306,819	$87,224,626	2.25%

1/ Includes gas plant leased to others.

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 20

MONTANA DEPRECIATION SUMMARY

Year: 2009

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	This Year Bal.	Current Avg. Rate
1	Production & Gathering				
2	Products Extraction				
3	Underground Storage				
4	Other Storage				
5	Transmission				
6	Distribution	$68,009,721	$39,154,211	$40,150,025	3.30%
7	General	5,885,798	3,539,440	3,525,339	1.68%
8	Common	13,329,107	4,447,623	4,834,617	4.04%
9	**TOTAL**	$87,224,626	$47,141,274	$48,509,981	3.30%

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)	$624,348	$521,197	-16.52%
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	163 Stores Expense Undistributed			
15				
16	**TOTAL Materials & Supplies**	$624,348	$521,197	-16.52%

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					
8	**TOTAL**				10.913%
9					
10	Actual at Year End				
11					
12	Common Equity		51.492%	12.000%	6.179%
13	Preferred Stock		2.540%	4.594%	0.117%
14	Long Term Debt		45.662%	6.845%	3.126%
15	Short Term Debt		0.306%	11.590%	0.035%
16	**TOTAL**		100.000%		9.457%

STATEMENT OF CASH FLOWS

Year: 2009

	Description	Last Year	This Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2				
3	**Cash Flows from Operating Activities:**			
4	Net Income	$293,673,229	($123,274,095)	-141.98%
5	Depreciation	34,040,420	35,082,590	3.06%
6	Amortization	316,354	(319,003)	-200.84%
7	Deferred Income Taxes - Net	19,761,591	8,387,646	-57.56%
8	Investment Tax Credit Adjustments - Net	(248,195)	(199,265)	19.71%
9	Change in Operating Receivables - Net	3,271,846	(3,724,383)	-213.83%
10	Change in Materials, Supplies & Inventories - Net	8,217,051	(8,443,567)	-202.76%
11	Change in Operating Payables & Accrued Liabilities - Net	(34,470,080)	13,052,368	137.87%
12	Change in Other Regulatory Assets	2,019,006	7,104,393	251.88%
13	Change in Other Regulatory Liabilities	(781,318)	200,390	125.65%
14	Allowance for Other Funds Used During Construction (AFUDC)	(119,056)	(5,557,565)	-4568.03%
15	Change in Other Assets & Liabilities - Net	(13,303,075)	45,568,156	442.54%
16	Less Undistributed Earnings from Subsidiary Companies	(171,164,580)	255,489,860	249.27%
17	Other Operating Activities (explained on attached page)			
18	**Net Cash Provided by/(Used in) Operating Activities**	$141,213,193	$223,367,525	58.18%
19				
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment			
22	(net of AFUDC & Capital Lease Related Acquisitions)	($105,520,724)	($125,809,740)	-19.23%
23	Acquisition of Other Noncurrent Assets	5,940,589	(6,588,982)	-210.91%
24	Proceeds from Disposal of Noncurrent Assets			
25	Investments In and Advances to Affiliates	(172,005,700)		100.00%
26	Contributions and Advances from Affiliates	121,000,000	22,915,660	-81.06%
27	Disposition of Investments in and Advances to Affiliates			
28	Other Investing Activities: Depreciation & RWIP on Nonutility Plant	122,650	136,225	11.07%
29	**Net Cash Provided by/(Used in) Investing Activities**	($150,463,185)	($109,346,837)	27.33%
30				
31	**Cash Flows from Financing Activities:**			
32	Proceeds from Issuance of:			
33	Long-Term Debt	$100,508,867	$27,493,724	-72.65%
34	Preferred Stock			
35	Common Stock	15,011,178	65,207,454	334.39%
36	Other:	57,000,000	264,363	-99.54%
37	Net Increase in Short-Term Debt			
38	Other: Commercial Paper			
39	Payment for Retirement of:			
40	Long-Term Debt	(53,600,000)	(5,600,000)	89.55%
41	Preferred Stock			
42	Common Stock			
43	Other: Adjustment to Retained Earnings	(44,761)	(384,084)	-758.08%
44	Net Decrease in Short-Term Debt			
45	Dividends on Preferred Stock	(685,004)	(685,004)	0.00%
46	Dividends on Common Stock	(109,925,942)	(115,447,274)	-5.02%
47	Other Financing Activities (related to IGC acquisition)		(57,000,000)	
48	**Net Cash Provided by (Used in) Financing Activities**	$8,264,338	($86,150,821)	-1142.44%
49				
50	**Net Increase/(Decrease) in Cash and Cash Equivalents**	($985,654)	$27,869,867	2927.55%
51	**Cash and Cash Equivalents at Beginning of Year**	$3,219,158	$2,233,504	-30.62%
52	**Cash and Cash Equivalents at End of Year**	$2,233,504	$30,103,371	1247.81%

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 24

LONG TERM DEBT

Year: 2009

	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	6.61% Senior Notes	09/09	09/16	$25,000,000	$24,423,218	$25,000,000	6.61%	$1,778,500	7.11%
2	6.66% Senior Notes	10/09	09/16	25,000,000	24,423,218	25,000,000	6.66%	1,791,500	7.17%
3	5.98% Senior Notes	12/03	12/33	30,000,000	29,456,832	30,000,000	5.98%	1,861,500	6.21%
4	6.33 % Senior Notes	08/06	08/26	100,000,000	89,123,930	100,000,000	6.33%	7,514,000	7.51%
5	6.04 % Senior Notes	09/08	09/18	100,000,000	99,637,568	100,000,000	6.04%	6,181,000	6.18%
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24									
25									
26	**TOTAL**			$280,000,000	$267,064,766	$280,000,000		$19,126,500	6.83%

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

PREFERRED STOCK

Year: 2009

	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%	600,000	36,995	5.29%
4										
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30										
31										
32	**TOTAL**					$19,947,548		$15,600,000	$721,995	4.63%

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

COMMON STOCK

Year: 2009

		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	January								
2									
3	February								
4									
5	March	181,743,059	$12.97	($1.87)	$0.1550	108.29%	$22.89	$12.79	N/A
6									
7	April								
8									
9	May								
10									
11	June	183,963,530	13.02	0.30	0.1550	48.33%	19.76	15.70	N/A
12									
13	July								
14									
15	August								
16									
17	September	185,161,819	13.37	0.50	0.1550	69.00%	21.16	17.44	N/A
18									
19	October								
20									
21	November								
22									
23	December	187,747,560	13.61	0.39	0.1575	59.62%	24.22	19.96	N/A
24									
25									
26									
27									
28									
29									
30	TOTAL Year End	188,389,265	$13.61	($0.68)	$0.6225	191.54%			N/A

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

Company Name: Montana-Dakota Utilities Co. **SCHEDULE 27**

MONTANA EARNED RATE OF RETURN

Year: 2009

		Description	Last Year	This Year	% Change
		Rate Base			
1					
2	101	Plant in Service	$85,306,819	$87,224,626	2.25%
3	108	(Less) Accumulated Depreciation	47,141,274	48,509,981	2.90%
4					
5		**NET Plant in Service**	$38,165,545	$38,714,645	1.44%
6					
7		CWIP in Service Pending Reclassification	$549,950	$485,126	-11.79%
8					
9		Additions			
10	154, 156	Materials & Supplies	$624,348	$521,197	-16.52%
11	165	Prepayments	18,578	23,204	24.90%
12		Prepaid Demand/Commodity Charges	1,247,383	1,072,885	-13.99%
13		Gas in Underground Storage	3,133,884	6,868,124	119.16%
14		Other Regulatory Assets	225,561	186,894	-17.14%
15					
16		**TOTAL Additions**	$5,249,754	$8,672,304	65.19%
17					
18		Deductions			
19	190	Accumulated Deferred Income Taxes	$4,982,872	$5,718,989	14.77%
20	252	Customer Advances for Construction	713,923	796,890	11.62%
21	255	Accumulated Def. Investment Tax Credits	49,565	27,029	-45.47%
22					
23					
24		**TOTAL Deductions**	$5,746,360	$6,542,908	13.86%
25		**TOTAL Rate Base**	$38,218,889	$41,329,167	8.14%
26					
27		**Net Earnings**	$1,637,863	$3,176,154	93.92%
28					
29		**Rate of Return on Average Rate Base**	4.37%	7.99%	82.84%
30					
31		**Rate of Return on Average Equity**	2.48%	9.15%	268.95%
32					
33		Major Normalizing Adjustments & Commission			
34		Ratemaking adjustments to Utility Operations 1/			
35					
36		Adjustment to Operating Revenues			
38		Weather Normalization	$252,974	($69,394)	-127.43%
39		Late Payment Revenue	35,392	31,248	-11.71%
40		Gain from Disposition of Utility Plant 2/	43,180	41,971	-2.80%
41		Penalty Revenue 3/	(44,451)	30,134	167.79%
42					
43		Adjustment to Operating Expenses			
44		Elimination of Promotional & Institutional Advertising	(39,525)	(15,322)	61.23%
45		Elimination of Supplemental Insurance	(336,836)	77,414	122.98%
46		Elimination of 401K Tax Deduction	215,158	214,569	-0.27%
47					
48		Total Adjustments to Operating Income	$448,298	($242,702)	-154.14%
49		**Adjusted Rate of Return on Average Rate Base**	5.57%	7.38%	32.50%
50					
51		**Adjusted Rate of Return on Average Equity**	4.95%	7.97%	61.01%

1/ Updated amounts, net of taxes.
2/ Amortized over five years.
3/ Adjusted to reflect a three year average.

MONTANA COMPOSITE STATISTICS

Year: 2009

		Description	Amount
1			
2		Plant (Intrastate Only) (000 Omitted)	
3			
4	101	Plant in Service	$81,474
5	107	Construction Work in Progress	2,129
6	114	Plant Acquisition Adjustments	
7	104	Plant Leased to Others	
8	105	Plant Held for Future Use	
9	154, 156	Materials & Supplies	521
10		(Less):	
11	108, 111	Depreciation & Amortization Reserves	48,510
12	252	Contributions in Aid of Construction	797
13			
14		**NET BOOK COSTS**	$34,817
15			
16		Revenues & Expenses (000 Omitted)	
17			
18	400	Operating Revenues	$77,731
19			
20	403 - 407	Depreciation & Amortization Expenses	$2,880
21		Federal & State Income Taxes	888
22		Other Taxes	2,929
23		Other Operating Expenses	67,857
24		TOTAL Operating Expenses	$74,554
25			
26		Net Operating Income	$3,177
27			
28		Other Income	741
29		Other Deductions	1,493
30			
31		**NET INCOME**	$2,425
32			
33		Customers (Intrastate Only)	
34			
35		Year End Average:	
36		Residential	68,846
37		Firm General	8,351
38		Small Interruptible	45
39		Large Interruptible	5
40			
41		**TOTAL NUMBER OF CUSTOMERS**	77,247
42			
43		Other Statistics (Intrastate Only)	
44			
45		Average Annual Residential Use (Dkt))	90
46		Average Annual Residential Cost per (Dkt) ($) * 1/	$6.83
47		* Avg annual cost = [(cost per Dkt x annual use) + (monthly service charge x	
48		Average Residential Monthly Bill	$51.23
49		Gross Plant per Customer	$1,055

1/ Reflects cost per dk effective November 1, 2009.

MONTANA CUSTOMER INFORMATION

Year: 2009

	City/Town	Population (Includes Rural) 1/	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1	Belfry	219	130	18		148
2	Billings	89,847	44,625	4,378		49,003
3	Bridger	745	411	62		473
4	Crow Agency	1,552	306	74		380
5	Edgar	Not Available	102	8		110
6	Fromberg	486	279	17		296
7	Hardin	3,384	1,252	197		1,449
8	Joliet	575	360	41		401
9	Laurel	6,255	3,772	275		4,047
10	Park City	870	593	26		619
11	Pryor	628	93	13		106
12	Rockvale	Not Available	65	4		69
13	Silesia	Not Available	32	2		34
14	Warren	Not Available	0	2		2
15	Alzada	Not Available	11	7		18
16	Baker	1,695	792	177		969
17	Carlyle	Not Available	7	1		8
18	Fort Peck	240	131	10		141
19	Fairview	709	361	54		415
20	Forsyth	1,944	870	150		1,020
21	Frazer	452	102	14		116
22	Glasgow	3,253	1,621	314		1,935
23	Glendive	4,729	3,038	412		3,450
24	Hinsdale	Not Available	116	20		136
25	Ismay	26	11	4		15
26	Malta	2,120	996	201		1,197
27	Miles City	8,487	3,886	553		4,439
28	Nashua	325	167	22		189
29	Poplar	911	842	135		977
30	Richey	189	115	25		140
31	Rosebud	Not Available	43	6		49
32	Saco	224	38	7		45
33	Savage	Not Available	147	19		166
34	Sidney	4,774	2,336	414		2,750
35	Terry	611	315	59		374
36	St. Marie	183	187	11		198
37	Wibaux	567	219	49		268
38	Whitewater	Not Available	30	9		39
39	Wolf Point	2,663	1,355	200		1,555
40	MT Oil Fields	Not Available	1	3		4
41	**TOTAL Montana Customers**	138,663	69,757	7,993	0	77,750

1/ 2000 Census.

MONTANA EMPLOYEE COUNTS 1/

Year: 2009

	Department	Year Beginning	Year End	Average
1	Electric	18	17	18
2	Gas	42	40(1)	41(1)
3	Accounting	19	8	14
4	Management	7	5	6
5	Service	47(1)	36	42(1)
6	Communications/Substation/Training	4	2	3
7	Power Production	29	31	30
8				
9				
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41				
42				
43				
44	**TOTAL Montana Employees**	166(1)	139(1)	154(1)

1/ Parentheses denotes part-time.

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2009

	Project Description	Total Company	Total Montana	
1	Projects>$1,000,000			
2	Common-Intangible			
3	Replace Customer Information System	2,344,777	607,586	1/
4	Electric-Steam Production			
5	Replace U1 Boiling Bank Tubes at Heskett	1,450,616	360,079	1/
6	Purchase 25MW Wygen III Power Plant in WY	7,828,966	0	
9	Electric-Other Production			
10	Install 30MW Wind Generation in ND and MT	40,442,605	10,038,655	1/
11				
12	Electric-Transmission			
13	Purchase Land for a Transformer switch in Bismarck, ND	2,153,610	0	
	Construct New Heskett 230/115 Substation	10,995,816	1,704,036	1/
	Install 115 KV line in Bismarck, ND	2,091,089	0	
14	Electric-Distribution			
15	Construct Distribution Substation in Bismarck, ND	1,273,172	0	
	Construct Distribution Substation in Mandan, ND	1,764,227	0	
16	Gas-Production			
18	Install Gas Extraction Facility at Landfill in Billings, MT	8,502,470	2,421,081	1/
19				
20	Other Projects<$1,000,000			
21	Electric			
22	Production	8,707,273	2,161,767	1/
23	Integrated Transmission	2,379,335	544,369	1/
24	Direct Transmission	2,117,284	370,247	2/
25	Distribution	16,056,867	3,480,408	2/
26	General	2,407,768	524,394	1/
27	Common:			
28	General Office	1,832,824	431,775	1/
29	Other Direct	188,915	42,396	2/
30	Total Electric	33,690,266	7,555,356	
31	Gas			
32				
33	Distribution	12,798,817	3,425,519	1/
34	General	2,041,375	517,477	2/
35	Common:			
36	General Office	1,226,817	363,587	1/
37	Other Direct	96,423	37,558	2/
38	Total Gas	16,163,432	4,344,141	
39	TOTAL	$128,701,046	$27,030,934	

1/ Allocated to Montana.

2/ Directly assigned to Montana.

TRANSMISSION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2009

	Total Company			
		Peak Day of Month	Peak Day Volumes Mcf or Dkt	Total Monthly Volumes Mcf or Dkt
1	January	NOT APPLICABLE		
2	February			
3	March			
4	April			
5	May			
6	June			
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	NOT APPLICABLE		
15	February			
16	March			
17	April			
18	May			
19	June			
20	July			
21	August			
22	September			
23	October			
24	November			
25	December			
26	**TOTAL**			

DISTRIBUTION SYSTEM - TOTAL COMPANY & MONTANA

Year: 2009

	Total Company			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
1	January	26	294,428	6,878,552
2	February	26	259,929	5,538,928
3	March	10	269,172	5,062,512
4	April	4	168,853	3,412,945
5	May	13	98,241	2,012,896
6	June	7	81,265	1,619,783
7	July	9	47,995	1,328,317
8	August	20	50,525	1,368,544
9	September	30	76,270	1,438,227
10	October	9	181,217	3,980,646
11	November	23	161,326	4,087,165
12	December	14	310,868	7,586,184
13	**TOTAL**			44,314,699

	Montana			
		Peak Day of Month	Peak Day Volumes Dkt	Total Monthly Volumes Dkt
14	January	26	87,051	1,930,929
15	February	26	75,496	1,560,831
16	March	10	73,265	1,382,153
17	April	4	55,489	1,070,489
18	May	13	31,051	632,768
19	June	9	26,989	573,159
20	July	6	20,247	483,390
21	August	24	21,132	509,415
22	September	30	31,281	496,166
23	October	11	57,837	1,231,412
24	November	14	52,462	1,271,661
25	December	14	97,766	2,291,822
26	**TOTAL**			13,434,195

STORAGE SYSTEM - TOTAL COMPANY & MONTANA

Year: 2009

		Total Company						
		Peak Day of Month		Peak Day Volumes (Dkt)		Total Monthly Volumes (Dkt)		
		Injection	Withdrawal	Injection	Withdrawal	Injection	Withdrawal	Losses
1	January	15	26	2,334	161,267	12,017	2,805,919	
2	February	21	26	7,231	130,898	42,791	2,029,288	
3	March	21	10	30,026	150,269	145,069	1,382,423	
4	April	22	4	54,601	61,637	494,406	371,014	
5	May	24	16	90,089	4,173	1,799,309	19,432	
6	June	28	21	128,230	754	3,003,664	3,210	
7	July	7	5	134,137	157	3,403,627	215	
8	August	23	25	105,590	653	2,593,724	2,108	
9	September	6	8	102,626	3,696	2,160,993	6,175	
10	October	3	9	43,916	73,219	355,455	643,607	
11	November	6	28	13,714	58,615	147,679	1,057,347	
12	December	20	8	12,554	173,352	41,282	3,543,341	
13	TOTAL					14,200,016	11,864,079	

		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							

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 33

SOURCES OF GAS SUPPLY

Year: 2009

	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					
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27					
28					
29	1/ Supplier information is proprietary and confidential.				
30					
31					
32					
33	**Total Gas Supply Volumes**	34,265,973	38,972,199	$6.732	$3.456

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2009

	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	$71,868	$74,661	-3.74%	N/A	6,057	N/A
3	(As Detailed on Schedule 36B)						
4							
5							
6							
7							
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29							
30							
31							
32	**TOTAL**	$71,868	$74,661	-3.74%	N/A	6,057	N/A

MONTANA CONSUMPTION AND REVENUES

Year: 2009

	Sales of Gas	Operating Revenues		DK Sold		Avg. No. of Customers	
		Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1	Residential	$49,407,605	$56,330,800	6,204,526	5,816,464	68,846	68,138
2	Firm General	28,444,787	32,477,324	3,688,817	3,461,670	8,351	8,265
3	Small Interruptible	590,262	936,469	111,591	103,905	7	6
4	Large Interruptible	33,351	25,411	5,619	3,686	0	0
5							
6							
7							
8							
9							
10							
11	TOTAL	$78,476,005	$89,770,004	10,010,553	9,385,725	77,204	76,409
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	$619,033	$685,064	0.7	0.8	38	40
20	Large Interruptible	496,918	540,118	3.6	3.9	5	5
21							
22							
23							
24	TOTAL	$1,115,951	$1,225,182	4.3	4.7	43	45

Company Name: Montana-Dakota Utilities Co.

SCHEDULE 36A

NATURAL GAS UNIVERSAL SYSTEM BENEFITS PROGRAMS

Year: 2009

	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	$584,592	$0	$584,592		
24	Furnace Safety/Repair	50,000	0	50,000		
25						
26						
27						
28						
29	Other					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42	Total	$634,592	$0	$634,592		2009
43	Number of customers that received low income rate discounts			(Average)	3,393	
44	Average monthly bill discount amount ($/mo)				$13.13	
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: 2009

	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	High Efficiency Furnace	$60,150	$0	$60,150	4,858	2009
3						
4	Programmable Thermostat	6,480	0	6,480	1,199	2009
5						
6	Weatherization Kits	5,238	0	5,238	N/A	2009
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	$71,868	$0	$71,868	6,057	2009